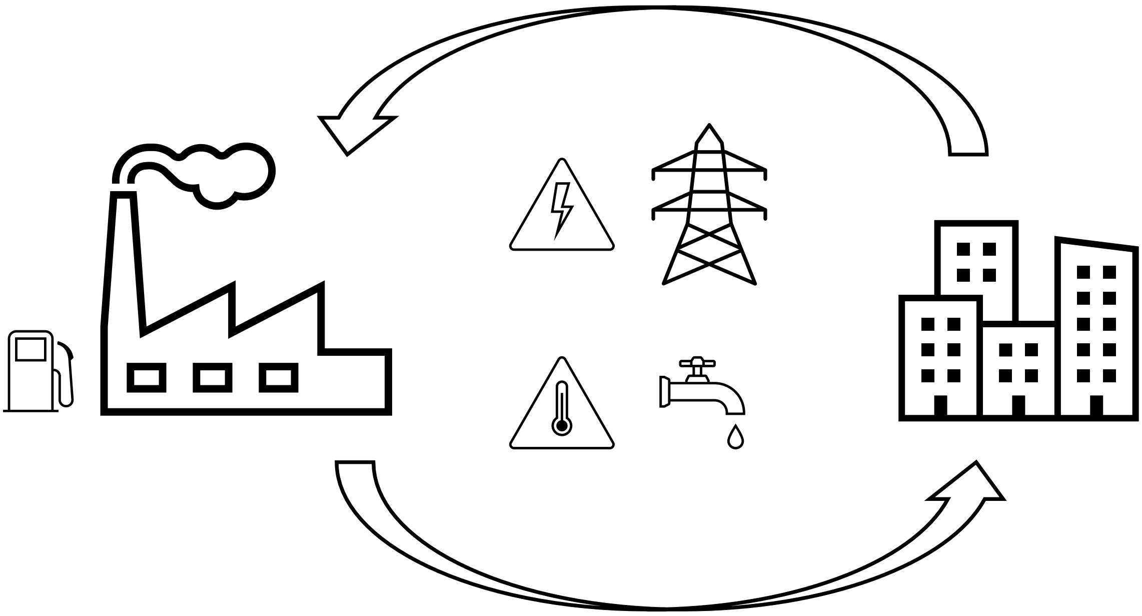

Assessing the impact of decarbonization pathways for oil refineries on the city energy system

A case study of Gothenburg

Master's thesis in Sustainable Energy Systems

KUMAIL MARNATE
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DEPARTMENT OF SPACE, EARTH AND ENVIRONMENT,
ENERGY TECHNOLOGY

CHALMERS UNIVERSITY OF TECHNOLOGY
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Abstract

Decarbonization of the refining industry will play an important role in reducing greenhouse gas emissions of its downstream actors but also from the industry itself. This work investigates the refining sector of the city of Gothenburg by assessing the impact of different decarbonization pathways on the local energy system. The work highlights how the operation of both the electricity and the district heating network will be impacted, the new investments in these networks that will be needed, and how the refinery will operate in synergy with the energy system. The decarbonization pathways are modelled for the year 2045 with their corresponding energy balances and integrated into the city energy system model.

The decarbonization pathways attempt to achieve net-zero emissions on the refining industry and it was noticed that this goal might not be achievable if the feedstock is fossil based crude oil. The fossil based crude oil can be produced synthetically from either restructuring the refineries as an electro-refinery or a bio-refinery. The former comes with an enormous electricity demand while the latter comes with a large demand for biofuel with minimum impact on the electricity grid. City investments in variable renewable electricity generation can synergise well with a flexible future refinery supporting the grid as a variation management strategy. The type of strategy will used at the refinery will depend on setup, season and energy system investments. A large impact of these decarbonization scenarios will also be on the residual heat available from the refineries for the district heating network as they could be higher or lower compared to their current shares. This thesis also discusses how the change in excess heat availability can be catered for by the energy system in the most economical way.

This work highlights that any decarbonization of the refining industry should be a combined effort between the actors in the local, if not regional, energy system and the refinery stakeholders for an optimum economic solutions and energy consumption.

Keywords: refinery, decarbonization, jet fuel, kerosene, industry, net-zero, emissions, VMS

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Kumail Marnate and Adam Fast
Gothenburg
June 2021

Glossary of terms

CO_2	Carbon dioxide
BER	Bio-electro refinery
CAPEX	Capital Expenditure
CBR	Carbon capture and bio-blending refinery
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CD	Closing down
CFB	Circulating fluidized bed
CHP	Combined heat and power
COP	Coefficient of performance
DH	District heating
DSM	Demand side management
EB	Electric boiler
EF	Electric furnace
ER	Electro refinery
FLH	Full load hours
FT	Fischer Tropsch
GHG	Green House Gas
GWh	Giga watt hour
HGO	Heavy gas oil
HOB	Heat only boilers
HP	Heat pump
HTFT	High temperature Fischer Tropsch
HVO	Hydrotreated vegetable oil
HYBRIT	Hydrogen breakthrough ironmaking technology
LCOE	Levelized cost of electricity
LGO	Light gas oil
LP	Low pressure
LPG	Liquefied petroleum gas
LTFT	Low temperature Fischer Tropsch
MEA	Mono-ethanolamine
MWh	Megawatt-hour
O&M	Operation and maintenance
OPEX	Operational Expenditure
P2H	Power to heat
Peak	Peak power
PEM	Proton Electrolyte Membrane
PTES	Pit thermal energy storage
PV	Photovoltaic
rWGS	Reversed water gas shift
SMR	Steam methane reforming
SNG	Synthetic Natural Gas
SOC	State of charge
SOEC	Solid Oxide Electrolysis Cell
TES	Thermal energy storage
TRL	Technology readiness level
TTES	Tank thermal energy storage
TWh	Terawatt-hour
VMS	Variation management strategy
VRE	Variable renewable energy

Contents

1
Introduction

The industrial sector is a major source of Greenhouse Gas (GHG) emissions and one of the hardest to decarbonize. Most other energy-intensive sectors (electric power, residential building/offices heating and transportation) have well-defined decarbonization strategies with multiple solutions available today. Some of these sectors are already well on their way towards decarbonization. Industry, however, has a much more complicated situation given that it serves a wide and complex variety of downstream applications as well as being linked to complex upstream supply chains [1]. The electricity sector, on the other hand, has a single downstream application to fulfil i.e. to deliver power to the consumer.

The more complex a network of actors, artefacts and knowledge gets, the more it gets entrenched in the quagmire of path-dependency [2]. Such networks, that have evolved as a result of their collective historical actions, tend to base their decisions that concern the future on their historical ones. For instance, an industrial plant that has produced hydrogen using Steam Methane Reforming (SMR) technology since it was built, is highly likely to re-invest in the same technology even if a cleaner and a superior technology is available today or in the future. One of the reasons, as mentioned, is the complexity of the network. The infrastructure components that characterize the existing technology have co-evolved together and are in place, from the acquisition of the raw material (methane) to delivering the product to the consumer. The complexity of the network will also grow at the plant level. For instance, an industrial plant can recover its excess process heat to meet its short-term demand, a necessary and affordable step, but such small steps accumulate, over a long period of time, to a point that escaping this complexity becomes economically unaffordable [3]. The consequence of such "technology interrelatedness" is that the cost of making a change is extremely high, and can only be overcome if borne collectively by all stakeholders involved. The other reason, as described by Anna Bergek [4], can be the legitimacy of the "successor" technology. The industrial actors are generally reluctant to take the first-mover risk for novel technologies with low technical maturities [5] e.g. producing hydrogen from water electrolysis instead of SMR.

Although such inertia of the industrial sector creates a resistance for its decarbonization, it does not make it immune to the problem of climate change. The main strategy adopted so far by climate policy decision-makers, is to select specific parts of the value chain and force it (or parts of it) to change to a decarbonized version. The socio-technical fossil-fuel regime [5] cannot be changed overnight, and it must instead go through a transition which could take decades. Oil refineries cannot completely modify all of their operations in the short term, but decarbonization measures could be restricted to specific parts of their processes or complete restructuring in the future.

Decarbonization of some industrial processes may lead to a substantial increase of electricity demand, as shown by the HYBRIT project [6] and an increased heat demand [7]. This research thesis will focus on a particular industrial sector i.e., the refining industry. An investigation on potential decarbonization technologies and strategies for this industry will be examined through a case study of an oil refinery located in the port of Gothenburg on the West Coast of Sweden. the study will assess the impact of the refinery's changing energy demand (heat and electricity) on the city energy system of Gothenburg as the local utility provider of the city is responsible to meet the electricity demand of all the industries within. The utility provider also has an integrated district heating network which uses the process waste heat from these refineries and waste-to-energy plant [8] to meet the demand for the rest of the city, in addition to conventional heat-only and cogeneration units.

The potential large-scale electrification of the refining industry in the city's port area has been studied earlier [9] and, among other barriers e.g. grid capacities and investments, the impact on the hourly electricity dispatch could become a major issue for the utility. A recent study by Heinisch et. al [10] on the electrification of transportation also suggests that the electrification of other sectors could potentially occur simultaneously, and the city energy system may face issues such as grid congestion. This grid congestion could be both in the national grid, where the city imports electricity from, but also the local distribution grid. The city energy system has a decarbonization ambition of its own as it aims to become fossil free by the year 2025 [11] and it is important to highlight the impacts of these large-scale electrifications on the local grid so that the investments are optimized for the whole system. The city also has a target to have a fossil-free district heating network [9] for which it is heavily reliant on the waste heat from oil refineries and any change on the waste heat availability due to a future decarbonization of the refining industry would impact the whole energy system due a synergy between the electricity and district heating network [10]. The purpose of this thesis is to highlight these impacts that a potential decarbonization of the refining industry would have on the city energy system.

1.1. Background

This research is centred around two large oil refineries (owned and operated by ST1 and Preem) located in the port of Gothenburg. The refineries produce fuel for the transportation sector and feedstock for the petrochemical sector. The production of these outputs causes emissions in the entire value chain from the extraction of the feedstock to the final use by the consumers as shown in Figure 1 below. Even though the emissions both upstream and downstream from the refinery are significantly higher than the refining process, they largely depend on how the refineries are structured e.g., a refinery focused on biofuel production would have lower absolute emissions. Therefore, innovations in the refinery structure are an important research study and a part of this work. This central part of the figure below i.e., the refinery structure which accounts for 4% of the total emissions, is also where the refinery interacts with the energy system. This is the major focus of this work. However, any change in the refinery structure and feedstock might also help reduce the emissions upstream and downstream. For example, an increasing share of biomass as feedstock to the refinery will reduce the emissions in the whole value chain if the biomass is produced sustainably. This is also shown by the renewable fuel (e.g. tall oil) as feedstock to the refining part in Figure 1, this part is not refined (as the crude and renewable feedstock) but can be used to produce biofuels instead. As discussed earlier, there is much more than just the annual electricity demand and waste heat supply to study the impact of decarbonization but also how these can impact the hourly operation of the energy system and if the future refineries can support the energy system as a variation management strategy (VMS), promote renewable energy generation and produce net-zero emissions products.

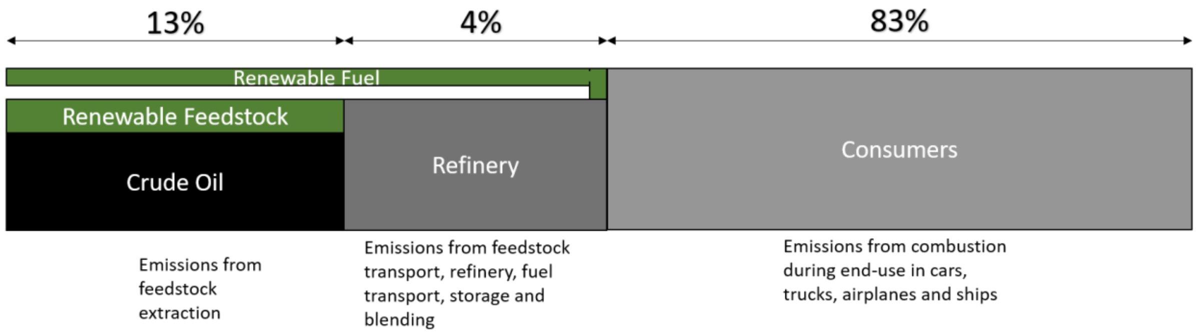

Figure 1: The emission distribution across the whole value chain of a typical Swedish Refinery [12].

The absolute CO_2 emissions and energy flows for this specific part of the value chain for the refineries under investigation can be seen in Table 1. This is accomplished primarily through the use of fossil feedstock (crude oil) and the utilization of internal fuels (fuel gas). The processing of the former and the consumption of the latter lead to emissions both from the refineries (through process heating by combustion of fuel gas) and from the end-usage of the processed products. The refineries are working towards decreasing these emissions, as discussed by Jannasch et. al. [9], with plans of implementing carbon capture and storage (CCS), building water electrolysers (instead of SMR) to produce hydrogen and producing electrofuels and biofuels. These strategies will decrease the emissions, but it is uncertain if the refineries' goal to reach net-zero-emissions by 2045[1] can be met through them and the current pathway can prove to be insufficient.

[1] The Swedish Climate policy states that the country is to have net-zero emissions by 2045 [52].

Table 1: Overview of the annual fuel, feedstock and energy demand along with CO2 emissions from the refineries in 2018.

	CO_2 emissions $kton$	District heating supply GWh_{heat}	Electricity demand $GWh_{electricity}$	Processed crude oil feedstock $kton$	Processed bio-feedstock $kton$ or m^3	Ref.
St1	540	671	150	3800	375 $kton$	[13]
Preem	536[2]	562	177	5675[3]	200000 m^3	[14]

Internal fuel usage:

	Fuel gas GWh	Natural gas GWh	Propane GWh	Fuel oil GWh	Ref.
St1	2174	217	0	0	[13]
Preem	2265	289	13	1	[14]

Table 2: Share of annual residual heat supply in Gothenburg's district heating system, the remaining DH demand is met by heat production in plants owned by the local energy supplier.

	Heat [GWh]	Year	Part of total DH [%]	Ref.
ST1	671	2018	14	[13]
Preem	536	2018	11	[14]
Renova(WTE)[4]	1501	2019	32	[15]
DH demand	4673	2012	100	[10]

Oil refineries are complex networks of systems with multiple interconnected process units. Most of the process heat demand is fulfilled by combustion of fuel gas, which is a by-product of the internal distillation processes. This adds complexity to the decarbonization of the conventional refineries since subjecting one particular process to decarbonization could cause indirect problems for other processes, for example by changing the availability of excess heat or residual fuel gas. This means that the conventional refinery plant is partly locked-in with their existing processes and any large-scale changes made at these refineries have to be carefully investigated and the consequences have to be weighed and compared. The complexity of the network extends to other facilities beyond the refineries. The refineries under investigation are also exporters of residual heat as shown in Table 2.

The operation of the refineries is rather constant even though it decreases during summer the hourly production throughout the seasons is constant . This in turn leads to a constant demand of electricity and supply of excess heat. When planning future refineries flexible operation should be considered since high shares of VRE in the energy system could synergise well with flexible operations.

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[2] The CO_2 emissions number presented in Preem's environmental report is 536 $kton$ [14], but they have recently constructed two new SMR units that will increase the emissions by 50%, which could lead to a yearly total of 780 $kton$ of CO_2 emissions [53]. But it should be stated that this is a part of their decarbonization plan through increased biofuel production, which will reduced the consumer's emissions.

[3] Out of the 5675 $kton$, 273 $kton$ are semi-finished products.

[4] The city's waste-to-energy (WTE) is owned and operated by Renova.

The residual heat from the refineries is important to the City DH network as it constitutes a substantial part of the heat supply, approximately 25% (~1.2 TWh/a), see Table 2. The refineries have a higher production volume during winters than in summers [14] leading to a higher residual heat availability in winter. This complements the district heating network well as the city heating demand during the winter is higher than in summer [16]. If this heat supply is lost due to changes at the refineries, the DH network heat supply must compensate for this loss. This means that the future of the DH network is dependent on the future of the refineries. The decarbonization of refineries could also imply an increased residual heat output, reducing the need for other heat generation technologies. Regarding the city electricity system, the refineries are not large electricity consumers as of today, but this can change in the future when alternative production processes with significantly higher electricity consumption replaces the already existing fossil powered processes. One example of this is hydrogen production through electrolysis, which could replace SMR where the former consumes electricity and the latter methane. This thesis investigates these types of processes, with potential to reduce carbon dioxide emissions from the refining industry, and how they will be combined into a complete refinery that in turn will impact the city energy system.

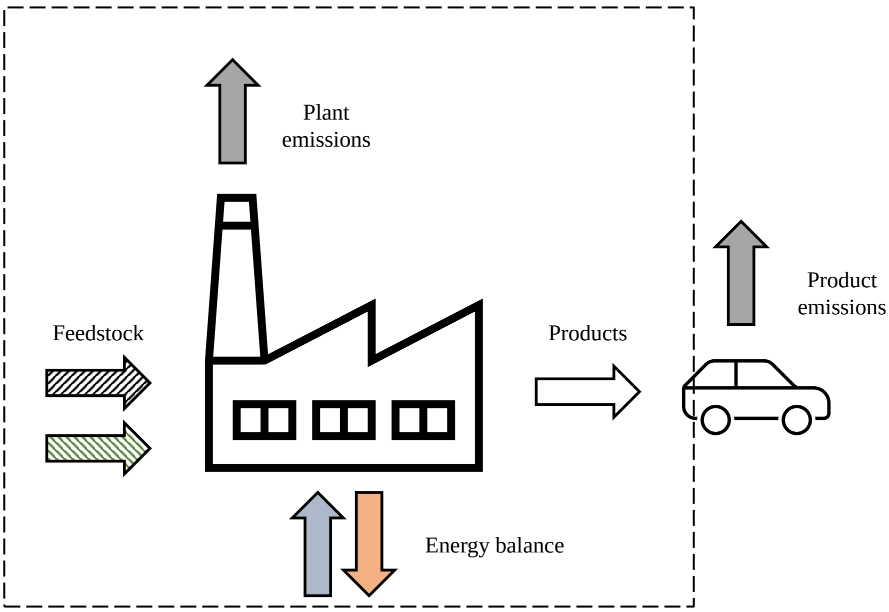

Figure 2: A simplified view on how the boundaries for the scenarios are set. The plant emissions are the main boundary (shown by dashed lines), and the goal is to reach net-zero emissions. The product emissions are also covered within the results and discussion as they are impacted when the plant emissions are reduced. They are, however, not the primary goal of the scenarios.

There are multiple solutions that are discussed today which could potentially decarbonize conventional refineries. A typical refinery is shown in Figure 2. Some solutions involve replacing fossil fuel fired boilers and furnaces with electric ones [7]. However, these solutions focus on decarbonization of individual processes and not on the excess of fuel gas that would occur with the implementation of these solutions. Since a major part of emissions (see Table 1) from the refineries result from the combustion of this fuel gas [7], exporting it for use elsewhere would just transfer the emissions from one source to another. Therefore, unless the fuel gas originates from a biogenic source (and not fossil crude oil), a different approach for decarbonization has to be taken. Another way of decarbonizing is to implement a post-combustion Carbon Capture and Storage (CCS) technology which could reduce the plant emissions by up to 85-90% [17]. The Carbon Capture process has an electricity and steam demand (which can also be electrified with electric boilers) and will be a new load added to the energy system. Furthermore, if biogenic emissions are captured, they could provide a net-negative effect or if used as feedstock for electro-fuels, they would become net-zero (this type of technology is called CCU[5]) and is another solution towards decarbonization. Jannasch et. al. [9] discuss that electro-fuel production could place an additional strain on the energy system as it comes with a high electricity demand. In this research, the scope will not be fixed on individual existing processes within the refineries but on the refineries as a whole.

