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Development of a decision support tool for operational optimization of the steam utility system at Preemraff Lysekil

Master's thesis within the Innovative and Sustainable Chemical Engineering programme

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Abstract

Steam is of high importance for an oil refinery. It is used as a heating media and to generate mechanical shaft work. Steam is produced by heat recovery units and steam boilers. The steam boilers are fuelled mainly by internally produced combustible gas (refinery gas). When there is a deficit of refinery gas, Liquefied Natural Gas (LNG) can be imported to use as a make-up. The cost for producing steam is dependent on the amount of purchased LNG to fuel the steam boilers. Work for pumps and compressors can be obtained either by electricity (motor mode) or by steam (turbine mode). This possibility to switch energy source affects the steam balance of the refinery. Furthermore, electricity and LNG prices affect the choice of driver mix that minimizes the refinery utility costs. Thus there is a clear need for a model of the steam utility system that can be linked to a tool for optimizing the operating cost for pumps and compressors.

The basis of this project was a model developed in Aspen Utility Planner in a previous master thesis. This model has been further developed and improved in this project to become easier to use and run from an Excel interface. Furthermore, the model has been improved to better represent the steam network at Preemraff Lysekil.

After an investigation of key variables, such as the production and consumption of steam in the different production units at the refinery, the model was validated against measurements from different operational scenarios.

Steam system simulations can be run through the Excel interface. The Aspen Utilities Planner simulation environment is only required for development of the steam system flowsheet configuration. The model was tested for a number of representative operating situations, and it was concluded that the model provides reliable results for stable operating conditions and also provides results that are within the acceptable error margin for unstable operational situations i.e. when parts of the refinery are shut down, but for these cases the reliability of the model decreases. The optimization function is working and provides solutions that reduce the estimated utility cost. Further investigations should concern investigation of steam system balances during operating situations when parts of the refinery are shut down.

Keywords: Steam system, Optimization, Utility cost, LNG, Refinery gas, Aspen Utilities Planner.

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Sekpoom Kobjaroenkun, Gothenburg, May 2018
Johan Gunnarsson, Gothenburg, May 2018

Notation

Abbreviations

CT	Compressor turbine
FCC	Fluidized Catalytic Cracker
Fuel gas	Mix of refinery gas and LNG, the feed to the boilers
HRSG	Heat recovery steam generators, hot flue gases
ICR	Iso-Cracker reformer
in	Incoming media
LHV	Lower heating value
LNG	Liquefied Natural Gas
meas	Measured value
MILP	Mixed integer linear programming
MINLP	Mixed integer non-linear programming
MWT	Molecular weight
NHTU	Naphtha Hydro-Treating Unit
out	Outgoing media
output	Value calculated by the program
PFD	Process Flow Diagram
Refinery gas	Internally produced combustible gas
SG	Steam generator
VGO	Vacuum gas oil
230	NHTU and Reformer units
810	Hydrogen Production Unit (HPU) and Iso-Cracking Unit (ICR)areas

General variables

f	Fuel
H	Specific enthalpy
I	Current
m	Mass flow
m^3	Volumetric flow
n	Molar flow
P	Power
Q	Energy
re	Refinery gas
s	Steam
tot	Total amount
w	Water
ε	Motor efficiency
η	Efficiency

Pressure levels

VHP	Very High Pressure steam level
HP	High Pressure steam level
MP	Medium Pressure steam level
LP	Low Pressure steam level

Units

€	Euro
°C	Degree Celsius
h	Hour
J	Joule
K	Kelvin
SEK	Swedish Krona
t	Metric ton
U	Voltage
W	Watt

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1
Introduction

1.1 Background

The Paris Agreement signed in 2015 aims to respond to the threat of climate change by limiting the risk of global temperature to well below 2 °C above pre-industrial levels. This will require many different types of action, including reduced energy consumption. In Sweden, industry had a consumption of 140 TWh out of a total final usage of 370 TWh [1] in 2015. According to Preem's environmental report from 2015 [2], Preem had a total fuel usage of 6.4 TWh, this is the contribution from the use of fuel gas, LNG and coke from the cracker unit. Preem AB represents 80% [3] of the Swedish refining capacity, corresponding to 345 000 barrels per calender day [3]. Specific numbers from the agency "Naturvårdsverket" show that Preem Lysekil had CO_2 emissions of roughly 1.4 million tonnes in total in 2016 [4].

Steam is of the highest importance in order to keep the refinery running. Most of the steam is produced in boilers that mainly use residual gases (light non-condensed components) from the process, so called refinery gas, as a fuel. However, if needed or if there are economic advantages, make up gas to the fuel gas system can be obtained by purchased liquefied natural gas (LNG). There is sometimes an excess of steam, which is because the refinery gas has no market value and too much flaring of refinery gas is not allowed due to environmental regulation. Therefore, in periods when there is an excess of refinery gas, it is better for the refinery to produce an excess of steam. Some venting will always occur since producing exactly what is required is operationally difficult. In the refinery steam system, very high pressure (VHP) steam is generated and let down to lower pressure levels and, if necessary, the amount that is not needed is vented to the atmosphere causing an energy loss. Other than letting down steam through the let down valves between each header level, there are machines like pumps and compressors that can be driven by steam turbines or electric motors, depending on steam availability and the economic trade-off between the electricity cost for motor drive and the fuel cost for steam production. The possibility to switch the machines to be driven by steam turbine instead of motor drive can be utilized to increase the steam demand and reduce steam loss from venting. Selecting which pumps and compressors that should be driven by motors and steam turbines is a complex combinatorial problem, which means that an optimization model is useful for making the operation of steam utility system as economically efficient as possible. The amount of steam that needs to be produced will also affect the fuel gas system balance. A more detailed description of the steam network with its main components is described in Section 2.2.

A steam model that reflects the real system well and therefore can be utilized by the refinery to improve their economic and environmental performance. For this reason, Subiaco [5] developed a steam model representing Preem's steam system. However, the model developed by Subiaco [5] is in need of additional validation and further development in order to be useful as a decision support tool for Preem staff.

1.2 Aim and objectives

The aim of this work is to improve and develop the steam system model created by Subiaco [5] into a decision support tool for operational optimization at Preemraff Lysekil. To achieve the aim, the objectives are to:

- validate key variables and improve the model so it better reflects actual operation of the refinery. This will give results that are more reliable and closer to values measured at the refinery.
- make the optimization mode functional, verify its reliability and make it easy to use through the Excel interface,
- develop a user interface for convenient updates of model data according to the most recent process data values,
- develop a basic mapping of the marginal changes in the LNG fuel system due to changes in operation of the steam system,
- develop a better fuel gas system model which will make the estimation of the refinery gas and the LNG consumption more reliable.

The work has been carried out in sequences according to the milestone seen in Figure 1.1.

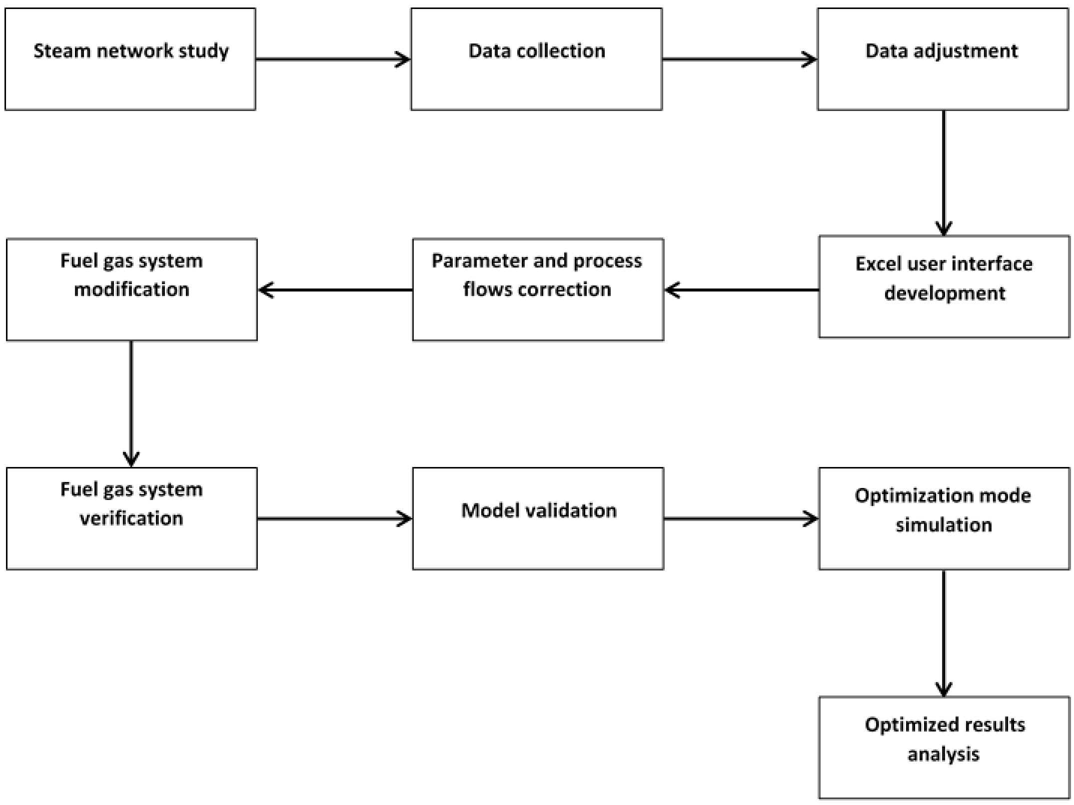

Figure 1.1: Main step in project execution.

1.3 Scope and limitations

The scope of this master thesis is divided into three parts;

1. Validation of steam system model, including fuel gas consumption.

2. Use of the model in optimization mode using Excel interface.

3. Structure and simplify simulation of model and enable updates of most recent process data.

The first and second aspects, validation of the model and using the model in optimization mode, are the most important to achieve reliability and usefulness as a decision support tool for optimization. However, considering the complex steam system with substantial volumes of data together with the limitation of the software, the latter aspect should be done very carefully and properly to make it more convenient for the users and to reduce the risk of human errors.

This master thesis regards the steam system only. It does not take the effects within the process itself into consideration, except for changes in process steam generation and consumption during different operating scenarios.

The model is constructed based on the current design of the steam network at the refinery. Proposed retrofits of the steam network are not taken into consideration.

The model describes steady-state operation. Dynamic situations like start-up and shut-down situations are not considered in this thesis.

1.4 Outline of the thesis

A thorough understanding of the Preem steam network, of the Aspen Utilities Planner and of the original model which are described in Chapter 2, 3 and 4, was a prerequisite for this work. Chapter 5 gives an explanation of how the work was conducted for some specific parts. The model was tuned with operational data which is described thoroughly in Chapter 6. Finally, the validated model was run in optimization mode and the results were analyzed in Chapter 7.

This report includes an final evaluation of the model, summarizing discussions and also conclusions which can be found in Chapter 8, 9 and 10, respectively. Furthermore, to make it easier for Preem staff and Chalmers researchers to use the model, a Microsoft Excel interface was further developed and a user guide was produced. A summarized steam model user guide can be found in Appendix A.

1.5 Literature review on operational optimization of utility systems

The focus of this literature review is to obtain an understanding of the concepts behind the program that is used, present information about actual implementation of similar models at process plants and what are the practical aspects of a steam network that can be included in a theoretical model.

Partly based on the work by Papoulis and Grossmann [6] Micheletto et al. [7] in Sao Paulo in Brazil at RECAP refinery formulated a MILP problem of the refinery's utility system that involved energy and mass balances, the operational status of refinery units connected to the steam system and steam consumption/production of these units. The model was able to decrease the operational costs for the refinery by up to 10% by providing an optimal configuration of the setting of units and also by identifying steam losses and inefficient units. The model was integrated into RECAP's database in order to plan on using the utility system efficiently. This shows that a MILP solver has been successfully integrated into a real operating plant with decreased operational costs and also that it can interact with operational data from a refinery.

As one of three improvements to their plant model, Zhang and Hua [8] suggested to incorporate a MILP model of the utility system in the complete plant system in order to improve energy efficiency. The other two improvements focusing on consumption of the units in the process and balancing the steam, fuel gas and fuel oil for the plant. The model approach including above improvements were implemented in a real industry. This shows that a MILP model of a utility can be integrated with the remaining parts of a process. It also shows that the model in this paper is well built as it also is subdivided, thus decreasing complexity of the flows.

The comparison by Bruno et al. [9] between MILP and MINLP showed that using fixed variables for variables such as pressure and efficiency (MILP) gave results which were considered infeasible compared to the results obtained from the MINLP solver. This is due to the fixed operating parameters in a MILP model, i.e. the flexibility of less fixed variables give a more optimal outcome. In the MINLP, model variables such as temperature and pressure are not fixed and therefore the system becomes nonlinear. According to Bruno, the ability of MINLP models to handle such non linearities gives more reliable results than a MILP model.

A practical approach for making steam systems more efficient and track steam consumption was suggested by Aegerter [10] and Bickham and Wadel [11], where the focus is more on practical issues such as keeping boiler efficiency high, turbine operation and maintenance of equipment in the process. Aegerter [10] argues that, for example, a faulty valve can leak through around 4500 kg/h of steam. The importance of investigating the performance of equipment and pipes and how this is handled by operating staff is highlighted. In this report, the practical aspects for making a steam system more efficient and investigating on the leakage will be taken into the theoretical MILP model.

2

Steam network at Preem Lysekil

The complex steam network at Preem refinery in Lysekil consists of several components and variables that affect the operation of the network. A description of the main components is provided together with examples of research connected to Preem refinery.

2.1 Research connected to the studied oil refinery

In the previous research by Riccardo Subiaco involving the Preem refinery and the steam network a model for simulation and optimization of the steam network was developed [5]. This model is also the foundation and starting point for this thesis. Cristina Murcia Mayo [12] studied in her MSc thesis computer based analysis tools for handling of data for industrial energy systems analysis. Also CIT Industriell Energi AB has, as part of a research collaboration between Preem and Chalmers, conducted pinch analysis study of the refinery in Lysekil [13].

Studies being performed currently include a project by Ph.D candidate Sofie Marton who is using the refinery in Lysekil as a case study for heat integration. The study will investigate a number of retrofits for heat exchanger within the refinery. The retrofits are being investigated in the perspective of operability connected to the changes in the heat exchanger network [5].

Examples of other research projects that have been conducted in collaboration between Chalmers and Preem regarding heat integration [14], bio-refinery with biomass feedstock, chemical looping combustion, automation of heat integration project and catalytic reactions regarding bio-oils. For short descriptions of these projects, see [15].

2.2 Description of the steam system

As mentioned in Section 1.1, steam is one of the most important hot utilities in an oil refinery [16]. It is used both as a heat carrier and a source for mechanical work in the refinery. Steam is in this particular plant produced in steam boilers, heat recovery steam generators (HRSG) and process coolers. The steam network at the refinery consists of four pressure levels, also called headers; very high pressure (VHP), high pressure (HP), medium pressure (MP) and low pressure (LP) [17]. Equipment that works between the pressure levels such as pumps, compressors and blowers are units that can be set in two different modes, motor or turbine. For motor mode, electricity is the source of power and for turbine mode, steam is the source of power. These two modes are not used simultaneously, either the unit is motor driven or steam driven. Figure 2.1 illustrates the general overview of the steam network in the refinery.

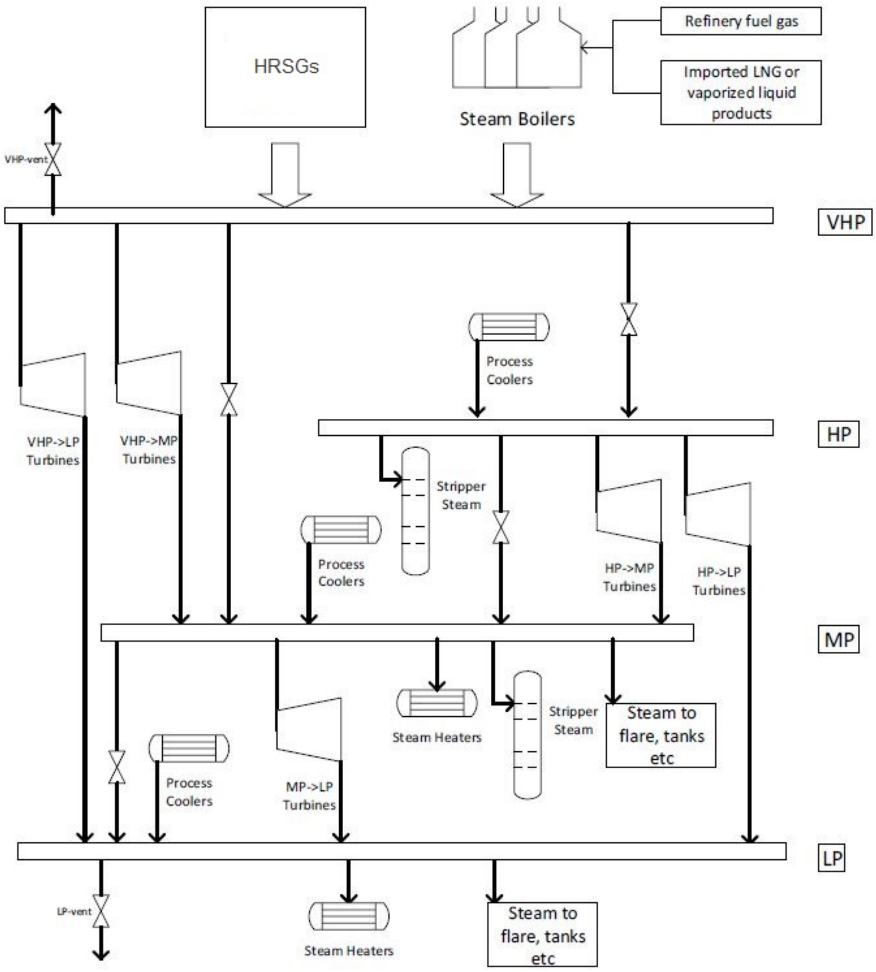

Figure 2.1: The overview of the refinery steam network [17].

The HRSG:s and boilers are the main producers of VHP, there are three boilers and two HRSG:s [5]. HRSG:s produce VHP steam by recovering heat from flue gases. For the operation of boilers, different scenarios for VHP steam can be identified depending on which time of the year it is. The boilers use mainly refinery gas to produce steam and the refinery gas mainly consist of non-condensed lighter substances. The amount of refinery gas obtained will partially depend on the ambient air temperature. In the summer when the air has high temperature, a smaller amount of lighter substances can be condensed compared to the winter. This results in a greater amount of refinery gas. Thus, in summer, VHP steam will be produced mainly by using refinery gas for steam boilers and the HRSG:s are usually not in operation. In the winter, on the other hand, when the ambient air temperature is low, the cooling system operates more efficiently. The amount of refinery gas obtained will generally be less compared to summer. In this situation, the energy demand for the production of VHP steam cannot be covered with refinery gas only. Consequently, purchased LNG is used as a make-up fuel. This leads to the consideration of how to balance the energy demand. A decision between importing LNG and keep producing the same amount of steam or going over to motor driven units is crucial. In the future, the trade-off between LNG and electricity may very well be important all year around, depending on prices and emission restrictions.

The HP steam originates from process cooling and a mixture of steam that is throttled from excess VHP steam. Steam at MP and LP level both have inflows of steam in similar ways, de-pressurized steam from higher pressure levels that has performed work in turbines, from an excess of steam and is throttled and also from process coolers.

As the condensate leaves the LP level, parts of it can be recovered and reused in order to reduce the demand for make-up water. The main lines of the steam system are the headers which are branched out over the entire process (except HP, which is at the new hydrogen producing unit) [5] and then distributes the steam to the consumers i.e. mainly steam heaters. As there are four different pressure levels there are four main headers, one for each level extended along the entire plant and they are connected through the throttles and turbines that act as pressure sinks. Unlike other pressure levels, the HP steam header is a local header which is used only to supply steam at the newest hydrocracker unit [17].

The trade-off between electricity price and the price for LNG is of importance during the colder period of the year since the amount of refinery gas is usually not enough to cover the demands of the boilers during this part of the year. During the cold period of the year the HRSG´s produces larger amounts of steam and the energy content of the hot flue gases produced within the refinery is recovered for steam production thereby making use of energy that otherwise would remain unused.

The environmental regulations also come in as a variable for how to balance the steam production. The combustion of fuel gas through flare stack is one way to reduce the excess steam, however, over-flaring can violate environmental permits. Hence, flaring should be kept within its regulation and consequently the use of fuel gas should be maximized.

2.3 Main components of the steam system

There are several units in the refinery that interact with the steam system. So, understanding of how they interact and affect the steam system is important to follow the procedure of this report.

2.3.1 Steam header

The steam headers are spread out around the refinery, connected to both producers and consumers. Pressure and temperature at the headers are considered constant, however, since it can be some distance between a producer and a consumer these statements are not completely true but the differences are small enough for the assumption to hold. As described in Section 2.2 there are four main headers, of which one is purely for one specific area (810) of the refinery.

The number of steam consumers increases as steam goes to the lower pressure headers. At the VHP header the steam is mainly used to obtain mechanical work for high power demanding units and the use of VHP steam as injection steam is small in relation to the total steam flow at this header. The HP level header is confined to a specific area which is relatively new, and the HP level measurement system is more reliable and tracking the steam easier as this subsystem is less complex. The MP level is similar to the LP level and it is also connected to a high number of heat exchangers. Thus the tracking of steam is more difficult at the MP and LP levels due to the greater number of connections to heat exchangers, direct steam users, and other unidentified and unknown steam consumers.

Steam that is extracted from turbines and let-down valves is super-heated. This means that the temperature is above the saturation temperature. In order to keep the steam at the steam headers at saturation temperature, de-superheaters are used. These units inject water at lower temperature that cools down the steam to the desired temperature.

2.3.2 Steam tracing and steam traps

Steam tracing is the heating of pipes in the process and heating of tanks. The reason for this is to maintain desired temperature of the fluid inside the pipe or tank so that appropriate flow properties are maintained and the fluid can be easily pumped and transported without too high friction losses. The heating demand for steam tracing depends partly on the season of the year and it is difficult to track since there are no flow measurements and the documentation is lacking.

Steam traps are positioned along the steam headers meant for removing condensed steam that would otherwise accumulate within the pipes and affect the steam quality and also be a cause of corrosion. The removal is different from trap to trap, in some traps the condensate is let out to the ground while in others the condensate is expanded to the header below.

2.3.3 Let-down valves

The let-down valves are directly connected to different headers and are used to allow make-up steam from one header to the header below and also to avoid the ventilation of steam at high pressures in case of overproduction. Flow rate equations for these valves can be obtained from Preem´s operational system as a function of the valve opening. These equations are of importance since the flow measurement is not always reliable. By comparing the flow measurement with the valve opening the reliability of the flow measurement can be improved.

2.3.4 Switchable drives

At the refinery there are pumps, compressors and blowers that transport different media. These units are driven using either electricity by motor or steam expansion through turbines. This is designed so that a unit, for example P-3204 has two units A and B where one is motor-driven and another one is a turbine-driven. The setup design can be seen in Figure 2.2.

