Optimising an Existing Utility System using STAR Software

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Abstract

Utility systems produce the heat and power requirements for a production plant. This study is to simulate an existing system using STAR software, optimise it, then explain the differences between this base case and three different scenarios. This report will aim to decrease the fuel use in the system by increasing the efficiency across 3 areas. Scenario 1 is to increase the blowdown in the HRSG. In the base case the operating cost was $3,640,000,000 and this was reduced to $2,780,000,000 when optimised. In all three cases the system reduced the overall operating cost and reduced the fuel usage.

Contents

1 Introduction

A utility system is a collection of industrial units, such as boilers and turbines, which typically generate heat, power and/or cooling to supply industrial processes. These systems must also be flexible to cope with fluctuations in demand. Examples of utilities are electricity, steam, refrigerants, and inert gases.

To understand if a proposed system would meet the process requirements, utility systems are often simulated. These models also run alongside real-time operation to identify and prevent any operation/safety issues. If a boiler unit were to go offline, the model can be quickly altered to represent the current state of the utility system and re-perform optimisation; most decisions should already be made ahead of time to minimise the time taken to act. Software such as STAR contains models for different types of units present within utility systems.

Computational models are a useful tool for optimisation because they can be run quickly and cheaply with minimal financial and safety impacts in the event of an error. It helps us to isolate components of the system we want to observe; we can ignore things such as the effects of recycling boiler feedwater (BFW), any fouling, superheating steam mains, and tracing. A model can visually simplify the system making it easier for people to understand, and computers require less time and resources to calculate properties of interest.

Optimisation is used to model changes in the system and identify an optimised operation based on available components (i.e. turbine down for repair). Software can calculate or provide data to calculate values such as steam prices and marginal steam prices where marginal steam prices are useful for comparing costs when the goal of optimisation is not cost (I.e. maximum power generation).

1.1 Objectives

The main objectives of this research are outlined below:

- Calculate missing flowrate parameters.
- Simulate a given utility system using the STAR V2.9-146 software.
- Optimise this given system with the objective function of minimizing operating costs
- Individually optimise the base case with the objective function of reducing fuel consumption via the three different parameters: introducing a blowdown to the heat recovery steam generator (HRSG) unit, increasing the inlet temperature to the HRSG unit, and shutting down the boiler which uses fuel oil.

The method to achieve these objectives is given in the next section of this report.

2 Methodology

2.1 Determining the Missing Flowrate Data

There were some missing values on the given flowrate data, the mass flowrate of the HRSG, the flowrate through letdown 1 and 3, and the flowrate through the vent. To calculate the flowrate of each missing value, we carried out a mass balance around the steam mains. It was not necessary to use energy balances as the specific enthalpy is a constant value in each header. First, a mass balance was carried out around the very high pressure (VHP) header to determine the mass flowrate of L1 (Letdown 1). This value is then used in the mass balance around the high pressure (HP) header to find the mass flowrate of the HRSG. The same method is applied to the medium pressure (MP) and low pressure (LP) steam headers, where the mass flowrate of L3 is used to find the mass flowrate of the vent in the LP header. No unit conversion was required.

Example calculation of mass balance around VHP header:

$$B1_M + B2_M + B3_M = ST1_M + ST2_M + L1_M$$

$$120 + 135 + 180 = (75 + 195) + 150 + L1_M$$

$$L1_M = 15\ KG\ S^{-1}$$

The values are as follows: [m(HRSG), m(L1), m(L3), m(vent)] = [105, 15, 22.5, 30] where m is in kilograms per second.

The initial base case was carried out in a step wise manner; it was noted that errors could occur if the system was built completely and then run, leading to errors in convergence and incorrect degree of freedoms across the steam headers. Minimum and maximum inputs are constraints utilised for the optimisation stage and don't affect degrees of freedom in the system.

The data inputted into STAR followed that of the brief, however a run through of specific parts of the system is useful to understand the degree of freedom analysis as well as the group approach. For Steam turbines 1,2 and 3 the current inlet and one current outlet flow were specified with the minimum and maximum outlet flows specified on all streams. Steam turbine 4 had maximum and minimum flows for both inlet and outlet set but the current flow (unspecified) acted as a degree of freedom. Boilers 2 and 3 had current, maximum and minimum flows inputted however boiler 1 had its current flow left unspecified to prevent an over specified system. Additionally, let down valve 2, let down valve 3, deaerator, P1, P2, P3, steam generator (SG) and HRSG current flows were specified. Although, there was no HRSG flowrate given in the brief this was calculated in accordance with the calculations above. Let down valve 1 and the vent were left unspecified as degrees of freedom. The vent was modelled as a process export class whereas the SG was set simply as a supplying process. Gas turbine specifics consisted only of shaft wok of 130,000 kW as given in the brief. Additional specification involved temperature and pressures of all the mains as well as outlet temperatures of the boilers to match the temperature of the VHP steam main. The total flows for the steam headers were determined by the input flows and outlet demands.