In order to assess refinery decarbonization solutions and investigate the impact they have on the city energy system several scenarios are constructed. They are based on different pathways that the refineries could take and include technologies and their corresponding energy balances. They also cover most of the refinery value-chain by including feedstocks to finished products. The scenarios are designed with the goal of plant net-zero emissions but in Scenario 1 this goal is not reached (see method chapter for more on this).

1.2. Aim

The aim of this thesis is to investigate the impacts of decarbonization of the refineries in Gothenburg on the local electricity and heating system. Since the refineries provide excess heat to the city's district heating system, any change to the heat balance at the refineries could affect the district heating system.

Also, the electricity balance and the plant flexibility are relevant to investigate. Some of the scenarios can significantly affect the demand of electricity, which in turn could mean that the refineries could support the electricity grid by providing demand side management (e.g. load-shifting), if the processes allow for it. Potentially, these scenarios could prove that the future refineries will affect the cost of electricity as well as district heating in the region.
The investigation is divided into different scenarios where each scenario is a set of different decarbonization technologies with the aim of reducing the emissions to net-zero.

This thesis aims at answering the following questions:

1. What are possible decarbonization scenarios for oil refineries?

2. How do these decarbonization scenarios impact the interaction between refineries and the local energy system?

[5] Carbon Capture and Utilization.

2.
Method

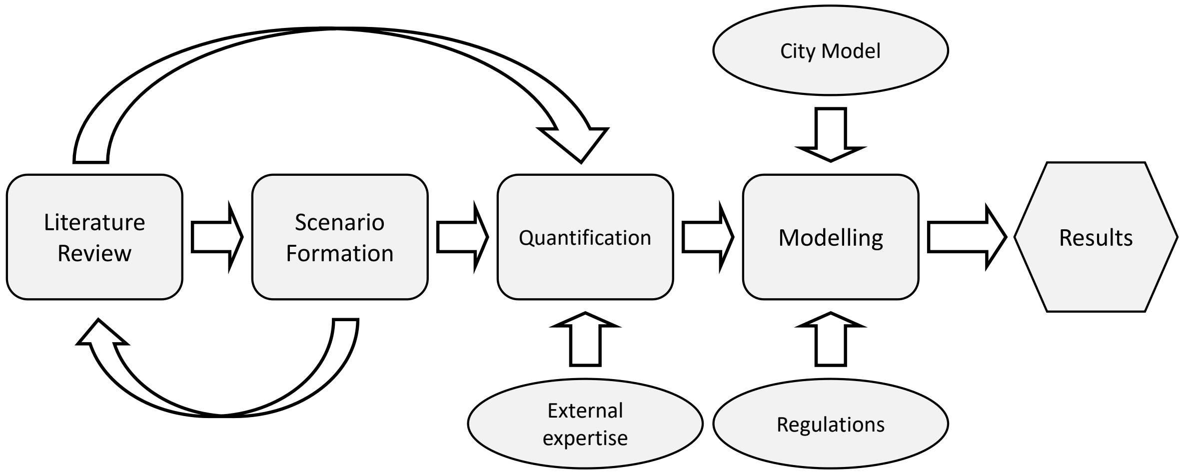

Figure 3: Methodology flow diagram, the circles represent the inputs while the rectangles represent the different steps that were followed to get to the results.

The project started with a detailed investigation and the familiarization with the processes at the refineries (a generic conventional refinery and also both the refineries under study). The processes may vary between different refineries depending upon their desired outputs. This was followed by the identification of possible decarbonization technologies and strategies along with the limitations that could hinder their integration. Multiple combinations of these technologies and strategies were investigated in order to defined scenarios (as shown in Figure 3 as scenario formation). Four scenarios were formulated and modelled with a common objective of achieving net-zero emissions at the plant site. The scenarios are described briefly below and explained in detail in later sections.

- **Scenario 1 - CCS & bio-blending (CBR).** This scenario explores the impacts of implementing CCS at the refineries on the heating and electricity system. The capture rates of CCS are not 100% due to techno-economic constraints and thus this scenario cannot achieve net-zero emissions as long as fossil feedstock is used. Due to this, the fossil crude intake in this scenario is reduced by blending in biofuel to further reduce the emissions in the final pool. The blending of bio-products does not directly reduce plant emissions but instead reduces the product emissions, but neither the plant nor the product emissions reduce to net-zero. The capture of biogenic emissions from the production of bio-fuel is not investigated.

- **Scenario 2 – Bio Electro Refinery (BER)** explores the impacts of a complete future restructuring of the refinery sector. The feedstock is assumed to consist of biomass, biogenic CO_2 and hydrogen, and the product mix is changed i.e. the focus of production shifts from production of Diesel which is the main output of both the refineries under investigation [13], [14] This scenario has no plant or product greenhouse gas emissions, and is mainly producing fuel for a sector that is hard to decarbonize; the aviation sector

(Air Transport Action Group [18] and Gross [19]. See the discussion on "complications using biomass as feedstock for kerosene production" for more information.

- **Scenario 3 – Electro Refinery (ER)** is similar to scenario 2 – BER but with one large change, mainly that there is no biomass feedstock and the feedstock consists of biogenic CO_2 and hydrogen. The plant has neither plant nor product greenhouse gas emissions and it is assumed to produce aviation fuel (kerosene) as the main output.

- **Scenario 4 - Closing Down (CD).** This scenario **)** investigates the impact of a complete shut-down of the refineries**.** Since these large industrial processes consume electricity and supply large quantities of residual heat, it is important to investigate the impact on the energy system if the refineries are shut down. This scenario also serves as a reference when examining how the other scenarios will impact the energy system.

The refineries, however, are both exporting and fulfilling the local demand for transportation fuels. Restructuring (Scenario 2 & 3) or closing down the refineries (Scenario 4) would mean this demand would have to be substituted from somewhere else, if it is still existing. This project does not focus on identifying exact alternate solutions for this possible gap in supply but rather how a possible scenario will impact the energy system. A qualitative solution for the substitution would be indicated e.g. import or using methanol as feedstock [20]. The refineries would have to shut down if their entire value chain emissions and dependency on crude oil as a feedstock are not reduced. 22 out of 34 refineries in North-West Europe are expected to not survive the future shrinkage of fossil fuel demand [21]. As discussed, the impact of these scenarios would be studied in an existing dispatch and investment model on the Gothenburg energy system developed by the Energy Technology division at Chalmers. The scenarios will be quantified in terms of change in electricity demand and excess heat availability.

2.1. City model

The city model is a linear optimization model as first introduced in [10] and has been expanded in this work to investigate the potential future impact of the refineries. The model covers future electricity and heat loads with corresponding generation (dispatch) with an hourly resolution for the entire year. The model is also an investment model i.e., if the existing generation capacity is not able to meet the future demand, it invests in new technologies for both heat and/or electricity with their respective storages from a large array of available technologies. The choices of the new investments and the operation of the generation mix is done based on the capital costs (for former) and operation and maintenance costs since the objective function of the model is to minimize the annual system cost i.e. the investments and operational cost of all the technologies (see equation (1)).

The model already has a set of existing technologies which are shown in Figure 4 and Table 3, and since the model has a limitation of zero emissions it does not select fossil generation technologies to satisfy the heat or electricity demand. These existing technologies refer to those that exist in the city energy system today. Both the refineries under investigation have a goal to achieve net-zero emissions for their entire value chains by 2045 [9]. Therefore, the system is modelled for that year with a 50% increase in both heat and electricity demand to take city growth into account. Electricity can be imported to the city but limited by grid capacity while export is not modelled in this work.

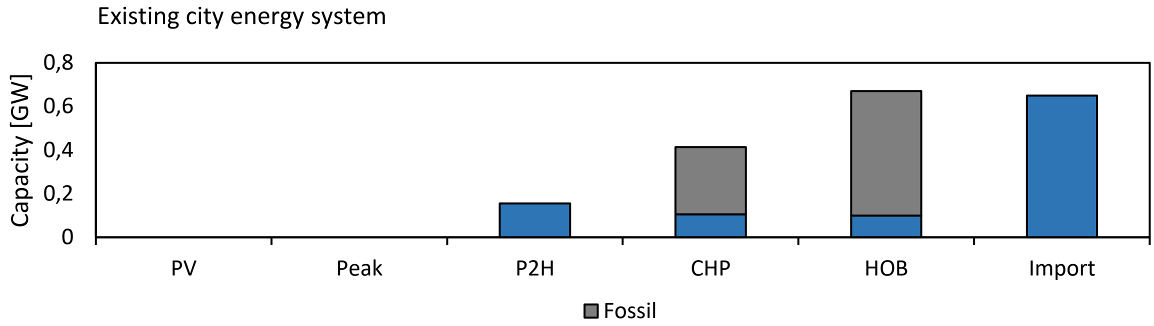

Figure 4: The existing generation capacities (in GW) of the electricity and heating system in the city. The blue bars represent technologies that are either biomass fired or depend on clean electricity. The grey ones are fossil and will be phased out.

Table 3, The existing generation capacities (in GW) of the electricity and heating system in the city.

Generation unit	CHP	CHP	HP	HOB	HOB	Import
Fuel type	Biomass	Natural gas	Electricity	Natural gas	Oil	N.A.
El. gen. cap.	0.11	0.31	0	0	0	0.66
Heat. gen. cap.	0.75[6]	0.24[7]	0.16	0.27	0.3	0

$$MIN: \mathrm{C^{tot}} = \sum_{\mathrm{i}\in \mathrm{I}} (\mathrm{C_i^{inv}}\, \mathrm{s_i} + \sum_{\mathrm{t}\in \mathrm{T}} (\mathrm{C_i^{run}} \mathrm{p_{i,t}} + \mathrm{C_i^{run}} \mathrm{q_{i,t}})) + \sum_{\mathrm{t}\in \mathrm{T}} \mathrm{C_t^{el}} \mathrm{w_t}\, , \forall \mathrm{t} \in \mathrm{T} \tag{1}$$

The electricity balance is expressed by equation (2), which makes sure that the demand is met at all hours.

$$(\mathrm{D_t^{el}} - A^{SD,el}) + \sum_{\mathrm{i}\in \mathrm{I_{ElSt}}} \frac{\mathrm{p_{i,t}^{ch}}}{\eta_{\mathrm{i}}} + \sum_{\mathrm{i}\in \mathrm{I_{PtH}}} \frac{\mathrm{q_{i,t}}}{\eta_{\mathrm{i}}} + \sum_{\mathrm{i}\in \mathrm{I}_{rt}} \mathrm{p_{i,t}} \leq \sum_{\mathrm{i}\in \mathrm{I}\backslash \mathrm{I_{ElSt}}\backslash I_{rt}\backslash I_{PtH}\backslash I_{HSt}} \mathrm{p_{i,t}} + \mathrm{w_t} + \sum_{\mathrm{i}\in \mathrm{I_{ElSt}}} \mathrm{p_{i,t}^{dch}}\, , \forall \mathrm{t} \in \mathrm{T} \tag{2}$$

The heat balance is similar to the electricity balance and is expressed by equation (3):

$$D_t^{\hbar} + \sum_{i\in I_{HSt}} \frac{q_{i,t}^{ch}}{\eta_i} \leq \sum_{i\in I\backslash I_{HSt}\backslash \mathrm{I_{ElSt}}} q_{i,t} + \sum_{i\in I_{HSt}} q_{i,t}^{dch} + (X_t - A^{SD,\hbar})\, , \forall t \in T \tag{3}$$

The decarbonization pathways of the refineries are implemented into the model in terms of electricity demand and residual heat availability and hence the equations have been slightly modified from the original set-up [10] to incorporate this impact in both equation (2) and (3). The description of the symbols can be seen below. The refinery technologies are added to the array of available technologies for the model and equation (1) minimizes the cost of achieving net-zero emissions for the refineries in addition to the capital and operational costs of the generation mix as discussed earlier. It should be noted that equation (1) does not represent the

[6] Calculated using alpha value 0.14.
[7] Calculated using alpha value 1.3.

annual system cost for this work as in [10] since the refineries have also been added into the system boundaries. There are different decarbonization pathways (scenarios) investigated in this work and are integrated differently into the city model. The following sections will explain all four scenarios and their integration in detail.

Explanation of the symbols (sets, variables & parameters) used in the equations of the City model. The dashed line is to sperate the refinery specific symbols.

T	is the set of all time steps
I	is the set of all the technologies in the city energy system
I_{PtH}	is the subset to I for all power-to-heat technologies
I_{ElSt}	is the subset to I for all electricity storage technologies
I_{HSt}	is the subset to I for all thermal storage technologies
C^{tot}	is the total system cost to be minimized
C_i^{inv}	is the investment cost (annualized) including the fixed O&M cost for each technology i
C_i^{run}	is the running cost for each technology i (including fuel cost)
C_t^{el}	is the cost to import electricity to the city from the national grid
s_i	is the capacity of technology i invested in
$p_{i,t}$	is the electricity generation by technology i at time step t
$q_{i,t}$	is the heat generation by technology i at time step t
w_t	is the electricity imported to the city at time step t
D_t^{el}	is the electricity demand at time step t
D_t^{h}	is the heat demand at time step t
$p_{i,t}^{ch}$	is the electricity charged to electricity storage technologies at time step t
$p_{i,t}^{dch}$	is the electricity discharged from electricity storage technologies at time step t
$q_{i,t}^{ch}$	is the heat charged to thermal storage units at time step t
$q_{i,t}^{dch}$	is the heat discharged from thermal storage units at time step t
X_t	is the heat production profile of the industrial excess heat at time step t
η_i	is the efficiency (or COP) of each technology i
I_{rt}	is the subset of I, that includes all new technologies introduced in the refineries
$A^{SD,h}$	is the constant (at every time step t) reduction in waste heat availability from scaling down the existing refineries
$A^{SD,el}$	is the constant (at every time step t) reduction in electricity demand from scaling down the existing refineries

2.2. Scenario 01 – CCS & Bio-blending Refinery (CBR)

This scenario investigates the emission reduction potential with a post-combustion CCS integration into the existing setup of the refineries in combination with renewable fuel blending (HVO diesel) into the final product pool. These methods are combined since neither of the two can reduce the plant emissions to net-zero. The emission reduction from CCS is limited by its capture rate which is reported up to 85-90% in the literature [17]. Therefore, bio blending as an additional measure is investigated to make up for the remaining 10-15% emissions. The blending of HVO diesel does not directly reduce the plant emissions but rather indirectly through the reduction in the amount of fossil crude oil processed as feedstock. The scenario aims to keep the total output of diesel from the refinery to the same levels as today by increasing the renewable content because diesel is the main product of both the refineries [13], [14].Because of lower crude feedstock processing, the amount of LPG, gasoline, kerosene, heavy fuel oil and light fuel oil produced will also be reduced. This would impact the downstream consumers of the refineries and is discussed further in section 4.3 but not investigated as a part of this work. A process overview of the CBR scenario is shown in Figure 5.

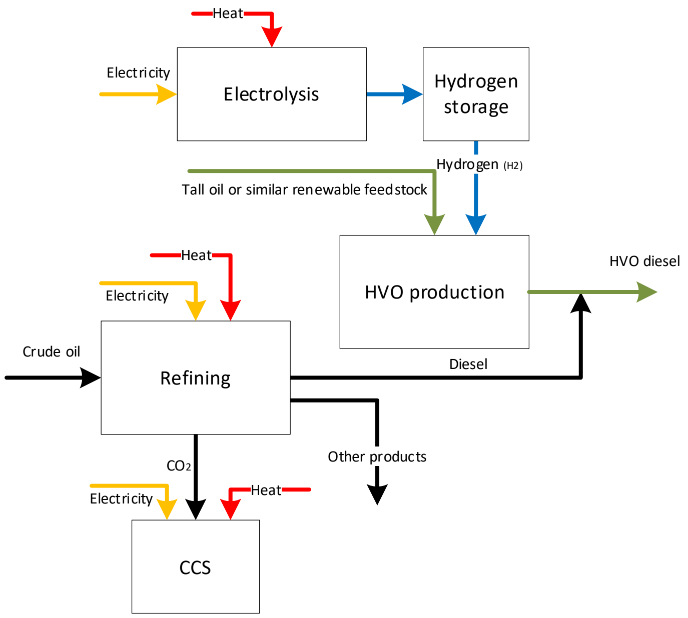

Figure 5: Process overview of the refinery setup for scenario CBR.

A technical feasibility project between Volvo Cars and Taxi Göteborg showed that their newer models can run on 100% HVO fuel without any conversions or adjustments [22]. Therefore, the biodiesel sold by the refineries has no technical limitation from that perspective. The higher the blend ratio, the less are the well-to-wheel emissions as a part of those emission that arise from combustion would be biogenic[8] [23]. [24], [25]The generation of this HVO fuel could, however, face barriers from the energy system as the hydrogen required for its production has to be “green” to have no adverse environmental impact and this green hydrogen production requires high amount of green electricity [26]. These impacts will be studied in this scenario for different blend ratios. ST1 has already initiated its plan to produce 200 000 tonnes/a of

[8] The absolute emissions from combustion offset by the regrowth of biomass.

HVO diesel and bio-jet fuel [9] which could be blended in their final pool to give a blend ratio of 10% HVO to fossil diesel[9]. This would be the starting point of this scenario to study how it would impact the energy system while using the same blend ratio for Preem.

Figure 6 shows the most important feedstocks, energy inputs and outputs along with the production outputs for this scenario (CBR) where letter (a) represents ST1 and (b) represents Preem. The share of outputs shown in the figure is based on the current production of ST1 [13]. Such information was not publicly available for Preem and therefore the same ratio between the outputs is considered for both the refineries. This assumption is based upon the fact that they have similar processes and output products [13], [14]. The detailed description of the processes is discussed in the next section along with how the model is constructed.

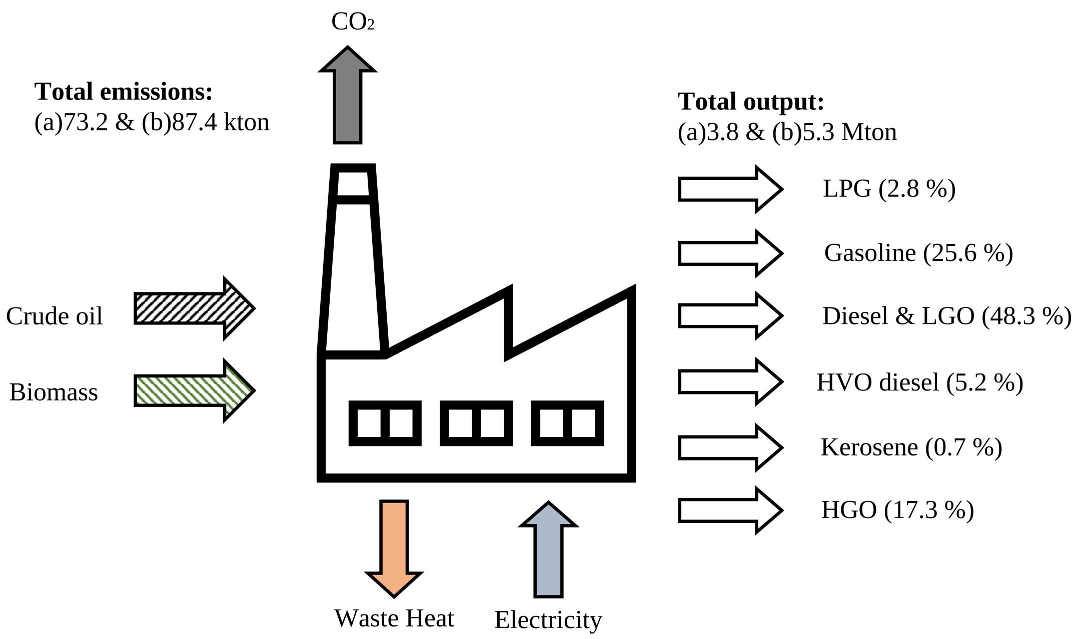

Figure 6: The assumed annual input, outputs and emissions from the refineries.