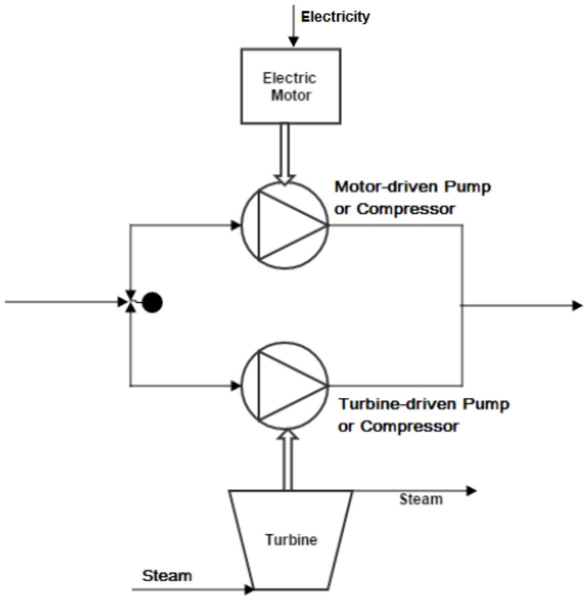

Figure 2.2: The design setup for pumps/compressors, adapted from [5].

However, there are some units that have the setup of two turbine-driven and one motor-driven pump, then a second turbine unit can be added to Figure 2.2. This second turbine can be considered as a back-up unit, i.e. this setting is implemented for units that are fundamental for the operation of the refinery. Examples are the pumps that feed steam producers with water.

Furthermore, there are some units that only utilize either the turbine or the motor during extreme cases. For instance, the blowers for the steam boiler only utilizes the motor unit during start-up since it takes its steam from the boiler which it is connected to. The opposite example is that some units only use the motor since the response is faster. In such cases, the pump is only used partly for keeping a level, in situations like this the motor is the one that is operational and the turbine is started manually when there are longer operational deviations.

The refinery does not measure all the steam that goes through every turbine. However, the current that is used for the motors is measured. As further explained in Section 6.1.3, this, can be used to determine the power demand of pumps and compressors.

2.3.5 Steam boilers and HRSG:s

There are three steam boilers at the refinery. Due to operational security at least two boilers always need to be in operation. If only one boiler would be in operation and there would be an emergency shutdown of that boiler, this would lead to a shutdown of the whole refinery due to a failure from having insufficient steam. The boilers are the most flexible steam producers, HRSG:s are limited by the amount of hot flue gases and the heat exchangers are limited in the same way by the heat content of the hot process stream. Fuel to the boilers can be imported to fit the need for steam production.

The boilers operate within an interval of steam production. Operation at the upper limit is unusual, where an operation close to the lower limit is quite common. There are examples of situations when the boilers, in reality, are operated below the nominal minimum load limit. Thus the value of the lower limit will be of special interest for the model validation, as further discussed in Section 6.1.2.

The HRSG:s have, like the boilers, upper and lower limits for steam production, however if they are shut down they still produce approximately 1-2 t/h of steam as the water is circulated to avoid over-heating and the flue gas is mainly by-passed, the only way to completely stop it is to block the incoming water.

2.3.6 Fuel gas system

Refinery gas mainly consists of light components that are difficult to condense, there are around 20 producers of refinery gas and the majority are vessels and towers. The number of consumers are around 25, mainly furnaces. The production of internal refinery gas partly depends on the ambient temperature, but according to Preem staff there are other factors that affect it as well and it is too simplified to relate the production to outdoor temperature only.

The production of refinery gas is measured and there are also measurements after the refinery gas has been mixed with the imported LNG. After mixing, the measurements are extensive, the variables that are measured are, for example, density and heating value etc. which are controlled.

Preem can, as mentioned in Section 2.2, import LNG when needed, the mix of LNG and refinery gas is the fuel gas which is incinerated in the boilers to create heat for steam production. At times when there is no need for LNG import, fuel gas is only pure refinery gas. At times when the fuel gas is pure refinery gas the amount of produced steam from the boilers cannot be decreased since the refinery gas cannot be stored nor flared excessively due to environmental permits as described in Section 1.1.

3
Aspen Utilities Planner

Aspen Utilities Planner is a part of the Aspen Energy & Utilities Optimization tool, which is an equation oriented tool designed to simulate and optimize utility systems. It also handles economical calculations that are connected to the utility system. Different kinds of utility systems such as power, fuel and steam can be handled in the Aspen Utilities [18]. Like other Aspen programs such as Aspen HYSYS or Aspen Plus, Aspen Utilities Planner creates a flowsheet in which the process is modelled by using blocks that represent different units in the process and also simulates these units' behaviour. In the program there are two modes that can be utilized during steady state simulation, these are: scenario and optimization modes.

In Aspen Utilities Planner there are three kind of variables that can be used; fixed variables, free variables and initial variables.

- Fixed variables are the input parameters needed to be specified. They can be kept constant, for example, the specifications of equipment and efficiencies but some of them i.e. temperature and pressure can be changed by users to test different operating conditions.
- Free variables are the unknown variables which will be adjusted when simulating the model, if the problem is feasible.
- Initial variable are only used for dynamic simulation which is not of interest here.

3.1 Scenario mode

In this mode, the number of fixed variables are less than in optimization mode since the focus is to mimic a certain operational situation and setting in a time period or time point. This mode is a good step before using the optimization tool, this since the results can be used to troubleshoot a model under development. By comparing output values to measured values from Preemraff Lysekil, a hint of how accurate the model is can be obtained, assuming the measured values are reliable. Once the model produces reliable results that are consistent with measured ones the model can be used in optimization mode.

The setting of the units (pumps, compressor etc.) is fixed, as are temperature and pressure at the steam headers, power demand of the units (pumps, compressor etc.), some efficiencies for example for boilers and motor driven pumps, as well as the consumption and production of steam including the boilers. Flow through valves between the headers, LNG flow and water make up to the system are the variables that are used by the solver to solve the mass balances in this mode. Steam flow through units are free variables although constrained by temperature and pressure at the headers, thus making previous mentioned flows the variables that will be used by the solver.

3.2 Optimization mode

The solver used by the Aspen Utilities Planner is a Mixed Integer Linear Programming (MILP) solver. MILP is a mathematical optimization program used for problems with linear constraints, objective functions and a mix of continuous and integer variables.

In this mode there are more free variables than in scenario mode, this is for the solver to have more degrees of freedom. Examples of fixed variables during optimization, some of which are the same as in scenario mode, are; temperature and pressure at the steam headers, power demand of the units (pumps, compressor etc.), some efficiencies for example for boilers and motor driven pumps and the consumption and production of steam excluding the boilers. Example of free variables are flow through valves, steam flow through units although constrained by temperature and pressure at the headers as described in Section 3.1 and boiler steam production.

The solution to the optimization model should be a more cost effective operational setting of the switchable drives that optimizes the trade-off between use of electricity and production of steam to minimize total utility costs. It is not as simple as to say that a low electricity price means that all units should be motor driven or vice versa, the optimal solution will probably include a mix of turbine and motor driven units. For the program to be able to solve such a complex problem, the number of fixed variables needs to be smaller than for scenario mode. Instead, creation of inequality and equality constraints is also needed. An example of constraints in the model are the operational settings of the units in the model, which can be either:

- Available,
- Must Be On, or
- Not Available.

Here, "Available" refers to an inequality constraint while "Must Be On" and "Not Available" are equality constraints. Further examples of constraints are minimum and maximum values for units. These constraints will keep the solver within realistic values, preventing it from yielding values that are nonphysical. However, the constraints regarding steam producing units such as internal coolers and the operational mode for pumps and compressors depend on the operating scenario, hence, the constraints need to be edited by using so-called data editors, see Section 3.2.1.

3.2.1 Data editors

In the data editor, there are basically three kinds of data that the user needs to define in Aspen Utilities Planner i.e. demand, availability and tariffs. Demand is a constraint group of utility supplied or demanded for each equipment. Availability is used to set the on/off constraints as well as the minimum and maximum possible value for each equipment. Demand and Availability profiles can be found in the 'Profile' database. Tariffs are the purchasing or selling price for each utility type that are used in the plant and can be found under 'Tariff'. Besides these three editors, there is a more advanced editor called Demand Forecasting but this capability was not used in this project. Figure 3.1 shows the default editor interface in Aspen Utilities Planner.

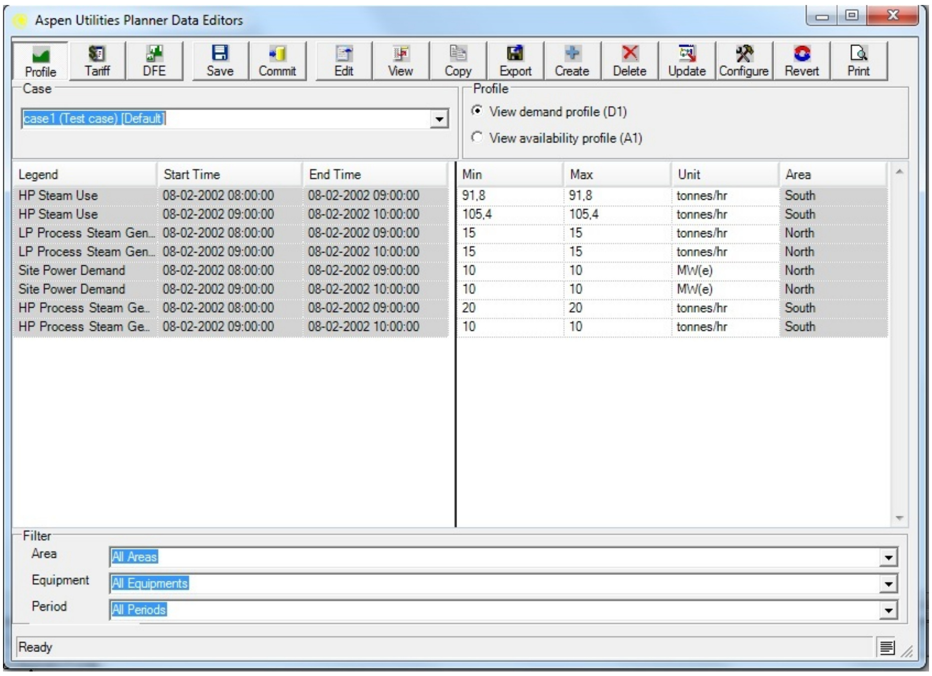

Figure 3.1: Default Aspen Utilities Planner Data Editors.

Aspen Utilities Planner has a default format for each data type and is stored as a Microsoft Access database, Tariff data is stored as a TariffData.mdb, Demand and availability data are stored as a Profile.mdb. There is another database used by Aspen Utilities Planner named Interface.mdb. The interface is used when the optimization mode is run and will collect data from other databases and store the results. Figure 3.2 displays the relationship between the various editors and databases.

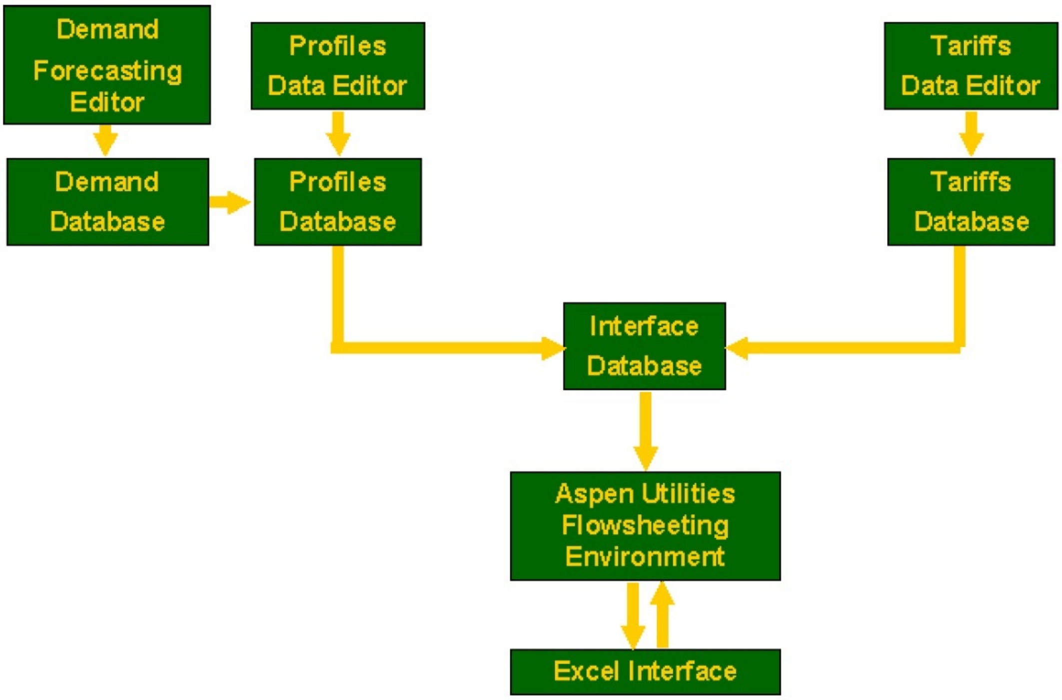

Figure 3.2: Overall relationship between various data editors and corresponding databases, adapted from [18].

A practical problem related to the optimizer solver can be that the simulation is unfeasible. Here, the error diagnostic function, which are presolve error checking and error tracking, can be used to detect the cause of the problem.

The presolve error checking function is used to identify if there are infeasibility errors present, for example, when a variable has its maximum bound smaller than the minimum bound. This kind of feasibility problem is easy to tackle.

On the other hand, there could be other types of error that are much more difficult to detect. This kind of unfeasible error takes place when the mass balance for a process block does not agree and cannot be detected by the presolve function. Another error diagnostic function called "error tracking" is used to deal with the problem. By introducing an additional variable to each balance equation which is minimized in the objective function, the problematic equations and the corresponding blocks will be shown in the message window.

3.3 Microsoft Excel interface

With the use of Aspen Utilities Planner add-ins 'Utilities340', it is possible to connect the flowsheet from Aspen Utilities Planner to Microsoft Excel spread sheet. The users can develop their unique spreadsheet to send inputs and retrieve results, shown in Excel interface. An explanation on how to connect and use Aspen Utilities Planner - Microsoft Excel interface from scratch can be found in 'Aspen Utilities User Guide V8.8' [18].

4

Original model of the refinery steam system

The steam network model from the previous work by Subiaco [5] built in the Aspen Utilities Planner flowsheet can be seen in Figure 4.1 below. In order for the model to be solved correctly using Aspen Utilities Planner, the model was specified as a MILP problem, that is, all constraints and the objective function are linear. As mentioned in Section 3, Aspen Utilities Planner is a program that solves an optimization model and this model has the objective to optimize the operation of the steam system to minimize the operating cost.

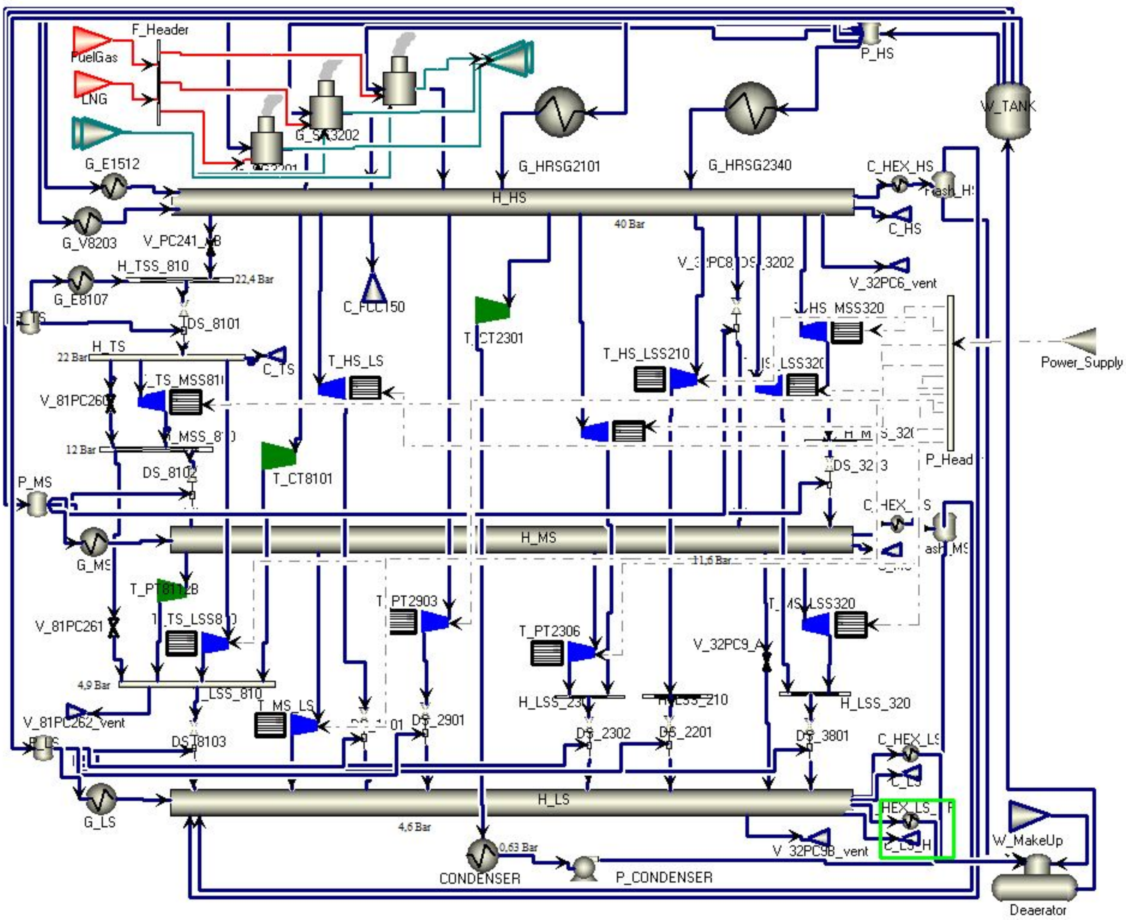

Figure 4.1: The original steam network model [5].

In Figure 4.1, all producers and consumers of steam to, from and in between the steam headers have been modelled. For convenience, consumers and producers of steam that are connected to the same header have been lumped depending on category, for example all the internal process heating at each header is represented by a single condenser, all internal process cooling is represented by an evaporator. Steam consumption that leaves the system, i.e. injections and similar, are represented by a demand block. Also the units that works between the different headers are lumped in order to make overview easier, one pump in Figure 4.1 can represent a number of pumps in reality.

Another practical feature of the model is that the units are lumped together not only depending on between which headers the unit is working, but also according to Preem's own unit classification. This makes it easier for example to trace the steam flow in a specific point in the physical process.

Parts of the system representing steam consumption, such as leakage and other steam consumers for which there is no measurement, have also been aggregated. These are represented in Figure 4.1 as a heat exchanger and a steam demand in the green square at the lower right-hand corner. These two flows are connected to the water balance and affects the variable representing the make-up water to the system.

The fuel gas system in the original model created by Subiaco [5], consists of refinery gas supplier, LNG supplier and fuel header which contains the mixed gases of refinery gas and LNG so-called fuel gas. The fuel gas system was originally modelled assuming a constant LHV of fuel gas and LNG. At Preemraff Lysekil, the composition of the mixed fuel gas is measured by on-line gas chromatograph and after that the LHv and density is calculated based on the composition. The LHV of the fuel gas needs to be converted into mass basis by using its density before feeding to the model. LHV of LNG is not measured but instead its composition is measured, therefore the LHV of LNG can also be calculated.

In the original model created by Subiaco [5], the composition of fuel gas at the header feeding fuel to the boilers was calculated assuming a fixed %LNG by molar composition for a given scenario. The LHVs of both refinery gas and LNG were specified as fixed values as can be seen in Table 4.1.

Table 4.1: LHVs of refinery gas and LNG from original model.

Fuel	LHV[MJ/kg]
Refinery gas	37
LNG	45

With the LHVs, molecular weights of both refinery gas and LNG, and the percentage of LNG in the fuel gas together, the heat provided from the relationship between the refinery gas and LNG in the original model created by Subiaco [5] was calculated from Equation 4.1.

$$\begin{aligned} n_{LNG} &= \%LNG \times (n_{LNG} + n_{re}) \\ \frac{Q_{LNG}}{LHV_{LNG} \times MWT_{LNG}} &= \%LNG \times \left(\frac{Q_{LNG}}{LHV_{LNG} \times MWT_{LNG}} + \frac{Q_{re}}{LHV_{re} \times MWT_{re}} \right) \end{aligned} \tag{4.1}$$

Regarding variables in the original model, they are built up similarly to the descriptions in Sections 3.2 and 3.1. The number of fixed variables depends on the type of simulation. Variables that are always fixed are temperature, pressure, steam production from process cooling and steam consumption for injection and process heating. During scenario mode simulation, the operational setting of pumps and compressors are also fixed, as well as the steam production from the boilers. In optimization mode, the operational setting of pumps and compressors can be set freely and also the steam production from the boilers, within the constraint boundaries. For a more detailed description of the original steam system model, see [5].

For the original model created by Subiaco [5], an Excel interface was available for running the model and structuring the resulting output. However, running simulations from the Excel interface was limited to scenario mode simulation runs only. The optimization mode could not be operated from the Excel interface. In this project, Excel spreadsheets where new scenarios could be added and a simplified flowsheet of the steam network existed and have been further developed.

5
Methodology

5.1 Initial studies and planning

As mentioned in Section 2.1, the basis of this project is the model developed by Subiaco [5] and therefore a thorough review of that report was essential to understand what kind of problems needed to be tackled in this thesis. Furthermore, a comprehensive understanding of the steam network at Preem refinery and a basic understanding of the refinery process was necessary, see Section 2.2.

In order to work with and understand the original model, a thorough study of the structure of Aspen Utilities Planner was conducted. The study of the program combined with the thesis report of Subiaco [5] provided knowledge about how the original model was built and the ideas behind its construction.

A more general literature review of examples where similar models were investigated and implemented was also conducted. Also the practical aspects that are of importance when investigating a real process were reviewed. Both of these topics were described in Section 1.5.

5.2 Verification of parameters

Validation of the model was achieved by identifying key variables in the system and re-check the values and constraints that Subiaco [5] calculated. Results and variables that were investigated are presented in Section 6.1 together with a comparison of the values used by Subiaco for the same variables.

5.3 Data collection

The data collection started by gathering the data tag for each equipment that is related to the steam network. This was carried out in collaboration with Preem's staff. Meters for flows, temperature and pressure are spread around the plant. They measure up to 3 times a second and the data are directly send to the control room and stored in different temporal resolution. A process diagram showing the location of all data collection points within green circles is presented in Figure 5.1. The producers and consumers for each header are lumped together and are represented by a single producer and a single consumer.