Some key input parameters are outlined on the next page.

Table 1: Given parameters for the Utility System

Parameter	Value
Fuel Oil unit cost ($ kg^{-1})	3.600
Natural gas unit cost ($ Nm^{-3})	1.202
Fuel Oil LHV (kJ kg^{-1})	40,000
Natural Gas LHV (kJ Nm^{-3})	34,468.8
Site Power Demand (kW)	440,000
Site Power Import Max (kW)	25,000

2.2 Simulation using STAR

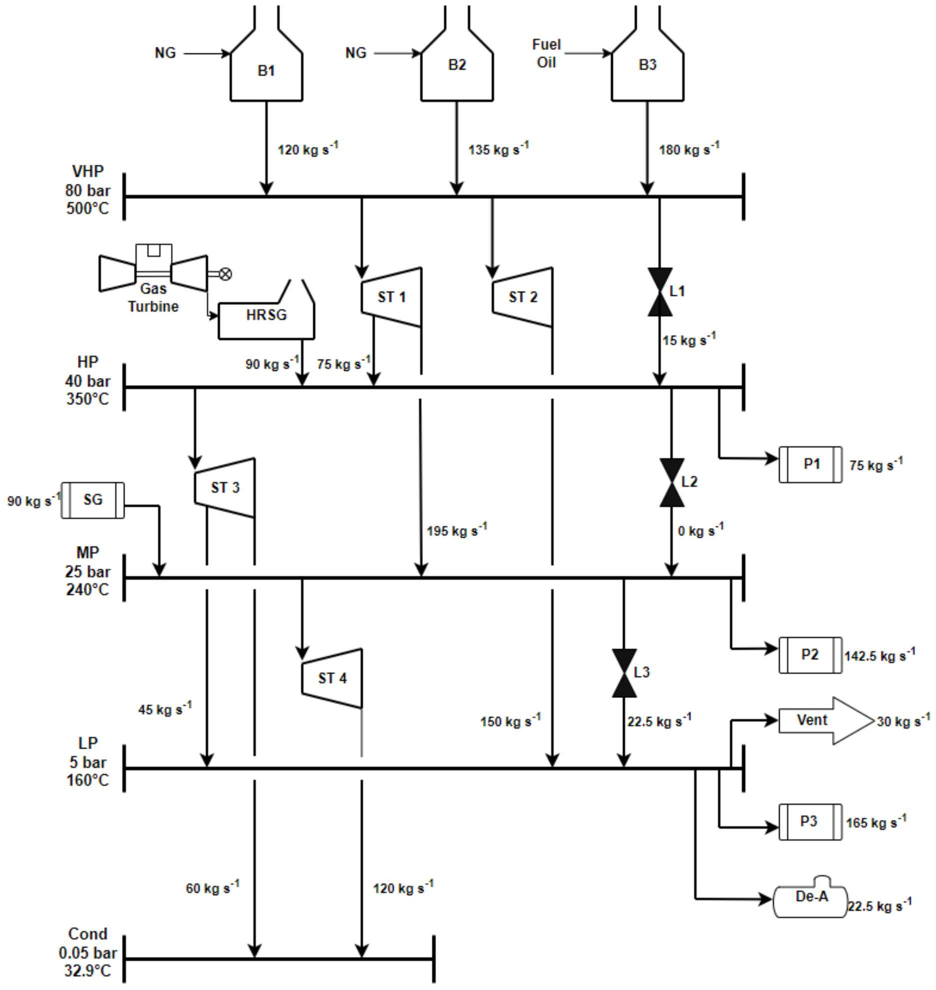

Figure 1: Process Flow Diagram of the Given Utility System

Figure 1 shows a process flow diagram of the system with all flowrates indicated. The base case utility system consists of 5 steam mains: Very High Pressure, High Pressure, Medium Pressure, Low Pressure and a condensing main. Steam is provided to the system via 5 sources: 2 natural gas fuelled boilers, an oil fuelled boiler, a steam generator and a HRSG. The boilers provide steam to the VHP main whilst the HSRG and steam generator (SG) provide steam to the HP and MP respectively to supplement the steam produced by the boilers. There are 4 steam turbines in the system that let down steam to lower pressure mains whilst producing power to supply the power requirements of the system. Additionally, a gas turbine utilises natural gas to produce work and its exhaust gases are passed to the HRSG for steam production. Let down stations are located between each steam main which allows for excess steam to be passed between the mains and allows for extra control over steam flowrates. The HP and MP mains provide steam for process heating. The LP main provides steam for process heating as well as venting surplus steam and supplying some to the deaerator.