[9] This blend ratio is calculated with respect to their current production capacity. There is a possibility that their production levels would be reduced because of the restrictions in the EU on fossil fuel usage downstream by 2045. The refineries also export a large share of their production, and this share could be transferred outside the EU to maintain current production levels.

2.2.1. Scenario 1 - CBR modelling equations

This section will go through the mathematical equations describing the model construction for CBR. The symbols used in these equations are described below the equations.

The CCS technology considered in the scenario is mono-ethanolamine (MEA) based post-combustion carbon capture requiring large amount of energy to regenerate the absorbent from the captured carbon dioxide [17]. The advantage of using post-combustion carbon capture is to avoid any restructuring of the existing processes and the ability to efficiently capture the CO_2 even if its concentration in the flue gas is low [17]. Johansson et. al [17] carried out a study on these parameters for Preem and reported over 8.7% CO_2 concentration levels in both their main chimneys that account for more than 89% of their emissions [14]. Both the processes CCS [27] and the HVO production [28]have small auxiliary electricity demands expressed as [equation (4) & (5), respectively]:

$$\boldsymbol{p_{CCS,t}} = \boldsymbol{co_{2_t}}\, \boldsymbol{H_{ccs}}\, \boldsymbol{A^{ccs,el}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{CCS} \in \boldsymbol{I_{rt}} \tag{4}$$

$$\boldsymbol{p_{HVO,t}} = \boldsymbol{A^{hvo,el}}\, \boldsymbol{hvo_t}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{HVO} \in \boldsymbol{I_{rt}} \tag{5}$$

The production of HVO includes a step called hydrotreatment [28] which requires the green hydrogen discussed earlier. The production of this hydrogen is modelled assuming water electrolysis and as the model has a limitation on emissions, the electricity demand for the electrolysis process will be met with renewable sources of electricity. Three electrolysis technologies are commonly discussed for large-scale production of hydrogen and the Solid Oxide Electrolysis Cell (SOEC) is considered for this work since the Danish technology data for renewable fuel [29] suggests that both its investment and operational cost will be the cheapest amongst the three in the year 2050 with further development of the technology. The electricity demand (35.86 $MWh/tonne_{h_2}$), however, is high for this electrolyzer [27] and is introduced in the model with equation (6). The amount of hydrogen needed determines the sizing of the SOEC (see equation (7)).

$$\boldsymbol{p_{Electrolyser,t}} = \boldsymbol{A^{electrolyser,el}}\, \boldsymbol{h_{2_t}^{ch}} + \boldsymbol{h_{2_t}^{ch}} \quad \boldsymbol{A^{electrolyser,steam}}/\boldsymbol{\eta_{EB}}, \\ \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{Electrolyser} \in \boldsymbol{I_{rt}} \tag{6}$$

$$\boldsymbol{s_{electrolyser}} \geq \boldsymbol{h_{2_t}^{ch}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{Electrolyser} \in \boldsymbol{I_{rt}} \tag{7}$$

There is heat demand in the form of LP steam for both CCS [17] and HVO[28] Appendix A) but the temperature and the pressure of this steam varies [27], [28], [30]. Both these steam demands are assumed to be met with 99% efficient electric boilers [31] and are introduced as an electricity demand to the city model as shown in equation (8) & (9).

$$\boldsymbol{p_{CCS,t}^{heat}} = \boldsymbol{co_{2_t}}\, \boldsymbol{\eta_{ccs}}\, \boldsymbol{A^{ccs,h}}/\boldsymbol{\eta_{EB}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{CCS}\,\&\,\boldsymbol{EB} \in \boldsymbol{I_{rt}} \tag{8}$$

$$\boldsymbol{p_{HVO,t}^{heat}} = \boldsymbol{A^{hvo,h}}\, \boldsymbol{hvo_t}/\boldsymbol{\eta_{EB}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{HVO}\,\&\,\boldsymbol{EB} \in \boldsymbol{I_{rt}} \tag{9}$$

The total demand of HVO depends upon the blend ratio and has been introduced (see equation (10)) as an annual quantity that can be produced flexibly to study the impact without restricting the model. This is further covered in the *sensitivity analyses* in Section 3.2.

$$\sum_{t\in T} \boldsymbol{hvo_t} \geq \boldsymbol{A^{hvo,p}}, \qquad \boldsymbol{t \in T} \tag{10}$$

The electrolyzer has a high electricity demand [29] to produce hydrogen therefore the operating cost would largely depend upon the electricity price. This cost can be minimized by introducing a storage for hydrogen to enable producing more hydrogen during hours of low electricity prices to be consumed later. The city model already has hydrogen tank and lined rock caverns as possible hydrogen storage technologies. The amount of hydrogen consumed is determined by the amount of HVO produced and is expressed as equation (12). The capacity of the hydrogen storage is set with equation (13 ensuring that its greater than the highest state of charge required from equation (11).

$$\boldsymbol{soc_t^{H_2}} \leq \boldsymbol{h_{2_t}^{ch}} - \boldsymbol{h_{2_t}^{dch}} + \boldsymbol{soc_{t-1}^{H_2}}, \qquad \forall \boldsymbol{t \in T} \tag{11}$$

$$\boldsymbol{h_{2_t}^{dch}} \geq \boldsymbol{A^{hvo,h_2}}\, \boldsymbol{hvo_t} \tag{12}$$

$$\boldsymbol{s_{H_2st}} \geq \boldsymbol{soc_t^{H_2}}\, \boldsymbol{LHV^{H_2}}, \qquad \boldsymbol{H_2st \in I}, \forall \boldsymbol{t \in T} \tag{13}$$

$$\boldsymbol{s_{hvo}} \geq \boldsymbol{hvo_t}, \qquad \forall \boldsymbol{t \in T}, \boldsymbol{hvo \in I_{rt}} \tag{14}$$

Where,

$A^{hvo,p}$	$[t]$	is the total annual demand of HVO
$A^{hvo,el}$	$[GWh/t]$	is the electricity demand of unit HVO production
$A^{hvo,h}$	$[GWh/t]$	is the heat demand of unit HVO production
$A^{ccs,el}$	$[GWh/t]$	is the electricity demand of the carbon capture plant for unit CO_2 captured
$A^{ccs,h}$	$[GWh/t]$	is the heat demand of the carbon capture plant for unit CO_2 captured
$A^{electrolyser,el}$	$[GWh/t]$	is the electricity demand of the electrolyser for unit $h_{2_t}^{ch}$ production
A^{hvo,h_2}	$[GWh/t]$	is the hydrogen demand of the unit HVO production
$A^{SMR,h}$	$[GWh/t]$	is the heat demand per $h_{2_t}^{SMR}$ produced in unit SMR
$h_{2_t}^{SMR}$	$[t]$	is the amount of hydrogen produced in unit SMR
hvo_t	$[t]$	is the amount of HVO produced at time step t
co_{2_t}	$[t]$	is the CO_2 emissions from the refineries at time step t
$soc_t^{H_2}$	$[t]$	is the state of charge of the hydrogen storage at time step t
$h_{2_t}^{\mathrm{ch}}$	$[t]$	is the amount of hydrogen charging to the hydrogen storage at time step t
$h_{2_t}^{\mathrm{dch}}$	$[t]$	is the amount of hydrogen discharging from the hydrogen storage at time step t
LHV^{H_2}	$[GWh/t]$	is the energy density in the unit H_2
η_{EF}	$[-]$	is the electricity to heat efficiency of an Electric Furnace
η_{EB}	$[-]$	is the electricity to heat efficiency of an Electric Boiler
H_i		is the process conversion efficiency of technology i

2.3. Scenario 02 – Bio Electro Refinery (BER)

It was clear from the previous scenario (CBR) that it is difficult to achieve net-zero emissions as long as the feedstock is fossil-based crude oil. This scenario investigates potential routes to synthetically produce refinery feedstock (syncrude) through biogenic sources via the Fischer-Tropsch process. The Fischer-Tropsch (FT) converts syngas, a mixture of carbon monoxide and hydrogen, to syncrude and this syncrude would be biogenic if the syngas production does not involve fossil resources. Mortensen et. al [32] suggested three potential routes to achieve this as depicted in the Figure 7.

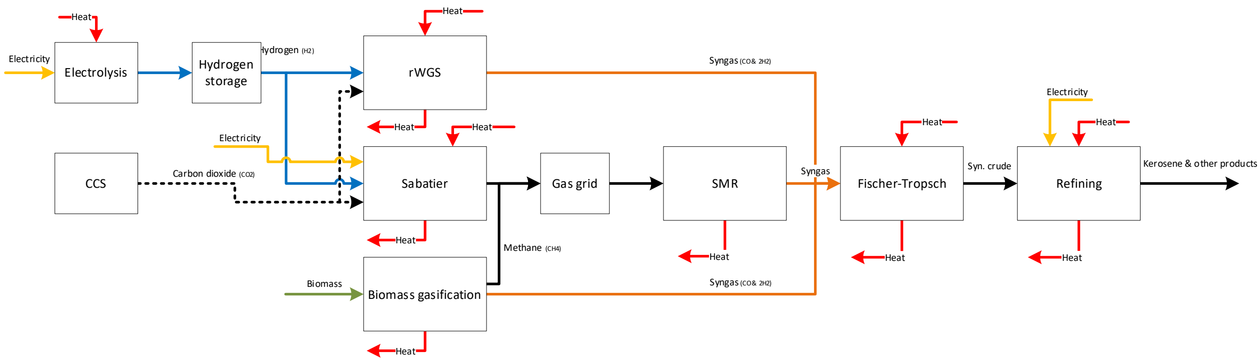

Figure 7: Process overview of the refinery setup in the scenario BER. The interaction with the electricity system is shown by yellow arrows while the process heat supply and demand are shown by red. A magnified figure is shown in Appendix B.

The syncrude obtained from this process maximizes jet fuel production. The exact composition of the syncrude may vary depending upon the operating parameters and the type of catalyst used for the FT process [33]. However, the share of kerosene would be greater than two-third (vol%) for all conditions [32]. Reports by the Air Transport Action Group [18] and Gross [19] have emphasized that aviation remains one of the hardest sectors to decarbonize compared to other modes of transportation. Therefore, even though the demand of fossil fuel for passenger vehicle transport can be expected to decrease, the demand for fossil kerosene might still be the same in the future. This is the core focus of this scenario where the refineries would have to go through an overhaul of their processes altering the final mix of their products. Figure 8 shows the inputs to and outputs (including final mix of the products) from the refinery if they were to go down this path. This would impact the current actors which are downstream in the value chain e.g. the shipping industry would not have the heavy fuel oil as an output from the refineries anymore.

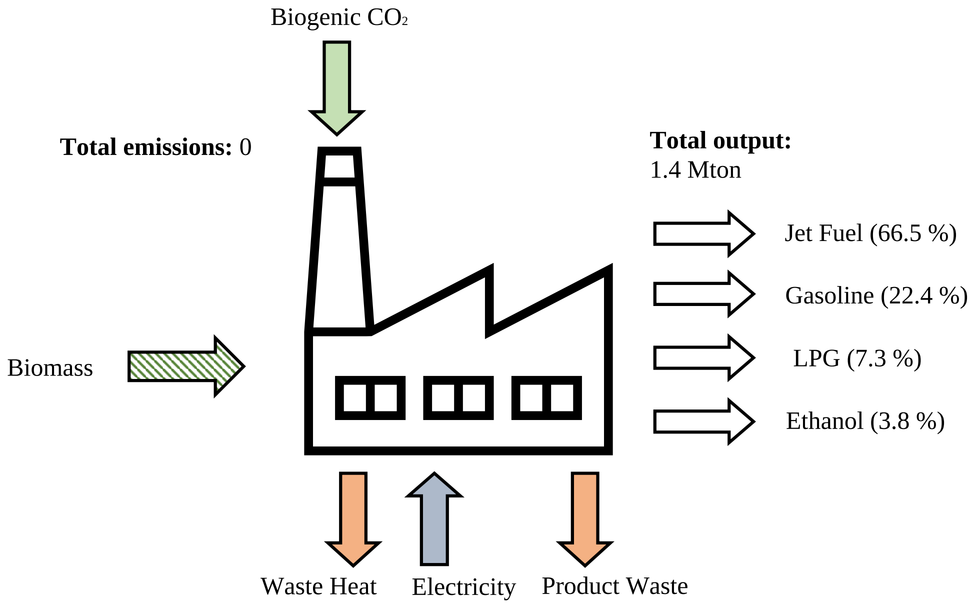

Figure 8: An overview of the annual inputs, outputs and emissions from the refinery in scenario BER.

As mentioned before and shown in Figure 7, there are three potential routes to produce syncrude. This will provide flexibility in its interaction with the city energy system and the preferred route (or the combination of different routes) it takes will depend on several factors exogenous to the refinery. These routes are discussed with their integration into the city energy model below:

2.3.1. Scenario 2 – BER modelling equations

2.3.1.1. Reverse Water Gas Shift (rWGS)

The production of syngas in this route comes from a rWGS process which requires CO_2 and H_2 as inputs. The former will be the captured biogenic emissions from either the bio-CHP plants within the energy system (or the city for our case) or imported from elsewhere. The work does not go into the detail of where these CO_2 emissions will potentially come from. However, if they are captured from the bio-CHPs there could be an extra electricity and heat demand for the capture process. The bio-CHPs might also be limited regarding the amount of CO_2 they can provide to the refineries. Therefore, the CO_2 emissions are assumed to be imported from outside the system. The H_2 can be produced via water electrolysis as discussed in section 2.2.1. The demand for both these inputs [34] are expressed by equation (15) and (16), respectively, for each time step, depending upon the syngas output. As the desired output from this process is syngas, the reactor can be fed with an excess of hydrogen [27] as shown in the chemical reaction (i).

$$CO_2 + 3H_2 \leftrightarrow CO + H_2O + 2H_2 \quad \Delta H = +41kJ/mol \qquad \text{(i)}$$

Since the rWGS is a highly endothermic process taking place at temperatures around 900°C, it needs a large amount of heat to drive the process [34]. This is expressed in equation (*17*) as an electrified heat demand which is assumed to be met with an electric furnace. As a process output, we also get vaporized steam [34] which will be used to deliver heat to the district heating network. The waste heat availability from the process in each time step is given in equation (18) while equation (19) determines the size of the plant for cost optimization in equation (1).

$$co_{2_t}^{rWGS,dch} = A^{rWGS,CO_2}\, SG_t^{rWGS}\, H_{rWGS}, \quad rWGS \in I_{rt}, \quad \forall t \in T \tag{15}$$

$$h_{2_t}^{rWGS} = A^{rWGS,H_2}\, SG_t^{rWGS}, \quad \forall t \in T \tag{16}$$

$$p_{rWGS,t}^{heat} = A^{rWGS,heat,d}\, SG_t^{rWGS} / \eta_{EF}, \quad rWGS \,\&\, EF \in I_{rt}, \forall t \in T \tag{17}$$

$$q_{rWGS,t} = A^{rWGS,heat,s}\, SG_t^{rWGS}, \quad rWGS \in I_{rt}, \forall t \in T \tag{18}$$

$$s_{rWGS} \geq SG_t^{rWGS}, \quad rWGS \in I_{rt}, \forall t \in T \tag{19}$$

Where

SG_t^i	$[t/h]$	is the syngas produced per by technology i
$co_{2_t}^{rWGS,dch}$	$[t/h]$	is the CO_2 demand of technology $rWGS$ at time step t
$h_{2_t}^{rWGS}$	$[t/h]$	is the H_2 demand of technology $rWGS$ at time step t
A^{rWGS,CO_2}	$[t/t]$	is the CO_2 demand of unit $SG_{rWGS,t}$
A^{rWGS,H_2}	$[t/t]$	is the H_2 demand of unit $SG_{rWGS,t}$
$A^{rWGS,heat,d}$	$[GWh/t]$	is the heat demand of unit $SG_{rWGS,t}$
$A^{rWGS,heat,s}$	$[GWh/t]$	is the waste heat supplied of unit $SG_{rWGS,t}$
η_{EF}	$[-]$	is the electricity to heat efficiency of an Electric Furnace
H_{rWGS}	$[-]$	is the conversion efficiency of the rWGS process

2.3.1.2. *Sabatier Process*

The Sabatier process is an electro-methane production process utilizing the same inputs as rWGS i.e. CO_2 and H_2 at a high temperature and in the presence of catalyst [35] as expressed in chemical reaction (ii). The methane obtained from this route must be purified by drying to remove the excess water. This loss of renewable hydrogen in the form of water is an inevitable drawback of this route. However, the reaction is highly exothermic and can complement the district heating system, as expressed in equation (22). Equations (20 and (21) express the demand of hydrogen and carbon-dioxide for the Sabatier reaction per unit of electro-methane produced while also taking into account the efficiency of methanation [36]. Equation (23) determines the size of the plant.

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O \quad \Delta H = -165\, kJ/mol \tag{ii}$$

$$h_{2_t}^{eMethane} = A^{eMethane,H_2} ch_{4_t}^{eMethane,ch} H_{eMethane}, \quad eMethane \in I_{rt}, \forall t \in T \tag{20}$$

$$co_{2_t}^{eMethane} = A^{eMethane,CO_2} ch_{4_t}^{eMethane,ch} H_{eMethane}, \quad eMethane \in I_{rt}, \forall t \in T \tag{21}$$

$$q_{eMethane,t} = A^{eMethane,h,s} ch_{4_t}^{eMethane,ch}, \quad eMethane \in I_{rt}, \forall t \in T \tag{22}$$

$$s_{eMethane} \geq ch_{4_t}^{eMethane,ch} LHV^{CH_4}, \quad eMethane \in I_{rt}, \forall t \in T \tag{23}$$

The purified electro-methane can be sold to the natural gas grid. Audi (Germany) built a pilot plant to materialize this concept called the E-Gas project where they produce hydrogen from wind power and separate CO_2 from biogas [27]. The possibility of selling methane to the gas grid is what gives flexibility to this route: producing electro-methane during periods with lower electricity prices, feeding into the gas grid and then buying back to produce syngas and subsequently syncrude. In this way, the gas grid can support the electricity grid during hours of congestion by allowing the refineries to keep their production levels up by utilizing the electro-methane produced during hours of non-congestion. This process, however, comes with an extra conversion step to facilitate the syngas production which is discussed in the later section. These processes and their integration into the city model are found in a later section.

Where

$\hbar_{2_t}^{eMethane}$	$[t/\hbar]$	is the H_2 demand of technology $eMethane$ at time step t
$co_{2_t}^{eMethane}$	$[t/\hbar]$	is the CO_2 demand of technology $eMethane$ at time step t
$c\hbar_{4_t}^{eMethane,ch}$	$[t/\hbar]$	is the CH_4 produced by technology eMethane at time step t
LHV^{CH_4}	$[MWh/t]$	is the lower heating value of CH_4
$A^{eMethane,\hbar,s}$	$[GWh/t]$	is the waste heat supplied of unit $CH_{4,eMethane}$
$A^{eMethane,CO_2}$	$[t/t]$	is the CO_2 demand of unit $CH_{4,eMethane}$
$A^{eMethane,H_2}$	$[t/t]$	is the H_2 demand of unit $CH_{4,eMethane}$
$H_{eMethane}$	$[-]$	is the conversion efficiency of the Sabatier process

2.3.1.3. *Biomass Gasification*

The third route is the gasification of biomass in a circulating fluidized bed (CFB) gasifier. The biomass can either be gasified, cleaned and then upgraded to bio-methane and sold to the grid as discussed in the previous section or can skip the methanation process and syngas can be extracted as an output [29]. The former provides flexibility in terms of operation as the gasification will be decoupled from the syncrude production. The ability to sell to the grid could provide the refineries an additional incentive to invest in a larger capacity than what is needed as feedstock for their own production. Based on the technology development rate, the CFB gasification of biomass to synthetic natural gas (SNG) could have a conversion efficiency of 70% by 2050 while 20% of the fuel energy input is converted to waste heat (equation (26)) which can complement the district heating system [29].