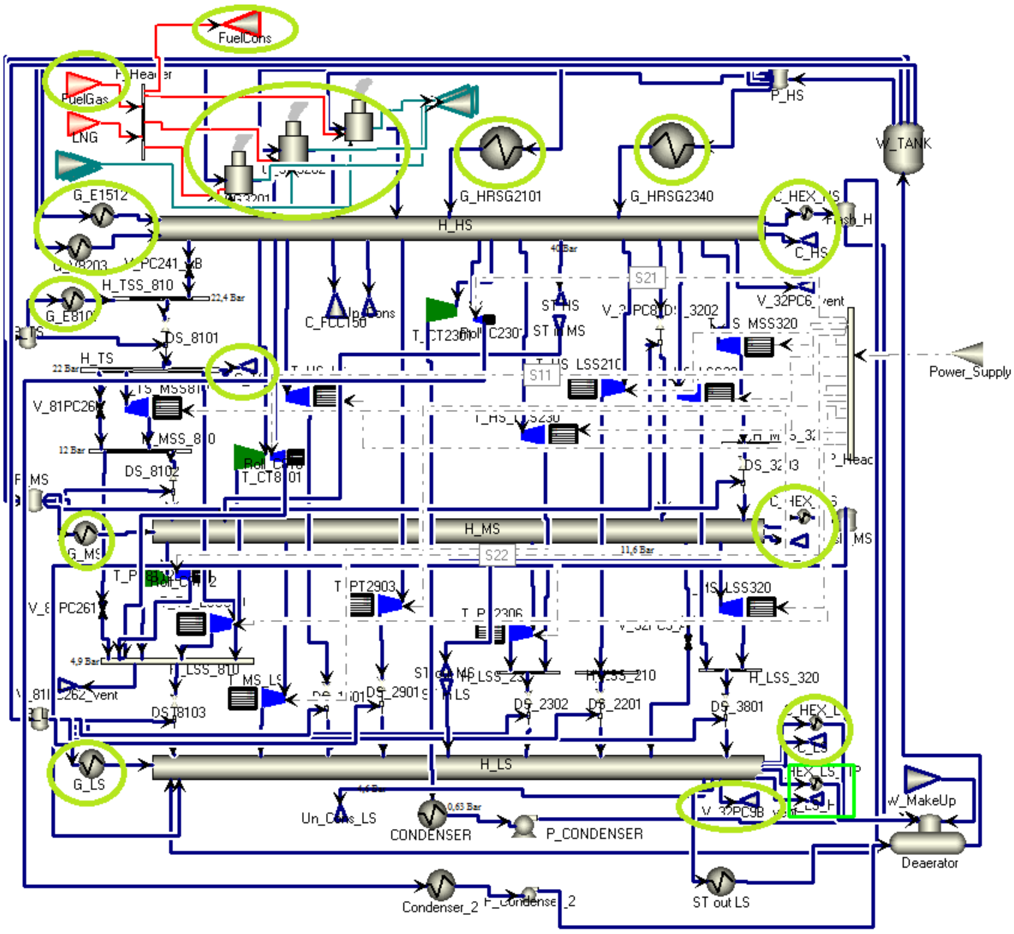

Figure 5.1: Process flow diagram showing data collection points

In order to import the data into the Excel interface, an Aspen Excel Add-in called "Utilities340" is used. With the function 'Current value', it allows the user to extract the actual value that is stored at that moment without averaging. For situations where there is no data available, see Subiaco [5].

Once all required tags were gathered, an Excel workbook was created for importing and structuring the data values. In order to avoid issues with data updating during optimization, this was done in a separate workbook and not included in the Excel workbook serving as the Aspen Utilities Planner interface. This workbook contains two spread sheets; 'Current data extract' and 'Current data summary'. The first sheet contains all the tags that are categorized into producers and consumers for each pressure header level. The other one contains a summation of each headers producers and consumers, which is structured similarly to the sheet used for simulation. An overview of the summary sheet can be seen in Figures 5.2. For more details, see Appendix B and Figure B.1.

SCENARIO SELECTION					Current	
					16	
					2018-06-09 11:40	
Section	Description					
Fuel	Fraction of LNG	6,74	%		6,74%	
STEAM PRODUCTION HS	Boiler 3201	0,36	Tonne/Hr		0,00	Tonne/Hr
	Boiler 3202	10,86	Tonne/Hr		10,86	Tonne/Hr
	Boiler 3203	26,75	Tonne/Hr		26,75	Tonne/Hr
	HRSG2101	26,07	Tonne/Hr		26,07	Tonne/Hr
	HRSG2340	22,44	Tonne/Hr		22,44	Tonne/Hr
	E1512 for HPS	27,74	Tonne/Hr		27,74	Tonne/Hr
	V8203 for HPS	32,33	Tonne/Hr		32,33	Tonne/Hr
TS	E8107 for TS level	47,00	Tonne/Hr		47,00	Tonne/Hr
MS	Production MPS	149,71	Tonne/Hr		149,71	Tonne/Hr
LS	Production LPS	26,25	Tonne/Hr		26,25	Tonne/Hr
HS -> Condenser	Load Factor CCR Turbine	90,00	%		90,00%	
HS -> LSS810	Load Factor ICR Turbine	93,12	%		93,12%	
HS -> LSS320	CT-3402	0	1		Motor	
	PT-3801 A	1	0		Turbine	
	PT-3802 A	0	1		Motor	
HS -> LSS230	PT-2310 A	0	1		Motor	
	PT-2305 B	0	1		Motor	
HS -> LSS210	PT-2102 B	1	0		Turbine	
	PT-2102 C	0	1		Motor	
	PT-2103 B	0	1	1	Motor	
	PT-2104 A	1	0		Turbine	
	PT-2107 A	0	1		Motor	
	PT-2201 B	0	0	1	Motor	
	PT-2202 B	0	1		Motor	
	PT-2203 A	0	1	1	Motor	
HS -> LSS	PT-2903	0	1		Motor	
HS -> LS	CT-1525 B	0	1		Motor	
	PT-3202 A	0			Motor	

Current data extract | Current data summary

Figure 5.2: Current data summary

5.4 Creating scenarios

In addition to the six scenarios created by Subiaco [5] (Scenario 0-5), eleven more (Scenarios 6-16) were created in this study. Of these the last one represents the latest data collected. Consequently the total number of scenarios are 17. The scenarios were selected to reflect different operational situations such as, parts of the refinery being shut down, stable operation with high utilization of refinery capacity and different data averaging periods for same operational situation.

The scenarios that were chosen to validate the model were 2, 3, 6, 8, 10 and 12 where 6 and 8 are based on a different averaging time compared to 10 and 12 respectively, see Sections 6.4.1.3, 6.4.1.4 and Table 5.1. These scenarios were chosen since they represent different operational situations at the refinery and at different times in history. Scenarios number 2 and 3 were created by Subiaco and the data was collected at different times in 2015; the data was also collected at a specific time point, the values obtained were not averaged. Scenario 2 represents stable operation in July with all the major units in operation, while Scenario 3 had both HRSG:s and CT-2301 shut down in April and thereby the major parts of the 230 area were shut down. This scenario was chosen to test if the model can simulate the process during periods of major disruption.

The data for Scenario 10 was collected in January 2018 when the refinery was at full operation with high utilization of refinery capacity. Scenario 12 represents operating conditions in April 2017 when the FCC area was shut down thus representing an unusual operational situation. The data for these two scenarios were averaged over one day. Scenarios 6 and 8 reflect data from the same time period, but averaged over a week, in order to observe the importance of averaging.

The problem that arose when averaging steam flows was that the operational setting of pumps and compressors also needed to be averaged. Some of these units can be changed several times per day when the operating personnel attempts to lower steam venting. Therefore when great excess or deficit of steam was found, an investigation of the operational mode of high power demanding units was done in order to make sure that averaging the operational mode of pumps and compressors would not affect the results to a large extent. The averaging was done using the mode of the pump or compressor that was most often in use during the chosen time interval.

The results from the validation part were used to decide which scenarios would be used to test the optimization function on the new model. For further description see Section 7.3. In Table 5.1, the basic information about the scenarios used in the validation is described and in Appendix F the same information is presented for all scenarios.

Table 5.1: Basic information for all scenarios.

Scenario	Operational situation	Averaging time	Creator/ creators	Time span/ dates
0	Free	-	Subiaco	-
1	Stable	Instant	Subiaco	13/9-2015 (3.10 AM)
2	Stable	Instant	Subiaco	14/7-2015 (2.50 AM)
3	HRSG:s and 230 area down	Instant	Subiaco	16/4-2015 (3.10 PM)
4	SG2101 and ICR down	Instant	Subiaco	12/1-2016
5	Stable	Instant	Subiaco	13/9-2015
6	Stable and high utilization	1 week	Gunnarsson and Kobjaroenkun	(2-8)/1-2018
7	Stable and high utilization	1 week	Gunnarsson and Kobjaroenkun	(22-29)/12-2017
8	FCC unit down	1 week	Gunnarsson and Kobjaroenkun	(1-4)/4-2017
9	ICR and HPU down	1 week	Gunnarsson and Kobjaroenkun	(16-22)/5-2016
10	Stable and high utilization	1 day	Gunnarsson and Kobjaroenkun	3/1-2018
11	Stable and high utilization	1 day	Gunnarsson and Kobjaroenkun	23/12-2017
12	FCC unit down	1 day	Gunnarsson and Kobjaroenkun	2/4-2017
13	ICR and HPU down	1 day	Gunnarsson and Kobjaroenkun	17/5-2016
14	VDU, ICR, HPU and FCC down	1 day	Gunnarsson and Kobjaroenkun	10/3-2018
15	VDU, ICR HPU and FCC down	1 day	Gunnarsson and Kobjaroenkun	16/3-2018
16	-	Latest values	Gunnarsson and Kobjaroenkun	-

For the scenarios that were not used in the validation process there were different reasons; Scenario 0 was not used due to it is used to test the change in system by manual input from the user. Scenario 1 was not used since it should be enough to pick one stable operating condition case from Subiaco. Scenario 4 was not used due to unsteady-state operating conditions. The remaining scenarios (Scenarios 7,9, 11, 13-16) created by Gunnarsson and Kobjaroenkun were not used since it was considered that they would not provide new results compare to the scenarios that were used. However, insights from the results from the other scenarios were further strengthened by analysis of Scenarios 1, 7 and 11, see Section 6.4.1.5.

5.5 Tuning of data

5.5.1 Steam mass balances over headers

In order to make the model as accurate as possible, mass balances over the VHP, MP and LP headers were set up. From the discussions with Preem staff and supervisors at Chalmers, it was decided that an error less than 10% of the incoming steam flow to the header would be acceptable, see Equation 5.1.

$$Error_{mea} = \frac{|m_{tot_{in_{meas}}} - m_{tot_{out_{meas}}}|}{m_{tot_{in_{meas}}}} < 10\% \quad (5.1)$$

Equation 5.1 indicating the measurement error was used to assess the deviations over a whole header. An indication of measure of model error can be seen in Equation 5.2 which was used to check the error for a specific flow or unit. Equation 5.2 was used primarily for the let-down valve flows.

$$Error_{mod} = \frac{|m_{meas} - m_{model_{output}}|}{m_{tot_{in_{header_{meas}}}}} < 10\% \quad (5.2)$$

It is assumed that, on each header level, there are steam flows that either leave the system or are let down through let down valves or turbines to the following header level and all of them are not measured. The unmeasured steam flows can, together with possible measurement errors, be aggregated into a parameter representing the mining and erroneous measurements which is set to the difference between the measured incoming and outgoing steam. In the model, these unknown steam flows were lumped together and represented by an additional steam consumer block for each header which has a constant value independent of scenario. The mass balance calculations were done based on the measured steam flows from Preem and estimated steam flows through operational turbines and the results are presented in Section 6.1.5.

5.5.2 Comparison with the validation results from the original model

It was decided to make a comparison between validation results for Scenarios 2 and 3 from the original and new model versions. The reason for this was to observe how the changes in the model and in the data for steam flows affect the validation. The comparison between the original and the new model is based on the latest version from Subiaco [5]. With the original model version, the changes in the new model will be compared with the starting point of the model in this project, as the results by Subiaco [5] could not be reproduced with the original model version. The results from these comparisons can be seen in Section 6.4.2.

6
Validation of model

The validation of the model is divided into different parts, the first part being checking of important parameter values, verifying flows and checking the reliability of measurment sensors. The second part is to validate the model against operational data sets from the refinery, so called "scenarios".

6.1 Verification of model parameters and process flows

This section describes the updates and corrections of model parameters that have been implemented in the new version of the model.

- Variables such as efficiencies.
- Constraints for steam producers such as the boilers.
- Power demand of pumps and compressors.
- Operational possibilities of pumps and compressors.
- Verification of steam demands at steam headers for process steam consumers, valves and other non-measured steam use.

6.1.1 The feedwater temperature

In the original model, the temperatures of the feedwater flows to the boilers were set to ambient temperature and therefore the enthalpy increase for the water was too high, thus overestimating the amount of fuel needed for the boilers. This was corrected to 115 °C after discussion with Preem staff and supervisor at Chalmers. This change gave a more accurate fuel consumption when comparing the model value to the measurement value. Table 6.1 shows the effect after changing the feed water temperature from 25 to 115 °C for one of the scenarios.

Table 6.1: Effect of feedwater temperature on fuel consumption.

Variables	Before	After	Measurement
Feedwater temperature [°C]	25	115	-
Total fuel consumption [Sm^3/h]	22261	21844	21625

6.1.2 Boilers

The efficiency of the three boilers were set to the same constant value, calculated according to Equation 6.1.

$$\eta = \frac{m_s(H_s - H_w)}{m_f LHV} \tag{6.1}$$

Where η is the efficiency of the boiler, m_s is the mass flow of steam, H_s is enthalpy of steam, H_w is enthalpy of the water entering the boilers, m_f is the mass flow of all the fuel to the boilers and LHV is the heating value of the fuel to the boilers.

The enthalpy values for the incoming water and outgoing steam are assumed to be constant since the pressure and temperature of the feedwater and VHP steam are controlled and rather constant. A study of the steam and fuel flows showed that they are strongly correlated, thus meaning that the efficiency is constant. The validation of boiler efficiency was performed done by plotting the nominator against the denominator from equation 6.1 and the results can be seen in Figure 6.1.

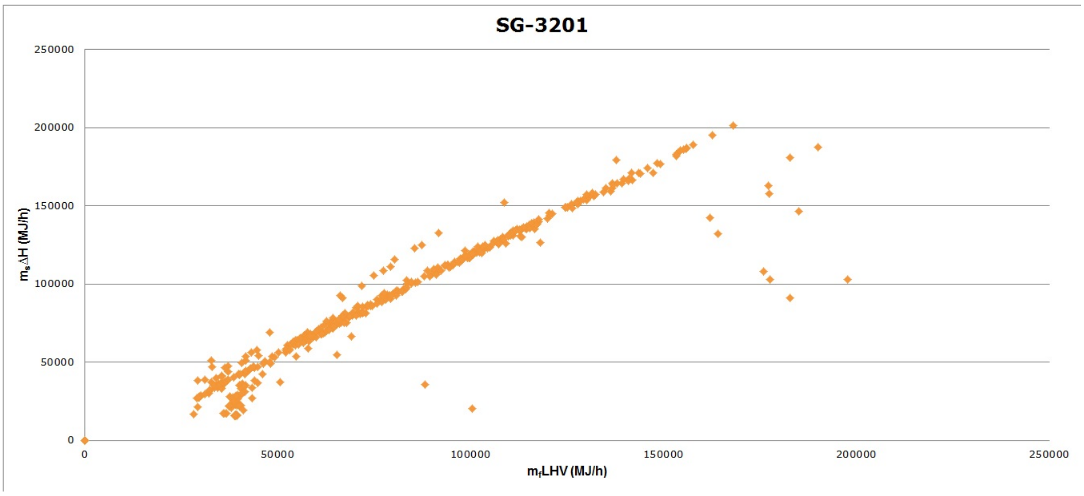

Figure 6.1: Relationship between steam production and fuel consumption.

It is clear to say that the relationship between the production of steam and the consumption of fuel is linear and the line intersects at the origin point. The slope of the straight line implies the constant efficiency of 88% of the boiler and the efficiency is independent on load. Outliers in Figure 6.1 can be because of start up or shut down of the boiler, during which fuel feed is increasing or decreasing substantially. Most of the outliers in Figure 6.1 correspond to a high value of fuel energy input while the energy consumption for steam production is low, this indicates a dynamic operation where the steam production has not yet responded. Figures for the remaining two boilers are presented in Appendix C.

To study the effect of the LHV value on the boiler efficiency, the efficiency was plotted against the LHV in Figure 6.2. Figure 6.2 shows no clear dependency between the efficiency and the LHV, which means that the boiler efficiency is independent of fuel LHV, at least within normal range of variation.

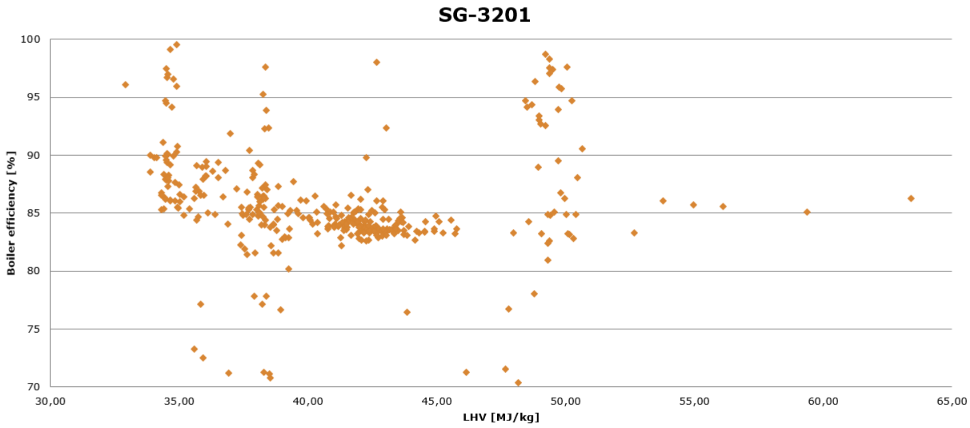

Figure 6.2: Boiler efficiency against LHV value for SG3201 boiler.

Constraints regarding the boilers were investigated and the maximum and minimum production for each boiler were identified, they are presented in Table 6.2. Although the production is rarely as high as 90 t/h, the value can be reached according to Preem staff. The lower limit is of more importance since the boilers more often operate close to their respective minimum load. The difference in minimum load between the original and the updated model is important since the refinery staff wants to have two boilers operational at all times since it is a severe operational risk to only use one. At the same time, overproduction of steam is not desirable and looking at Table 6.2 there will be a large difference in production if for any combination of boilers operated together.

Table 6.2: Load constraints on the steam boilers after modification, Subiaco values in parenthesis.

Process unit	Maximum load [t/h]	Minimum load [t/h]
SG3201	90 (50)	12 (20)
SG3202	90 (50)	12 (20)
SG3203	90 (50)	24 (20)

In addition, in the original model from Subiaco [5], a correction factor denoted "Performance Factor" in Aspen Utilities Planner was used in SG3202 boiler and set to 0.74 for the validation purpose. The performance factor acts like an additional boiler efficiency which should already be included when the boiler efficiency was calculated and also the definition of the performance factor remained unclear. Therefore, in this work, it has been considered that the performance factor should be set to 1 for all the boilers and would not be used as a tuning parameter anymore.

6.1.3 Pumps and Compressors

The power output required from a turbine for a pump or compressor in turbine mode was assumed to be equal to the power requirement from the motor when the pump or compressor is in motor mode. The current used by a motor unit is measured at the refinery and the power can be calculated using Equation 6.2.

$$P = \sqrt{3} * U * I * cos(\varphi) * \varepsilon \tag{6.2}$$

Where P is the power demand, U is the voltage, I is the current, $cos(\varphi)$ is the power factor which for most pumps and compressors could be obtained from manufacturing data and otherwise an estimation was made in collaboration with Preem staff and ε is the motor efficiency. The losses in a turbine are accounted for by the isentropic efficiency and in Aspen Utilities Planner there is no isentropic efficiency but the enthalpy levels used in the model are the real ones which mean that losses are already included. The losses in a motor is accounted for by the motor efficiency (ε) this can be entered into Aspen Utilities Planner. Comparison between the power demand values obtained using Equation 6.2 and the values used by Subiaco showed some deviant values but at least 75% of the pumps and compressors were within 10% limit. Units that were deviating significantly have already been corrected. The values for power demand of pumps and compressors in Subiaco's model seem to be the maximum load based on manufacturing data from Preem.

The configuration of parallel pumps and their possible operations are of importance. In some cases, there are three pumps for one task, A, B and C where two of them are driven by turbines and the third is a motor. This setting is for pumps and compressors that are essential for refinery operation such as boiler feedwater pumps. Only one of the three pumps is in operation at a time, when a turbine is set to not be in operation the solver will take it as the motor is in operation. In cases where there are more than one turbine, this will cause errors since electricity and/or steam demand that should be excluded will be included in such a case. This will affect the results and can be seen as not feasible. This problem has been solved solved by setting the power demand of the extra turbine to zero, in this way there would not be an effect if the turbine is considered to not be in operation. Similarly for turbines that are only operational during start up and shut down the power demand was set to zero.

A by-pass flow over all turbines has been added to the model in the new version. For safety reasons, each turbine is equipped with a by-pass which was not included in the original model. The by-pass is needed to make the turbine spin even if the operational mode is motor. The amount of by-pass steam is small for each turbine and documentation is inadequate, but by using information from the new VGO project and making an estimation based on the power demand of the pumps, the amount of steam by-passed for each turbine was estimated.

6.1.4 Let-down valves

The constraints for the let-down valves between the headers were set to more realistic values based on the manufacturing information, but also by plotting the flow as a function of the valve opening and thus obtaining an equation that could be used to verify the maximum and minimum flows of the valve. An example of the impact from faulty measurements at the let-down valves and how the equation for steam flow as a function of valve opening was used to check the accuracy of the steam flow can be seen in Section 6.4.

6.1.5 Correction of steam demands at headers

The values of the steam demands at the different headers (heat exchangers, strippers, etc.) obtained by Subiaco have been checked and some discrepancies were detected. It is obvious that the FCC unit consumes steam from the VHP steam header but in the model this steam demand was included twice. The steam tracing at the MP header for heating of pipes and tanks were included and entered as consumption of steam in the original model version. The steam tracing for tanks was judged to be modelled correctly. However a discrepancy was identified for steam tracing of the pipes. The steam condensate from this steam trace concerning the pipes is recycled back to the water system and should therefore not be added to the consumption of make-up water. Steam tracing to the tanks however is a consumption of make-up water. This was incorrectly modelled in the original model version and has now been corrected.

Another error in the original model was that the deaerator was considered to consume approximately 12 t/h of LP steam, but the steam that is consumed in the deaerator is determined by the vapour/liquid equilibrium in a condensate vessel. This production of steam from equilibrium was not accounted for as a steam producer in the model, thus the consumption of this steam should not be included in consumption of steam in the model either. As the LP steam enters the deaerator, it is condensed and used as feedwater to steam producers. Therefore the whole process can be considered as an internal circulation of steam and condensate and should not be considered as a pure consumption.

After correction of inconsistencies in the modelling of some steam consumers, the mass balances for the steam headers were evaluated. This showed that for the four scenarios mentioned in Section 6.4, there was often an excess of VHP steam, thus indicating an unknown consumer at this level. The MP level generally showed a deficit of steam but adding an unknown producer of steam was considered to be unrealistic and consequently the difference between production and consumption was assumed to depend on the quality of the measurements. At the LP level there was an excess of steam which was also to attribute an unknown consumer. For the HP steam header, mass balances were only calculated for the first three scenarios. This since this header has more free variables than the other headers and is also connected to a smaller number of units, thus the mass balances were for these three scenarios well within the 10% limit, as defined in Section 5.5.1 it was decided to accept the model for this header without adding any additional parameters representing unknown steam flows. The extension of the model in the form of consumers, inflows and outflows can be seen in Table 6.3 and the new flowsheet can be seen in Figure 6.4.