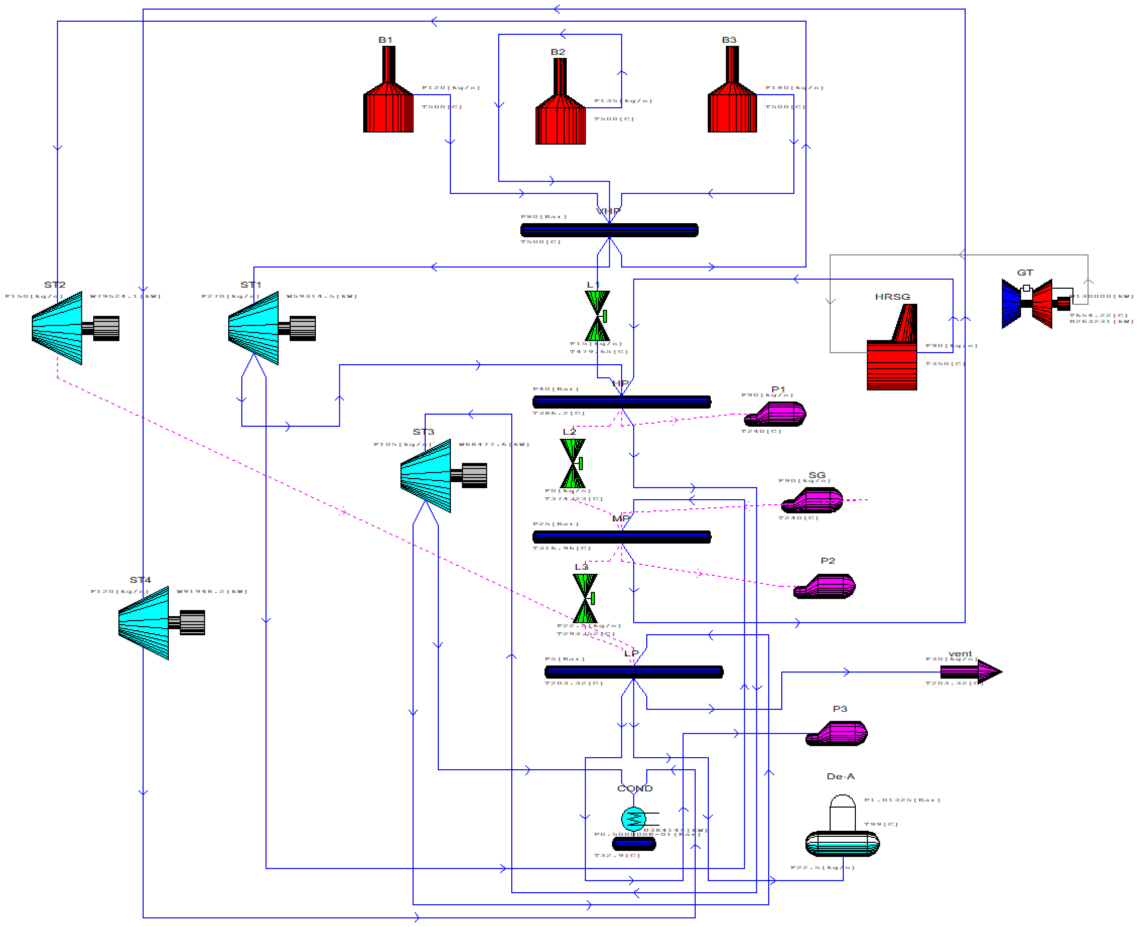

Figure 2: Screenshot of the Utility System in the STAR Software

2.3 Optimisation Using STAR

STAR has an inbuilt optimisation tool which is extremely useful. When using this option, make sure the system has all relevant minimum and maximum bounds and that any unit that must remain unchanged should have the current flow box ticked. In this report, optimisation was carried out with the objective function of minimising the operating costs whilst maintaining the gas turbine performance.

3 Simulation of Base Case Results

3.1 Boilers

Boilers 1 and 2 use natural gas whereas boiler 3 uses fuel oil. It can be seen from figure 1 that Boiler 1, Boiler 2 and Boiler 3 produce 120 kg s^{-1}, 135 kg s^{-1} and 180 kg s^{-1} respectively with blowdown rates of 2%, 3% and 5%. The purpose of the blowdown is to control boiler water limits and remove suspended solids, hence why the fuel oil boiler has a higher blowdown rate. The use of fuel oil in this system produces SO_x emissions.