The biomass-to-syngas route has an even better conversion efficiency (76.5%) [29] since it skips the extra methanation step, but it does not allow interaction with the natural gas grid. The CFB gasifier is limited to a stable load operation therefore, the gasifier capacity (equation (25)) for the syngas route would be limited to the syngas demand of the FT process. The equations below describe how this route is integrated into the city model:

$$\boldsymbol{bm_t} \geq \boldsymbol{ch_{4_t}^{bMethane,ch}}\ \boldsymbol{LHV^{CH_4} H_{bMethane}} + \ \boldsymbol{SG_t^{Gasi}}\ \boldsymbol{LHV^{SG} H_{SG}}, \forall \boldsymbol{t} \in \boldsymbol{T}, \boldsymbol{bMethane}\ \&\ \boldsymbol{SG} \in \boldsymbol{I_{rt}} \tag{24}$$

$$\boldsymbol{s_{gasification}} \geq \ \boldsymbol{ch_{4_t}^{bMethane,ch}}\ \boldsymbol{LHV^{CH_4}} + \boldsymbol{SG_t^{Gasification}}\ \boldsymbol{LHV^{SG}}, \quad \forall \boldsymbol{t} \in \ \boldsymbol{T} \tag{25}$$

$$\boldsymbol{q_{gasification,t}} = \boldsymbol{A^{bMethane,h} ch_{4_t}^{bMethane,ch}} \ + \boldsymbol{A^{SG,h}}\ \boldsymbol{SG_t^{Gasification}}\ , \boldsymbol{captureplant}\ \in \boldsymbol{I_{rt}}, \forall \boldsymbol{t} \in \boldsymbol{T} \tag{26}$$

The input to the gasifier is biomass (equation (24)) and, depending upon the output of the refineries, a limitation of this route is the amount of biomass available for the refineries. Mortensen et. al [32] project that the Swedish demand of jet fuel could be around 14 TWh/a by 2050 and the demand for the entire Nordic region could rise to 60 TWh/a. These demands are high compared to the amount of sustainably available biomass within Sweden and could potentially see the refineries opting for a combination of different routes discussed in this scenario. The energy systems model will help in suggesting this optimum combination.

Where

$ch_{4_t}^{bMethane,ch}$	$[t]$	is the biomethane charged to the methane grid at time step t
bm_t	$[t]$	is the amount of biomass consumed in gasification at time step t
LHV^{SG}	$[GWh/t]$	is the lower heating value of syngas
$A^{bMethane,\hbar}$	$[GWh/t]$	is the excess heat supplied per unit production of biomethane from gasification
$A^{SG,\hbar}$	$[GWh/t]$	is the waste heat supplied per unit production of syngas from gasification
$\mathrm{H}_{bMethane}$	$[-]$	is the process conversion efficiency of the bio methane gasification process
H_{SG}	$[-]$	is the process conversion efficiency of the syngas gasification process

2.3.1.1. Common Processes

Each of the three different routes discussed earlier in this section have some common processes as shown in Figure 7 and will be described here in detail. The rWGS and Sabatier processes require carbon dioxide as feedstock. For these routes to be sustainable, this carbon dioxide demand must be met through biogenic emissions. For our case, the city model has biomass/biogas fired combined heat and power technologies (CHP) and boilers and provides an opportunity to utilize these emissions as a feedstock to the refineries. This process is commonly termed as CCU where these emissions need to be captured and transported to the refineries. The carbon capture technology considered for our case is the amine-based post-combustion capture (discussed in CBR scenario) with capture rate of 85% [17]. However, due to modelling complications, it was decided to import CO_2 and put this constraint of available CO_2 outside of the boundaries and thus not causing unrealistic operations. For the sake of clarity, when CO_2 was constrained to be captured within the city, the model invested and operated HOBs in order to just supply the CO_2. This is unrealistic and thus we suggest that this could be a part of a future study of CO_2 scarcity for electrofuel production.

The other common feedstocks to both the rWGS and Sabatier processes are hydrogen and carbon dioxide. The hydrogen must be produced from renewable sources to be called "Green Hydrogen". The hydrogen demand could be met with water electrolysis. While there are different available water electrolysis technologies, a Solid Oxide Electrolyzer Cell (SOEC) is considered for this work as it is expected to be cheaper and scalable compared to other available technologies in 2050 [37]. Other candidate technologies include Alkaline Electrolyzers and Proton Exchange Membrane (PEM) electrolyzers. The electrolyzer has a high electricity demand [37] to produce hydrogen (see equation (29)) therefore the operating cost would largely depend upon the electricity price. This cost can be minimized by introducing a storage of hydrogen and producing more hydrogen during hours of low electricity prices to be consumed later. The city model already has hydrogen tank and lined rock caverns as possible hydrogen storage technologies. Equation (28) sets a capacity on the potential hydrogen storage based on the state of charge in equation (27) while the capacity of the SOEC electrolyzer (see equation (30)) depends upon the maximum hydrogen demand during operation.

$$\boldsymbol{soc_t^{H_2} \leq h_{2_t}^{ch} - h_{2_t}^{eMethane} - h_{2_t}^{rWGS} + soc_{t-1}^{H_2}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T} \tag{27}$$

$$\boldsymbol{soc_t^{H_2}\, LHV_{H_2} \leq s_{H_2st}}\,, \boldsymbol{H_2st} \in \boldsymbol{I_{rt}}, \qquad \forall \boldsymbol{t} \in \boldsymbol{T} \tag{28}$$

$$\boldsymbol{p_{electrolyser,t} = A^{electrolyser,el}\, h_{2_t}^{ch}}\,, \qquad \boldsymbol{electrolyser} \in \boldsymbol{I_{rt}}, \forall \boldsymbol{t} \in \boldsymbol{T} \tag{29}$$

$$\boldsymbol{p_{electrolyser,t} \leq s_{electrolyser}}\,, \qquad \boldsymbol{electrolyser} \in \boldsymbol{I_{rt}}, \forall \boldsymbol{t} \in \boldsymbol{T} \tag{30}$$

Where

$soc_t^{H_2}$	$[t]$	is the state of charge of H_2 at time step t
$h_{2_t}^{ch}$	$[t]$	is the H_2 produced by technology wE at time step t

The electro-methane from the Sabatier and the bio-methane from the gasification will be fed to the natural gas grid and then extracted when needed for the steam reforming process (SMR) to produce syngas as shown in equation (31).

$$\mathrm{soc_t^{CH_4}} \leq ch_{4_t}^{\mathrm{bMethane,ch}} + \mathrm{ch}_{4_t}^{\mathrm{eMethane,ch}} - ch_{4_t}^{\mathrm{SMR,dch}} + \mathrm{soc_{t-1}^{CH_4}}, \qquad \forall \mathrm{t} \in \mathrm{T} \tag{31}$$

Where

$soc_{t-1}^{CH_4}$	$[t]$	is the state of charge of CH_4 at time step t

The SMR process both complements the Sabatier and Gasification by decoupling it from the crude synthesis plant. As the name suggests, the process requires steam as a reforming agent for methane and this demand for steam (see equation (33)) could be met with electric boilers for our case. The chemical reaction of the process is shown in equation iii while its integration into the model is shown in equation (32) with a conversion efficiency as reported by Keipi T. et. al [38]. The investment costs depending on the plant size (see equation (34)) are discussed later.

$$\boldsymbol{CH_4 + H_2O \rightarrow CO + 3H_2} \quad \Delta \boldsymbol{H = 206\ kJ/mol} \tag{iii}$$

$$\boldsymbol{ch_{4_t}^{SMR,dch} \geq A^{SMR,CH_4} SG_t^{SMR} H_{SMR}}, \qquad \boldsymbol{SMR} \in \boldsymbol{I_{rt}}\,, \qquad \forall \boldsymbol{t} \in \boldsymbol{T} \tag{32}$$

$$\boldsymbol{p_{SMR,t}^{heat} = A^{SMR,heat,d} SG_t^{SMR} / \eta_{EB}}\,, \qquad \boldsymbol{SMR}\ \&\ \boldsymbol{EB} \in \boldsymbol{I_{rt}}, \forall \boldsymbol{t} \in \boldsymbol{T} \tag{33}$$

$$\boldsymbol{s_{SMR} \geq SG_t^{SMR}}, \qquad \boldsymbol{SMR} \in \boldsymbol{I_{rt}}, \forall \boldsymbol{t} \in \boldsymbol{T} \tag{34}$$

Where

$ch4_{t}^{SMR,dch}$	$[t]$	is the CH_4 demand of technology SMR at time step t
A^{SMR,CH_4}	$[t/t]$	is the CH_4 demand of unit $SG_{SMR,t}$
$A^{SMR,heat,d}$	$[GWh/t]$	is the heat demand of unit SG_t^{SMR}
H_{SMR}	$[-]$	is the conversion efficiency of the SMR process

So far, all the process routes have been discussed with respect to production of syngas. The catalytic synthesis of syngas to syncrude via FT and the refining of syncrude to get the final mix of the products are common to all the routes. The Fischer-Tropsch reaction is the key to this scenario and is independent of the method of syngas production as shown in equation (35 with a conversion efficiency of 85% [30]. There are several FT technologies available, differing mainly on the type of catalyst used, the reactor type and the process temperature. De Klerk [33] discusses a high temperature FT (HTFT) and a low temperature FT (LTFT) for synthetic crude oil production and the properties of the Syncrude also varies with type of Fischer Tropsch process. For this work, an HTFT (250 - 340°C) is considered with jet-fuel as a main product as De Klerk [33] suggest that the main product from the LTFT would be waxes. Mortensen et. al [32] suggest a higher share of jet fuel could be obtained from an LTFT process but with an increased consumption of green hydrogen. Nevertheless, the FT has some process excess heat availability (see equation (36)) which could either be used to drive a rWGS or be delivered to the district heating network. For this work, the latter was selected, but depending upon the routes opted for by the refineries an internal heat integration could reduce the heat demand for the refinery.

$$\boldsymbol{SC_t \leq \left(SG_t^{rWGS} + SG_t^{SMR} + SG_t^{Gasification}\right) H_{FT}}, \qquad \boldsymbol{FT \in I_{rt}\ \forall t \in T} \tag{35}$$

$$\boldsymbol{q_{FT,t} = A^{FT,h}\, SC_t}, \qquad \boldsymbol{FT \in I_{rt}, \forall t \in T} \tag{36}$$

Where

SG_t^{rWGS}	$[t/h]$	is the synthetic gas produced by the rWGS technology at time step t
SG_t^{SMR}	$[t/h]$	is the synthetic gas produced by the SMR technology at time step t
$SG_t^{Gasification}$	$[t/h]$	is the synthetic gas produced by the Gasification technology at time step t
$A^{FT,h}$	$[GWh/t]$	is the waste heat supplied of unit SC_t (synthetic crude)
H_{FT}	$[-]$	is the process conversion efficiency of the Fischer-Tropsch process

The last step of this scenario is refining the syncrude obtained from the FT. This refining can be done in the existing refining facilities available for both the refineries with some modifications [32]. For the integration into the city model, only the pre-set jet-fuel demand is translated into the annual syncrude demand is introduced as equation (37). The FT and Refining step also have combined costs and the capacity of these are limited according to equation (38).

$$\boldsymbol{\sum_{t \in T} SC_t \geq A^{SC,demand}}, \qquad \boldsymbol{t \in T} \tag{37}$$

$$\boldsymbol{s_{FT\&Ref} \geq SC_t}, \qquad \boldsymbol{FT\&Ref \in I_{rt}, \forall t \in T} \tag{38}$$

Where

SC_t	$[t/h]$	is the synthetic crude produced at every time step t
$A^{SC,demand}$	$[t]$	is the total synthetic crude demand

2.3.2. Cost Summary

The optimum operation of this scenario within the city model is completely dependent on the cost of investment and operation of the different routes discussed earlier. Since this is a cost minimization model (see equation (1)), a thorough economic analysis of every technology was performed and are incorporated into the model. A detailed summary of these costs found in literature are listed in the Table 4 below.

Table 4: Summary of the economic analysis performed according to different costs and technological data available in the literature.

Technology	**Capital Cost**	**Operating Costs**		**Ref.**
		Fixed OPEX	**Variable OPEX**	
rWGS	0.251 m€/$tonne_{syngas}$		6.3 €/$tonne_{syngas}$	[34]
SMR	0.45 m€/$MW_{hydrogen}$	5% of Capex	Electricity and Methane Price	[38]
SMR	0.4-0.6 m€/$MW_{hydrogen}$	1% of Capex	3% of Capex	[39]
SMR	0.57 m€/$MW_{hydrogen}$	1% of Capex	3% of Capex	[39]
Gasification	1.5 m€/MW_{mehane}	0.024 m€/MWh_{mehane}/y	1.6 €/MWh_{mehane}	[37]
Gasification	1.1 m€/MW_{mehane}	FUEL COST INCLUDED IN THE MODEL		[40]
Gasification	1.7 m€/MW_{mehane}			[41]
Sabatier	0.2 - 0.6 m€/MW_{mehane}	4% of CAPEX		[36]
Fischer-Tropsch	1.59 m€/$MW_{syncrude}$			[29]
Electrolysis (SOEC)	0.4 m€/ $MW_{electricity}$	12000 €/$MW_{electricity}$	Electricity Price	[37]
Electrolysis (Alkaline)	0.5 m€/$MW_{electricity}$	25000 €/$MW_{electricity}$	Electricity Price	[37]
Electrolysis (PEM)	0.4 m€/$MW_{electricity}$	20000 €/$MW_{electricity}$	Electricity Price	[37]
Post Combustion Amine Carbon Capture	1.5 m€/(tCO2output/h)	0.048 m€/(tCO2 output / h)	2.5 €/(tCO2 output)	[37]
Hydrogen Storage	0.0012 m€ /$MWh_{hydrogen}$	0.000024 m€/$MW_{hydrogen}$	0.000012 m€/$MWh_{hydrogen}$	[37]

CO_2 Storage (Steel Tanks)	0.46 €/ton CO2 (Specific Cost including CAPEX and OPEX)	[42]

2.4. Scenario 03 – Electro Refinery (ER)

ST1 aims to transform their Göteborg refinery to produce electrofuels along with biofuels [9] and since bio-feedstock is limited due to both its availability and sustainability, investigating a scenario which just focuses on electrofuel production is interesting. With the focus still on jet fuel production as the BER scenario, this scenario is very similar to it. There is, however, one large difference i.e. gasification (biomass) route is not included, as shown in Figure 9.

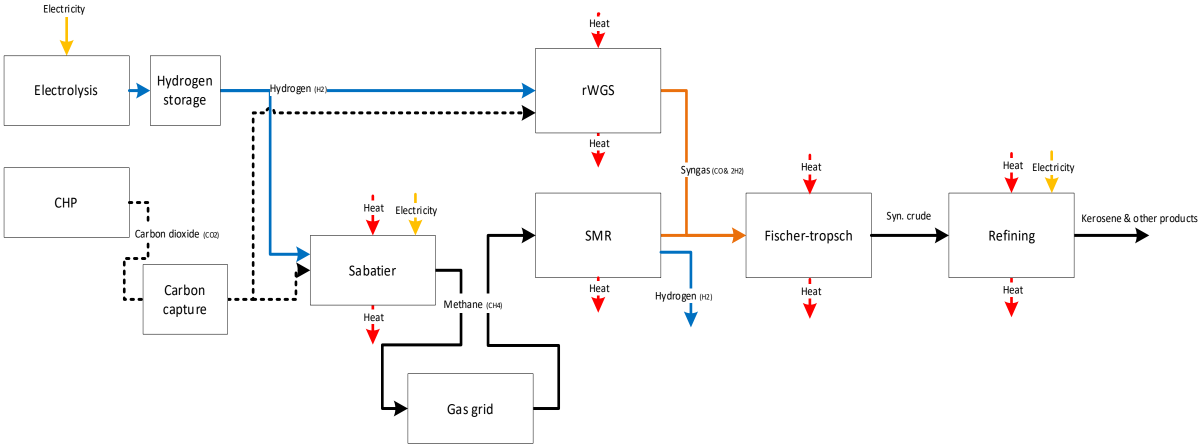

Figure 9: Process overview of the refinery setup in the scenario ER. The interaction with the electricity system is shown by yellow arrows while the process heat supply and demand are shown by red.

The syncrude production has two possible routes in this scenario i.e. rWGS or Sabatier with SMR. Both routes have been discussed in detail in the BER scenario. In this case, the electro-methane produced through the Sabatier process will still be sold to the gas grid and bought back to meet the syncrude demand. The cost summary discussed in Table 4 in the BER scenario suggests that due to an extra capital investment required for the Sabatier route (i.e. SMR to convert methane to syngas), it is more profitable to adopt the rWGS route at almost all times. This could potentially change if the methane sold to the grid and bought back would have a price gradient. For instance: if the methane price at hour X is higher than at hour Y, the refineries would prefer to produce more electro-methane at hour X. This is similar to how the electricity market works and incentivizes potential investments in storage or other variation management strategies (VMS). The city model, however, uses a fixed price for natural gas for a whole year and since the goal is to study the impact of these scenarios on the energy system, flexible methane pricing is not considered in this work as both the scenarios BER and ER have the same feedstock with a potential to store H_2 and to operate the plants flexibly. In order to test the robustness of the results, a sensitivity analysis on the capital investment for rWGS is performed and discussed in the results since the techno-economic data available in the literature was limited.

The integration of this scenario into the city model is the same as for the BER scenario and therefore the mathematical equations with their necessary variables and parameters discussed for the BER still hold true for this scenario. The equations for the gasification route are not valid anymore and are disregarded when modelled. The inputs and outputs are shown below in

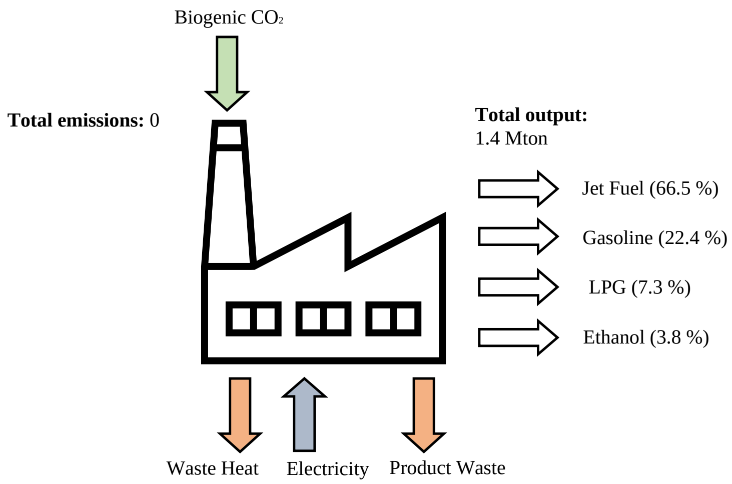

Figure 10: An overview of the annual inputs, outputs and emissions from the refinery in scenario ER.

Figure 10 where the emissions, total outputs and the ratio between outputs are the same as Scenario 2 – BER however there is no biomass feedstock to the refinery.