Consumption of steam is considered to leave the system while outflow and inflow are steam flows between two headers, so the outflow from VHP header is equal to the inflow to MP header. The values shown in Table 6.3 were obtained by trial- and error to make sure the error according to Equation 5.1 became less than 10%. The combination of values shown in Table 6.3 is not a unique solution to make the system deviate within 10% limit. There could possibly be other combinations that result in the balance within the boundary but not all combinations were tested. However, this is the solution that gives the overall best results of the combinations that were tested, by using trial and error and also finding a combination that fits the most scenarios the values in Table 6.3 was selected. These steam demands and steam flows were not included in the original model by Subiaco. Subiaco assumed that all undefined outflow from the system flows from the LP level, this flow were retained as it was in the original model since that parameter influences the water make-up balance. Insertion of these steam parameters made the model better match more scenarios. The values can be regarded as tuning parameters for the model. These parameters were inserted at VHP, MP and LP header. VHP and LP header were given unknown consumptions and the unknown inflows and outflows were added between VHP-MP, MP-LP and LP-deaerator, see Table 6.3. The total inflow of steam to each header level is presented in Table 6.4.

Table 6.3: Additions to model in form of a constant flow to miscellaneous unspecified steam consumers.

	Steam leaves system	Steam from header to header	
Header	Consumption [t/h]	Outflow [t/h]	Inflow [t/h]
VHP	10	1	0
MP	0	5	1
LP	10	3	5

Table 6.4: Total inflow of steam at each header in t/h for Scenarios 2, 3, 10 and 12.

	Total inflow to each header [t/h]			
Header	Scenario 2	Scenario 3	Scenario 10	Scenario 12
VHP	153.4	104.8	144.2	134.6
MP	186.1	92.2	198	168.3
LP	221.7	174.7	199.3	205.5

Not every header for every scenario is within the 10% error, there are a few scenarios where the error is around 15%. The reasons for this large deviation are from the operational status of the refinery and reliability of the valve measurements. When parts of the refinery are shut down the fixed values from Table 6.3 deviates more from their true values. This is because flowmeters can get saturated with condensate and the measurement devices can be by-passed. Hence values for the let-down values become unreliable. By plotting the steam flow through the valve together with valve percentage opening the reliability of the valve can be determined. An example of the reliability of the let-down valve between VHP and MP header can be seen in Figure 6.3, which is from Scenario 12. The red line represents the opening percentage of the valve while the orange line corresponds to the amount of flow in t/h. It is clear that at the end of the time span, the valve is around 21% open but the flow is 0 t/h despite a pressure difference of 28.4 bar. The staff at Preem also stated that specifically the valve between VHP and MP header has a minimum setting of 4% in valve opening which corresponds to approximately 7 t/h. This constraint has been added in the new version of the model, but it is considered a weak constraint which means that the solver can override it in order to solve fundamental equations for example mass balances. The lower limit value of 7 t/h has been used when measurement values have been < 7 t/h when calculating mass balances. When using the model for optimization the measured value for the let-down valves will not need to be considered, however if the parameters would be tuned in the future, it would be important to keep in mind the reliability of the flowmeters at the let-down valves.

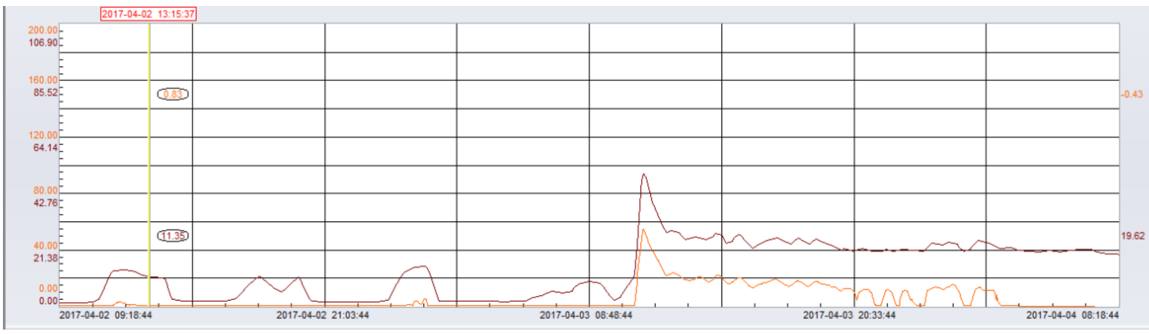

Figure 6.3: Let-down valve between VHP and MP header for Scenario 12. The red line represents the opening percentage of the valve while the orange line corresponds to the amount of flow in t/h.

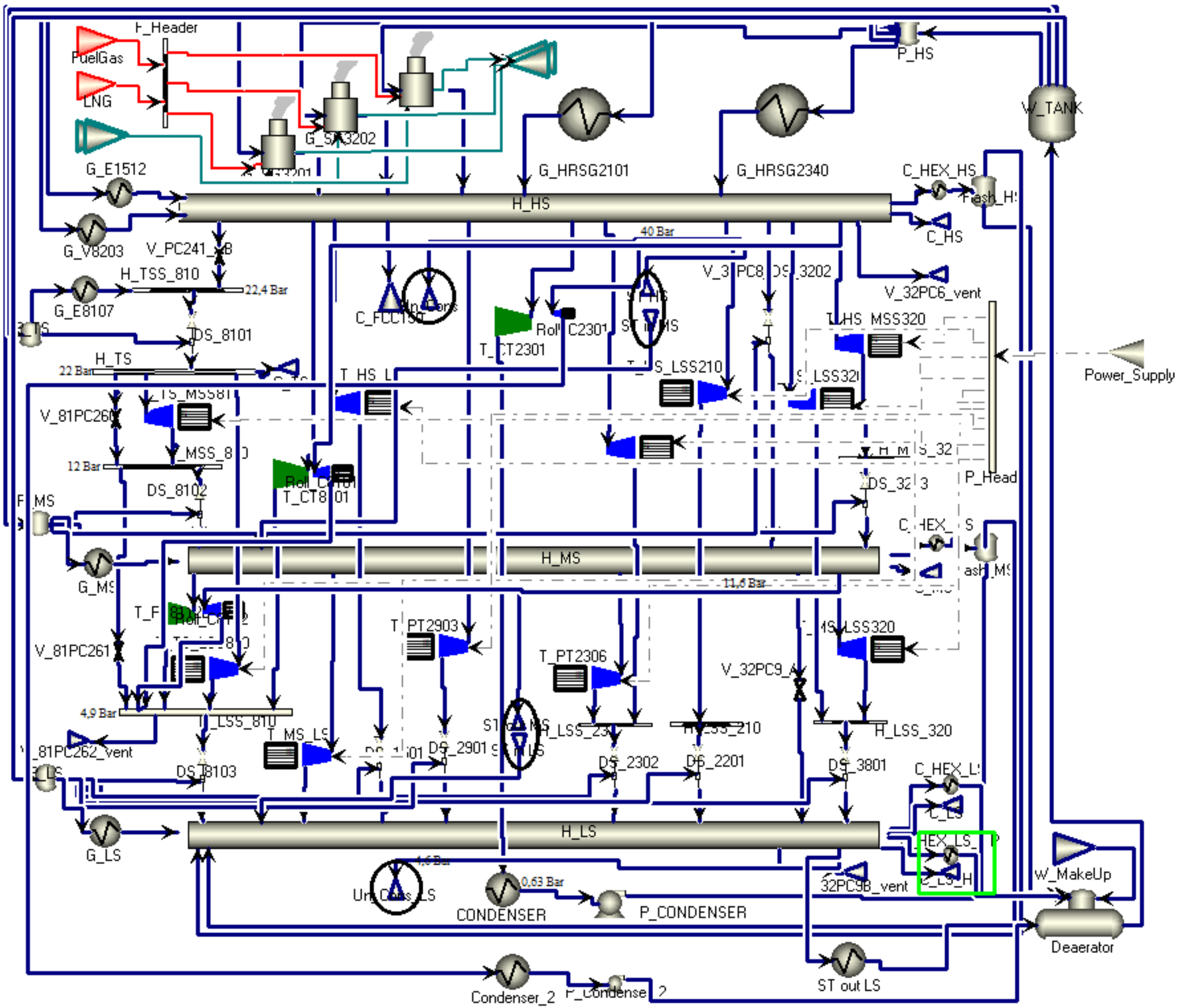

Figure 6.4: The steam model after adding undefined steam flows, circled in black.

6.1.6 Conversion factor

In the original model version it was discovered that the wrong conversion factor between standard cubic meter (Sm^3) and normal cubic meter (Nm^3) had been used. From the discussion with Preem staff, the definitions for Sm^3 and Nm^3 at Preem are 15 °C, 1.01325 bar and 0 °C, 1.01325 bar, respectively. By using Equation 6.3, T_1 is 288.15 K and T_2 is 273.15 K. This provided a conversion factor of 1.0549 $\frac{Nm^3}{Sm^3}$.

$$\frac{V_1}{V_2} = \frac{P_2 \times T_1}{P_1 \times T_2} \tag{6.3}$$

6.1.7 Investigation on LHV of fuel gas and LNG

One improvement that has been done was to set the LHV for LNG and fuel gas to have specific values for each scenario. This improved the precision and accuracy of the model.

Based on an investigation conducted two years ago shown in Figure 6.5, it is reasonable to set the LHV of LNG (orange values) as a constant value approximately 45 MJ/kg. On the other hand, the LHV of mixed fuel gas (green values) varies within the range of 34-46 MJ/kg, which has a significant effect on the duty of boilers. This variation is obviously from the LHV of the refinery gas which is not measured. So, the first modification done in the model of the fuel gas system was to have the LHV of fuel gas as a variable whose value needs to be imported for every scenario.

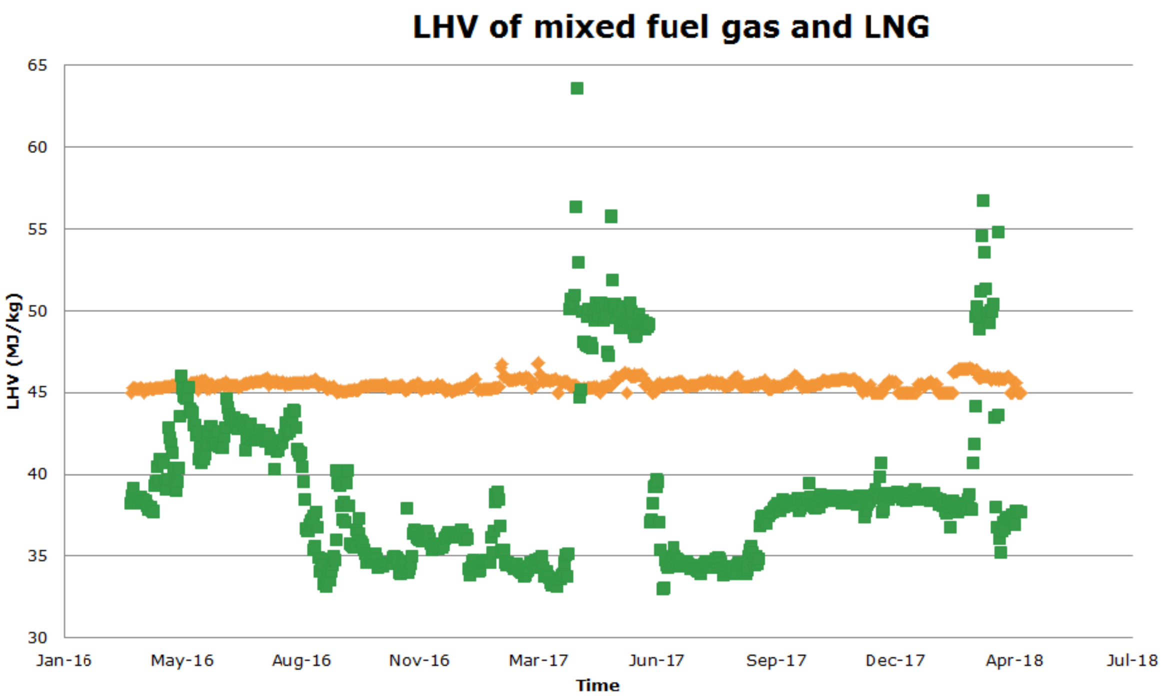

Figure 6.5: The LHVs of the fuel gas and LNG where the orange and green represent LNG and fuel gas mix, respectively.

Further investigation of the fuel gas system revealed that it was not adequate to model the supplied refinery gas and LNG flows by a fixed LNG % by volume. The purpose of the optimization is to find an opportunity to run the whole steam system network with minimum operating cost including a possibility to be operated with a reduced use of LNG. Coupling fuel gas and LNG by a constant ratio could not yield such results. The improved model of the fuel gas system was performed so that the amount of refinery gas supplied to the steam boilers and other consumers cannot change, it is a constant value and only the flow of LNG changes. These values can be retrieved from Preem process data, by setting the amount of the refinery gas to a fixed value the model became more realistic. Moreover, this change also gave better results for the total utility cost calculation from optimization mode since in the original model the cost for LNG was calculated based on the flow of fuel gas. The result after the improvements in the fuel gas system is shown in Section 6.3.2.

Regarding the LHV of the fuel gas it was discovered during the data collection that the LHV of fuel gas became unrealistic for some of the scenarios. The LHV of the fuel gas from the measurement is in volume basis and seems to be quite stable. Although when it is converted to mass basis, the value starts to deviate. These deviations was observed when the density of the fuel gas became low, approximately lower than 1 kg/m^3. The LHV then became higher than the LHV of pure LNG. This was considered unrealistic since the major component of fuel gas is the refinery gas which has a lower LHV than LNG. It was assumed that the density value is not always reliable and a method to tackle this problem was introduced. For Scenario 8 and 12 in Sections 6.4.1.4 and 7.4.3, the calculated LHV of the fuel gas were 48.2 and 50.3 MJ/kg, but they were changed to be 35 and 38.7 MJ/kg, respectively. The method of changing this was to use the fraction of LNG in the fuel gas as a validated value. The calculation has been done according to Figure 6.6.

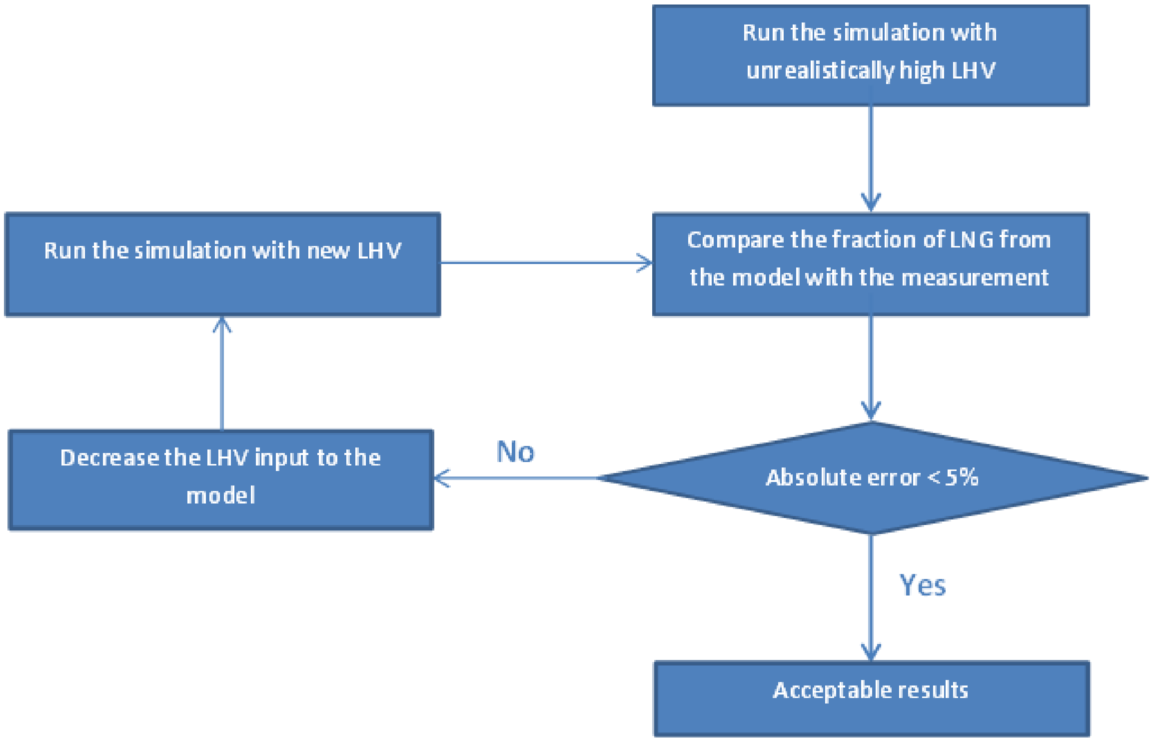

Figure 6.6: Iterative LHV procedure.

The simulation with unrealistically high LHV of the fuel gas resulted in too little LNG use in the model or negative flow of LNG which makes the model neither accurate nor reliable. Decreasing the LHV of fuel gas input to the model decreased the use of LNG which leads to iterative process. The limitation is that the difference the fraction of LNG from the model and measurement must be within 5% error. This method should be implemented when the extracted density of fuel gas from Preem system has a value below 1 kg/m^3

6.2 Custom script

In Aspen Utilities Planner, there is an opportunity to write custom scripts to specifically control the unit behavior. The custom scripts were used in the first version of the model for let-down valves between some headers. The existing script was written in Visual Basic language in a hierarchical order with if-else conditions. If-else conditions were written for controlling specific valves when there were excesses or insufficient amount of steam flows at a particular header. For example, when the excess of VHP steam is larger than the allowable flow between VHP and MP headers, the rest of the flow will be distributed to the HP header which is a local header instead.

However, some equations control the let-down valves by setting a constant value for the steam flow for example, for the valve 81PC241 that connects the VHP header with the HP header. Attempts were made to make the flow through this valve dependent on the steam production and consumption at the HP header. However, as the flow variable was designed as a free variable, the number of degree of freedom in the model became larger thus causing the system to be unspecified. This could be solved by setting a free parameter as fixed within Aspen Utilities Planner but that resulted in unrealistic values in other parts of the model. According to the staff at Preem the valve 81PC241 is mainly opened during start-up of 810 area which means that the system will not be at steady state and therefore it was decided to keep this variable as fixed by the script.

An improvement that was successfully implemented in the script is the script for LP steam venting to the atmosphere. The script is activated only when the optimization mode run results in a negative value for the LP vent steam flow. The water mass balance in the model for each header was not coupled to the steam production at the VHP steam header, which means that in optimization mode, the LP steam venting valve can go to negative values to satisfy the mass balance at the LP steam header. The new added equations allow the script to couple the LP steam header to boilers and ensure positive steam flows also for the venting to the atmosphere. This is further discussed in Section 7.4.

6.3 Modification of fuel gas system

The fuel gas modification was performed by verifying the assumptions in the original model from Subiaco [5] and re-modelling the relationship between refinery gas and LNG supply.

6.3.1 Fuel gas system re-modeling

The fuel gas system should be re-modelled since the fuel gas system was originally modelled using Equation 4.1 assuming a fixed share of LNG for a given scenario to provide the heat from fuel header to the boilers. In scenario mode, this way of modeling should be adequate to obtain correct results. In optimization mode, this method will not be sufficient to capture the fact that reduced fuel use will primarily lead to a reduction of LNG import and thereby reduce the share of LNG in the fuel gas mix.

The solution of the problem mentioned in the above paragraph is to model the refinery gas and LNG separately and by setting the volumetric flow of the refinery gas as a fixed input value and the flow of LNG to be free. So, the simulation will calculate the amount of LNG flow needed to fulfill the boilers' duties. Setting the flow of the refinery gas as a fixed value also requires a fixed molecular weight and the LHV at the refinery gas supplier box. Instead, the molecular weight and the LHV of the mixed fuel gas in the model need to be free variables. However, the molecular weight and LHV are measured at the fuel gas header in the refinery after mixing with LNG, but these values are assumed to be close enough to the values of the refinery gas before mixing with LNG and used as input for the refinery gas supply. This assumption is justified by the fact that the proportion of LNG to the refinery gas is small and normally not bigger than 15% by volume which has insignificant effect on the LHV of the fuel gas after mixing. With this assumption, there will be a small and negligible difference in the LHV of fuel gas from measurements and the model results. Table 6.5 shows the comparison of the LHV value of the mixed fuel gas from measurement and simulation for Scenarios 2 and 3.

Table 6.5: Comparison between the measured and simulated LHV of the fuel gas.

Scenarios	2	3
LHV measured [MJ/kg]	38	36.6
LHV simulated [MJ/kg]	38.1	37.2

Additionally, for the model to better represent reality, an extension including other fuel gas consumers should be added to the model. Figure 6.7 shows how the fuel gas system was constructed in the Aspen Utilities Planner flow sheet. A green circle shows an additional fuel demand block representing a constant fuel gas demand for other fuel gas consumers like furnaces.

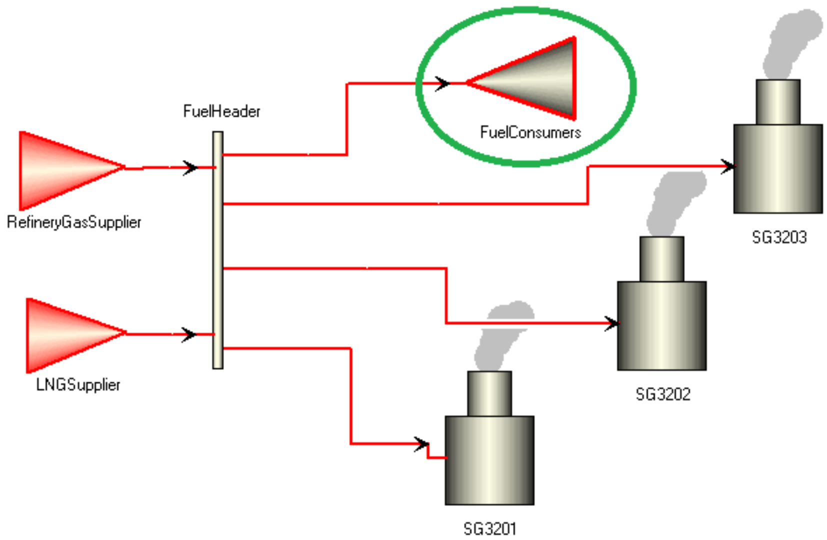

Figure 6.7: Simplified fuel gas system scheme.

After adding the rest of the consumers, the accuracy of the composition of mixed gas was improved significantly and became very close to the calculated value. This improvement is from the fact that the fuel gas flow to the system became very large when including all other fuel consumers so the effect from small deviations of the fuel flows to the boilers became negligible. The results after implementing the improvements for the fuel gas system can be seen in Section 6.3.2 and the final steam model version can be seen in Appendix D.4.

6.3.2 Fuel gas system verification

The verification of the results obtained from the modified fuel gas system was performed by comparing with the values from the measurements that can be seen in Table 6.6. The two scenarios were chosen from the original work to verify the model, which are Scenarios 2 and 3. Scenario 2 occurred during the summer period and was chosen due to its high temperature. Scenario 3 took place during the maintenance of both HRSG:s and NHTU/ Reformer unit.