Table 2: Boiler Specifications

	Boiler 1	Boiler 2	Boiler 3
Steam flowrate (kg s^{-1})	120	135	180
Fuel Type	Natural Gas	Natural Gas	Fuel Oil
Fuel Flowrate (Nm s^{-1}/kg s^{-1})	37.9564		17.4391

3.2 Mains

Table 3 contains key mains data such as the pressure, nominal temperature, operating temperature and degree of superheat in each of the steam mains. The mains are: very high pressure, high pressure which directly supplies process 1, medium pressure which supplies process 2, low pressure which supplies the final process, used as deaerating steam in boiler feedwater treatment, and some steam is vented. Vented steam is lost energy and water however it can be used as a degree of freedom; a key indicator of a non-optimised process is vents on mains above LP since further energy could have been extracted from the lost steam (either heat or power). The condensation main does not contain any degrees of superheat as the steam is now water, as shown by its operating temperature.

Table 3: Specifications of the Steam Mains

	VHP	HP	MP	LP	Cond
Pressure (Bar)	80	40	25	5	0.05
Nominal Temperature (°C)	500	350	240	160	32.9
Operating Temperature (°C)	500	386.2	316.2	203.32	32.9
Degree of superheat (°C)	205.03	135.86	93.02	51.47	-

3.3 Steam Turbines

Table 4: Specifications of the Steam Turbines

	ST 1	ST2	ST3	ST4
Shaft work (kW)	61148.9	81983.6	70595.5	94792.0
Mechanical efficiency (%)	97	97	97	97
Inlet Flow (kg s^{-1})	270	150	105	120
Outlet 1 Flow (kg s^{-1})	75	150	45	120
Outlet 2 Flow (kg s^{-1})	195	-	60	-

Steam turbines generate power by expanding steam from a higher pressure to lower pressure. Therefore, boilers typically produce steam at a higher pressure than is required for heating so that the turbines can extract power. The 4th turbine produces the most power since it has the largest pressure drop although the 2nd turbine has the highest flowrate.

3.4 Gas Turbine and HRSG

The gas turbine used in the base utility system runs on natural gas. This produces 13 MW of power. The gas turbine is connected to a heat recovery steam generator that utilises the hot exhaust gases from the gas turbine to produce 90 kg s^{-1} of steam that will be fed into the HP main to supplement the steam produced in the boilers. This combination of devices is an example of cogeneration as there is production of useful heat and power from the same heat source. The function of the gas turbine is to produce power however exhaust gases are typically between 500-650°C and can be used to produce high pressure steam in a HRSG. The energy content recovered from the exhaust reduces the steam boiler requirements and therefore lowers overall fuel consumption (emissions and costs).

Figure 3 shows the temperature enthalpy profile of the HRSG, showing an actual stack temperature of 216.99°C and a theoretical flame temperature of 792.96°C. Supplementary firing is used to raise the temperature of the gas turbine exhaust gases entering the HRSG which in turn allows for increased steam production, as the relationship between exhaust gas temperature and steam output are not linear. Here, an additional 1.68 Nm^3 s^{-1} natural gas is consumed.

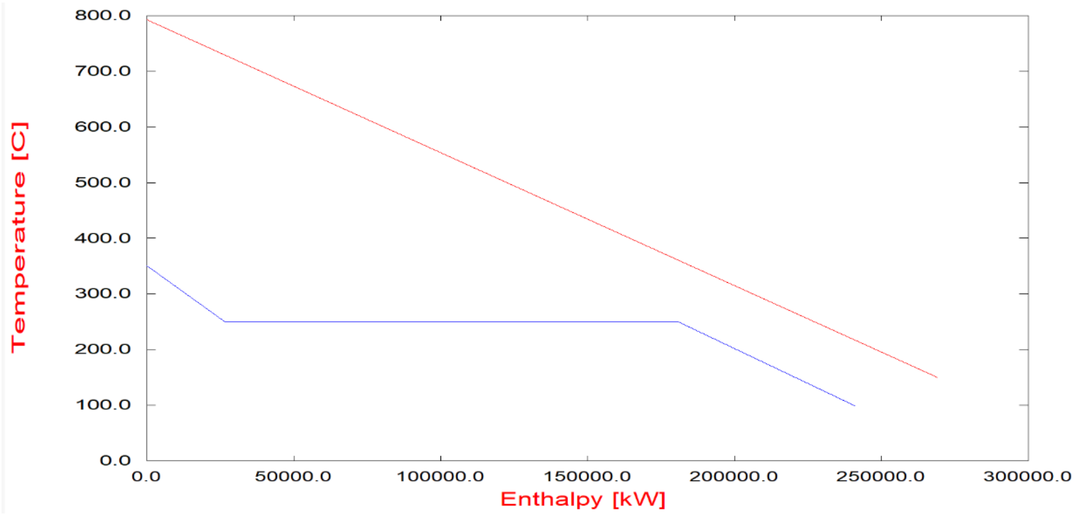

Figure 3: Temperature/Enthalpy diagram for the HRSG showing the steam profile (blue) and the flue gas profile (red)