2.5. Scenario 04 – Closing Down (CD)

The major focus of the refineries in the city of Gothenburg is the production of transportation fuel [13], [14] which is exported mainly to northwestern Europe [12]. The European Green Deal seeks a 90% reduction in GHG emissions by 2050 in the transportation sector [43] along with other similar stringent initiatives to meet the climate target. This would greatly influence the markets of these refineries and without investing in low-carbon emission technologies, a shut down will be a likely scenario especially since the closure of the refineries under our study would not be a threat to the petrochemical industry (as the Gothenburg refineries do not cater to them). Samadi et. al [20] discuss a similar fate for the Dutch refineries in the port of Rotterdam for their business-as-usual cases if they are not aligned with the market and policy developments.

As discussed in Chapter 1, the refineries are responsible for a large part of the residual heat supply to the city district heating network and closing them down would leave a large need for new heat supply. This, along with a reduced electricity demand due to the shutdown, is investigated in this scenario. The integration of this scenario to the city model does not require any equations but just modifying the scalars $A^{sd,el}$ (refinery electricity demand) & $A^{sd,h}$(refinery heat availability) in equations 2 and 3 discussed earlier. The scenario is an extreme case since the refineries have already started planning on pathways to achieve net-zero emissions by 2045 but it is not completely unlikely. The results from this scenario will also serve as a reference case showing the impact of the refineries on the energy system.

3. Results

3.1. Results of Scenario 4 – Closing Down

The results of the CD scenario will serve as a reference to evaluate the impact of the refining industry on the city energy system in the other scenarios. The closing down of the refineries would not only release their electricity demand (0.327 TWh per year) but also remove the residual heat they currently supply to the district heating system (1.233 TWh per year). Since the model also considers the city growth, both the electricity and the heat demand of the city are higher in the scenarios compared to today's levels. The reduction in electricity demand

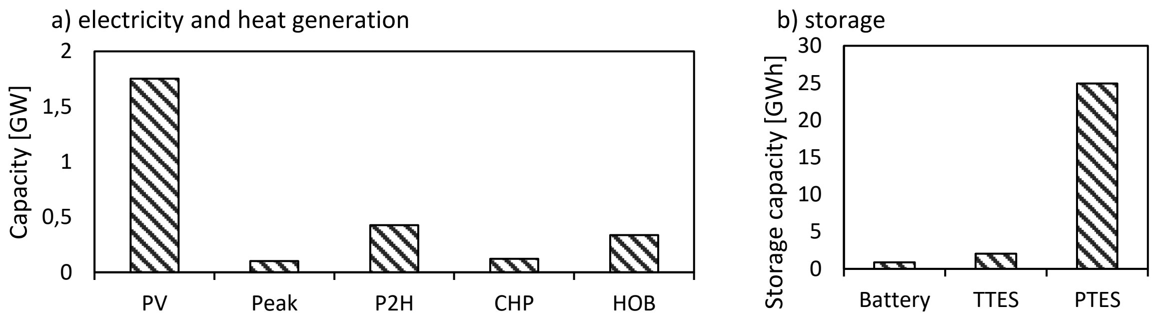

Figure 11: The new investments in a) electricity and heat generation technologies in GW and b) electricity and thermal storages in GWh for scenario CD.

from the closing down of refineries has a lower impact than the city growth and the city energy system needs to make new investments in electricity generation capacity to make up for both the city demand growth and the phasing out of the existing fossil-based CHP units. These are made mainly in Solar PVs (see Figure 11a) as it is the least expensive of all available technologies. Due to the intermittency in solar generation and low production during winter, some investments are made in the biofuel-fired CHPs which provide a stable base-load generation and in biogas turbines peak power to meet the deficit at hours when the generation from the PVs, CHPs and Import are insufficient. There are some investments in batteries (see Figure 11b) to reduce the curtailment from solar generation and then shifting this generation to non-solar hours. The investments in batteries help to reduce the capacity of the bio-gas turbines and provide a more even electricity cost for the consumers.

There are new investments in heat generation technologies as well to make up for the complete loss of residual heat from the refineries and the city growth. There is a synergy between the electricity and the district heating system which is further enhanced by large investments in Power-to-Heat technologies (P2H) such as electric boilers and heat pumps. Similar to batteries, the P2H technologies help to reduce the curtailment from solar power by either meeting the heating demand or storing the surplus in either of the thermal storages (see Figure 11b), Tank Thermal Energy Storage (TTES) and Pit Thermal Energy Storage (PTES). The major difference between them is their investment cost and charging/discharging capacity, making the former suitable for a short-term (hours to days) of storage capability and the latter suitable to managed variations of longer timescales (weeks to months). The correlation between solar

PVs and P2H causes heat deficit in winter months when the demand is higher. Investments in biomass fired HOBs (with only 93 full load hours (FLH)) are made to make up for this gap. The operations of these technologies are a complex optimization performed by the model and an hourly resolution gives us a clearer picture on how the closing down on the refinery impacts the system.

During the summer months, it is evident from the investments discussed earlier that the electricity generation is dominated by PVs. The refinery demand (now excluded due to shut down) was also comparatively low during the summer due to lower production and maintenance and does not have any large impact on the operation. For the hours with no-solar generation, the demand is met partly by discharging the batteries and rest of it is made up with import as the cost of import depending on the price of electricity in the SE3[10] region is also low. This daily pattern is seen in Figure 12a where the dashed line represents the battery SOC, the yellow area is the PV generation and the grey area is the import.

The refineries had a constant electricity load during the winters and opens an incentive to invest in a stable generation source. This stable generation is provided by the CHPs while maximizing imports. The generation from peak power is optimized to cover for the low solar generation as seen in Figure 12b.

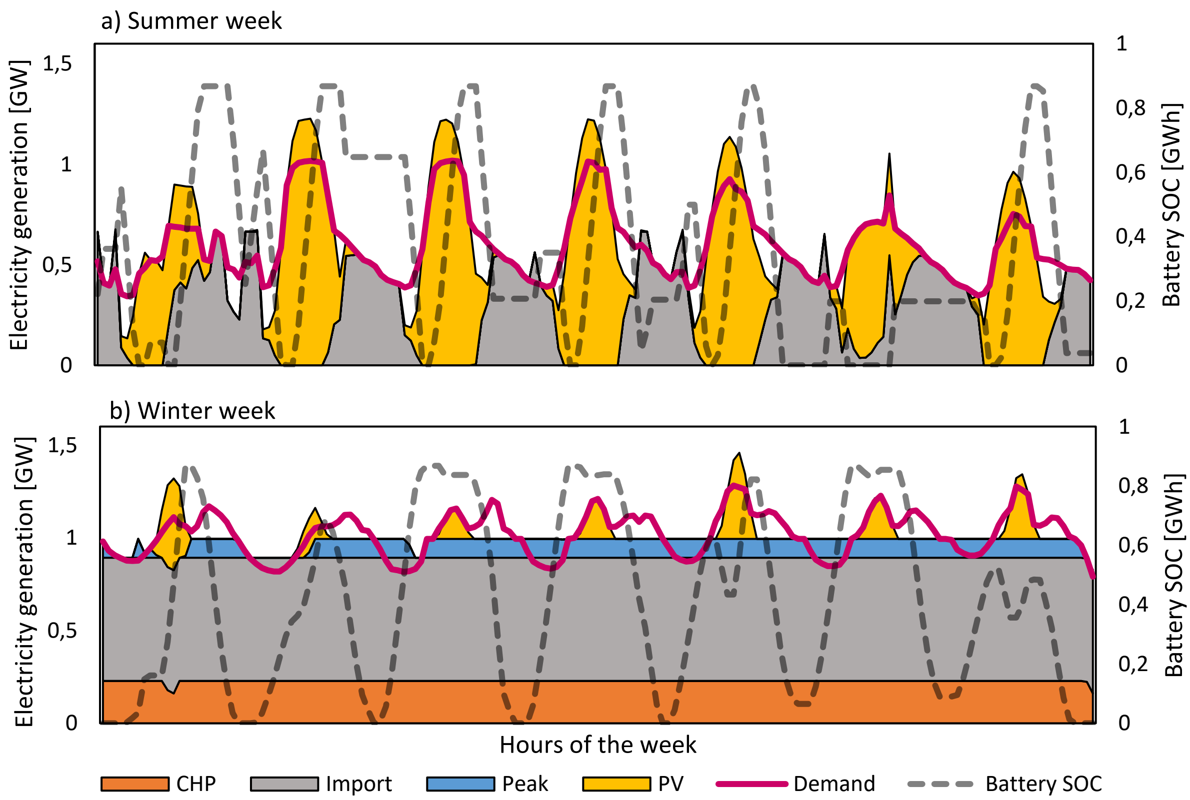

Figure 12: Operation of the electricity system for scenario CD during a (a) summer and a (b) winter week. The secondary axes show the battery state of charge in GWh.

[10] SE3 is one of the four regions Swedish Electricity Market is divided in.

It is worth mentioning here that the CHP capacity displayed in Figure 11a is the electricity generation capacity. The heat generation is greater than what is shown[11]. The heat generation is also complemented with a large PTES and a smaller TTES. The PTES is shifting weekly and seasonal load variations and TTES daily load variations. Their operation is shown in Figure 13(a) where the dashed line represents the PTES charging at the start of the week (summer) and discharging at the end when the TTES cannot charge during low solar generation. The TTES handles the daily variations as it provides a quick discharging ability as shown by the dotted line. During the summer, the residual heat from the refinery is also already low and the operation is not impacted too much by the shutting down of the refineries other than the charging of the PTES which discharges during winter months to reduce the capacities invested in HOB units. The impact of the closing down of the refineries is quite evident in a winter month (in Figure 13b) where the share of residual heat was higher during those month. The removal of this residual heat is supplemented by the PTES charged during summer by P2H. The CHPs are also operating at full capacities, but this is insufficient to meet the heat demand hence the P2H units no longer operate correlated to solar generation and operate more frequently.

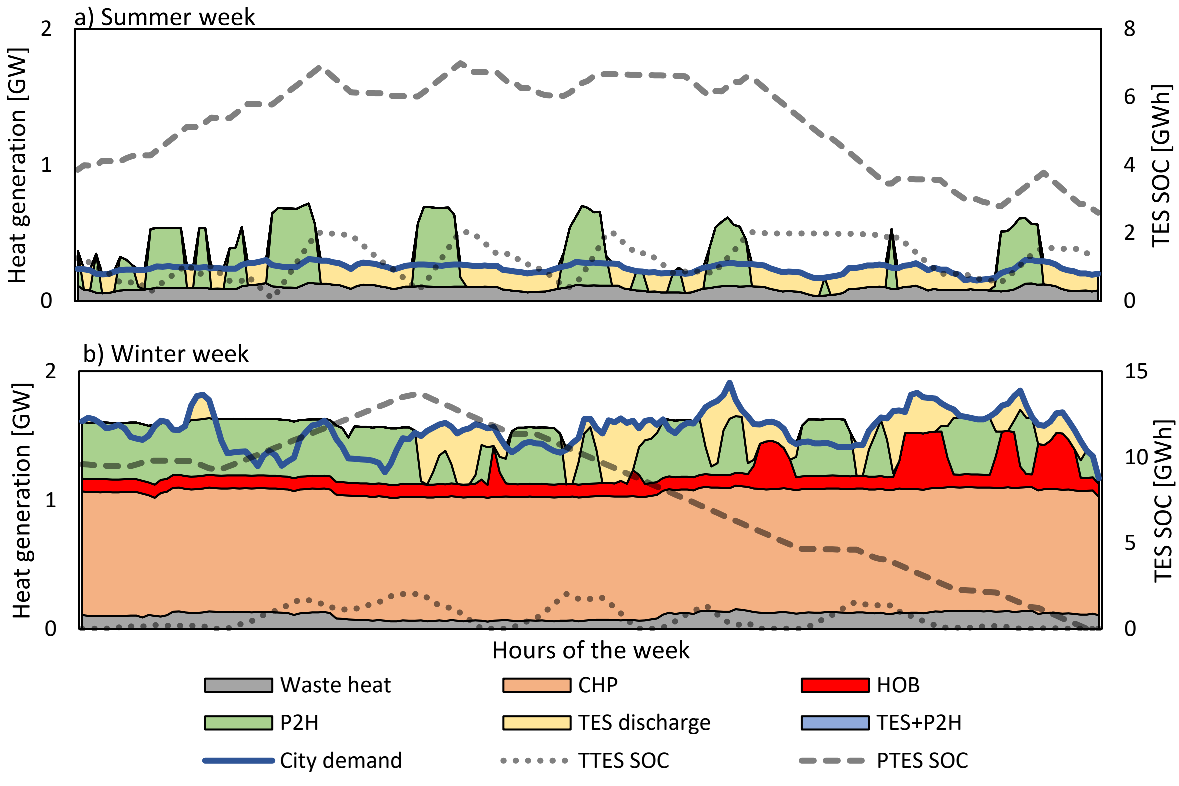

Figure 13: Operation of the district heating system during a (a) summer and a (b) winter week. The secondary axes show the thermal storages (both TTES and PTES) in GWh.

[11] The heat capacity is found by dividing the electricity capacity by the alpha value: $C_{heat} = \frac{C_{electricity}}{\alpha}$, where the alpha value depends on the CHP technology.

3.2. Results of Scenario 1 – CCS & Bio-blending refinery

The results of Scenario 1 (CBR) are discussed in the light of different blend ratios (BR) for HVO to diesel. The ratios of 10, 20 and 30% are investigated to study how a higher renewable content in the fossil diesel will impact the system differently. These ratios are referred to as symbols in this section for example a 10% blend ratio is 10BR. Table 5 expresses how these different blend ratios impact the electricity and the district heating system on an annual basis. Due to an increased demand of hydrogen to produce HVO, the electricity demand will increase substantially with an increasing renewable content. The annual electricity demand will have to increase almost six fold for even the smallest (10BR) case compared to the current refinery demand of 0.327 TWh per year (Table 1). The increased production of renewable diesel is compensated by reduced production of fossil-based diesel as can be seen from a reducing total production in Table 5. The impact of a reduced output from the refineries on the value chain is further discussed in section 4.3. Table 1 also shows how the refineries contribute to the district heating system (1.23 TWh_{heat} per year). The reduced total production also lowers the heat supply of the refineries to the district heating network. This section discusses how the model tries to fill that gap in the waste heat availability. An additional sensitivity analysis was performed for the 10BR case introducing flexibility limitations to the hourly production of the HVO (10BR-FL) based on the current production pattern used at Preem refinery Göteborg i.e. the production can be lowered to 70% percent of the maximum capacity of the unit [14].

Table 5: The annual electricity demand, waste heat availability, plant emissions and total final production from different cases in scenario CBR.

	Annual electricity demand [TWh]	Waste heat availability [TWH]	Plant emissions [kt]	Total production [Mt]
10 BR	1.77 (22%)	1.11 (16%)	146.20	8.80
20 BR	2.42 (28%)	0.99 (14%)	129.90	8.38
30 BR	2.76 (31%)	0.86 (12%)	113.80	8.02
10 BR & FL	1.77 (22%)	1.11 (16%)	146.20	8.80

In order to keep the production cost of HVO to a minimum, the system tries to avoid events of very high net load (and corresponding high electricity prices) for all the cases. The duration curves of HVO production in Figure 14 also shows this. For cases with low HVO production capacity i.e. 10BR, the system finds more events to produce at maximum capacity than 20BR and even more than 30BR due to a lower electricity demand. For the 10BR-FL case and from an annual time perspective, the refineries can invest in a lower HVO production capacity than it does for 10BR and only allowing for a lower production at extremely high electricity prices.

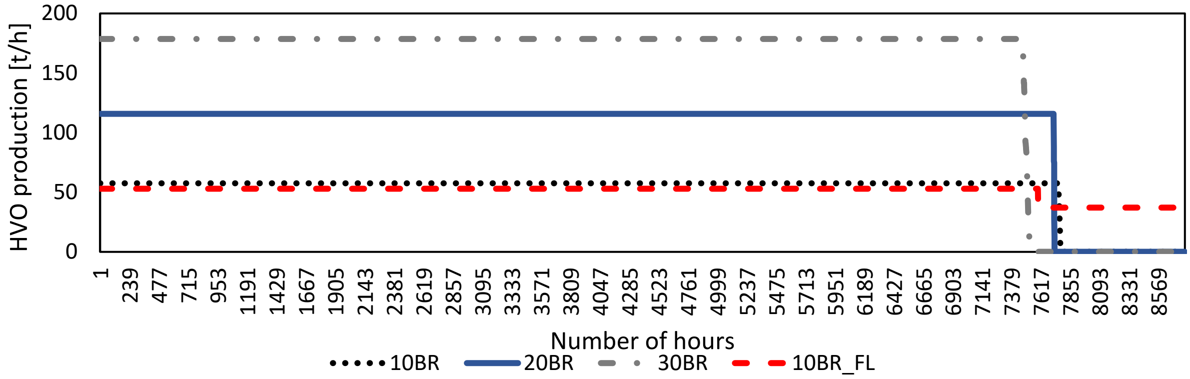

Figure 14: The duration curves of the refinery HVO production in different cases investigated.

While still analysing on an annual time scale, it was noted for all the different cases (see Figure 15) that the majority of the new investments in electricity generation were made as expected in PVs combined with batteries due to a lower levelized cost of electricity (LCOE). The figure also provides a comparison between this scenario and CD. The latter has at least 1.83 TWh/a of lower electricity demand than the smallest case investigated here. It is evident that the refineries have prompted more investments in solar power in combination with batteries but are not the prime reason for this choice as we also noticed investments in solar PVs in the scenario CD.

Due to a synergy between the electricity and the district heating network, investments were also made in biomass fired combined heat and power (CHP) units to provide a stable generation especially during winters when the generation of solar PVs is much lower. This seasonal and hourly dispatch is discussed in greater detail later. Investments in peak power i.e. gas turbines were also noticed in all the cases. However, these are very small and only made to complement the electricity system during very high net load events. The operation of the peak power plants for the 10BR case was limited to only 532 full load hours (FLH) annually. The different cases show a regular pattern in these investments as shown in the Figure 15 below. The case with highest electricity demand (30BR) has the highest investment in PVs. Increased battery

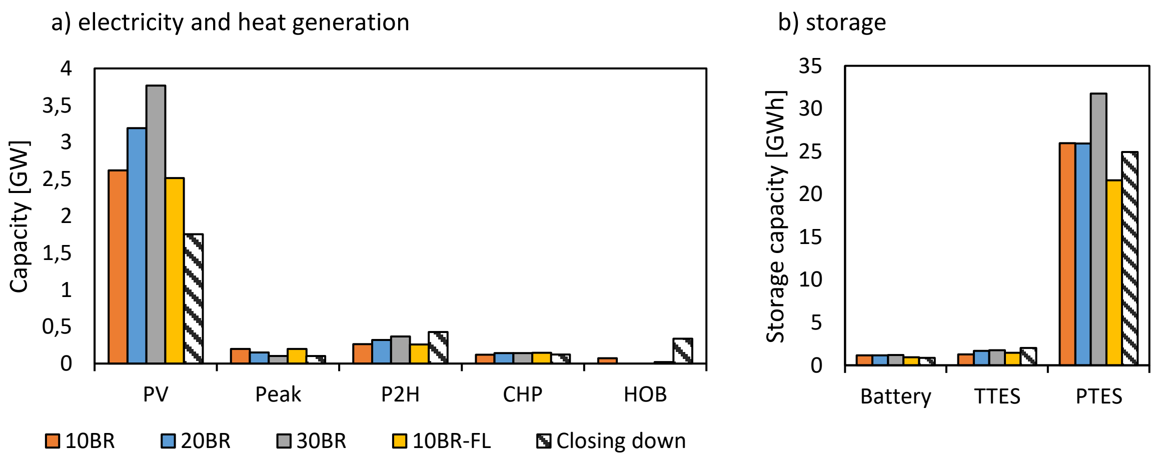

Figure 15: The new investments in a) electricity and heat generation technologies in GW and b) electricity and thermal storages in GWh for scenario CBR.

investments are generally expected with increased PV but this is not the case here. The daily solar variations are instead interacting with the SOEC and hydrogen storage at the refinery. Figure 15 shows the correlation between the PV generation and the SOC of hydrogen storage.