Table 6.6: Verification of model outputs for the fuel gas system against measurement values for Scenarios 2 and 3.

	Scenario 2		Scenario 3	
Variables	Model	Measured	Model	Measured
LHV of fuel gas [MJ/kg]	38.1	38	37.2	36.6
Percentage of LNG [%]	2.8	5	10.9	10
Fuel gas flows to the boilers [Nm^3/h]	3276	4308	3034	2803
Total fuel gas flows [Nm^3/h]	44588	45620	23043	22812

A comparison cannot be done against the original model since there were many changes applied in the new model making the comparison between the results from the original and new model not applicable. From Table 6.6, it can be seen that the new model results in an accurate value for the LHV of fuel gas and the total fuel gas flow for Scenario 3 also shows rather good agreement for the LNG share and fuel gas flow to the boilers. In Scenario 2, the deviation between the fuel gas flow to the boilers from the model compared to measurement is more pronounced. However, the deviation can be seen as less important when comparing to the total fuel gas flows. This deviation is suspected to come from the molecular weight of the refinery gas put into the model. The molecular weight of the refinery gas is not measured and the assumption of molecular weight equal to 35 kg/kmol, from Subiaco [5], has been used. The effect from changing the molecular weight of the refinery gas for Scenario 2 and 3 is further analyzed in Sections 6.4.1.1 and 6.4.1.2.

The molecular weight of the refinery gas could be calculated from the mixed fuel gas composition and the composition of imported LNG and LNG flow (measured). Accessing historical data that shows the composition for the LNG could not be done, only live data was available, also accessing historical data regarding the composition for the imported LNG could require approval from the company that sells the LNG to Preem. Information regarding the pressure and temperature at the specific point of interest i.e. the inlet to the steam boilers would be needed to get as accurate value as possible. The LHV of the refinery gas can be calculated once the composition of the refinery gas is known. Thus with the information mentioned, the molecular weight and LHV of the refinery gas could be calculated for previous operational situations. For live data the calculations could be performed as mentioned.

It is not adequate to verify the modified model with only 2 scenarios. The new scenarios, Scenarios 6 and 10, have been created and used to verify the new model. Scenarios 6 and 10 represent normal operating conditions in the beginning of January 2018. The data for Scenario 6 was collected with a week time average but the data for Scenario 10 was collected with a one-day average.

Table 6.7: Verification of the model outputs for the fuel gas system against measurement values for Scenarios 6 and 10.

	Scenario 6		Scenario 10	
Variables	Model	Measured	Model	Measured
LHV of fuel gas [MJ/kg]	38.9	38.6	39	38.8
Percentage of LNG [%]	6.9	8.3	7.5	8.82
Fuel gas flows to the boilers [Nm^3/h]	1613	2358	1772	2483
Total fuel gas flows [N^3m/h]	49305	50050	49052	49763

Table 6.7 demonstrates the comparison between the results obtained from the new model and the measured values for Scenarios 6 and 10. Similarly to Table 6.6, the model gave accurate results when compares to the measurement values for all values except the fuel gas flow to the boilers. It was expected that this deviation occurred from the initial molecular weight of refinery gas put into the model. Scenarios 6 and 10 represent the same situation and it might be that the molecular weight of the fuel gas at this specific time was not 35 kg/kmole since both of the scenarios gave roughly the same relative difference in fuel gas flows to the boilers. The effect of LHV and molecular weight of the fuel gas were studied further and discussed in Section 6.4.1.3.

6.4 Validation against operational data

In this validation the values generated by the model are compared with the operational values that were extracted from the refinery. The scenarios that were chosen to be used for validation were scenarios 2, 3, 6/10 and 8/12 and more detailed information about settings and values for the different scenarios can be found in Section 5.4.

- Scenario 2: Occurred during the summer period, Scenario 2 was chosen due to high air temperature.
- Scenario 3: Chosen due to shut down on both HRSG:s and shut down on NHTU/ Reformer unit.
- Scenarios 6 and 10: High utilization of the refinery and stable operation.
- Scenarios 8 and 12: FCC units were shut down.

6.4.1 Results after model changes

The validation is mainly performed using the Excel result interface created by Subiaco. The 10% validation limit is checked for the difference between measured and model output values and also for the mass balance difference over each header based on measurements.

6.4.1.1 Scenario 2

The results from Scenario 2 are presented in Table 6.8. Table 6.9 presents the results regarding mass balances and the 10% validation limit can be seen. In Table 6.9, the first column "Error [%]" is calculated using Equation 5.1 for the three headers and Equation

5.2 for the three valves. Second column "Error [t/h]" is the absolute difference, for the headers it is between inflow and outflow and for the valves it is the difference between measured value and model output value. This setting will be used for the remaining scenario validation.

Table 6.8: Validation results for Scenario 2.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	359,20	360,8	1,60	0,44%
Utilized Make up	Tonne/Hr	123,48	121,4	2,08	1,71%
LS venting	Tonne/Hr	25,54	29	3,46	11,93%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	23,89	23	0,89	3,88%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	7,17	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	0	0,00	0,00%
MS -> LS valve	Tonne/Hr	15,07	21,8	6,73	30,87%
Turbine ICR CT8101	Tonne/Hr	27,17	27	0,17	0,64%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	12,48	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	27,51	27,7	0,19	0,69%
DS 8103 Steam-out	Tonne/Hr	42,16	42	0,16	0,38%
Used Electric Energy	kW	4758,16	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	42268,24	43246,1	977,86	2,26%

It is clear that most of the results are well within the limits but there are larger deviations at the MP header. The deviations at the MP header are assumed to originate from steam tracing that mainly is taken from the MP level. The deviations that are at the MP header are expected since at this header there are number of unspecified consumers of steam.

Table 6.9: Difference between in- and outflow at the headers (row 1-3) and difference between output and measured values for let-down valves (row 4-6) calculated by Equations 5.1 and 5.2 and mass flows for Scenario 2.

Parameter	Error [%]	Error [t/h]
VHP header	0.5	0.9
MP header	5.7	10.7
LP header	1.4	3.1
VHP-MP valve	0.6	0.9
MP-LP valve	3.6	6.7
LP venting	1.6	3.5

In Table 6.8 shows the use of fuel gas by all measured consumers. The difference between the measured and output value is small, however, a comparison of the measured flow to the boilers and the model output value is also interesting and indicates how sensitive the fuel gas system is to the LHV and also the molecular weight of the fuel gas. In Table 6.10 the change in fuel gas flow to the boilers while changing the molecular weight or the

LHV of the refinery gas. The values of LHV and molecular weight from Table 6.10 used for Table 6.8 is the second row. As can be seen, small changes in these two variables affects the flow significantly, however, the total consumption of fuel gas remains relatively unchanged due to the size difference of the flows.

Table 6.10: Comparison of values for total flow of fuel gas to the boilers when changing molecular weight and LHV of the refinery gas for Scenario 2.

	Flow of fuel gas to boilers [Nm^3/h]
Measured value	4308
MW=35 kg/kmol LHV=38 MJ/kg	3276
MW=30 kg/kmol LHV=38 MJ/kg	3819
MW=35 kg/kmol LHV=37 MJ/kg	3365

6.4.1.2 Scenario 3

In Table 6.11, the validation of Scenario 3 can be seen. The output results are more deviating compared to Scenario 2, reasons for this are considered to be the shut-down of different area units and that the data extracted for Scenario 3 was taken shortly after a change of refinery operating condition and therefore might not be in steady-state. In Table 6.11, the time point that was used is the same as the one Subiaco used.

Table 6.11: Validation results for Scenario 3.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	234,44	235,48	1,04	0,44%
Utilized Make up	Tonne/Hr	107,92	107	0,92	0,86%
LS venting	Tonne/Hr	17,06	5,24	11,82	225,57%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	-2,42	3	5,42	180,53%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	9,30	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	9,29	2,7	6,59	244,10%
Turbine ICR CT8101	Tonne/Hr	27,17	27,3	0,13	0,46%
Turbine TS -> MSS810	Tonne/Hr	14,79	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	9,90	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	25,21	25,8	0,59	2,29%
DS 8103 Steam-out	Tonne/Hr	39,48	37,55	1,93	5,14%
Used Electric Energy	kW	5653,59	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	21844,37	21625,22	219,15	1,01%

In Table 6.12, the sensitivity of the fuel gas flow to the boilers depending on molecular weight of refinery gas and the LHV of refinery gas can be seen, the row "Measured values" presents the value used to obtain the results in Table 6.11. The same pattern as in Table

6.10 can be observed, changes in the molecular weight and LHV of the refinery gas affect the flow of the fuel gas. This implies that caution should be taken when extracting data for LHV and calculating the molecular weight. It was assumed that one of the reasons why this scenario overestimates the fuel gas consumption to the boilers is because the measured value is to low. When looking closer at the measured values it was discovered that one of the measured values of fuel gas is unrealistically low compared to the steam production. By studying fuel gas consumption at similar loads it can be concluded that the total consumption of fuel gas to the boilers should be approximately 850 Nm^3/h higher than the measured value in Table 6.12. Thus the underestimation of fuel gas consumption is more similar to Scenario 2.

Table 6.12: Comparison of values for total flow of fuel gas to the boilers when changing molecular weight and LHV for Scenario 3.

	Flow of fuel gas to boilers [Nm^3/h]
Measured value	2803
MW=35 kg/kmol LHV=36.6 MJ/kg	3034
MW=30 kg/kmol LHV=36.6 MJ/kg	3505
MW=35 kg/kmol LHV=36 MJ/kg	3085

In Figures 6.8, 6.9 and 6.10, the values of flow and percentage of valve opening for VHP-MP, MP-LP and LP-vent valves can be observed. From these figures, it can be deduced that the system had just made a transition, this since it is clear that the steam flows and valve openings MP-LP let-down valve and LP-vent valve has made a change. Also the VHP-MP valve can be considered unreliable since it, during that day, shows no flow although the valve is around 18% open. In Figure 6.8, the brown line represents the valve opening and the orange one which is not visible since the value is negative and never exceeds zero, is the steam flow.

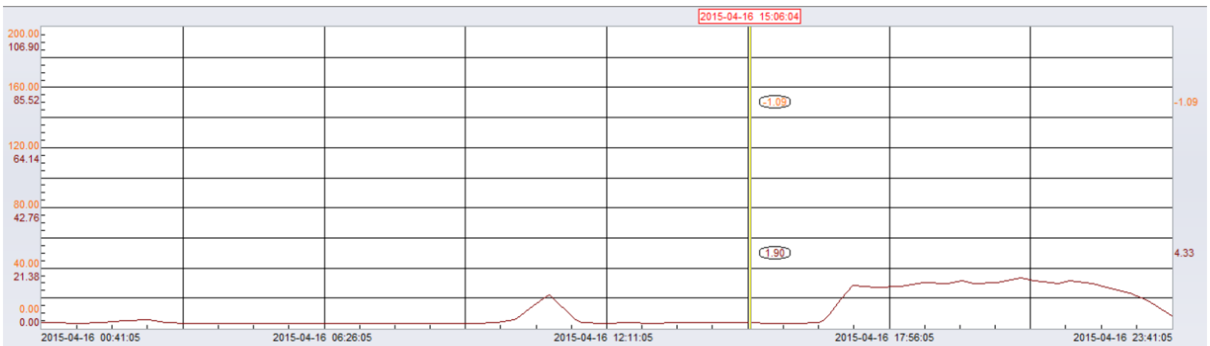

Figure 6.8: VHP-MP valve for Scenario 3, the brown line is valve opening [%].

In Figure 6.9, the brown line is valve opening and the blue one is steam flow. It can also be noticed that the data seems to be extracted directly after a change of operation. It could be argued that data before the operational change should be used to ensure the system was in steady state.

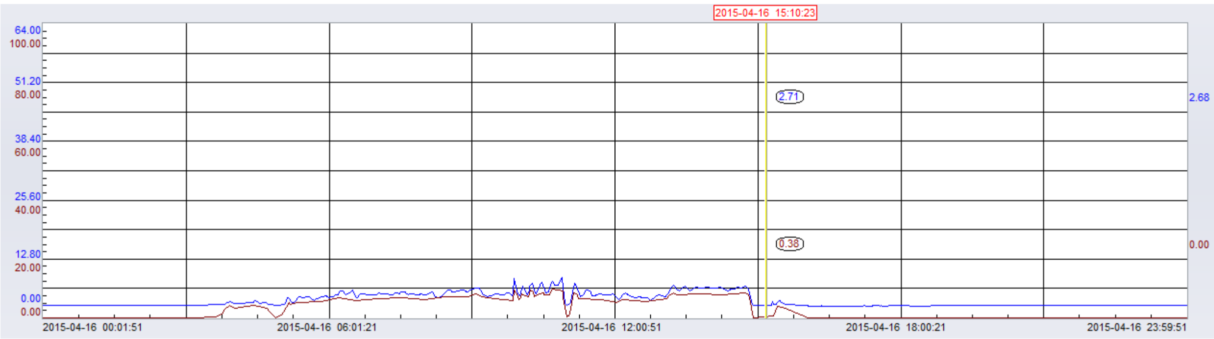

Figure 6.9: MP-LP valve for Scenario 3, the brown line is valve opening [%] and the blue line is steam flow [t/h].

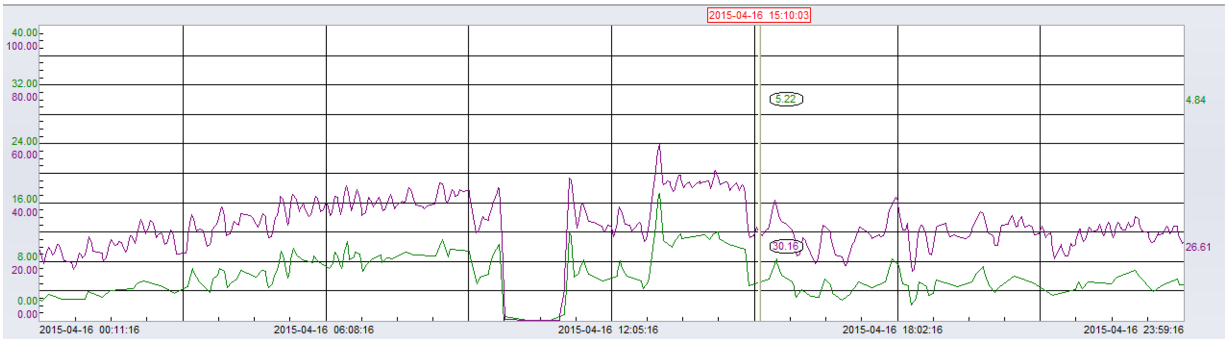

Figure 6.10: LP vent valve for Scenario 3, the pink line is valve opening [%] and the grren line is steam flow [t/h].

In Figure 6.10, it can be seen that around the time the data was collected (yellow line in Figures 6.8, 6.9 and 6.10) the LP vent makes a spike down and that just before the data was collected the values where more stable. The green line represents the steam flow and the pink line valve opening in percentage.

By using data from when the system was in steady-state and the default value for the VHP-MP let down valve described in Section 5.5.1, the result of the manual mass balance can be seen in Table 6.13. Results using the measured values used by Subiaco when the system has just changed can be seen in Table 6.14.

Table 6.13: Difference between in- and outflow at the headers (row 1-3) and difference between output and measured values for let-down valves (row 4-6) for Scenario 3, with values before operational change.

Parameter	Error [%]	Error [t/h]
VHP	8.8	9.2
MP	6.6	6.3
LP	6.9	13.1
VHP-MP valve	8.9	9.4
MP-LP valve	3.5	3.4
LP venting	4.8	9.1

Table 6.14: Difference between in- and outflow at the headers and let down valves in percentage and mass flow for Scenario 3, with values after operational change.

Parameter	Error [%]	Error [t/h]
VHP	4.9	5.2
MP	13.4	12.3
LP	3.3	5.8
VHP-MP valve	5.1	5.4
MP-LP valve	7.2	6.6
LP venting	6.6	11.8

Overall, the deviations are smaller when the system is in steady-state but it also shows that the model provides results that are generally acceptable, given that most of the results are within the 10% validation limit. The largest deviations are at the MP header and that is reasonable since there are a high number of undefined consumers and producers at the MP header. Also in this scenario, parts of the refinery were shut down for maintenance, and steam is used as cleaning media during this time with some flow meters being by-passed consequently, an unknown amount of steam will be used but not measured. This is a source of error for all scenarios with larger shut downs, the cleaning can have a duration of up to three days according to Preem staff, also all units are not always cleaned at the same time, thus there can be long periods with unknown steam consumption.

6.4.1.3 Scenario 6 and 10

Validation results for Scenario 10 can be seen in Table 6.15, and in Table 6.16 for Scenario 6. Scenario 6 is obtained the same time as Scenario 10, but the values are averaged over a week instead of over one day.

Table 6.15: Validation results for Scenario 10, with averaging time of one day.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	368,66	378,9	10,24	2,70%
Utilized Make up	Tonne/Hr	127,37	121,41	5,96	4,91%
LS venting	Tonne/Hr	23,40	14,46	8,94	61,84%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	15,48	6,81	8,67	127,35%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	15,81	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	17,16	3,05	14,11	462,66%
Turbine ICR CT8101	Tonne/Hr	28,86	30	1,14	3,79%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	36,67	36,94	0,27	0,74%
DS 8103 Steam-out	Tonne/Hr	36,36	30,07	6,29	20,93%
Used Electric Energy	kW	4874,39	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	46499,20	47173,67	674,47	1,43%

It can be seen that the model results are closer to the measured values for Scenario 6. The reason behind this is assumed to be the averaging of the data values, averaging over a week should be more reliable than using a day average according to Preem staff. Flow through the LP vent valve is quite the same for both scenarios, however, Scenario 6 is more accurate regarding the steam flow through the VHP-MP and MP-LP let-down valves. This probably originates from the operational setting of pumps and compressors, some of these units that might have been averaged to motor mode in Scenario 10 have been averaged to turbine mode in Scenario 6 which is overall a more accurate setting.

Table 6.16: Validation results for Scenario 6, with averaging time of one week.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	369,22	373,7	4,48	1,20%
Utilized Make up	Tonne/Hr	127,40	117,64	9,76	8,29%
LS venting	Tonne/Hr	22,48	9,73	12,75	131,07%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	8,94	7,6	1,34	17,61%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	16,11	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	1,97	5,28	3,31	62,60%
Turbine ICR CT8101	Tonne/Hr	28,68	30,08	1,40	4,64%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	36,98	34,53	2,45	7,10%
DS 8103 Steam-out	Tonne/Hr	36,18	33,25	2,93	8,80%
Used Electric Energy	kW	4577,04	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	46739,90	47445,46	705,56	1,49%

In Tables 6.17 and 6.18, the results from the mass balances in Scenarios 10 and 6 can be seen. All values are well within the error limit. This strengthens the suggestion that the model performs within the acceptable limits for steady-state operations. Also in these tables the effect of averaging time can be seen as Scenario 6 generally has lower errors than Scenario 10. The variable that stands out in both cases is the LP vent valve flow. This is as mentioned earlier not surprising since at the LP header there are a number of unknown flows of steam that cannot be measured. Furthermore the value that is obtained from Preem system is not a measurement but a calculation by their process program. This means that there can be doubts about the reliability of the value obtained from Preem as well.

Table 6.17: Difference between in- and outflow at the headers (row 1-3) and let down valves (4-6) in percentage and mass flow for Scenario 10.

Parameter	Error [%]	Error [t/h]
VHP	5.9	8.6
MP	3.6	7.2
LP	5.6	11.1
VHP-MP valve	6	8.7
MP-LP valve	7.4	14.6
LP venting	4.7	9.4

Table 6.18: Difference for in- and outflow at the headers (row 1-3) and let down valves (row 4-6) in percentage and mass flow for Scenario 6.

Parameter	Error [%]	Error [t/h]
VHP	0.6	0.8
MP	4.5	8.5
LP	6	13.2
VHP-MP valve	0.9	1.3
MP-LP valve	1.7	3.3
LP venting	5.8	12.8

A sensitivity analysis for the molecular weight and LHV of refinery gas was done for Scenarios 6 and 10 as was done for the other scenarios and the results can be seen in Tables 6.19 and 6.20. The row with "Measured values" in both tables represent the molecular weight and LHV used to obtain the results in Tables 6.15 and 6.16. The difference in measured value for the fuel gas system is because the boilers produces more steam in Scenario 10 than in Scenario 6. It can be said that results from Tables 6.10 and 6.12 together with the results from Tables 6.19 and 6.20 imply that that the fuel gas system is sensitive to changes in molecular weight and LHV for the refinery gas. Since the pattern was obvious this comparison was omitted in Section 6.4.1.4.

Table 6.19: Comparison of values for total flow of fuel gas to the boilers when changing molecular weight and LHV for Scenario 10.

	Flow of fuel gas to boilers [Nm^3/h]
Measured value	2483
MW=35 kg/kmol LHV=38.8 MJ/kg	1772
MW=30 kg/kmol LHV=38.8 MJ/kg	2052
MW=35 kg/kmol LHV=38 MJ/kg	1807

Table 6.20: Comparison of values for total flow of fuel gas to the boilers when changing molecular weight and LHV for Scenario 6.

	Flow of fuel gas to boilers [Nm^3/h]
Measured value	2360
MW=35 kg/kmol LHV=38.6 MJ/kg	1613
MW=30 kg/kmol LHV=38.6 MJ/kg	1870
MW=35 kg/kmol LHV=38 MJ/kg	1639

6.4.1.4 Scenario 8 and 12

The results from validation of Scenario 12 and 8 can be seen in Tables 6.21 and 6.22, respectively. It can be observed that different averaging times do not affect the results significantly for this case. Similarly to Scenario 3, which also occurs during maintenance of parts of the refinery, Scenario 12 has deviating results, especially for the MP-LP let down valve and the LP-vent valve. These deviations are assumed to originate from the use of steam for cleaning, as described in Section 6.4.1.2.

Table 6.21: Validation results for Scenario 12, with averaging time of one day.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	338,04	324,62	13,42	4,13%
Utilized Make up	Tonne/Hr	123,31	92,86	30,45	32,79%
LS venting	Tonne/Hr	29,30	0,5	28,80	5759,59%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	18,84	3,21	15,63	486,83%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	7,31	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	13,27	7,62	5,65	74,17%
Turbine ICR CT8101	Tonne/Hr	27,55	29,23	1,68	5,75%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	27,65	29,14	1,49	5,11%
DS 8103 Steam-out	Tonne/Hr	34,99	29,74	5,25	17,66%
Used Electric Energy	kW	4924,10	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	51727,07	52542,71	815,64	1,55%

Table 6.22: Validation results for Scenario 8, with averaging time of one week.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	337,63	338,15	0,52	0,15%
Utilized Make up	Tonne/Hr	124,04	109,25	14,79	13,54%
LS venting	Tonne/Hr	32,61	1	31,61	3161,42%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	18,18	3,98	14,20	356,72%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	7,83	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	12,78	6,93	5,85	84,41%
Turbine ICR CT8101	Tonne/Hr	27,67	29,32	1,65	5,64%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	28,21	29,75	1,54	5,18%
DS 8103 Steam-out	Tonne/Hr	35,12	29,71	5,41	18,20%
Used Electric Energy	kW	4492,47	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	51713,02	55610,87	3897,85	7,01%

The results using Equations 5.1 and 5.2 can be seen in Tables 6.23 and 6.24. The default value for the VHP-MP valve described in Section 5.5.1 has been used in both Tables 6.23 and 6.24 and it can be observed that although there are greater deviations for the other Scenarios, the results are still close to the set 10% validation limit. The error regarding the LP vent valve can be neglected since, after looking at Tables 6.21 and 6.22 the value for this valve is unrealistically low, if the refinery only vented 1 t/h of steam then the system would be quite optimized already and Preem staff agreed that it is unrealistically low. Assuming a LP venting valve value closer to 10 t/h is reasonable based on stable operational data and suggestions from Preem staff. This will give results that are better but still there are deviations.