3.5 Capital expenditure

In our STAR simulation, the gas turbine is the only object which has specified models (including economic parameters). This allows STAR to determine the cost of the GT based on its geometry. The costing of the GT is the only variable affecting the capital cost since cost parameters are not provided for other units, resulting in a constant capital cost of $4.22822E+07. These parameters will vary for different unit types, manufacturers, and sizes. Therefore, we have not taken capital cost into consideration for our optimisation. This is an important factor as it will impact the economic favourability of the proposed optimisation changes, by changing variables such as payback time.

4 Simulation of Optimized Case

4.1 Outline

As previously mentioned, the optimisation of the base case was carried out with the objective to minimise the total operating costs for a constant heat and power demand.

4.2 Results and Discussion

Table 5: Comparison of Flows in the Base Case and the Optimised Base Case

	Base	Optimised Base	Difference
Boiler 1 (kg s^{-1})	120	150	30
Boiler 2 (kg s^{-1})	135	165	30
Boiler 3 (kg s^{-1})	180	81.511	-98.489
ST 1 (kg s^{-1})	270	231.511	-38.4890
ST 2 (kg s^{-1})	150	165	15
ST 3 (kg s^{-1})	105	120	15
ST 4 (kg s^{-1})	120	74.011	-45.989
Vent (kg s^{-1})	30	0	-30
Natural Gas (Nm^3 s^{-1})	37.9564	43.7967	5.84028
Fuel Oil (kg s^{-1})	17.4391	7.89709	-9.54198

In the optimised case the overall steam production across all three boilers is reduced by 38.489 kg s^{-1}. Although the natural gas consumption increases by 15.4% this is offset by the 54.7% decrease in fuel oil use. The steam input from the HRSG and steam generator remains the same at 90 kg s^{-1} each. The optimisation of the system results in the vented steam being removed, avoiding unnecessary steam loss. The remaining reduction in production of steam can be attributed to the steam turbine flowrates. Given the lower production in the boilers there is a lower total flowrate of steam through the steam turbines. However, this flow is distributed differently across the turbines. In ST2 and ST3 the steam load through each is increased by 15 kg s^{-1} which allows for slightly higher power production and steam supply to the condensing main. Higher condenser load however leads to higher cooling water costs. ST3 stops providing steam to the LP main meaning ST2 is entirely responsible for the steam requirements of P3. Due to the higher steam flow provided by ST3 to the condensing main the steam flowrate through ST4 is reduced. Finally, ST1 increases its steam output to the HP main but decreases its output to the MP main. All let downs have a flowrate of 0 through them, meaning all the produced steam passes through the steam turbines, fully utilising the steam for power production. It follows that given this lower steam flowrate through the steam turbines less power is produced by the steam turbines. This is shown in table 6.

Table 6: Comparison of Power in the Base Case and the Optimised Base Case

	Base	Optimised Base	Difference
Total Site Power Demand (kW)	440000	440000	0
Power generation (kW)	429264	423980	-5284.80
ST shaftwork (kW)	299264	293980	-5284.80
Power import (kW)	19715.2	25000	5284.80

It can be seen that there is a reduction of 5284.8 kW that is produced by the steam turbines in the optimised case. The STAR optimiser has utilised the full amount, 25 MW, of available import power to make up the difference in power lost from the steam turbine production. This results in lower fuel and therefore operating cost as is shown in table 7 – technology used to produce electricity for the national grid is typically more efficient for since that is its intended purpose.

Table 7: Comparison of Operating Costs with Fuel Breakdown between the Base Case and the Optimised Case

	Base	Optimised Base	Difference
Total Operating Cost (\$ yr^{-1})	3.64398E+09	2.78355E+09	-8.60433E+08
Natural Gas fuel cost (\$ yr^{-1})	1.41251E+09	1.62985E+09	2.17340E+08
Fuel Oil fuel cost (\$ yr^{-1})	1.94369E+09	8.80178E+08	-1.06351E+09
Total Fuel Cost (\$ yr^{-1})	3.35620E+09	2.51003E+09	-8.46172E+08

The cost benefit of the optimised system is clearly outlined in table 7. There are increases in the condenser cooling water cost, power import cost and natural gas cost due to higher consumption. However, these increases are offset by the reduced expenditure on fuel oil. Overall, there is a 23.6% decrease in operating costs in the optimised system.