The demand for peak power capacity is reduced for higher blend ratios with this higher shifting ability but it is still invested into because of low winter generation from PVs. The FLH of peak power plants in the 30BR case decreased to 479 hours with no generation during the summer season. Due to the flexibility in operation of the HVO production plant, the refineries have not impacted the investments in peak power and CHPs, and they are still only invested in to complement the deficit in solar generation.

The lower waste heat availability, as shown in Table 5, for all the cases (especially with higher blend ratios) fits well with an increased electricity demand for this scenario. The investments in PVs also favour investments in power to heat (P2H) technologies like electric boilers. This was also observed in the CD scenario. However, since the refineries are still delivering waste heat to the district heating network, the investments in P2H are smaller. The operation of these P2H technologies is shown later on an hourly scale with solar power generation. For 10BR (which has lowest investments in solar PVs), however, new but small investments were also made in biogas fired heat only boilers (HOB) to meet the heat demand during extreme winter days. The increased investments in P2H technologies also incentivizes thermal energy storages as shown in Figure 15b.

The 10BR-FL case is a little different when compared to the other three cases. The reduced maximum HVO production capacity means lower PV capacity and the technologies that complemented PV investments i.e. P2H, batteries and TTES. The demand for HVO production is more evenly distributed which leads to comparatively higher (but still small as a whole) investments in CHP units. The frequency and the magnitude of the low net load events is decreased which means a larger capacity and more FLH (654 hours) for peak power. The stable operation of the HVO plant provides an unfluctuating waste heat availability from the refinery. However, lower production capacity during the summer provides less waste heat and the deficit is met by P2H and a slightly larger TTES. The reduced excess waste heat in summer also leads to reduced investments in PTES.

The hourly operation of a summer and winter week for 30BR is shown in Figure 16 and Figure 17 respectively. The high investments in PVs mean it is sufficient to meet the daytime load during the summer (Figure 16a). The surplus solar generation is used to produce hydrogen at the refinery but also to shift electricity from day to night with batteries, and the remaining night time demand is met by import (which again is the cheap electricity imported from SE3). The import also complements the system during daytime on cloudy days. The P2H operates in a similar manner in combination with thermal storages as discussed in section 3.1 (and shown in Figure 16b) as a consequence of lowered waste heat availability from the refineries. During summer the refinery has a constant output, but the electricity demand is shifting in correlation with the PV production as explained above. This is due to electrolyser production in combination with hydrogen storage. Usually, a CHP is also a technology that could solve both the increased demand in electricity and deficit of waste heat availability, but the model is minimizing the cost and finds the combination of PV with Batteries and P2H with TES a more optimal solution.

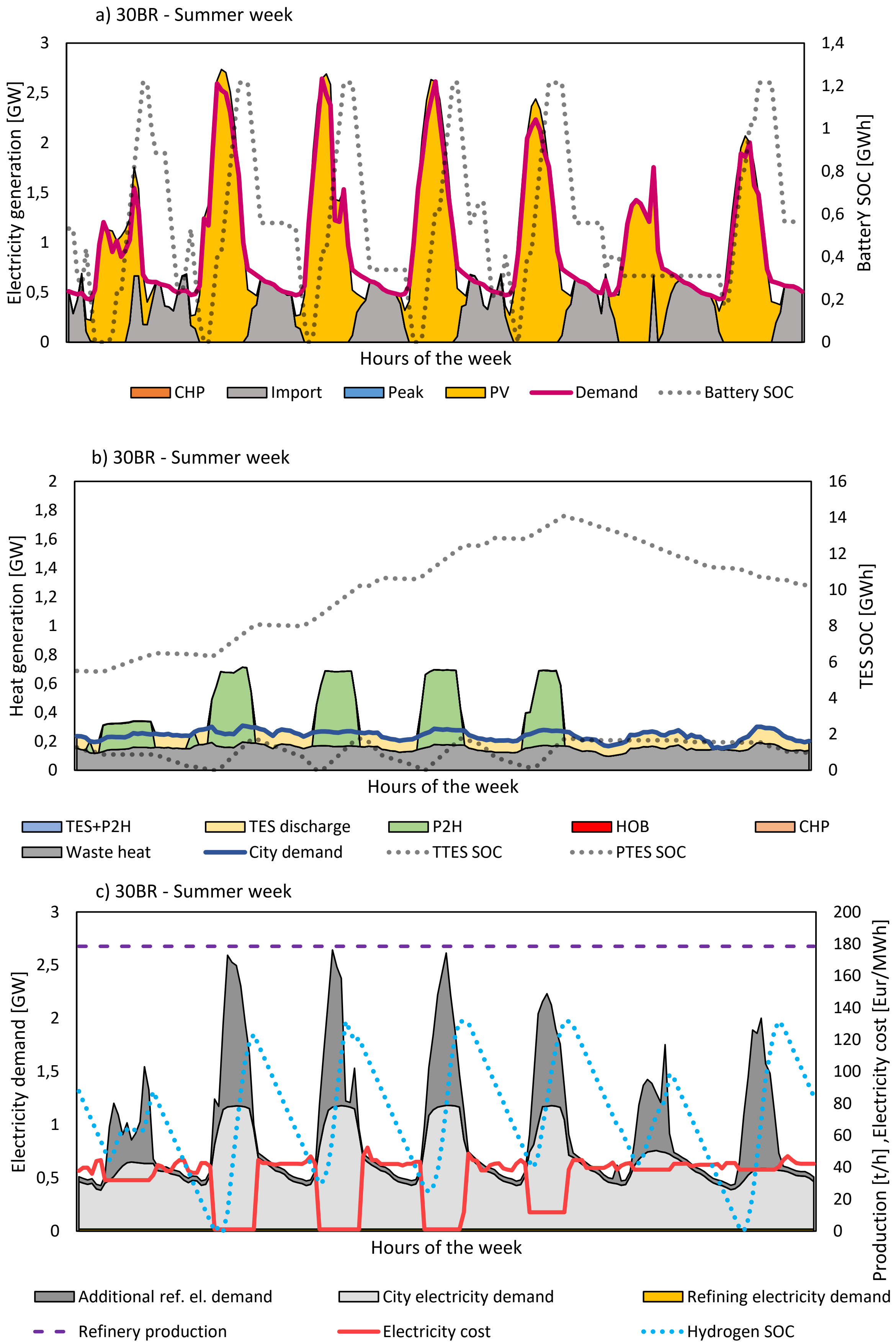
a) 30BR - Summer week
Electricity generation [GW]
BatterY SOC [GWh]
Hours of the week
CHP
Import
Peak
PV
Demand
Battery SOC
b) 30BR - Summer week
Heat generation [GW]
TES SOC [GWh]
Hours of the week
TES+P2H
TES discharge
P2H
HOB
CHP
Waste heat
City demand
TTES SOC
PTES SOC
c) 30BR - Summer week
Electricity demand [GW]
Production [t/h] ,Electricity cost [Eur/MWh] & Hydrogen SOC [t]
Hours of the week
Additional ref. el. demand
City electricity demand
Refining electricity demand
Refinery production
Electricity cost
Hydrogen SOC

Figure 16: Operation of the system for scenario CD during a summer week where (a) is the electricity system with battery SOC on the secondary axis, (b) is the district heating network and (c) the city and refinery electricity demand with SOC of the H_2 storage on the secondary axis aswell.

The hourly operation during the winter shows a completely different operation pattern from the refineries (see Figure 17c). The electricity generation during a winter week, as shown in Figure 16a, suggests that due to low solar generation the CHPs are forced to operate at maximum capacity while the city imports electricity at the maximum grid capacity to minimize peak generation. During the winter there is no substantial difference between daytime and night-time generation and the electricity load is primarily balanced with batteries, which are charged both during night-time and at hours with PV production (Figure 17a). Figure 17c shows that the refinery is complementing the electricity system by absorbing excess PV generation. The surplus from solar is however noticed to be small during winter and it shows that the refinery changes from an absorbing VMS to a shifting strategy by moving operation to a few limited hours and avoid high net load events. This limited production is made up for during summer months when there is large surplus from PVs.

The winter heat generation is dominated by CHP and waste heat (now reduced). This reduction which incentivized thermal storages and HOB units, sees their operation meet the deficit when the CHPs are not enough as shown in Figure 17b. The TTES is operating more like the PTES during winter since we do not have the same pattern of daily solar variations in combination with P2H. Compared to the preceding scenario discussed in section 3.1, the operation of P2H is not witnessed in winters and this is due to flexible operations by the refinery leaving little to no room for another VMS (P2H in this case) to absorb excess PV production.

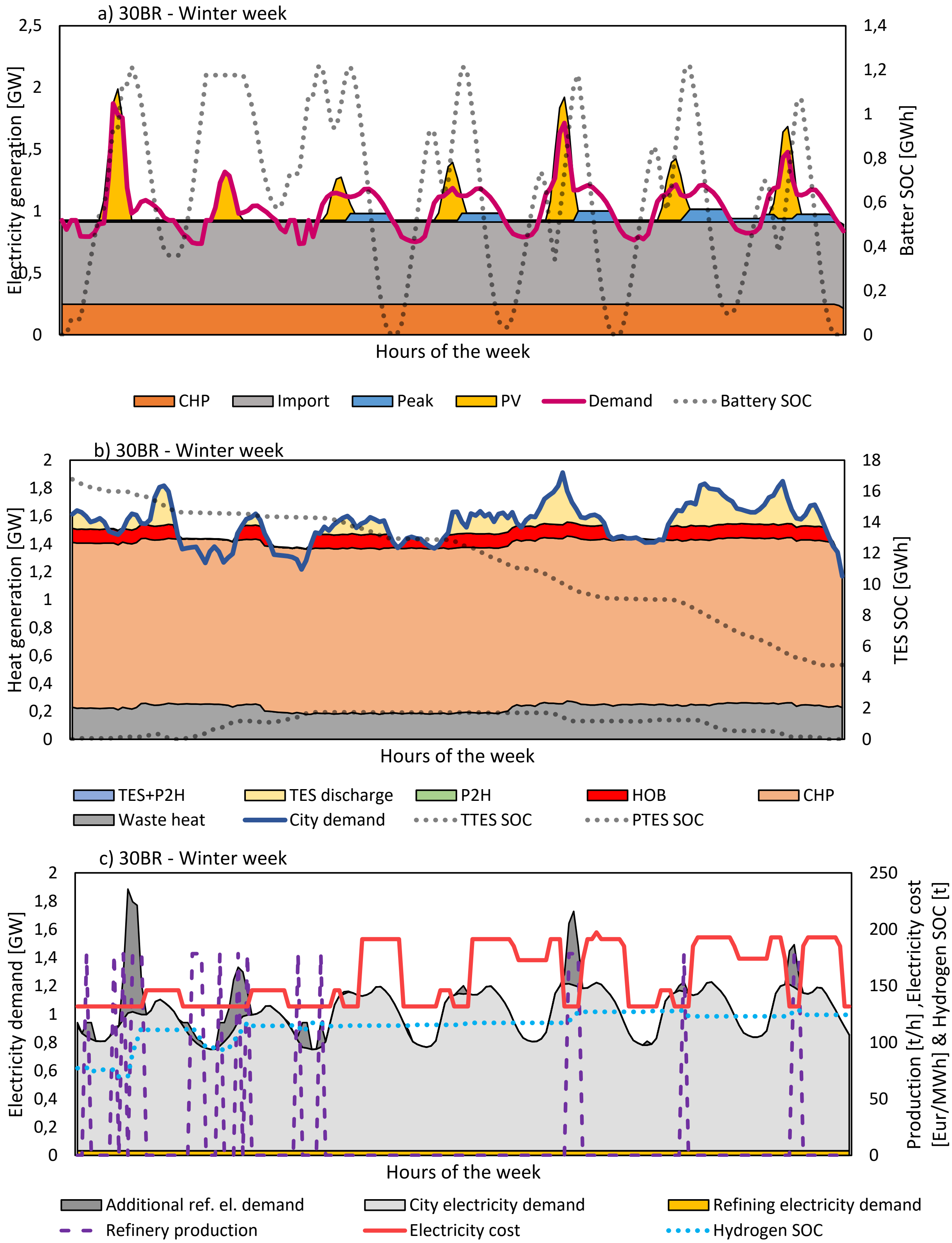

Figure 17: Operation of the system for scenario CD during a winter week where (a) is the electricity system with battery SOC on the secondary axis, (b) is the district heating network and (c) the city and refinery electricity demand with SOC of the H2 storage on secondary axis.

3.3. Results of Scenario 2 – Bio Electro Refinery

The BER scenario, as discussed earlier, calls for a complete restructuring of the current setup of the refineries. The refining part of the value chain is expanded by production of syncrude at the refinery while the conventional refining stage still exists with some modifications. While the electricity and the heat demand for the refining part is not as large as it is today, the technologies involved in the pathway to produce Syncrude have an electricity demand and residual heat availability of their own. The way the refineries operate depends on the exogenous conditions e.g., biomass price, electricity price, synergy with the DH network, capital and operational costs etc as discussed in this section. The different cases investigated for this scenario are biomass prices of €40/MWh$_{fuel}$, €80/MWh$_{fuel}$ and €120/MWh$_{fuel}$ in order to test the robustness of the results. Another case is investigated with the refinery producing four times more kerosene to meet the whole Nordic demand instead [32]. The Table 6 highlights the route(s) the system prefers in different cases and the annual production from these routes while the Table 8 shows the corresponding electricity demand and the residual heat availability from the refinery. The capacities of the hydrogen storage invested in by the refineries are shown in Table 7.

Table 6: The annual production of syngas through different routes for the different cases investigated in scenario BER.

	rWGS [kton]	Gasification into syngas [kton]	Gasification into methane [kton]	Sabatier [kton]
Biomass cost 40 €/MWh	61.02	1790.48	0	0
Biomass cost 80 €/MWh	1180.10	670.65	0	0
Biomass cost 120 €/MWh	1274.00	447.90	0	129.58
Nordic kerosene demand	65.76	7832.01	0	0

Table 7: Invested capacities by the refineries in hydrogen storages in GWh.

	Hydrogen Storage [GWh]
Biomass cost 40 €/MWh	0.52
Biomass cost 80 €/MWh	16.10
Biomass cost 120 €/MWh	22.24
Nordic kerosene demand	0.56

Table 8: The annual electricity demand, waste heat availability, plant emissions and production from different cases in scenario BER.

	Annual electricity demand [TWh]	Waste heat availability [TWh]	Plant emissions [Gt]	Total production [Mt]
Biomass cost 40 €/MWh	0.47	2.87	0	1.57
Biomass cost 80 €/MWh	7.97	3.07	0	1.57
Biomass cost 120 €/MWh	11.03	3.30	0	1.57
Nordic kerosene demand	0.71	12.20	0	6.71

The refinery was coupled in all these cases to the energy system with a common objective of minimum annual cost i.e. the technologies chosen by the refineries to produce syncrude, the capacities invested and the operation of these technologies are all optimized to achieve a lowest possible system cost. The Sabatier route was only selected in one of the investigated cases to avoid additional capital investments for an extra conversion step of methane to syngas by SMR. The case with biomass price €120/MWh leads to small gasification plants out due to high operational costs and hence allows operation of the Sabatier reactor. The refinery operation is discussed with an hourly perspective later in this section. The gasification-to-syngas route is always preferred over gasification-to-biomethane due to a higher efficiency of the former. For a biomass price of €120/MWh, there are already investments in the SMR for the Sabatier route but the refinery still prefers producing syngas due to higher efficiency.

It is evident from the results that the refinery operation is sensitive to the biomass price. For the cases with a biomass price of €40/MWh, the refineries only produce just over 3% of the syncrude via the rWGS route. However, this share increases for the cases when the operational costs of running the gasification plant become higher even though the electricity demand from the hydrogen production for the rWGS is extremely high (see Table 8). The case with the Nordic kerosene demand was also modelled with a biomass price of €40/MWh and similar preferences are noticed where the operation of rWGS was limited to the same hours while the increased demand was met by investing in a higher capacity for the gasification plant. The potential supply of sustainable biomass is hard to deduce but with regards to current Swedish's regulation an approximate could be 200 TWh/a within Sweden (see Appendix A) and the model does not see it as a limitation with the refinery demand being 70 TWh/a (see discussion in 4.1).

The residual heat availability from the refinery in all the cases is quite high and most of this heat comes from the excess heat of the FT process. For the Nordic case, where the refinery is producing four times more Syncrude, this number is almost twice the heat demand of the city (6.2 TWh) and since the system tries to optimize the FLH of the FT unit, this residual heat availability is seen to be evenly distributed annually. Table 9 summarizes the new investments made by the system to make up for this increased electricity demand and handle the residual heat supply.

Table 9: The new investments in electricity and heat generation technologies in GW and storages in GWh for scenario BER.

	Electricity & heat generation [GW]					*Storage [GWh]*		
	PV	**Peak**	**P2H**	**CHP**	**HOB**	**Battery**	**TTES**	**PTES**
Bm40	1.95	0.14	0.02	0.06	0.14	1.23	0.35	119.16
Bm80	10.10	0.07	0.28	0.01	0.00	5.30	0.18	567.61
Bm120	13.41	0.00	0.31	0.07	0.00	7.22	0.00	661.60
Nordic kerosene	2.06	0.22	0.00	0.00	0.00	1.31	0.00	0.00
Closing down	1.75	0.10	0.43	0.12	0.34	0.87	2.03	24.93

A similar pattern is noticed as in the scenarios CD and CBR where the increased electricity demand is met by investments in solar PVs and batteries that can shift the surplus solar generation. As the investments in PV and the residual heat availability from the refinery have increased, the system loses incentive to invest in CHP. For the 40BM case, there are still some investments in CHPs to cover for the high heat demand and lower solar generation in winter months. This gap in baseload generation created by the CHP especially in winter months is met by an increased investment in peak power (compare with closing down in the table). The waste heat from the refinery reduces the investments needed in both HOB and P2H by introducing large PTES to make use of the surplus waste heat availability especially during the summer (see Figure 18) to be used during winters. The investments in PVs are optimized in isolation from the district heating network. Higher hourly residual heat availability also reduces the demand for a short-term storage i.e., TTES and is evident from reduction in its investments.

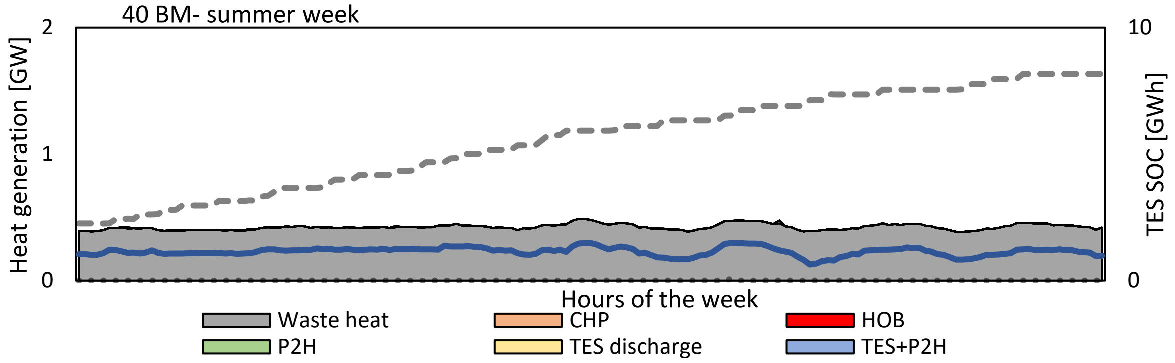

Figure 18: The operation of the district heating network during a summer week for 40 BM.