Table 6.23: Difference between in- and outflow at the headers and let down valves in percentage and mass flow for Scenario 12.

Parameter	Error [%]	Error [t/h]
VHP	8.4	11.3
MP	1.9	3.2
LP	8.3	17.1
VHP-MP valve	11.6	15.7
MP-LP valve	3.3	5.6
LP venting	14.01	28.8

Table 6.24: Difference between in- and outflow at the headers and let down valves in percentage and mass flow for Scenario 8.

Parameter	Error [%]	Error [t/h]
VHP	7.7	10.8
MP	4.7	7.8
LP	11.9	25
VHP-MP valve	10.1	14.2
MP-LP valve	3.5	5.8
LP venting	15.05	31.6

6.4.1.5 Scenarios 1, 7 and 11

In Appendix E, the result from validation of Scenarios 1, 7 and 11 can be seen. These scenarios are as Scenarios 2, 6 and 10, they represent stable operation of the refinery with high utilization of refinery capacity. Also the results are similar to those of Scenarios 2, 6 and 10 in terms of deviations in relation to the incoming steam to the each steam header. These results strengthen the fact that the model provides reliable results during stable operational situations with as few areas of the refinery shutdown as possible.

6.4.2 Comparison of results from original and new models

In Tables 6.25 and 6.26,a comparison between the original and the new model versions can be seen for Scenarios 2 and 3. In these figures, OMV stands for "Original model version" while NMV stands for "New model version". The common results for both scenarios are that both the new and the original model perform well regarding the feed and make up water. It can also be said that the original model version performs better overall for Scenario 3 than the new model version. However, this is the contribution from the large changes in steam tracing consumption that Subiaco used as a tuning parameter to fit the model to each scenario. The accuracy regarding prediction of fuel gas consumption by the boilers is discussed at the end of this section.

Table 6.25: Comparison between validation results from original and new model versions for Scenario 2.

DATA VALIDATION						
VARIABLE	UNIT	OMV VALUE	NMV VALUE	MEASURED VALUE	OMV RELATIVE ERROR	NMV RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	359,33	359,20	360,8	0,41%	0,44%
Utilized Make up	Tonne/Hr	116,07	123,48	121,4	4,39%	1,71%
LS venting	Tonne/Hr	27,39	25,54	29	5,54%	11,93%
LSS810 venting	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
HS venting	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
HS -> MS valve	Tonne/Hr	23,99	23,89	23	4,32%	3,88%
HS -> TS valve	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
TS -> MSS valve	Tonne/Hr	7,35	7,17	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
MS -> LS valve	Tonne/Hr	21,27	15,07	21,8	2,45%	30,87%
Turbine ICR CT8101	Tonne/Hr	27,17	27,17	27	0,64%	0,64%
Turbine TS -> MSS810	Tonne/Hr	19,09	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	12,39	12,48	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	27,60	27,51	27,7	0,34%	0,69%
DS 8103 Steam-out	Tonne/Hr	41,98	42,16	42	0,05%	0,38%
Used Electric Energy	kW	5939,49	4758,16	unm	#VALUE!	#VALUE!

Table 6.26: Comparison between validation results from original and new model versions for Scenario 3.

DATA VALIDATION						
VARIABLE	UNIT	OMV OUTPUT VALUE	NMV OUTPUT VALUE	MEASURED VALUE	OMV RELATIVE ERROR	NMV RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	234,87	234,44	235,48	0,26%	0,44%
Utilized Make up	Tonne/Hr	103,09	107,92	107	3,65%	0,86%
LS venting	Tonne/Hr	4,93	17,06	5,24	5,90%	225,57%
LSS810 venting	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
HS venting	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
HS -> MS valve	Tonne/Hr	4,42	-2,42	3	47,48%	180,53%
HS -> TS valve	Tonne/Hr	0,00	0,00	0	0,00%	0,00%
TS -> MSS valve	Tonne/Hr	9,48	9,30	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	5,15	9,29	2,7	90,67%	244,10%
Turbine ICR CT8101	Tonne/Hr	27,17	27,17	27,3	0,46%	0,46%
Turbine TS -> MSS810	Tonne/Hr	14,70	14,79	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	9,81	9,90	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	25,31	25,21	25,8	1,91%	2,29%
DS 8103 Steam-out	Tonne/Hr	39,30	39,48	37,55	4,66%	5,14%
Used Electric Energy	kW	7002,27	5653,59	unm	#VALUE!	#VALUE!

The results displayed in Tables 6.25 and 6.26 indicate that the modifications that have been improved in the new model compared to the original have improved the ability to predict the outcome of different scenarios without manually changing data and assumptions between the scenarios. The approach of a model that generically fits more scenarios is more reliable and also easier to use since the possibility for mistakes when analyzing new operational scenarios are fewer.

A further comparison of the mass balances that are presented in Tables 6.27 and 6.28 shows that based on the 10% validation limit it can be observed that for the stable operational situation (Scenario 2) the deviations are of the same magnitude for the new and original model while for Scenario 3 with operational disturbances the new model version has greater errors than the original model. This indicates that the new model is well adapted for operational scenarios with high utilization of refinery capacity, while for scenarios with operational disturbances such as shut down of different areas the new model is more unreliable. However, the new model is tested against more scenarios than the original model. The data and the modelling is more consistent between various scenarios, and the model is better adapted to be able to handle new operational cases.

Table 6.27: Difference between in- and outflow at the headers (row 1-3) and let down valves (row 4-6) in percentage and mass flow for Scenario 2, original model values in parenthesis.

Parameter	Error [%]	Error [t/h]
VHP	0.5 (1.8)	0.9 (2.9)
MP	5.7 (2.5)	10.7 (4.7)
LP	1.4 (1.4)	3.1 (3.1)
VHP-MP valve	0.6 (1.8)	0.9 (2.9)
MP-LP valve	3.6 (0.9)	6.7 (1.6)
LP venting	1.6 (0.7)	3.5 (1.5)

Table 6.28: Difference between in- and outflow at the headers (row 1-3) and let down valves (row 4-6) in percentage and mass flow for Scenario 3, original model values in parenthesis. For new model version result from after operational change is displayed.

Parameter	Error [%]	Error [t/h]
VHP	4.9 (2.4)	5.2 (2.6)
MP	13.4 (0.8)	12.3 (0.8)
LP	3.3 (3.6)	5.8 (6.1)
VHP-MP valve	5.1 (3.2)	5.42 (3.3)
MP-LP valve	7.2 (4.8)	6.6 (4.6)
LP venting	6.6 (0.1)	11.8 (0.2)

The original model version was validated against 4 different scenarios created by Subiaco, the new model has been thoroughly validated against two of the scenarios created by Subiaco but also by 4 other scenarios created by Gunnarsson and Kobjaroenkun. Seven more scenarios were created by Gunnarsson and Kobjaroenkun and the new model was tested against these scenarios as well but not as thoroughly as described in Section 6.4. This indicates, as mentioned earlier, that the new model version is more adapted to different operational situations but performs best when the refinery is at high utilization of the refinery capacity.

Comparison of the consumption of fuel gas to the boilers between the new and original model became difficult since, as described in Section 6.1.6 the original model used the wrong conversion factor and model formulation. The new model version predicts the composition of the fuel gas well. There are some deviations between the new model output values and the measured values regarding the amount of fuel gas to the boilers, but as described in Sections 6.4.1.1, 6.4.1.2 and 6.4.1.3 these deviations can be explained by small variations in property data for the refinery gas.

7 Optimization mode

In addition to the normal scenario mode simulation, one objective to this work was to make the model work properly in optimization mode. In this chapter, the optimization mode of the steam model is described, and a practical approach for running the optimization from the excel interface is proposed. A guide briefly describing how to use the model in optimization mode can be found in Appendix A.

7.1 Optimization mode running from Aspen interface

Aspen utilities planner can be used as a stand-alone program for the simulation of the model. The model is optimized according to the constraints defined in the editors (Demand/Availability/Tariff), see Section 3.

7.1.1 Test runs

The test of running the optimization through the Aspen interface was performed using operating conditions and constraints from the previous work [5] from Scenario 1 (13rd September 2015). First, the model was run in scenario mode. Then the optimization was solved for two extreme cases; 'Cheap LNG' and 'Cheap Electricity' where 'Cheap LNG' represents the LNG price being close to zero, and vice versa for 'Cheap Electricity'. Table 7.1 shows the results from both modes.

Variables	Unit	Scenario mode	Cheap LNG	Cheap Electricity
LNG used	t/h	2.1	5.3	0.5
Electricity used	MW	4.6	0.6	5.8
Steam from boilers	t/h	70.6	133.2	36
Steam to atmosphere	t/h	43	111	5.1

Table 7.1: First optimization results from Aspen interface.

The optimizer has the objective function to minimize the total utility costs according to the tariff data. Availability data contains the minimum and maximum bound for feasible operation. When the price of LNG is much lower than the electricity price, the optimizer tries to minimize the use of electricity by changing pump settings to turbine drive. On the other hand, when the price of electricity becomes low, the optimizer changes pump settings to motor drive in order to minimize the import of LNG and thereby the steam production. However, these results are based on unrealistic energy prices, and are only to illustrate the extremes of the solution price.

7.2 Optimization mode running from Excel interface

The Aspen Utilities Planner Excel Add-in allows the user to run the simulation and view results from within Microsoft Excel. In previous work, the Excel workbook for steam model simulation was created, which works properly in scenario mode. However, enabling the optimization mode to run through the Excel interface was also desired.

Connecting the Aspen Utilities Planner interface to the Excel interface for optimization mode simulation had been achieved and the first run in optimization mode through Excel was performed with the same data and constraints as used in Aspen Utilities Planner and the results are identical to Table 7.1.

It can be concluded that the Excel workbook and Aspen Utilities Planner are now interlinked properly and the model can be run in optimization mode from Excel. Results obtained from both interfaces are exactly the same for the identical data input and constraints. However, solving the model through the Excel interface seems to have a number of advantages. It is more convenient and easier to use Excel since the user can design the workbook representing the current operating conditions of the steam network and link it to Aspen Utilities Planner. Another advantage could be that the data editor in the Excel interface allows the user to change constraint freely without changing the original constraints in Aspen. Consequently, the user can always test new constraints and go back to the original ones easily.

7.3 Scenarios in optimization mode

When testing the optimization mode of Aspen Utilities Planner and the Excel interface different scenarios were used. The same scenarios as used for the validation in Section 6.4 were used but Scenario 3 and Scenario 6 were excluded, due to the poor validation results, the unsteady-state operation of the refinery at that moment and also due to poor measurement value for fuel gas consumption for one of the boilers. When using the optimization function with Scenario 6 it was discovered that the same problem as for Scenario 10 existed, the boilers that are in operation have loads below the limits that the optimization function uses. Due to the similarity to Scenario 10, it was decided to omit this scenario. It was decided not to add new scenarios to the optimization since the remaining scenarios still represented both stable operation and partly shut-down operation of the refinery.

7.4 Optimization results

In order to make the most accurate comparison between actual operation and the result from the optimization, the prices of electricity and LNG at the specific time point represented by each scenario are used. The electricity prices as a spot market price excluding taxes and fees were retrieved from NORDPOOL website [19] and the LNG prices were obtained using eurostat [20], conversion to SEK/GJ was done using values from Forex [21]. The LNG price for Scenario 6 and 10 was not available so it was estimated from the scenarios were price data was available to 10 €/GJ. The resulting prices can be seen in Table 7.2.

Table 7.2: Prices for electricity and LNG at the specific time for these scenarios.

Scenario	Electricity [SEK/MWh]	LNG [SEK/GJ]
2	84.9	102.9
10	318.1	104
8/12	276.9	98.7

7.4.1 Scenario 2

Results from using the optimization function for Scenario 2 can be seen in Table 7.3 where a comparison of values for certain variables can be seen.

Table 7.3: Results from scenario simulation and optimization together with measured values from the refinery, for Scenario 2.

Variable	Scenario mode	Optimized mode	Measured Values
Cost Electricity [SEK/h]	404.4	426.5	-
Cost LNG [SEK/h]	5162	161.8	-
Total cost [SEK/h]	5566	588.4	-
LP venting [t/h]	25.5	0	29
VHP-MP valve [t/h]	23.9	8.9	23
MP-LP valve [t/h]	15.1	6.1	21.8
Total boiler production [t/h]	62	39.4	62

In Table 7.3, it can be seen that by optimizing the operation the total cost for the utility system is estimated to decrease by 4978 SEK/h. It must be noted that firstly, the results from optimization may not be the optimal results since when the model was run in optimization mode, the LP venting showed negative value around -0.5 t/h then the script meant to handle this problem described in Section 6.2 was activated. The activated script works only when optimization results show negative flow of LP venting valve and set the LP venting flow to be zero by adding the deficit amount of steam to one of the boiler.

As expected when the solver significantly decreases the steam production, the net change of pumps and compressors at the VHP header is 395.7 kW switching from turbine mode to motor mode, in total 15 out of 52 units are switched in mode. The combination of the operational mode for the pumps and compressors suggested by the solver can be seen in Figure 7.1.

When running the optimization solver more than one time on the same scenario after convergence it was discovered that different solutions were obtained. In Figure 7.2, the pumps and compressors settings for an alternative solution to Scenario 2 is shown. The net change of power demand is the same 395.7 kW changing from turbine mode to motor mode at the VHP header. The economical difference is negligible.

The reason for obtaining the different solutions with very similar operating cost can be because of two things; the difference in values between the two solutions fall within the error tolerance limit set in the solver or the solver got stuck in a local minimum. Decreasing the tolerance level did not have any effect, and verifying that the solver got stuck in a local minimum was not applicable. One indication is that there are different ways of adjusting the operational settings of the pumps and compressors to achieve the same (or very close to the same) reduction of utility cost. Even if this means that it is not possible to identify one optimal way for operating the system, the utility cost suggested by the solver can be seen as a target that can be achieved when making changes in the operational settings of pumps and compressors. However, a number of simulations was needed to achieve convergence. This was concluded to be because the solver got stuck in a local minimum, the indications are that after each simulation, a greater change was observed in the total utility cost. But after convergence, the optimizer cannot further decrease the use of LNG since it has been already approaching zero as can be seen in Table 7.3.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Turbine	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Turbine	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Turbine	PT-3203 A	T_HS_MSS320	Motor	Turbine
CT-1525 B	T_HS_LS	Turbine	Motor	PT-3203 B	T_HS_MSS320	Motor	Motor
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Turbine	Turbine	CT-8340 A	T_TS_LSS810	Turbine	Motor
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Motor	Turbine
PT-2305 B	T_HS_LSS230	Motor	Turbine	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Motor	Motor	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Motor	Motor	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Motor	Turbine	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Turbine	Motor	PT-1524 B	T_MS_LS	Turbine	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Motor	Turbine	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Turbine	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Motor
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Turbine
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Turbine
CT-3402	T_HS_LSS320	Turbine	Turbine	PT-3205 B	T_MS_LSS320	Turbine	Turbine
PT-3801 A	T_HS_LSS320	Turbine	Motor	PT-3206 B	T_MS_LSS320	Turbine	Motor
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.1: Changes of operational mode for pumps and compressors after optimization, for Scenario 2.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Turbine	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Turbine	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Turbine	PT-3203 A	T_HS_MSS320	Motor	Motor
CT-1525 B	T_HS_LS	Turbine	Motor	PT-3203 B	T_HS_MSS320	Motor	Turbine
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Turbine	Turbine	CT-8340 A	T_TS_LSS810	Turbine	Motor
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Motor	Turbine
PT-2305 B	T_HS_LSS230	Motor	Turbine	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Motor	Motor	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Motor	Motor	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Motor	Turbine	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Turbine	Motor	PT-1524 B	T_MS_LS	Turbine	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Motor	Turbine	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Turbine	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Motor
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Turbine
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Turbine
CT-3402	T_HS_LSS320	Turbine	Turbine	PT-3205 B	T_MS_LSS320	Turbine	Turbine
PT-3801 A	T_HS_LSS320	Turbine	Motor	PT-3206 B	T_MS_LSS320	Turbine	Motor
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.2: Changes of operational mode for pumps and compressors after the second optimization for Scenario 2.

It should also be noted that, although the net change in power demand is shifted from turbine drive to motor, some units are switched in the other direction. The reason for this is the fixed power load of the majority of the turbines in the system, which means that changes in steam flows are obtained in discrete intervals. Reaching a certain steam balances, therefore requires a mix of turbines in operation where the sum of their fixed loads together comes as close as possible to a desired total steam flow.

7.4.2 Scenario 10

The optimization results for Scenario 10 can be seen in Table 7.4. The results show that the total utility cost was lower in scenario simulation than in optimization. However, the data regarding steam production from the boilers calculated in scenario mode show that the production is below the minimum load that is constraining the optimization. If the minimum limit of the load constraints are changed to the same values as the production calculated in scenario mode, the optimizer provides a lower utility cost than otherwise, as seen in the last column of Table 7.4.

Table 7.4: Comparison of values before and after running optimization to measured values from Preem refinery, for Scenario 10.

Variable	Scenario mode	Optimization mode	Measured values	Adjusted minimum loads on boilers
Electricity cost [SEK/h]	1552	1215	-	1257
LNG cost [SEK/h]	15358	15878	-	15358
Total cost [SEK/h]	16910	17094	-	16615
LP venting [t/h]	23.4	25.1	14.5	22.5
VHP-MP valve [t/h]	15.5	10.6	6.8	10.2
MP-LP valve [t/h]	17.2	6.4	3.1	7.1
Total boiler production [t/h]	33.7	36	33.7	33.7

Hence, using the original load constraints for the boilers the solver cannot find a solution that provides a lower utility cost than the one from scenario simulation, applying a lower bound similar to the operating value in scenario mode for each boiler, the optimizer finds a lower cost. This shows that small adjustments of the constraints can lead to small changes in loads that have a crucial effect on the marginal fuel consumption and thereby the costs. It is not impossible to operate the boilers at loads lower than the minimum load given in Table 6.2 according to Preem staff, but the general limits should be according to Table 6.2.

In Figure 7.3, the changes in the operational mode for pumps and compressors after optimization can be seen. For the units connected to the VHP header, the net change in operational power demand is 593.3 kW from motor mode to turbine mode. This is as expected since steam was in excess in this scenario and for the optimal solution steam is better utilized. In Figure 7.4 the changes in operational mode for pumps and compressors can be seen when using the adjusted lower minimum load limit for the boilers. In this case the net change in operational power demand is 484.3 kW from motor to turbine mode. Comparing the differences between the two cases it was noted that they are small and that the solver is optimizing power demands in a similar way as in the optimization case described in Section 7.4.1. The total number of units that changes operational mode was 13 out of 52 units in both cases.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Motor	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Turbine	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Turbine	PT-3203 A	T_HS_MSS320	Motor	Motor
CT-1525 B	T_HS_LS	Turbine	Motor	PT-3203 B	T_HS_MSS320	Motor	Motor
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Motor	Turbine	CT-8340 A	T_TS_LSS810	Motor	Turbine
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Turbine	Turbine
PT-2305 B	T_HS_LSS230	Turbine	Turbine	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Motor	Motor	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Turbine	Turbine	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Motor	Turbine	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Turbine	Turbine	PT-1524 B	T_MS_LS	Motor	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Turbine	Turbine	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Motor	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Turbine
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Turbine
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Turbine
CT-3402	T_HS_LSS320	Motor	Turbine	PT-3205 B	T_MS_LSS320	Motor	Turbine
PT-3801 A	T_HS_LSS320	Motor	Motor	PT-3206 B	T_MS_LSS320	Turbine	Turbine
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.3: Changes of operational mode for pumps and compressors after optimization, for Scenario 10.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Motor	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Turbine	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Turbine	PT-3203 A	T_HS_MSS320	Motor	Motor
CT-1525 B	T_HS_LS	Turbine	Motor	PT-3203 B	T_HS_MSS320	Motor	Motor
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Motor	Turbine	CT-8340 A	T_TS_LSS810	Motor	Turbine
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Turbine	Turbine
PT-2305 B	T_HS_LSS230	Turbine	Turbine	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Motor	Turbine	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Turbine	Turbine	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Motor	Motor	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Turbine	Motor	PT-1524 B	T_MS_LS	Motor	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Turbine	Motor	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Motor	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Turbine
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Turbine
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Turbine
CT-3402	T_HS_LSS320	Motor	Turbine	PT-3205 B	T_MS_LSS320	Motor	Turbine
PT-3801 A	T_HS_LSS320	Motor	Motor	PT-3206 B	T_MS_LSS320	Turbine	Turbine
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.4: Changes of operational mode for pumps and compressors after optimization, for Scenario 10, with lower minimum limit on the steam boilers.

7.4.3 Scenario 8 and 12

Table 7.5 shows the results from optimization of Scenario 12. The utility cost decreases by 1051.6 SEK/h and also the unused steam that flows through the let down-valves decreases compared with the solution from scenario simulation. However, the steam vented to the atmosphere is as high as in Scenario 10. This is because there is no further value in achieving steam savings since the boilers are operating at their minimum load capacity. In Scenario 2, the availability of refinery gas in relation to the process steam demand is lower compared to the other scenarios, and therefore the steam flow through the LP vent is low, while for Scenario 10 and 12, the LP vent is relatively high.

Table 7.5: Comparison of values before and after running optimization to measured values from Preem refinery, for Scenario 12.

Variable	Scenario mode	Optimization mode	Measured Values
Cost Electricity [SEK/h]	1365	1243	-
Cost LNG [SEK/h]	21610	20762	-
Total Cost [SEK/h]	22975	22005	-
LP venting [t/h]	29.3	24.3	0.5
VHP-MP valve [t/h]	18.8	9.9	3.2
MP-LP valve [t/h]	13.3	7.5	7.6
Total boiler production [t/h]	40	36	40

In Figure 7.5, the changes in operational mode for pumps and compressors can be seen. The net change for units connected to the VHP header is 349 kW of power switched from motor to turbine drive, this is expected since the LNG price is low and the electricity price is high. There are only a few pumps settings change but the units that are involved are high power demanding units.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Turbine	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Motor	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Turbine	PT-3203 A	T_HS_MSS320	Motor	Motor
CT-1525 B	T_HS_LS	Motor	Motor	PT-3203 B	T_HS_MSS320	Motor	Motor
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Turbine	Turbine	CT-8340 A	T_TS_LSS810	Motor	Turbine
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Turbine	Turbine
PT-2305 B	T_HS_LSS230	Turbine	Turbine	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Turbine	Motor	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Motor	Turbine	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Turbine	Motor	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Motor	Turbine	PT-1524 B	T_MS_LS	Motor	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Motor	Motor	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Motor	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Motor
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Motor
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Turbine
CT-3402	T_HS_LSS320	Motor	Turbine	PT-3205 B	T_MS_LSS320	Motor	Motor
PT-3801 A	T_HS_LSS320	Turbine	Turbine	PT-3206 B	T_MS_LSS320	Motor	Motor
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.5: Changes of operational mode for pumps and compressors after optimization, for Scenario 12.