Table 8: Comparison of Emissions between the Base Case and the Optimised Case

	Base	Optimised Base	Difference
CO_X (kg s^{-1})	125.568	106.034	-19.5338
SO_X (kg s^{-1})	0.174391	0.0789709	-0.0954198
NO_X (kg s^{-1})	0.166688	0.151699	-0.014989

Since fuel consumption is directly correlated to environmental impacts, we expect to see a reduction in this as well. An overall decrease in carbon emissions of 19.5338 kg s^{-1} was seen in the optimised system. The reduction in SO_X can be directly attributed to the lower fuel oil consumption, as we know the natural gas does not produce SO_X emissions. We consider the emissions of CO_X and SO_X but not NO_X because this is difficult to determine without operating data. There are discrepancies within the STAR software whereby NO_X emissions do not add up correctly which we assume is due to truncation errors, so the value shown in table 8 was calculated manually.

5 Reducing Fuel Consumption via Blowdown in HRSG

5.1 Modification of base utility system

It is possible to recover some steam from the blowdown of the boilers and HRSG by passing the water (at saturated conditions) through a flash vessel. In this task 1 modification, there are 3 flash vessels: VHP (inlet) to HP (outlet), HP to MP, and MP to LP. The water at the higher pressure is passed through a flash vessel operating at the lower pressure to give water and steam product streams (both at the lower pressure). The steam vapour is then passed into the corresponding header, as the flash vessels operate at the same pressures as the mains (i.e. LP steam main and flash vessel are at 5 bar). The saturated water outlet from the flash is passed through the next flash vessel at the consecutively lower pressure. The condensates from process 1 and 2 are at the same pressures as the entering steam in the heat exchanger. They are also not desuperheated and therefore they can be joined at the inlet of appropriate flash vessels to increase the amount of steam at the outlet. This reduces the steam flowrate demand from steam sources within the utility system, and subsequently reduces the fuel flowrate required (to evaporate a smaller amount of water). It must be noted that a reduction in steam flowrate from the boilers and HRSG will result in a lower total blowdown flowrate.

The flash vessels do not have any minimum or maximum flowrate values. The LP flash vessel liquid outlet is set to loss to environment and there is no liquid outlet stream shown on the steam network environment. In reality, it would be recycled as condensate return.

For this task, 3 flash recovery vessels were chosen. This has a higher capital cost (and payback time) but maximises the most useful steam recovery (HP steam) from otherwise wasted energy. All streams that are available for flash recovery have been used, increasing the overall recovery/efficiency of the system although process 3 condensate is not used. In theory, there will be some blowdown from the steam generator to avoid build-up of solids from the BFW, however, it is assumed that there is no blowdown out of the MP steam generator in our simulation.

There is no flash vessel operating at 0.05 bar (LP to COND) because only a low amount of energy can be extracted from the water and the steam is at undesirable conditions. Hence there is a condenser before the condensing main. If the water is not subcooled (32.9°C), then it could potentially be used for tracing around BFW piping and tanks – especially during winter months – and it lowers the heating duty of the boilers. While the latent heat of saturated steam at 0.05 bar is 2344kJ kg^{-1} (valuable), it is limited to a temperature of 32.9°C, and this would be the upper value of temperatures within the heat exchanger since it is a ‘hot’ stream. It could be used in a deaerator, but the capital cost of another flash vessel is not justifiable.

The STAR software calculates the blowdown flowrate using the steam outlet flows and blowdown percentage.

From the base case, I changed the degree of freedom (DOF) from being in the VHP main (boiler 1 current flow ticked) to in the HP main (HRSG current flow unticked). This made no change to the base case “steam network optimisation difference” report.

5.2 Simulation of modified utility system

Table 9: Comparison between the Base Case and task 1

Fuel flows ($Nm^3\ s^{-1}$)	Base	Task 1	Difference
B1 fuel	11.3369	11.3369	0
B2 fuel	13.5273	13.5273	0
B3 fuel ($kg\ s^{-1}$)	17.4391	17.4391	0
HRSG	1.68398	1.4694	-0.21458
Steam flows ($kg\ s^{-1}$)	**Base**	**Task 1**	**Difference**
B1	120	120	0
B2	135	135	0
B3	180	180	0
HRSG	90	87.9282	-2.0718
Power (kW)	**Base**	**Task 1**	**Difference**
Power gen.	429264	433820	4556
Power import	19715.2	15159.8	-4556
ST shaftwork	299264	303820	4556
GT shaftwork	130000	130000	0
Emissions ($kg\ s^{-1}$)	**Base**	**Task 1**	**Difference**
Total COx emission	125.568	125.172	-0.396
Total SO_x emission	0.174391	0.174391	0
Cost ($ yr^{-1})	**Base**	**Task 1**	**Difference**
BFW import	2.92781E+08	2.91819E+08	-9.62E+05
Total fuel cost	3.35620E+09	3.34821E+09	-7.99E+06
Power cost	9.83394E+06	7.56172E+06	-2.27222E+06
Demineralised water cost	-3.13470E+07	-3.22802E+07	-9.332E+06
Condenser CW cost	1.65182E+07	1.70328E+07	5.146E+05
Total Op cost	3.64398E+09	3.63235E+09	-1.163E+07