Unlike the CBR scenario, the production of the refinery in a gasification dominated path (BM40) does not depend as much on the electricity price. The dominant gasification route has no interaction with the electricity system and the investments in hydrogen storage (as seen in Table 7) has decoupled the operation of the rWGS from the electricity grid. The storage makes use of the surplus solar generation and lower electricity prices (as seen in Figure 19b). The hydrogen storage provides a VMS to the grid by acting as an absorbing strategy for surplus generation in combination with the batteries which are shifting the surplus to the evenings and nights. This allows the rWGS to operate more flexibly (see Figure 19c). This production substitutes the generation from gasification and the total production from the refinery remains constant.

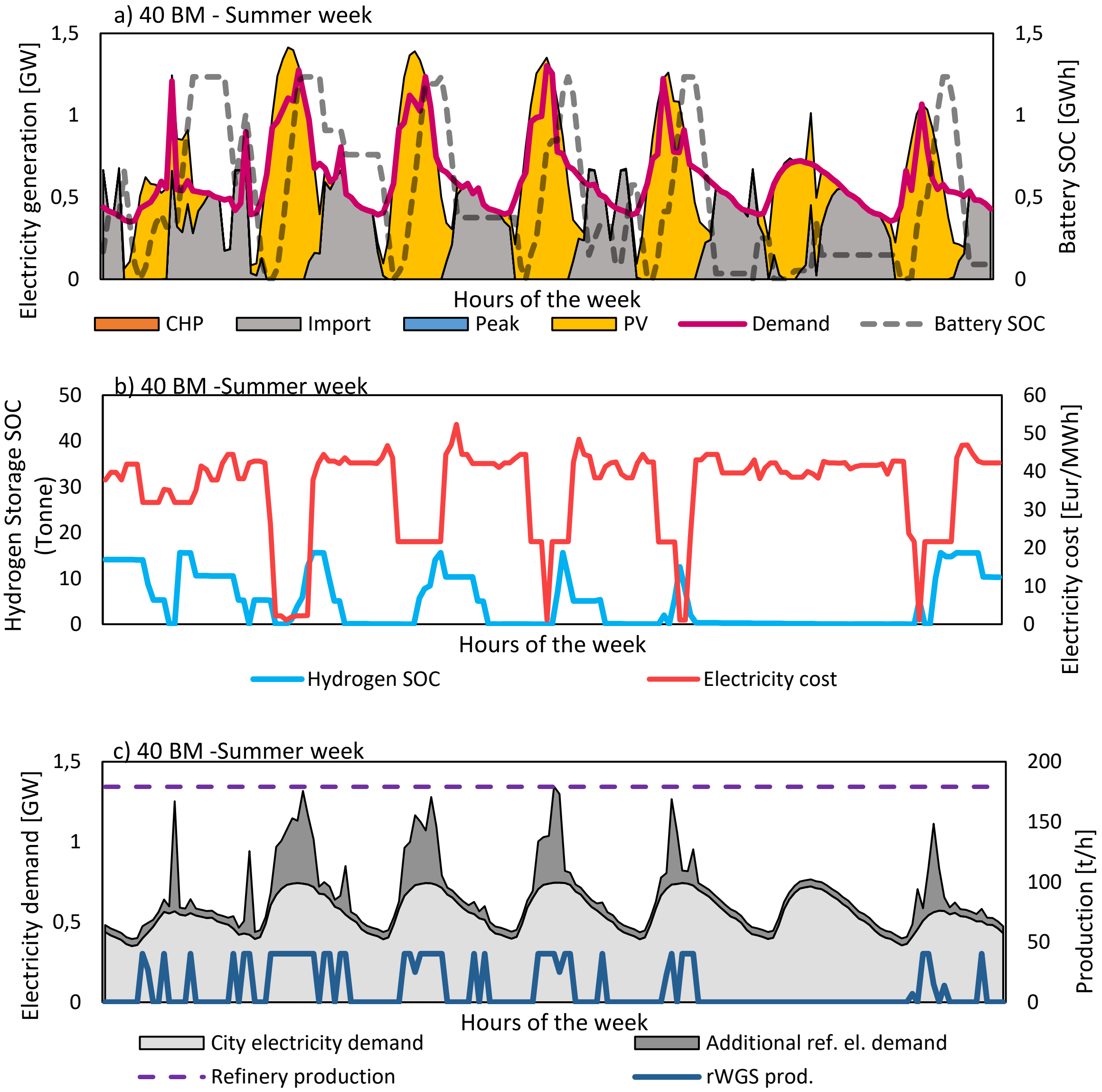

Figure 19: The operation of the system in scenario BER 40 BM for a summer week where (a) is the operation of the electricity system, (b) the SOC of hydrogen storage and the electricity price and (c) city and the refinery electricity demand along with rWGS production levels.

This pattern is clearly visible in the summer but in the winter the lower solar production eliminates the opportunity for the grid to utilize two VMS strategies. The batteries shift any surplus generation to reduce the FLH of peak power plants. However, there are still a few instances when the electrolyser steps in during hours when there is excess generation after the batteries have been fully charged. The rWGS contributes to the production on a very small-scale during winter to use this hydrogen.

The share of production through gasification reduces with the increasing biomass price making the other routes more prominent (as seen in Table 6). As a consequence, there is a substantial increase in the electricity demand for the refineries which are primarily met with large investments in solar PVs. Due to a high price of biomass, the investments of peak power plants (which already had high operational costs) is further disincentivized and the system uses batteries to complement the system during high net load events instead of investing peak power. The higher biomass price also makes it expensive to operate a CHP unit and hence we see lower investments for the 80 BM case. The 120 BM case, however, has more investments in CHPs which is due to a more complex refinery production as explained later. There are no investments in biomass-fired HOBs for both the cases and the investments in P2H with enormous capacities of PTES fill that gap. The P2H (also an absorbing VMS) charges the storage with surplus solar generation during the summer, as shown in Figure 20.

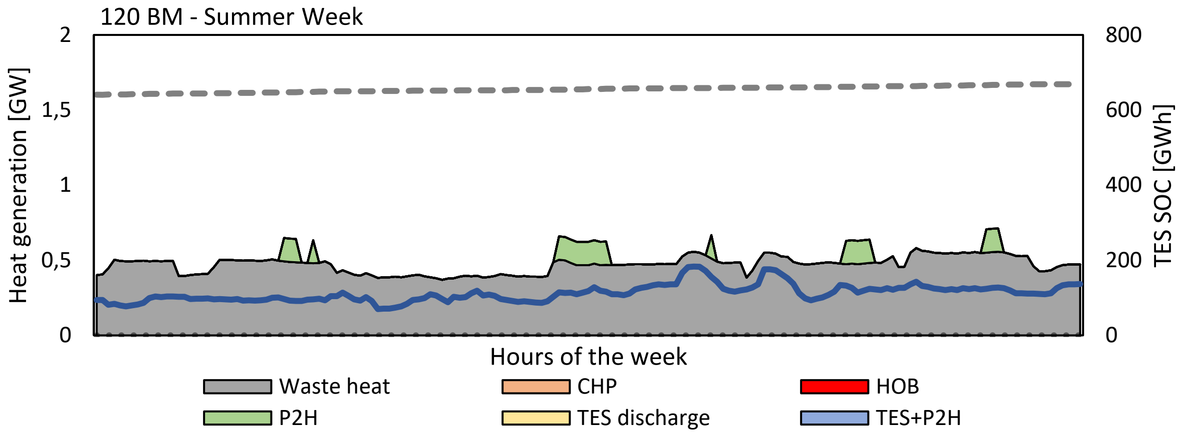

Figure 20: The operation of the DH network during a summer week for BM 120.

The operation of P2H in the figure above is optimized in combination with batteries and the refinery electrolyser as all three are dependent on solar production. The refinery has prompted the high solar investments in this case and therefore always orient themselves with the solar generation to operate the electrolyser and charge the hydrogen storage to ensure a constant production from the rWGS (as shown in Figure 21b). The batteries provide the VMS by shifting the surplus solar generation and in some cases also power the electrolyser if needed.

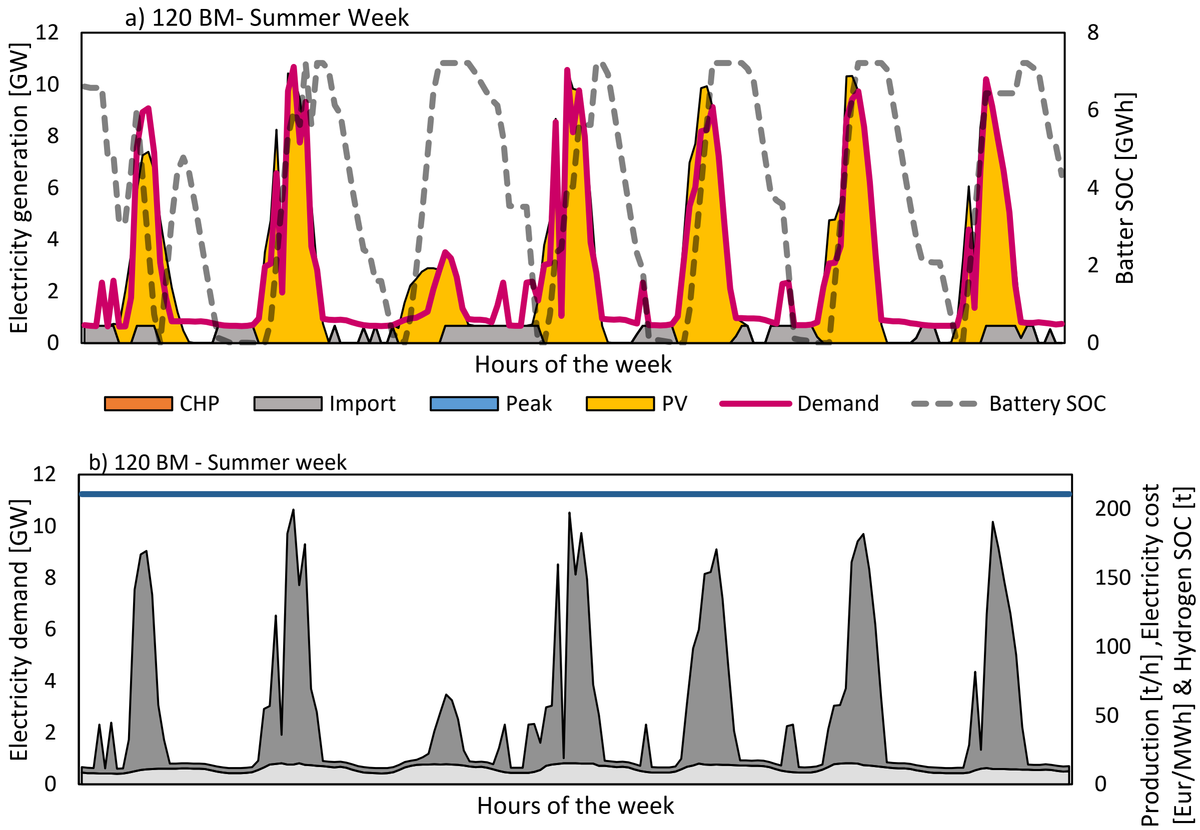

Figure 21: The operation of the system in scenario BER 40 BM for a summer week where (a) is the operation of the electricity system and (b) is the city and the refinery electricity demand along with rWGS production levels.

This refinery provides a VMS through the Sabatier route in this case (120 BM). The refinery tries to use the electrolyser and the hydrogen storage, it has already invested in for the rWGS, by absorbing any remaining surplus generation to produce electro-methane and storing it in the methane grid. This electro-methane also allows the refineries to maintain their constant production levels by extracting it back from the grid during the winter and producing syngas through SMR when the solar-dependent rWGS is forced to operate on a lower level. This flexibility allows the refinery to not over invest in the hydrogen storage but instead use the methane grid as a seasonal storage. Figure 22 below shows an annual operation of Sabatier and SMR averaged weekly for a year.

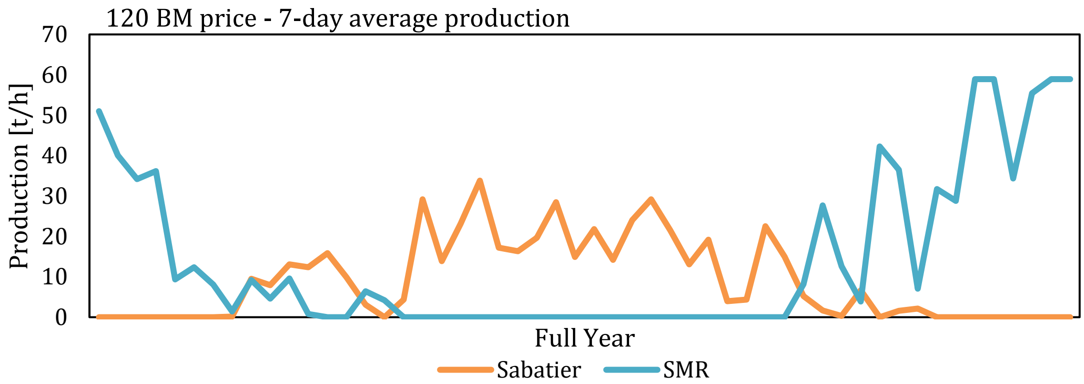

Figure 22: The operation of the Sabatier and the SMR for 120 BM over the whole year averaged out weekly.

The reduced production from rWGS in the winter means that there is a reduced waste heat availability during the winter in the 120 BM case compared to the 40 BM discussed above. The SMR, on the other hand, requires a large supply of heat and since it is added to the model as an electricity demand, the refinery have a comparatively higher electricity demand in the winter forces the system to invest in CHPs even though the operation cost is extremely high (see Table 9).

The case where the refinery meets the kerosene demand for the whole Nordic region sees very similar investments and operation with respect to the electricity system but a completely different from district heating networks' perspective as the residual heat from the refinery is more than sufficient to meet the heat demand. There are no investments in heat generation technologies or even storages as the heat available at every hour is sufficient to satisfy the demand of the city. The CHPs also become an unfavourable investment and the electricity generated from the CHPs is replaced by investing a little more in peak power. The FLH of the existing CHP is also limited to only 194 hours compared to 2558 hours for the 40 BM case. This heat is a major barrier for both the local utility provider and the refinery due to an infeasibly large residual heat supply and is discussed in detail in the next chapter.

3.4. Results of Scenario 3 – ER

Like the preceding scenario, the possibility for the refinery to meet the Nordic kerosene demand was also investigated as a sensitivity analysis besides the one with the Swedish demand. Two more sensitivity analyses will be discussed in this section on the CAPEX of rWGS increased by 25% and 50%. This was to ensure that the limited literature on the capital costs of rWGS does not alter the results oddly. With no possibility to run the gasification route, the refinery has two pathways to produce electro-fuels *i)* rWGS and *ii)* Sabatier as shown in the Table 10.

Table 10: The annual production of syngas through different routes for the different cases investigated in Scenario ER.

	rWGS [kton]	Sabatier [kton]
Swedish kerosene demand	1851.49	0
Nordic kerosene demand	7897.78	0
rWGS CAPEX 125%	1851.49	0
rWGS CAPEX 150%	1729.34	122.15

Table 11 shows how a new electrofuel production refinery in the city of Gothenburg will induce an extraordinarily large electricity demand. For the Swedish case, the refinery electricity demand is more than the rest of the city combined (6.17 TWh) and accounts for 67% of the total demand for electricity. While for the Nordic case, this share rises to 90%. This suggests that the energy mix and new investments would be dictated by refinery's production pattern. The residual heat availability for both the cases are in the same magnitude as in the BER scenario since the production capacities from FT remains the same. The total production in the Table 11 refers to the amount of syncrude processed and 61% of it is kerosene (see section 1.1).

Table 11: The annual electricity demand, residual heat availability, plant emissions and production from different cases in scenario ER.

	Annual electricity demand [TWh]	Residual heat availability [TWh]	Plant emissions [Gt]	Total production [Mt]
Swedish kerosene demand	12.48	3.19	0	1.57
Nordic kerosene demand	53.22	13.62	0	6.71
rWGS CAPEX 125%	12.48	3.19	0	1.57
rWGS CAPEX 150%	13.95	3.37	0	1.57

Table 12 shows the new investments made by the system to meet the heat and electricity demand. Once again it is noticed that an increased residual heat availability from the refineries disincentivizes investments in CHPs. This stable electricity generation to fill the void left by low solar production in winter is filled with peak generation from closed-cycle bio-gas turbines[12]. Compared to all other scenarios, the investments in this peak power capacity were

[12] This type of operation of a gas turbine is better classified as Intermediate power generation rather than Peak but in this work all gas turbines are classified as Peak whether they are closed or open-cycle gas turbines. For comparison, the FLH of the biogas turbine are 2811 and for the CHP 3984 (Swedish kerosene demand).

noticed to be the highest for an electrofuel refinery integration even though there are large investments in solar power and batteries. The trend seen in the three preceding scenarios suggested that with large battery investments the surplus in solar PV would reduce the demand for peak generation as the refinery load also had the flexibility to be shifted. The investments in the electricity system are scaled up for the case with the Nordic Production except that there are no investments in the CHPs as residual heat availability is again higher than the city demand due to higher production level.

Table 12: The new investments in electricity and heat generation technologies in GW and storages in GWh for scenario ER.

	PV	Peak	P2H	CHP	HOB	Battery	TTES	PTES
Swedish Kerosene Demand	10.79	1.27	0.17	0,05	0,00	3.56	0.50	32.15
Nordic Kerosene Demand	43.63	5.53	0	0	0	15.02	0	0
rWGS CAPEX 125%	10,80	1.27	0,18	0,05	0	5.57	0,51	32.24
rWGS CAPEX 150%	12.18	0.87	0.02	0.06	0,00	3.21	0.52	35.95

Investments in thermal storages were noticed in the Swedish case complementing the district heating network with surplus residual heat from the refinery eliminating the demand of peak heat generation i.e. HOB. There are some investments in P2H but their operation will be better explained from an hourly perspective later. The Nordic case once again has no investments in any heat generation technology and the existing capacities (in HOB and CHP) are seen to be enough for very few hours when the residual heat availability from the refinery (combined with small share from Renova) is not enough.

The refinery operation is rather complex in this scenario due to the interaction between the two process routes but regardless of how the syncrude is produced the output of the refinery remains constant during the entire year. Even though the output is constant the refinery still supports the electricity system by charging its hydrogen storage through electrolyser at hours with high PV production see (Figure 23). The storage is then discharged during hours with high electricity costs and thus reduces the need for further investments in generation capacity or VMS such as batteries.