In Table 7.6, the results for Scenario 8 can be seen. The results are, as expected, similar to the results from Scenario 12, the small differences that exist are assumed to come from the different input values.

Table 7.6: Comparison of values before and after running optimization to measured values from Preem refinery, for Scenario 8.

Variable	Scenario mode	Optimization mode	Measured Values
Cost Electricity [SEK/h]	1244	1240	-
Cost LNG [SEK/h]	12347	10244	-
Total Cost [SEK/h]	13591	11484	-
LP venting [t/h]	32.6	22.1	1
VHP-MP valve [t/h]	18.2	10.2	3.9
MP-LP valve [t/h]	12.8	7.8	6.9
Total boiler production [t/h]	45.1	36	45.1

In Figure 7.6, the changes in the operational mode for pumps and compressors can be seen, the net change for units connected to the VHP header is 109 kW of power switched from turbine to motor mode. Comparing Figures 7.5 and 7.6, it can be observed that the main parts of the pump and compressor system are the same for both before and after optimization. The main difference is that a large and power demanding unit CT-3402 is initially in turbine mode in Scenario 8 while in Scenario 12 it is in motor mode. That initial difference is assumed to affect the final optimization setting of the units.

Pump name	To-From	Before Opt	After Opt				
PT-8122 B	T_TS_MSS810	Turbine	Turbine	PT-3202 A	T_HS_MSS320	Motor	Motor
PT-8126 B	T_TS_MSS810	Motor	Turbine	PT-3202 B	T_HS_MSS320	Motor	Motor
PT-8127 B	T_TS_MSS810	Turbine	Motor	PT-3203 A	T_HS_MSS320	Motor	Turbine
CT-1525 B	T_HS_LS	Motor	Motor	PT-3203 B	T_HS_MSS320	Motor	Motor
PT-1534 B (F)	T_HS_LS	Turbine	Turbine	PT-8110 A (F)	T_TS_LSS810	Turbine	Turbine
PT-2310 A	T_HS_LSS230	Turbine	Motor	CT-8340 A	T_TS_LSS810	Motor	Turbine
PT-2307 A (F)	T_HS_LSS230	Turbine	Turbine	CT-8350	T_TS_LSS810	Turbine	Turbine
PT-2307 B (F)	T_HS_LSS230	Motor	Motor	PT-2905 B	T_MS_LS	Turbine	Turbine
PT-2305 B	T_HS_LSS230	Turbine	Motor	PT-2906 B	T_MS_LS	Turbine	Turbine
PT-2102 B	T_HS_LSS210	Turbine	Turbine	PT-3701 A (F)	T_MS_LS	Motor	Motor
PT-2102 C	T_HS_LSS210	Motor	Turbine	PT-3701 B (F)	T_MS_LS	Turbine	Turbine
PT-2103 B	T_HS_LSS210	Motor	Motor	PT-1511 A (F)	T_MS_LS	Turbine	Turbine
PT-2104 A	T_HS_LSS210	Turbine	Turbine	PT-1511 B (F)	T_MS_LS	Turbine	Turbine
PT-2107 A	T_HS_LSS210	Motor	Motor	PT-1524 B	T_MS_LS	Motor	Motor
PT-2110 A (F)	T_HS_LSS210	Turbine	Turbine	PT-1901 B (F)	T_MS_LS	Turbine	Turbine
PT-2110 B (F)	T_HS_LSS210	Motor	Motor	PT-2412 B (F)	T_MS_LS	Turbine	Turbine
PT-2112 (F)	T_HS_LSS210	Turbine	Turbine	PT-2413 B (F)	T_MS_LS	Turbine	Turbine
PT-2201 B	T_HS_LSS210	Motor	Motor	PT-2314 B (F)	T_MS_LS	Turbine	Turbine
PT-2202 B	T_HS_LSS210	Motor	Motor	PT-2343 B	T_MS_LS	Turbine	Motor
PT-2203 A	T_HS_LSS210	Motor	Motor	PT-2903	T_PT2903	Motor	Motor
BT-3201 (F)	T_HS_LSS320	Turbine	Turbine	PT-2306	T_PT2306	Motor	Motor
BT-3202 (F)	T_HS_LSS320	Turbine	Turbine	PT-3201 B	T_MS_LSS320	Turbine	Motor
BT-3203 (F)	T_HS_LSS320	Turbine	Turbine	PT-3204 B	T_MS_LSS320	Turbine	Motor
CT-3402	T_HS_LSS320	Turbine	Turbine	PT-3205 B	T_MS_LSS320	Motor	Turbine
PT-3801 A	T_HS_LSS320	Turbine	Motor	PT-3206 B	T_MS_LSS320	Motor	Turbine
PT-3802 A	T_HS_LSS320	Turbine	Motor	PT-3301 A (F)	T_MS_LSS320	Turbine	Turbine

Figure 7.6: Changes of operational mode for pumps and compressors after optimization, for Scenario 8.

8

Using the model as a decision support tool

This chapter, discusses how to use the new model from the Excel interface as well the aspects to investigate further when obtaining deviating results are described.

8.1 Scenario mode

The purpose of using the simulation model in scenario mode is to see how well the model reflects the real situation at the refinery at a specific time. If the results from scenario mode simulation are not accurate, the model cannot be used in optimization mode.

The first important step when using the simulationtool is to understand what variables to investigate and how to prioritize them when the model is not accurate. Thus, after the simulation has finished, the user should go to 'Validation' spreadsheet which compares calculated values of selected free variables with measurement values obtained from Preem's system. Table 8.1 shows a typical data validation sheet from the Excel interface.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	362,52	360,8	1,72	0,48%
Utilized Make up	Tonne/Hr	126,29	121,4	4,89	4,03%
LS venting	Tonne/Hr	28,87	29	0,13	0,46%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	23,89	23	0,89	3,88%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	10,31	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	0	0,00	0,00%
MS -> LS valve	Tonne/Hr	18,40	21,8	3,40	15,61%
Turbine ICR CT8101	Tonne/Hr	27,17	27	0,17	0,64%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	12,48	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	30,84	27,7	3,14	11,32%
DS 8103 Steam-out	Tonne/Hr	42,16	42	0,16	0,38%
Used Electric Energy	kW	4758,16	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	42268,24	43246,1	977,86	2,26%
LNG percentage	%	2,80	5,00	2,20	43,96%

Table 8.1: Validation table for checking accuracy.

Values within the blue and red rectangles are the values for steam system and fuel gas system, respectively. In the blue rectangle, the first two rows are the total feedwater and freshwater make-up to the steam system. The next three rows are the steam flows from venting valve for LP and VHP level headers. These flows are the flow going out of the system. The rest of the rows within the blue rectangle are the steam flow through valves and turbines between each header. Overall, if these water and steam flow values from the model and the measurement are within the limits of Equation 5.2 and has a absolute error less than 5 t/h, it can be concluded that the model reflects reality for steam system for the simulated scenario.

On the other hand, the red rectangle contains values from the fuel gas system which are the total fuel gas used and the LNG percentage in the fuel gas. It should be noted that if there is a deviation between measured and model values for the total fuel gas used, this deviation comes from the fuel flow to the boilers only since the rest of the flow is set to a fixed value representing others fuel gas consumers. The mismatch of this value corresponds to the error in LNG percentage as well. This error is expected to come from the molecular weight of the fuel gas in the model which is set to 35 kg/kmole, which is not measured at the refinery. One should carefully re-check the molecular weight of the fuel gas for the specific scenario before using the model and if possible, the LHV should also be checked. However, since the fuel gas system and the steam system are modelled separately, the error from each part does not affect the other part's accuracy in scenario mode.

However, in optimization mode, an error in the fuel balance could affect the optimal solution if the LNG share is close to 0%. In such cases the optimal solution is likely to involve reduction of the fuel flow to the boilers until the LNG share is equal to zero. The point at which this occurs is highly dependent on the modelled fuel gas balances, and thereby affected by errors in the fuel gas model.

Variables that usually deviate from the measured value are LP venting, steam flow through VHP-MP vent and steam flow through MP-LP vent. Sources for these deviations regarding these variables can be found at different places. Firstly, the deviation can come from the internal production and consumption of steam at the overhead header, so one should compare the steam flows for theses units to the valve opening. Since the valve opening percent is more reliable, if the steam flow value seems unreasonable, a regression equation for the flow based on the valve opening should be used to predict the amount of steam flow through the valve instead. Secondly, the deviation can come from an averaging usage of the pumps and compressors, which will be further explained in the coming paragraph. Deviations in the fuel gas system are usually connected to the production of the boilers, the LHV and molecular weight of the refinery gas. Some of these investigations requires access to the refinery data base which is not always possible. So, it is important to collect data as much as possible and also have data for checking these variables available.

When extracting data, consideration for averaging must be taken. As can be seen from Scenarios 6 and 10, there is a difference between using a daily or weekly average, and also other periods can of course be used. When averaging there are a number of variables to pay extra attention to. Cross reference of steam flows and pump and compressor settings is important. Steam production can peak and for a short while a high pump power can be required. The peak in steam production can effect the average quite much while a small time of operation of the pump will have a small affect in averaging. Thus deviating results can originate from the averaging, especially from averaging the operational setting of pumps and compressors.

8.2 Optimization mode

Prior to optimization, the users need to check all the constraints in the 'Demand', 'Availability' and 'Energy Cost Summary'. For example, the demands and supplies of steam for each unit need to be specified for the scenario to be optimized. To reduce error risk when entering all the constraints, the prepared spreadsheets built by Gunnarsson and Kobjaroenkun are set to automatically update when changing the scenario. The only spreadsheet that users need to change is 'Energy cost summary', which contains the electricity price and LNG price for the solver to optimize the results. Table 8.2 shows the Excel sheet where the user needs to correct the price for each scenario before optimization.

Legend	Units	Min	Max	Period 1			
				Fixed Cost	Var. Cost	Flow	Total Cost
Elec							
Electricity.Electricity_Tier2	MWh	0,00	99999999,00	0,00 kr	200,00 kr	5,03	1 005,90 kr
					Elec Sub Total	5,03	1 005,90 kr
Fuel							
LNG.LNG_Tier1	GJ	0,00	99999999,00	0,00 kr	100,00 kr	0,00	0,00 kr
					Fuel Sub Total	0,00	0,00 kr
						Total Cost	1 005,90 kr

Table 8.2: Energy prices in Energy Cost Summary.

According to Table 8.2, the two red marks are the cells containing prices with the electricity price in the unit of [kr/MWh] and the LNG price in the unit of [kr/GJ]. The optimizer approaches the optimal results by evaluating the operating costs and then proposes possible operating conditions for the boilers, pumps and compressors according to the constraints.

Furthermore, when utilizing the optimization function it is important to keep in mind the load constraints of the boilers. If the actual operations of the boilers have a load lower than the total minimum load applied in the constraint then it is possible that the solver might not find a solution that provides a lower utility cost. If such a case occurs, the users need to reduce the minimum load of the operated boilers to the actual operating value obtained from Preems system by editing in 'Availability' spreadsheet. Also it can be necessary to run the optimization function more than twice, since the solver usually converges when either total minimum steam production at the boilers is reached or when the import of LNG approaches zero, thus meaning that if minimum load for the boilers in operation is not reached at the first simulation more simulations is needed for convergence and similar as the flow of LNG approaches zero.

Additionally, it should be ascertained that the solver can only adjust the setting of pumps and compressors that are considered as possible to switch. This can be edited within the

'Availability' spreadsheet. Having too many units as "Available" can achieve results in which an unrealistic amount of units are changed, thus the user should set the units whose effects are to be investigated as "Available" and the remaining units as either "Must Be On" or "Not Available", depending on the operational mode.

It is also important to keep in mind what kind of operational scenario is investigated; if the refinery is partly shut-down then maybe the power demands of the pumps are not accurate. A shut-down can decrease the power demand for pumps and compressors to 75% of maximum capacity, thus affecting the steam flows. These power demands are also of importance since the solver may change a number of units only to gain a small net change of power, thus if the power demands do not have correct values then the changes suggested by the solver will not be accurate. The changes in power demands is applicable also when using the model in scenario mode.

It should be noted that it is not always possible to obtain realistic values, especially for the LP-vent valve. After optimization, the steam vented to LP-vent valve can become negative. Control of the steam flow through the LP-vent valve is of importance, if this value becomes negative then the script described in Section 6.2 should be activated, this means that the negative flow of steam will be added to the steam production at the boilers and the steam let to the atmosphere will be positive and close to zero, the solution is not optimal but still provides a lower utility cost than the actual operational situation.

When investigating the results from the optimization solver, a closer look on the steam flows through the let-down valves is recommended. The low steam flows through these valves indicate that steam is efficiently utilized and overproduction is small. If there are large flows of steam through the let-down valves then a closer investigation of pumps and compressors at the header in question is appropriate and also a control of the boilers.

9 Summarizing discussion

In this chapter, a summary of the strengths and limitations of the new version of the steam system model for Preemraff Lysekil is presented as well as some suggestions for further developments that could improve the model even further.

9.1 Improvements, strengths and limitations

Improvement of model parameters, including process steam flows have focused on parameters that are of significant importance for the steam system and on the mass balances. The goal was to construct a model that will be within the desired error limit for different operational situations. Furthermore, the use and extraction of results of the model through the Excel interface has been eased significantly.

The main improvements to steam system variables and process steam flows are presented in Chapter 6. These changes have made the model better representative of real operating conditions and constraints. For example, the amount of the refinery gas flow cannot be reduced further. While previously, the marginal change in fuel gas consumption had to be translated to a change in LNG consumption outside of the model, this is now internalized in the main steam system model.

A change in the feed water temperature in the model has a large impact on the fuel gas system and the boilers. This change together with the adjustments of the fuel gas system made the need for constant values other than the efficiency unnecessary. For example, the performance factor which was used as a tuning parameter in the original model has been removed and set to the default value. Also decreasing the number of fixed variables and replacing them with confirmed system conditions is considered as an improvement that makes it easier to understand and interpret the model parameters.

The changes connected to pumps and compressors are more of the tuning kind, the addition of the by-pass flow concerns quite a small flow of steam compared to the production of steam at each header but is a confirmed flow that has not been accounted for and can be seen as marginal fine tuning. Larger effects from changes of the pumps and compressors come from removal of power demands connected to pumps that are usually not in operation or have more than two operational alternatives as described in Section 6.1.3. This change concerns large power demands pumps such as PT-3202B (640 kW) and PT-2307B (363 kW). The inclusion of these power demands could have been acceptable in the model if making them "Not Available", in which case they would not affect the steam system.

However, in that case, they would imply an electrical consumption instead, something that would not affect the optimal solution, but its value due to the incorrect calculation is electricity costs.

Process steam flows that were calculated incorrectly in the original model have now been corrected or been given a more updated value according to Preem staff. The steam consumption decreased when these corrections were implemented, but there were no more known demands of steam, thus as described in Section 5.5.1 an unspecified consumption of steam was added to the model and also additional undefined flows of steam between the headers were added. This is not an ideal approach but there are no more measurements of steam flows. Furthermore, it is known that there is consumption of steam that is not measured. Thus in the new model version steam is not referred to the wrong consumer, and the unmeasured steam consumption more clearly works as a tuning parameter.

All work with the model can be handled from the Excel interface. This will decrease the risk of error due to handling since Excel is more well-known by Preem staff. Import of data for running simulations is also done through Excel and the interface is built up so that it easy and convenient to copy and paste the required data between the sheets. There are a number of steps to keep in mind but it is still more effective and user friendly than working either from both Aspen Utilities Planner and Excel at the same time or only Aspen Utilities Planner.

The validation results show that the model performs well during stable operational situations, i.e. when there are no parts of the refinery that are shut-down, and no major transitions between different operating modes. The tables in Section 6.4 showing the errors at the headers and the let-down valves supports this as the trend is that the errors increases for the scenario with areas shut-down. The decrease in performance is assumed to be connected to the degassing of process equipment during shut-down periods. Since during this process the flow meters for the steam are by-passed, and it is difficult to estimate how much steam is consumed by each area unit.

Results from the optimization function shows that the optimizer works as expected. The utility cost decreases compared to scenario mode. However, the solution from an optimization depends strongly on a few important constraints in the model, especially the minimum load of the steam boilers. Consequently, it is important to remember that if the operational situation shows that the boilers, for example produces less steam than the minimum load with the specific configuration of boilers then the constraints should be changed so that the economic comparison is on the same premise. For the scenarios investigated in Section 7.4, the optimization model had many pumps and compressors in "Available" mode. This is the reason why the solver changes a lot of pumps and compressors. In practice, more units should probably be set as "Must Be On", thus the solver will only work with a handful of pumps and compressors and the decrease in the utility cost will probably decrease. However, it would be more realistic to change the operational mode for only 3-4 units instead of around 15 as was suggested in some case in Section 7.4.

9.2 Further developments

Future work regarding this model should focus on the operational situations when parts of the refinery are shut-down. For these situations, the model results deviates the most from measured values. However, this is also when the data is less accurate since the refinery decreases the production. Furthermore during shut-down scenarios the power demands of the pumps and compressors should be investigated. It is possible that they are working at lower capacity rates, while as it is now the model assumes close to full load also during shut-down scenarios.

Another development would be to specify uncertain steam consumers such as steam tracing and also get an idea of leakages and small steam flows between the headers, this would decrease the values for unknown steam consumers and steam flows between the headers which would make the model more reliable.

Other than the developments on the steam system, it would be good to further investigate the fuel gas system part. In the model, there are only three boilers and other fuel consumers that connect to the fuel gas system and since they were modelled by fixing the amount of steam generated, therefore further modifications on fuel gas system would not influence the accuracy on steam system as a whole. Due to the limitation of the program, the density of gas cannot be entered directly to model the fuel gas system but instead the molecular weight and LHV of the fuel gas are needed. The current situation for the fuel gas system is that the molecular weight of the fuel gas fed to the boilers is not measured and the current value in the model is 35 kg/kmole according to Subiaco [5]. A small change in the molecular weight of the fuel gas highly affects both the fuel gas flows to the boilers and the proportion of LNG in the fuel gas. Thus, the accuracy of fuel gas system can be improved by tagging the molecular weight of fuel gas carefully. There are some properties needed in order to obtain the correct molecular weight of the refinery gas which are; the composition of the imported LNG, pressure and temperature for both LNG and refinery gas. With these properties density and conversion factors for flows can be found and since the flow of mixed LNG and refinery gas is measured and by removing the imported LNG and calculate the mass flow of the different components in the refinery gas the molecular weight can be found.

Another factor that greatly affects the fuel gas flows is the LHV of the fuel gas itself. Since in the model, only the mass basis LHV can be used, but in reality the LHV of the fuel gas is measured in volume basis and is calculated by using the density of the fuel gas to convert the unit. But the density of the fuel gas can sometimes go down to even 0.5 kg/m^3 according to the measured tag value and that is considered unreasonably low. If the unrealistically low value of the density of the fuel gas is used to calculate the LHV in mass basis, LHV of the fuel gas will become unrealistically high and cause a large deviation in the amount of fuel gas flow to the boilers. If such a situation takes place, one should further investigate what actually is a value of LHV at that specific moment.

10
Conclusion

In this master thesis, a model of the steam utility system of the Preem refinery in Lysekil has been further improved and developed. Model assumptions, parameter, and functions concerning equipment in the steam network, steam consumption and production, and the fuel gas system have been investigated. Furthermore, the model has been validated against new data scenarios extracted from Preem's database and an extensive development of the Excel user interface has been done.

Validation results for the latest steam model version show that the steam model and the fuel gas system have become more reliable during stable and full production operation of the refinery. The model can be solved in optimization mode for which the results provide lowered utility cost for the tested operational scenarios. An improved Excel user interface can be used to run the model in both scenario and optimization modes. Moreover, current operating conditions can be conveniently imported to the interface and simulated. The model user guide has been provided the description on how to import data, to run the model and to interpret the results.

The model can be used to predict how changes in LNG and electricity price influences the operation of the steam system, i.e. how could could the steam system including the operational setting of pumps and compressors be operated during for example high electricity price time. Other use of the model is to investigate operational changes i.e. without testing in reality. The optimization function can be used to observe small changes in the system, only changing one or two pumps but also situations when several changes between motor and turbine mode is needed. In research areas the model can be used to observe how increase and/or decrease in steam production/consumption affects the utility cost, these changes can be results from for example retrofits of heat exchanger networks or expansion of the refinery.

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A

Running optimization mode through Excel interface

This appendix briefly explains how to perform optimization mode simulation through Excel interface. With the use of add-ins function in Microsoft Excel, 'Utilities340' allows the simulation to be run both in Scenario mode and optimization mode through Excel. The following steps briefly describe how to open the Excel file with a connection to Aspen Utilities Planner:

1. Open up the Microsoft Excel file named STEAM.MODEL_LYSEKIL_Final
2. Go to the installation drive for Aspen Utilities planner and open up utilities340.xla to enable macro.
   Default location: ProgramFiles\AspenTech\Aspen Utilities Planner V8.8\bin
3. Click on Aspen Utilities in the ADD-INS menu bar then select 'Open Aspen Utilities' then choose Aspen Utilities Planner file STEAM.MODEL_LYSEKIL_Final
4. Select Show Aspen Utilities if the user wants to see Aspen Utilities Planner interface.

At this stage, the Excel file with a connection to Aspen Utilities Planner interface is ready to be used for Scenario mode simulation. The next steps describe how the optimization mode can be performed in this model:

1. Click on 'Aspen Utilities', on the list choose 'Editors' under 'Optimization' as can be seen in Figure A.1.

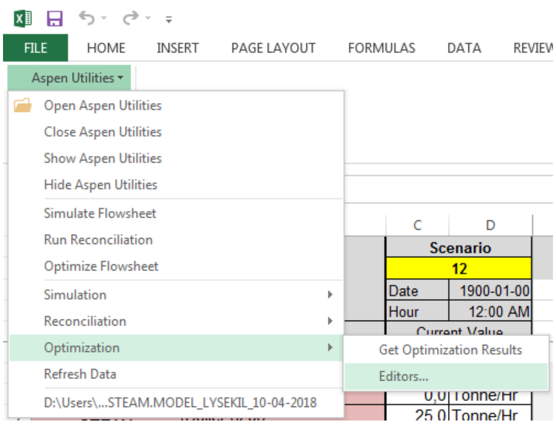

Figure A.1: Retrieving constraints from Aspen Utilities Planner to Excel

2. The program will ask if the user want to create the new data sheet containing

constraints, click Yes then the new spread sheets will be created as shown in the red block in Figure A.2.

Figure A.2: New spread sheets containing constraints

3. Select 'Optimize flowsheet' under 'Aspen Utilities' to run the simulation in optimization mode.

It is easy to make a human error during the simulation due to the complexity of the software, thus another user guide, which describes more thoroughly, has been created and is included as a separate file.