The change in fuel flow is due to the small amount of HP steam recovery from the VHP condensate. This decreases the steam flow out of the HRSG slightly. All sources of VHP condensate are used. Since there is no VHP recovery and not enough power is generated by the steam system, we can't lower the boiler flowrates without increasing power import costs. Heat is cheaper than power so this is undesirable. The HRSG uses supplementary firing so the reduction in steam flow is reflected in supplementary firing (-0.21 $Nm^3\ s^{-1}$) as shown in table 9. As a result, GT and exhaust gases in the system do not change and therefore GT shaftwork doesn't decrease. The goal of reducing fuel is achieved but the change is marginal; the only change is in natural gas flow (by 0.7%). The weighted avg. LHV of system fuel is 43.93 MJ kg^{-1} for the base case and 44.57 MJ $kg\text{-}^{1}$ for task 1. Using this analysis, the goal of reducing overall fuel consumption has been achieved and as a result the total operational cost decreases by $-1.163E+07 per year. The power generation is also increased as the recovered flash vapour is passed through the turbines. There is no change in SO_X emissions because it is only a product of fuel oil combustion.

A quantitative method to compare different scenarios is to calculate a weighted average LHV for the system. This means that for the same VHP steam requirements, we can assume that overall, less fuel is needed (lower fuel cost). This is also indicative of the VHP steam pricing since an increase in fuel flow will increase the fuel costs and therefore the VHP steam price. The equation is given below

$$\text{Weighted average LHV} = \frac{((m_{NG} \cdot LHV_{NG}) + (m_{oil} \cdot LHV_{oil}))}{(m_{NG} + m_{oil})}$$

The fuel oil composition is unspecified, so I estimated a possible composition that matches the LHV provided. This gives Methane, Ethane, Propane, n-Butane, n-pentane, Nitrogen, CO_2: 95.16, 0.78, 0.86, 0.65, 0.12, 1.75, 0.68%. This gives an LHV of 34.47MJ m^{-3} This was found using an online natural gas LHV calculator which had a truncation error of 2 d.p. For consistency, all calculations within this section (weighted avg. LHV) are carried out using values also truncated to 2 d.p. This composition has a density of 0.726 kg m^{-3} (LHV of 47.48 MJ/kg) [1,2].

5.3 Different configurations for modification

Max. useful steam recovery with lowest fuel flow (configuration 1)

Table 10: Breakdown of flash vessel flowrates for task 1 configuration 1

Flash	Inlet (kg s^{-1})	Vapour outlet (kg s^{-1})	Liquid outlet (kg s^{-1})	Operating pressure (bar)
VHP to HP	15.4500	2.07175	13.3782	40
HP to LP	88.3782	18.7577	69.6205	25
MP to LP	224.850	21.7627	120.737	5
Total power gen. (kW)	429981		Total fuel cost ($ yr^{-1})	3.34821E+09

Max. steam recovery with lowest fuel flow (configuration 2)

Table 11: Breakdown of flash vessel flowrates for task 1 configuration 2

Flash	Inlet (kg s^{-1})	Vapour outlet (kg s^{-1})	Liquid outlet (kg s^{-1})	Operating pressure (bar)
VHP to HP	15.4500	2.07175	13.3782	40
HP to MP	88.3782	6.02847	82.3498	25
MP to LP	224.850	34.3392	190.511	5
Total power gen. (kW)	434665		Total fuel cost ($ yr^{-1})	3.34821E+09

Comparing the two different configurations above, we can see that the maximum flowrate of HP steam is already produced from all sources of VHP condensate so the boilers have to produce the same amount of VHP steam; there is no change to the fuel flows. Both systems supply the required amount of process heat, and we prioritise the maximum amount of HP steam recovered to minimise the fuel flowrate through the HRSG. The 1st recovers less steam overall (0.15 kg s^{-1}) but there is more recovery at higher pressure levels. As a result, there is 4684 kW more power generation which reduces the power import cost. The 2nd produces the most amount of steam by flashing it to the lowest useful pressure (LP at 5 bar) but this is a less favourable configuration since both will have very similar capital costs. Since lower fuel flow is the objective of the task, other configurations such as a flash vessel configuration consisting of VHP to MP, HP to MP, and MP to LP were not considered since they avoid the production of HP steam hence fuel flow does not change; the aforementioned is a configuration to maximise the amount of MP steam produced. Therefore, the 1st set-up is used for optimisation.