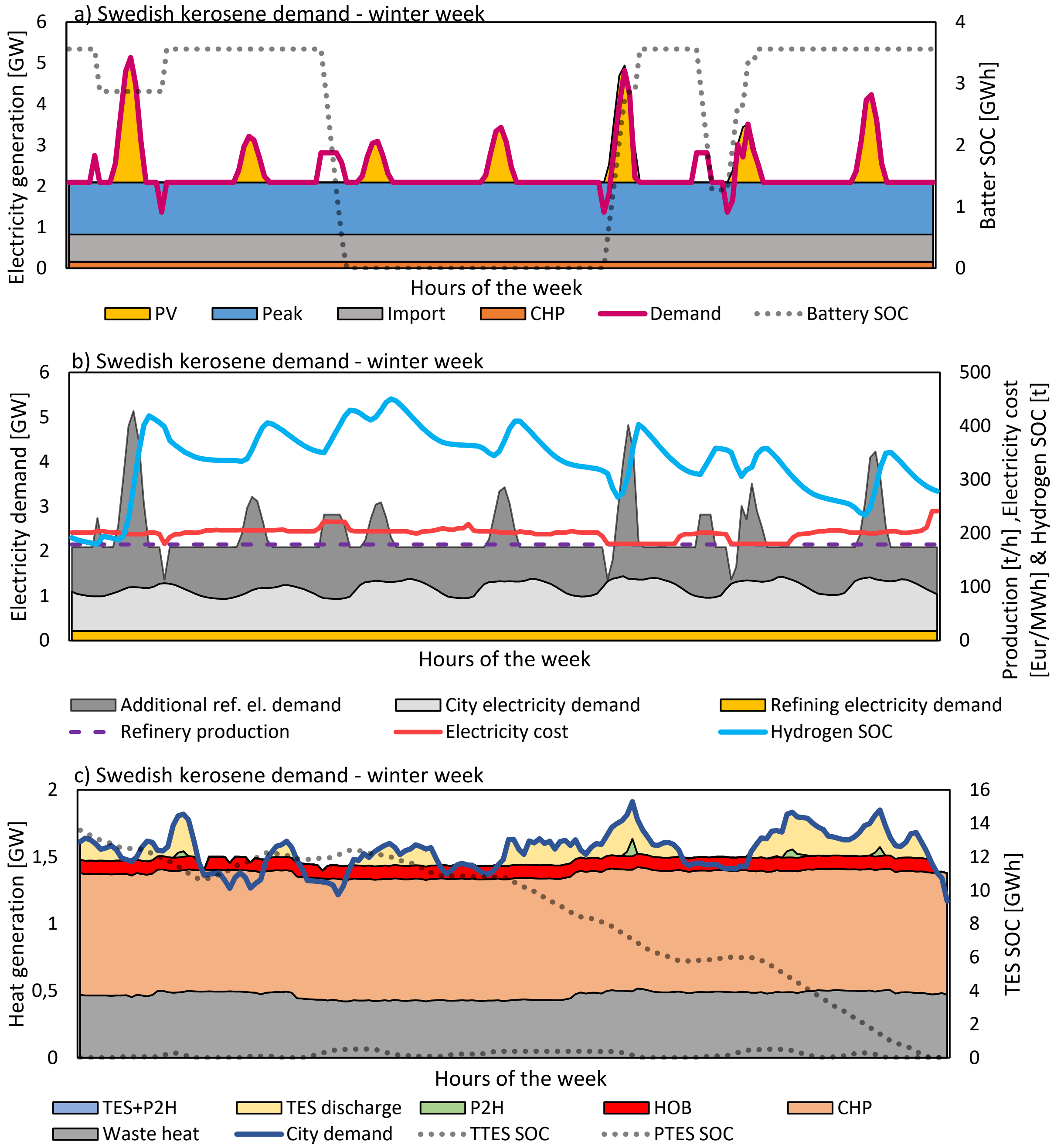

Figure 23: The operation of the system during a winter week for the Swedish Kerosene demand case where (a) is the electricity system, (b) is the city and refinery electricity demand with SOC of the hydrogen storage and (c) is the operation of the DH network.

The operation during a typical winter week suggests that the extremely high refinery electricity demand with low production of solar compels the system to operate the already existing CHPs and bio-gas turbine at full load while also importing the maximum capacity the grid can provide (see Figure 23a). The marginal electricity prices (Figure 23b) are extremely high during the winter due to this operation at full load. As discussed earlier, the CHPs are less favourable as an investment and can be seen in the Figure 23c. The increased residual heat availability has pushed CHP to the limit beyond which any new investments will reduce its value. The district heating network is complemented by the biomass fired HOB and the thermal storages to meet the deficit. The residual heat from the refinery during the summer, however, becomes a problem for the system as discussed in section 3.3 and must be addressed to ensure the feasibility of this scenario. Compared to the BER scenario, this scenario provides better opportunity for integration. The rWGS (unlike gasification in BER) is a highly endothermic reaction and it can be integrated with the exothermic FT plant and the rest of the refinery as a solution to this problem.

The sensitivity analysis performed on the capital investment costs of rWGS shows almost the same refinery operations as shown in Table 10 with some Sabatier production which in turn impacts the refinery electricity demand and the residual heat availability. The Sabatier process produces electro-methane during summer which is sold/stored in the methane grid and bought/discharged during high electricity cost hours in winter. But even though the CAPEX of rWGS is increased, the capacity of rWGS remains the same. This is due to the interaction between the refinery and the electricity system, mainly the PV generation. The model minimises the total system cost and it finds the most optimal solution by increasing the PV capacity and introducing the Sabatier pathway to take advantage of cheap electricity in the summer. When high electricity cost hours occur the SMR process consumes the electro methane that was produced at the low electricity cost hours. To conclude this paragraph: the increased rWGS CAPEX incentivizes investments of PV but dis incentivizes investments of batteries and P2H since less surplus PV generation is available. The reduced heat from P2H is met by investments in CHP.

4. Discussion

4.1. Complications using biomass as feedstock for kerosene production

The amount of sustainably available biomass within Sweden is a conflicting and debated subject but also in what sector it will contribute the most to mitigating climate change. As presented in Table 13 in Appendix A, substantial amounts of biomass and other products[13] are expected to be available in the future but there might be a growing demand when sectors aim to reduce their emissions. In 2018, the sectoral biomass consumption was divided as presented in Table 14, but this ratio is by no means fixed and is likely to shift, due to increasing biomass demand and price. The demand and price go hand in hand and is providing incentives for sectors to invest in alternate decarbonization technologies rather than using biomass as energy or feedstock. Another way of shifting the ratio would be to implement policies that for example taxes usage in unwanted sectors and/or subsidizes usage in wanted sectors.

How to define an unwanted or wanted sector is out of the scope of this thesis, but what is apparent at the moment of writing is that the aviation sector is hard to decarbonize [44]. One solution that could dramatically reduce the emissions is the usage of biomass as a feedstock for production of fossil free aviation fuels [45]. Other options exist, for example: hydrogen airplanes [46] & battery electric airplanes [44], but they have limitations in the form of weight, TRL, infrastructure, high CAPEX and more. Strong global policies could potentially shift the favour to one of the niche technologies, but the existing socio-technical regime is well established and will oppose changes. Thereof, the use of biomass as feedstock for aviation fuel is a less resilient way of reducing the aviation sectors emissions and the focus of our Scenario 2 – BER, but the scenario also includes a pathway that allows for production through the consumption of CO_2 and electricity in case that would reduce the total cost.

4.2. Limitations

This chapter contains the research limitations which are the subjects that are not be covered in detail or at all, they are listed below:

- **New nearby electrifications that could impact the model**
  Large changes in the local energy system would potentially alter the results of the model and when implementing more variables, it is hard to deduce a specific variable's impact on the results. Thus, limiting the complexity of the model by reducing the amount variables in terms of additional changes in the energy system allows for more a precise interpretation of the results. Additionally, the electrification of other sectors mainly transportation is not considered. The flexible charging of electrified transport is found to be optimum in combination with PVs similar to the results in this work [10] and thus they could outcompete batteries.

[13] Referring to products that can be used for the same purpose, such as slaughterhouse waste.

- **Decarbonization of refineries at other locations than Gothenburg**
  Different geographical locations have different availability of renewable electricity production and biomass as well as different energy systems infrastructure. The model used is based upon the energy system of Gothenburg, and thus the results are also specifically for the Gothenburg energy system. But this does not mean that the results are irrelevant for other locations, but, that they cannot directly be transferred to another energy system. For example, other locations might have less congestion in the national grid and thus allow for more import or the possibility to invest in wind power.

- **Land use limitation**
  The available land area in Gothenburg could potentially be a limiting factor when it comes to large scale construction of new processes. For example, the model is limited to not invest in wind power due to constraints of land use and other implications[14] that wind power has. But for the refineries we disregard this factor, to not constrain the model. The results show large investments in PVs, PTES and hydrogen storages which all require large areas, and this could potentially be a challenge for the urban environment.

- **No quantification of emissions other than CO_2**
  There are other emissions stemming from the refineries and the connected sectors, but most emissions are CO_2 , and for the purpose of investigating impacts on the energy system, the quantification of CO_2 is deemed enough. Other emissions would be CH_4, NO_x & SO_x, and even though methane (CH_4) has a greater CO_2-equivalent, the amount released is substantially less [13], [14].

- **No imports of biomass**
  The Swedish forestry sector is regulated by law to provide sustainable biomass [25]. There are also regulations in other countries intended to secure a sustainable use of forests, but this work does not consider import of biomass for the following reasons: (1) The transport of biomass is an additional loss of energy and (2) import of biomass may provide incentives for deforestation in other countries with less stringent regulations of the forestry sector. The biomass availability was also added as a constraint to the model but the availability was three times higher than the demand for the case with Nordic production and it does not impact the results.

4.3. Impact on downstream stakeholders

The downstream stakeholders for the two refineries under investigation are the different sectors of transportation. These actors are consumers in Sweden, Norway and a large part is also exported to North-western Europe [12]. The political and the environmental restrictions in Europe are striving for a 90% emission reduction from the transportation sector [43] and there is a variety of different pathways available for the sector to achieve this target. Some of these pathways e.g. electric and fuel cell electric vehicles suggest that the demand of the products from the refineries will be reduced.

[14] *Noise level* – wind passing over blade tips and mechanical noise from gear boxes, *Birds* – limitations due to protected areas, *Military* – air force exercises, and *Landscape* – public opinion on landscape changes [54]

For the case where the refineries maintain their current production mix and levels i.e. CBR, the downstream stakeholders are not impacted by the changes at the refineries. This work does not study any external impact on these stakeholders. However, the emissions from these downstream stakeholders still exist and might make them more susceptible to external impacts. These external impacts could be landscape developments [5] that prohibits the use of these products or consumers choice to pick an alternative technology.

For the BER and ER scenarios, there will potentially be no fossil emissions from the downstream stakeholders but the change in the production mix means that the refineries will have to break into newer markets to succeed. Marine transportation, which currently uses bunker or fuel oil, will be impacted by these scenarios. However, recent developments in the sector suggest that LPG can be used to power marine transportation [47] but there are also other potential future fuels or technologies that can aid the marine transportation sector.

The different refinery designs discussed in this work provide a range of different products, but it is not limited to these products. The same processes can be designed to produce other hydrocarbons and is a decision for the refinery owners to make. However, the aviation subsector has been long discussed as a potential barrier to the decarbonization of the transportation sector. Hence, we suggest that the refining industry shifts its focus towards producing fuel for the aviation sector. Preem, in cooperation with SAS, has also shown their intent to produce renewable aviation fuel [48] which shows that the market for these renewable fuels already exist and is a matter of correctly identifying them.

4.4. Refineries and the district heating network

For scenarios BER and ER and the cases where the refineries try to produce the Nordic Kerosene demands, the residual heat availability from the refineries is twice the city heat demand. The refineries, who today generate revenue by selling residual heat to the DH network, might instead have to pay to get rid of it for smooth operation. This heat might also not hold any value for the local utility since they are getting more than twice their generation demand for the entire city. There are two possible alternatives which this work has not covered. Firstly, the refineries have an opportunity to use the ocean as a sink to cool their process heat, but this could only be done for a part of the total due to environmental restrictions. Secondly, heat integration at the refineries could meet their new demand for process heat with part of the excess heat. Scenario ER provides better potential for this integration as the refinery production is dominated by rWGS which is a highly endothermic process. The integration requires a pinch point analysis to ensure feasibility of different parameters and must be a part of any future work. The refining capacity will then be restricted by how much the refineries can optimize the cooling of their waste heat by these methods.

The work does not consider any process residual heat under 100 °C. Any process heat below this can be made valuable by use of heat pumps and can also serve the district heating network. There have also been a lot of research and development towards a lower temperature district heating [49] and its' implementation could potentially mean that the waste heat availability from the refineries could be larger even without heat pumps.

4.5 Technological Innovations

The technologies analysed in this work have a varying TRL but with continuous technical development they become promising for the future refineries. For instance, CCS is not generally implemented in a refinery setup today but an essential technology for the future refineries especially if negative emissions (carbon sink) are needed. The varying TRLs, however, are a source of uncertainty to the implementation of these scenarios. The technologies with low TRLs can prove to be one of the barriers for the refineries and may require intensive legitimation [4] before they can be considered.

The scenarios BER and ER also assume refining syncrude in the same way as conventional crude oil. This work does not go into the technical modifications needed to ensure this could be done without any obstacles and might have an additional cost associated to this retrofitting [32]. Even the well-known technological innovations discussed in this work with high TRLs are not commonly used in the refining industry. However, the thesis does not investigate this aspect of the integration.

5.
Conclusions

The thesis set out to investigate the impact of different decarbonization pathways for the refineries on the energy system of Gothenburg. This work shows that future refineries will have a large impact on the city energy system and, in some decarbonization scenarios the refineries dictate the investments made in the system for electricity and heat generations. The refineries will increase the city electricity demand depending on the choice of refinery technologies from 0.62 TWh/a up to 10.95 TWh/a. The refineries will promote investments in solar PV in combination with batteries but the synergy between the electricity and the DH network makes it complex as the refineries interact with both by also providing waste heat. For some refinery decarbonization pathways, the waste heat availability is larger than the demand for heat and the refinery inhibits investments in CHP and heat generation technologies. The cheap residual heat from the refineries will also promote TES to shift this heat in time and thus will further reduce the need for heat investments in the system.

If the refineries intend to keep their same production mix (*Scenario CBR*), there will be a small reduction in the residual heat availability but an increase of up to a factor of 10 in the electricity demand (compared to today´s level) for the largest case investigated (30 BR). The blend ratio could be higher or lower and is a choice the refineries will make. The operation of the refineries also serves the electricity grid as a VMS by acting as an absorbing strategy in summer while shifting in the winter.

Scenario BER and *Scenario ER* allow the refineries to optimize production towards kerosene with specific operation parameters for the FT process and the composition of the syncrude. With the expected future biomass price €40/MWh, the biofuel pathway is cheaper but with an increasing biomass price, the electrofuel pathways are more incentivized. The smaller the ratio of biofuel to electrofuel, the larger is the impact of the refineries on the electricity system. For a case with three-fourth of the production coming from electrofuel, the increase in the refinery electricity demand was increased by a factor of 34 and it becomes such a large part of the system that it dictates both the investments and the dispatch in the city electricity system. The residual heat availability is always high, regardless of this ratio, and complements the DH network by reducing the need for heat generation investments. In the scenarios investigated, the total production volume corresponds to 30% of the current production volumes. Increasing the production would also magnify the results.

The larger biomass to electrofuel ratio only allowed the refineries to provide service to the grid as an absorbing strategy, creating value from the surplus generation during summer. However, the smaller ratios showed that the refinery can act as an absorbing in the summer and as a complementing strategy, which support the electricity system during high net load events in the winter, due to the flexibility of syngas production through different routes.

This work could be used to help identify the barriers to achieve net-zero emissions for future refineries. The refineries of Gothenburg have a large responsibility to reduce their emissions and this work shows that it is possible but with large impacts on the energy system. Therefore, the future refineries should collaborate with other actors in the energy system to optimize their investments and minimize their environmental impacts. Since this work highlights the importance of collaboration between industrial actors, policy-makers and energy system stakeholders, it is relevant for the future energy system in its path towards decarbonization.

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Appendices

Appendix A

Table 13: Current (2018) HVO feedstocks and future biomass availability in Sweden

	Swedish HVO feedstock demand 2018			**Future Swedish biomass availability & other waste products**		
HVO feedstock		Unit	Ref.		Unit	Ref.
Black liquor	154426	m^3	[50]	50	TWh	[51]
Slaughterhouse waste	538974	m^3	[50]	11	TWh	[51]
Palm oil	40555	m^3	[50]	-		
Rapeseed	6604	m^3	[50]	*Included in Energy crops*		
PFAD[15]	674984	m^3	[50]	-		
TCO[16]	55817	m^3	[50]	*Included in Energy crops*		
Other	525	m^3	[50]	-		
Agriculture waste	0			7	TWh	[24]
Forest residues	0			25-54	TWh	[24], [51]
Pulp wood, excluding bark	0			9.4 (81)[17]	TWh	[51]
Energy crops	0			45	TWh	[51]
Industrial wood waste	0			27	TWh	[51]
Total	**1471885**	$\mathbf{m^3}$		**174.4 - 203**	**TWh**	

Table 14: Sectoral Swedish biomass consumption in 2018, value in brackets is the percentage of total consumption.

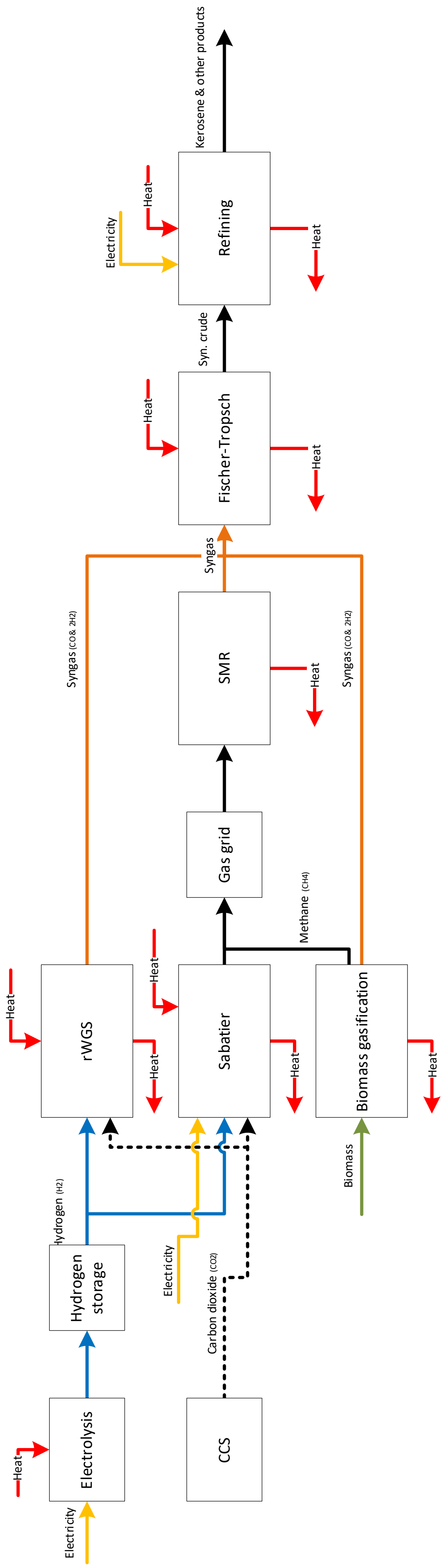
Electricity production	District heating	Industry	Transport	Residents and services	**Total**	Unit	Ref.
15 (11%)	38 (27%)	56 (39%)	18 (12%)	15 (11%)	**141**	TWh	[50]

Table 15: Current (2018) Swedish HVO feedstocks country of origin

SE	NL	BE	DE	GBR	ID	MY	FR	IE	FI	US	Others	Ref.
5%	4%	2%	8%	4%	34%	11%	3%	3%	4%	7%	15%	[50]

[15] PFAD is short for Palm Fatty Acid Distillate and is a waste product from refining of Palm oil [55]
[16] TCO is short for Technical Corn Oil and is a waste product from ethanol production [56]
[17] Number in brackets is the total Pulp wood, excluding, bark that is available. The number without brackets is the available Pulp wood, excluding bark, that is not used by the paper and pulp industry [51].

Appendix B



Kerosene & other products
Refining
Heat
Electricity
Heat
Syn. crude
Fischer-Tropsch
Heat
Heat
Syngas
SMR
Heat
Syngas (CO& 2H2)
Syngas (CO& 2H2)
Gas grid
Methane (CH4)
rWGS
Sabatier
Biomass gasfication
Heat
Heat
Heat
Heat
Heat
Biomass
Hydrogen (H2)
Hydrogen storage
Electricity
Carbon dioxide (CO2)
Electrolysis
CCS
Heat
Electricity