B

Excel sheet containing current data and tags

HS header

	SG 3201		SG 3202		SG 3203		HRSG 2101		HRSG 2340
	Steam flow	Temperature	Steam flow	Tempeture	Steam flow	Tempeture	Steam flow	Temperature	Steam flow
	t/h	C	t/h	C	t/h	C	t/h	C	t/h
Date	32FI109	32TC102	32FI209	32TC203	32FI309	32TC304	21FI350	21TC354	23FI350
2018-03-01 09:44:11	0,362541676	209,2948914	10,85978699	390,7604065	26,75341034	400,7198486	26,06839943	384,3848267	22,43670273

TSS header

	TSS 810			Total	Producer	Consumer	ICR810		Total
	Steam from HS	eam from E81	Pressure				8120 steam injectio	T-8121 steam injection	
	kg/h	kg/h	barg				kg/h	kg/h	
Date	81FI83	81FI22	81PC260				81FC48	81FC59	
2018-03-01 09:51:14	-77,24995422	47038,69922	21,32990646	46,96144926			3822,420898	3717,724609	7,54

MS header

	E1503	E1506	E2203		E2220	E2604			E2905,E2908A-F
	Steam flow	Steam flow	Steam flow	Steam flow	Water flow	Steam flow	Steam flow	Steam flow	Steam flow
	t/h	t/h	t/h	t/h	Sm3/h	t/h	t/h	t/h	t/h
Date	15FI93	15FI58	22FI19	22FI21	22FC36	26FI7A	26FI7B	26FI7C	29FI54
2018-03-01 09:53:35	3,759241819	12,6759634	21,87557983	20,86383629	1,926371932	8,200155258	10,33695984	7,459257603	62,6135788

LS header

	E2211A	E2418	E2602 A/B/C	E2922B	V3204	LSS ICR	Total	Producer	Consumer
	Steam flow	Steam flow	Steam flow	Steam flow	Steam flow	Steam flow			
	t/h	t/h	t/h	t/h	t/h	kg/h			
Date	32FI30	24FI50		29FI77	32FI14	81FI144			
2018-03-01 09:42:10	-0,07521154	10,56324673		-0,004355839	15,76175785	35078,16406	26,25		

Pump setting

	CT-3402		PT-3801		PT-3802		PT-2310		PT-2305
	Turbine	Motor	Turbine	Motor	Turbine	Motor	Turbine	Motor	Turbine
Date	340gc02	34mcl01	380GP01A	380GP01B	380GP02A	380GP02B	23MPL10A	23MPL10B	23MPL05B
2018-03-01 09:53:55	0	1	1	0	0	1	0	1	0

Water and valve

	HBW	LBW		Make up	Prereformer and reformer		Water recycled	Utilized feed water	Water make-up for model
	Water	Water		Water					
	t/h	t/h		t/h					
Date	32FC17	32FI35	Total	32FI1	82FC9	82FC10	82FC42		
2018-03-01 09:52:11	245,9459534	182,0756836	428,021637	139,6923828	67967,16406	7506,25	35307,44531	387,8556682	99,52641406

Figure B.1: Current data sheet

C
Boiler efficiencies

The relationship between boiler efficiency and LHV value can be seen in Figures C.1 and C.2.

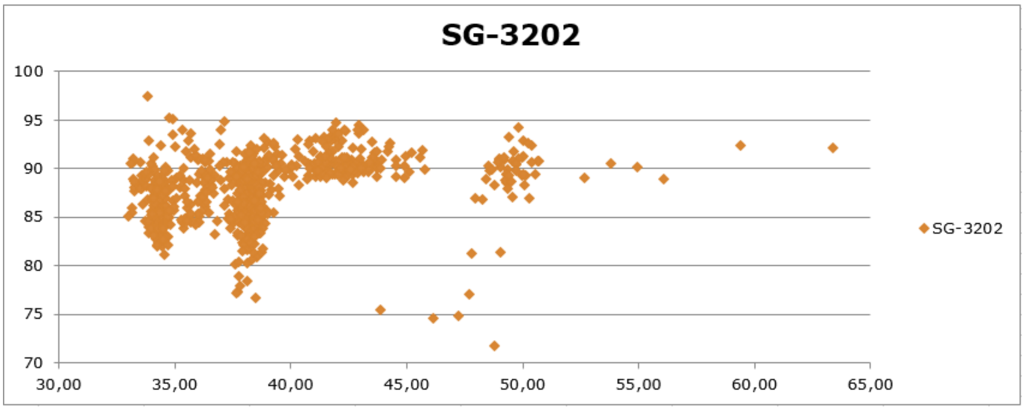

Figure C.1: Boiler efficiency against LHV value for SG3202 boiler.

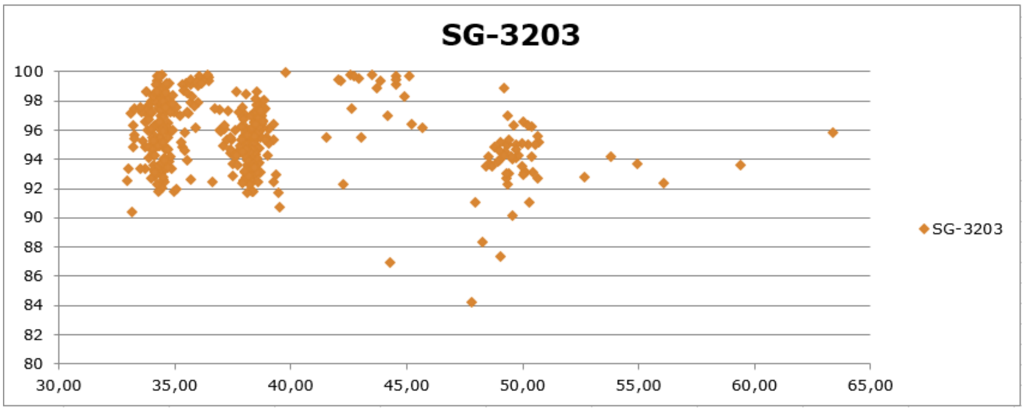

Figure C.2: Boiler efficiency against LHV value for SG3203 boiler.

In Figures C.3 and C.4 the steam production against the fuel consumption can be seen for SG3202 and SG3203.

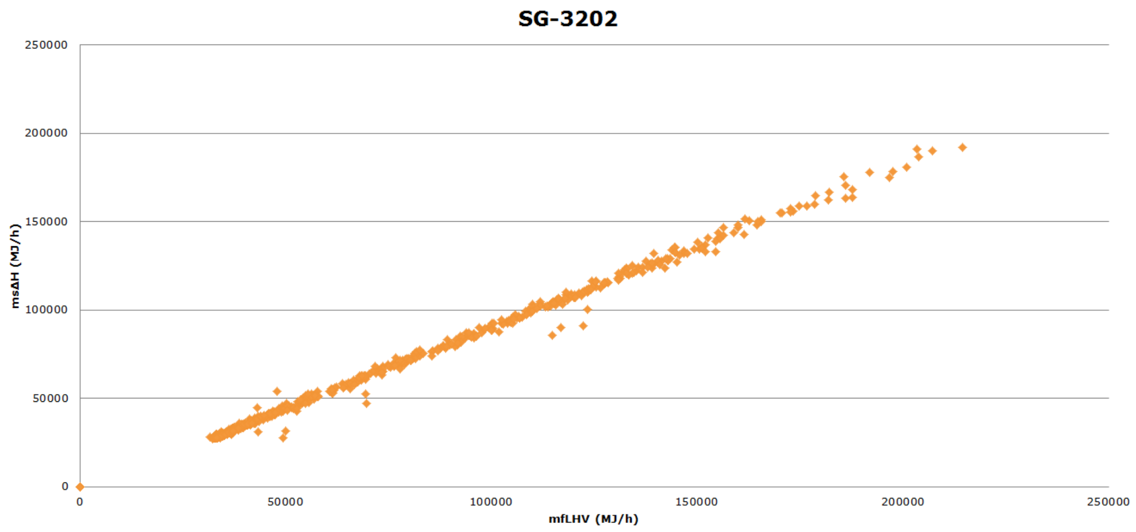

Figure C.3: Relationship between steam production and fuel consumption of SG3202.

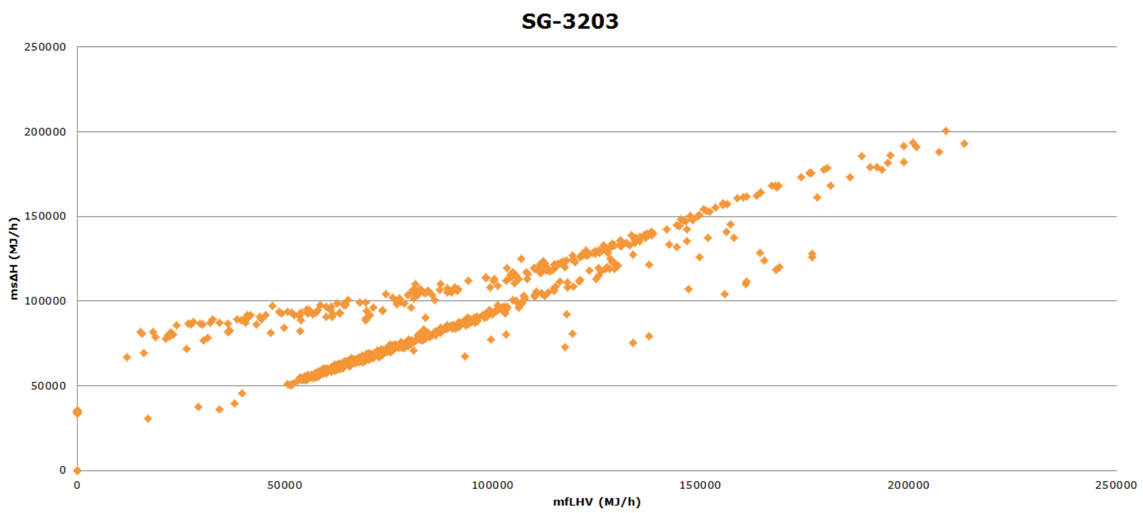

Figure C.4: Relationship between steam production and fuel consumption of SG3203.

D

Changes in the model

Here the changes done in the model are displayed so that the understanding of where in the model changes has been done.

In Figure D.1 the setting of the refinery gas to a fixed variable can be seen.

FuelGas.Summary Table

	Value	Spec	Units	Description
SpecifyFuelFlow	False			Specify fuel heat flow
CalculatePropsFromComp	No			Calculate fuel properties from composition?
FuelOut(*).F				
FuelOut("FuelOut1").F	108,876	Free	GJ/hr	Fuel heat flow
Fmass_out	2,86516	Free	tonne/hr	Fuel mass flow
Fmol_out	1834,84	Fixed	Nm3/hr	Fuel molar flow
MWout	35,0	Fixed	kg/kmol	Fuel molecular weight
CVout	38,0	Fixed	MJ/kg	Fuel calorific value
CI	0,0	Fixed		Fuel carbon index
NI	0,0	Fixed		Nitrogen index
SI	0,0	Fixed		Fuel sulphur index
OD	3,95	Fixed		Fuel oxygen demand

Figure D.1: Change for the refinery gas displayed.

In Figure D.2 the addition of the consumption of steam through by-pass flow that is always flowing can be seen.

T_HS_LSS230.Summary Table

	Value	Spec	Units	Description
NoPumps	5			Number of pumps
BypassOptInput	False			Send Power required from flowshee directly
PumpName(*)				
PumpName(1)	PT-2310 A			Pump name
PumpName(2)	PT-2307 A (F			Pump name
PumpName(3)	PT-2307 B (F			Pump name
PumpName(4)	PT-2305 B			Pump name
PumpName(5)	Roll_Cons_			Pump name

Figure D.2: Addition of turbine roll consumption.

Figure D.3 shows how the possibility to use two turbines at the same time was corrected.

T_HS_MSS320.Summary Table

	Value	Spec	Units	Description
NoPumps	5			Number of pumps
BypassOptInput	False			Send Power required from flowshee directly
PumpName(*)				
PumpName(1)	PT-3202 A			Pump name
PumpName(2)	PT-3202 B			Pump name
PumpName(3)	PT-3203 A			Pump name
PumpName(4)	PT-3203 B			Pump name
PumpName(5)	Roll_Cons_			Pump name
PumpOption(*)				
PumpOption(1)	Motor			Pump option
PumpOption(2)	Motor			Pump option
PumpOption(3)	Motor			Pump option
PumpOption(4)	Motor			Pump option
PumpOption(5)	Turbine			Pump option
PowerSupplyTotal	734,694	Free	kW	Total power supplied
SteamIn("SteamIn1").F	0,159354	Free	tonne/hr	Steam flow
SteamOut("SteamOut1").F	0,159354	Free	tonne/hr	Steam flow
Psin	40,0	Free	bar	Inlet pressure
Psout	12,0	Fixed	bar	Outlet pressure
Tsin	390,0	Free	C	Inlet temperature
Tsout	325,951	Free	C	Outlet temperature
PowerRequired(*)				
PowerRequired(1)	640,0	Fixed	kW	Power required by pump
PowerRequired(2)	0,0	Fixed	kW	Power required by pump
PowerRequired(3)	40,0	Fixed	kW	Power required by pump
PowerRequired(4)	40,0	Fixed	kW	Power required by pump
PowerRequired(5)	3,9	Fixed	kW	Power required by pump

Figure D.3: How multiple turbine choices was corrected.

In Figure D.4 the visible changes in the model PFD can be seen. The red circles represent added undefined consumptions that leaves the system, green circles represent unknown steam flows between the headers, the brown circles are addition of a small pump that represent the by-pass flow for the compressor turbines, the black one is therefore the condensation for CT2301 and the yellow circle represent all the consumers of the fuel mix at the refinery.

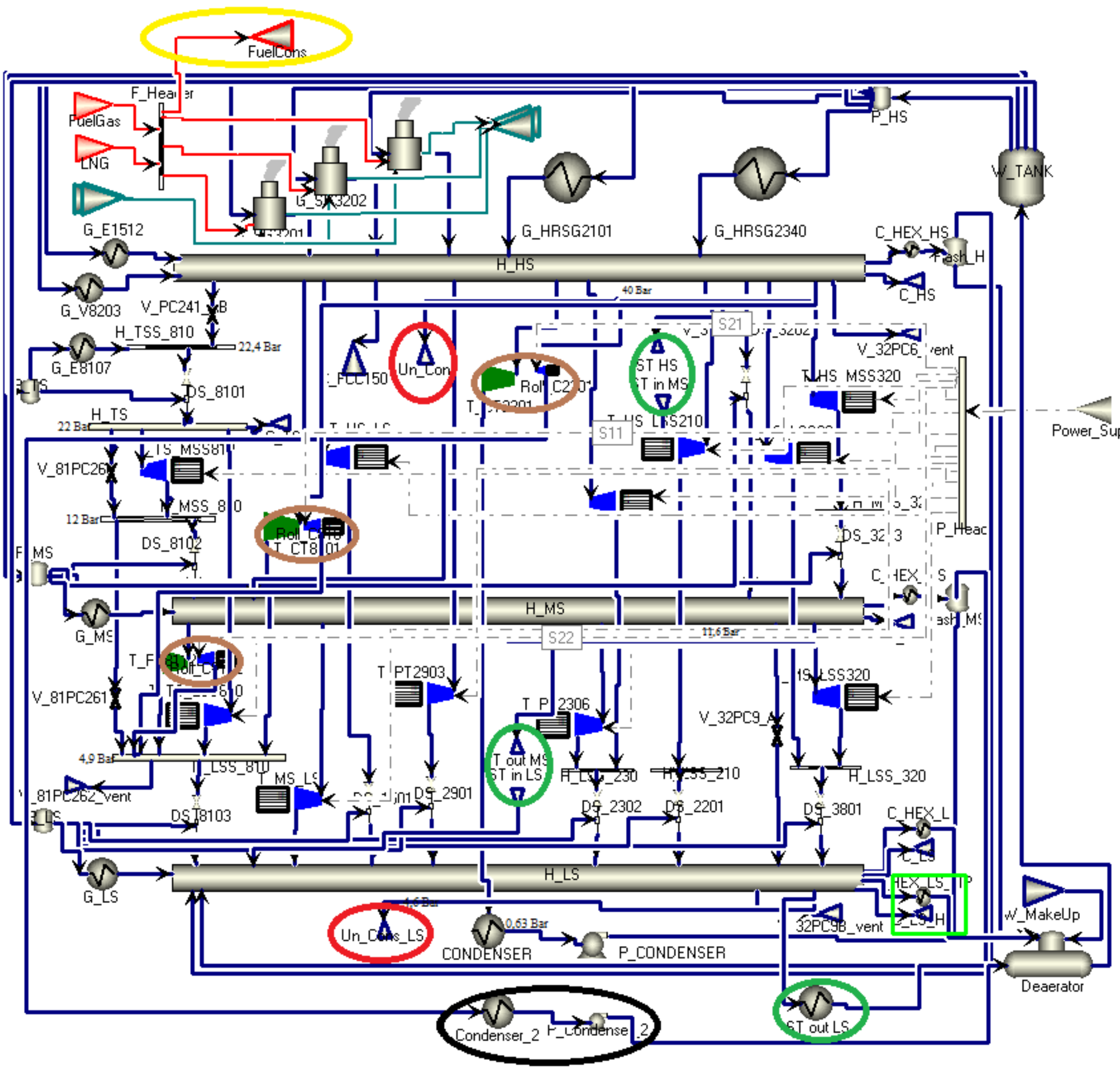

Figure D.4: Visible changes in the PFD.

E

Further validation results

The validation results and optimization results for scenarios 7 and 11 created by Gunnarsson and Kobjaroenkun and Scenario 1 created by Subiaco will be displayed. The results displayed are the validation table with measured values, model output values, relative and absolute error.

Scenario 1.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	353,02	355,16	2,14	0,60%
Utilized Make up	Tonne/Hr	139,59	134,1	5,49	4,09%
LS venting	Tonne/Hr	42,96	19,7	23,26	118,06%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	0,11	0	0,11	0,00%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	19,69	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	0	0,00	0,00%
MS -> LS valve	Tonne/Hr	44,63	21,8	22,83	104,75%
Turbine ICR CT8101	Tonne/Hr	27,17	27	0,17	0,64%
Turbine TS -> MSS810	Tonne/Hr	14,79	14,7	0,09	0,62%
Turbine TS -> LSS810	Tonne/Hr	5,19	5	0,19	3,73%
DS 8102 Steam-out	Tonne/Hr	36,22	33,2	3,02	9,09%
DS 8103 Steam-out	Tonne/Hr	34,60	34,2	0,40	1,18%
Used Electric Energy	kW	4571,43	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	40163,24	41293,33	1130,09	2,74%

Figure E.1: Validation table for Scenario 1.

Scenario 7.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	375,07	359,59	15,48	4,30%
Utilized Make up	Tonne/Hr	131,46	124,12	7,34	5,91%
LS venting	Tonne/Hr	25,81	15,44	10,37	67,14%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	13,69	6,33	7,36	116,21%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	17,20	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	10,41	6,33	4,08	64,43%
Turbine ICR CT8101	Tonne/Hr	28,38	29,95	1,57	5,24%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	38,14	38,22	0,08	0,21%
DS 8103 Steam-out	Tonne/Hr	35,86	29,68	6,18	20,83%
Used Electric Energy	kW	4802,04	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	46703,86	47349,91	646,05	1,36%

Figure E.2: Validation table for Scenario 7.

Scenario 11.

DATA VALIDATION					
VARIABLE	UNIT	OUTPUT VALUE	MEASURED VALUE	ABSOLUTE ERROR	RELATIVE ERROR
Utilized Feed Water	Tonne/Hr	376,33	384,16	7,83	2,04%
Utilized Make up	Tonne/Hr	132,89	129,39	3,50	2,71%
LS venting	Tonne/Hr	27,14	18,3	8,84	48,32%
LSS810 venting	Tonne/Hr	0,00	0	0,00	0,00%
HS venting	Tonne/Hr	0,00	0	0,00	0,00%
HS -> MS valve	Tonne/Hr	16,94	5,77	11,17	193,61%
HS -> TS valve	Tonne/Hr	0,00	0	0,00	0,00%
TS -> MSS valve	Tonne/Hr	17,52	unm	#VALUE!	#VALUE!
MSS -> LSS valve	Tonne/Hr	0,00	unm	#VALUE!	#VALUE!
MS -> LS valve	Tonne/Hr	21,42	5,15	16,27	315,95%
Turbine ICR CT8101	Tonne/Hr	28,70	30,13	1,43	4,76%
Turbine TS -> MSS810	Tonne/Hr	19,18	unm	#VALUE!	#VALUE!
Turbine TS -> LSS810	Tonne/Hr	5,19	unm	#VALUE!	#VALUE!
DS 8102 Steam-out	Tonne/Hr	38,48	39,09	0,61	1,55%
DS 8103 Steam-out	Tonne/Hr	36,19	29,6	6,59	22,26%
Used Electric Energy	kW	4900,92	unm	#VALUE!	#VALUE!
Used Fuel	Sm3/Hr	45557,52	46174,21	616,69	1,34%

Figure E.3: Validation table for Scenario 11.

F

Description of scenarios

In this appendix a description for all the scenarios will be provided, the description of the scenarios created by Subiaco is a interpretation of how the operational situation was by Gunnarsson and Kobjaroenkun. In Table F.1 one can see that some scenarios needs further explaining. Scenario 0 is a manual input scenario, that is to say the user can freely chose settings and values, Scenario 5 is just a copy of Scenario 1 created by Subiaco to be used in optimization and the lastly Scenario 16 is for use of the latest operational data.

Table F.1: Basic information about all scenarios.

Scenario	Operational situation	Averaging time	Creator/ creators	Time span/ dates
0	Free	-	Subiaco	-
1	Stable	Instant	Subiaco	13/9-2015
2	Stable	Instant	Subiaco	14/7-2015
3	HRSG:s and 230 area down	Instant	Subiaco	16/4-2015
4	SG2101 and ICR down	Instant	Subiaco	12/1-2016
5	Stable	Instant	Subiaco	13/9-2015
6	Stable and high utilization	1 week	Gunnarsson and Kobjaroenkun	(2-8)/1-2018
7	Stable and high utilization	1 week	Gunnarsson and Kobjaroenkun	(22-29)/12-2017
8	FCC unit down	1 week	Gunnarsson and Kobjaroenkun	(1-4)/4-2017
9	ICR and HPU down	1 week	Gunnarsson and Kobjaroenkun	(16-22)/5-2016
10	Stable and high utilization	1 day	Gunnarsson and Kobjaroenkun	3/1-2018
11	Stable and high utilization	1 day	Gunnarsson and Kobjaroenkun	23/12-2017
12	FCC unit down	1 day	Gunnarsson and Kobjaroenkun	2/4-2017
13	ICR and HPU down	1 day	Gunnarsson and Kobjaroenkun	17/5-2016
14	VDU, ICR, HPU and FCC down	1 day	Gunnarsson and Kobjaroenkun	10/3-2018
15	VDU, ICR HPU and FCC down	1 day	Gunnarsson and Kobjaroenkun	16/3-2018
16	-	Latest values	Gunnarsson and Kobjaroenkun	-