5.4 Optimisation of modified utility system

Table 12: Comparison between task 1 configuration 1

Fuel flows	**Task 1**	**Optimised**	**Difference**
Fuel oil (kg s^{-1})	17.4391	6.02539	-11.4137
NG total (Nm^3 s^{-1})	37.7419	43.7967	6.05484
Steam flows (kg s^{-1})	**Task 1**	**Optimised**	**Difference**
B1 steam	120	150	30
B2 steam	135	165	30
B3 steam	180	62.192	-117.808
HRSG steam	87.9282	90	2.07175
Power (kW)	**Task 1**	**Optimised**	**Difference**
Power generation	433820	423980	-9840.17
Power import	15159.8	25000	9840.17
ST shaftwork	303820	293980	-9840.17
GT shaftwork	130000	130000	0
Emissions (kg s^{-1})	**Task 1**	**Optimised**	**Difference**
Total COx emission	125.172	100.086	-25.0859
Total SO_x emission	0.174391	0.0602539	-0.114137
Costs (\$ yr^{-1})	**Task 1**	**Optimised**	**Difference**
BFW import	2.91819E+08	2.63896E+08	-2.79228E+07
Total fuel cost	3.34821E+09	2.30141E+09	-1.04680E+09
Power cost	7.56172E+06	1.24700E+07	4.90828E+06
Demineralised water cost	-3.22802E+07	-3.33969E+07	111670
Condenser CW cost	1.70328E+07	1.96796E+07	2.64681E+06
Total Op cost	3.63235E+09	2.56406E+09	-1.06828E+08

This task 1 model was then optimised with the objective to minimise the total operating costs, while maintaining the steam supply for process heating. As seen in table 12, the fuel oil flowrate can be decreased by 11.41 kg s^{-1} (-65.4%) and the natural gas flow decreased by 6.05 Nm^3 s^{-1} (16.0%). Giving a weighted average LHV of 46.29 MJ kg^{-1} (optimised) and 44.57 MJ kg^{-1} (non-optimised). As a result of lower fuel flow, 55.74 kg s^{-1} less steam is produced by the system, with a reduction in boiler 3 (the least efficient boiler). This lowers the amount of power generated by 9840.17 kW by the steam turbines. The system required a power input previously, so the cost of power import has increased by \$4.90828E+06 per year. However, reductions in fuel and BFW costs outweigh the increase in power, demineralised water, and condenser CW costs, resulting in a saving of \$1.06828E+08 for the total annual operating cost. The total SO_X released decreases by 65.4% since it is only a product of fuel oil in our simulation. CO_X is still emitted in significant quantities by natural gas however it is reduced by 20.0% due to changes to both fuel types. CO_X emissions are unavoidable due to the chemical composition of the fuel, while S is generally an impurity (typically pre-treatment results in higher purities of gas than liquid fuels while solids prove the most difficult). From the above data, we can conclude that the optimisation was successful in reducing the fuel flowrate which has a positive impact on economics and environmental emissions.

Setting the optimisation objective to minimise the boiler flow gives a saving in annual operating costs of $2.11409+E08, with $1.91216E+08 fuel cost saving. There is no change in fuel oil and a 13.6% decrease in natural gas. It does lower the total flowrate of steam through the boilers by 56.41 kg s^{-1} (0.67 kg s^{-1} less than in the minimum operating cost), but keeps the least efficient boiler running at full capacity. The weighted average LHV is 44.31 MJ kg^{-1} (< 46.29). Therefore, it is evident that this does not give the best solution to lower total fuel consumption.

Conclusion

There were three overall goals that needed to be carried out. Firstly, the construction of the base utility system was carried out by the group in a structured fashion overcoming convergence and degree of freedom issues. Missing flowrate values were accurately calculated resulting in a fully working utility system that met all of the system parameters. This led to the correct operating cost result of $3.64E+9 yr^{-1}.

Next, this initial base case was optimised using the inbuilt 'Steam Network Optimiser', with a stated optimisation objective of minimising operating costs. This optimisation bore positive results with a 26.3% reduction in operating costs. This cost reduction was found to have come primarily from the reduced consumption of fuel oil and lower overall steam production from boilers.

The final overall objective consisted of three individual tasks, looking at different scenarios with the target of reducing overall fuel consumption in comparison with the base utility system. The optimisation of these new modified systems would then be carried out and the results analysed. Task 1 looked at utilising flash vessels to recover steam from the boiler blowdowns. Three flash vessels were used in the modified system with the optimised results producing 55.74 kg s^{-1} less steam leading to 60.4% decrease in fuel oil use and only a 16% increase in natural gas consumption. There were also reductions in total operating cost of $1.163E+07 per year from the base system to the modified task 1 system meeting the target of the task.

References

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