Furnace Heat Generation
MSc Thesis

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FURNACE HEAT GENERATION

Alternative heat sources contributing to net-zero emissions

A case study at the Shell Netherlands Refinery

By

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Disclaimer

This report contains data and analysis from Shell scenarios. These scenarios are a part of an ongoing process used in Shell for over 40 years to challenge executives' perspectives on the future business environment and inform them about changes in energy scenarios. They are designed to stretch management to consider even events that may only be remotely possible. Therefore, scenarios are not intended to be predictions of likely future events or outcomes.

Additionally, it is essential to note that as of today, Shell's operating plans and budgets do not reflect Shell's Net-Zero Emissions ambition yet. Shell's aim is that, in the future, its operating plans and budgets will change to reflect this movement towards its new Net-Zero Emissions ambition. However, these plans and budgets need to be in step with the movement towards a Net-Zero Emissions economy within society and among Shell's customers.

Also, this report refers to Shell's "Net Carbon Footprint", which includes Shell's carbon emissions from the production of their energy products, their suppliers' carbon emissions in supplying energy for that production and their customers' carbon emissions associated with their use of the energy products they sell. Shell only controls its own emissions. The use of the term Shell's "Net Carbon Footprint" is for convenience only and not intended to suggest these emissions are those of Shell or its subsidiaries.

Moreover, this thesis report provides examples of furnaces, and these do not reflect reality. These examples are only used for clarification. No conclusion nor any other information of these examples can be used.

PREFACE

This thesis reports on 30 weeks of research to obtain a Master of Science degree in Mechanical Engineering at the Delft University of Technology and builds upon a prior 10-week internship. The work focuses on the energy transition of fired process heaters on the Shell Netherlands Refinery. It was exciting to research and a pleasure to be involved in the current generation's most outstanding global challenge.

I want to acknowledge the people who supported me during the internship and graduation. First, I would like to thank the Royal Dutch Shell and the Energy and Utility Technology team, of which I was part. My colleagues provided me with insights, expertise, motivation and introduced me to Shell's people that greatly assisted the research. I especially would like to thank my daily supervisor Marijne Timmers for our cooperation and always being available for all my questions. I want to thank Marc Zwart for the opportunity of graduating at the Shell Netherlands Refinery and the guidance throughout the process. Also, Tuur Vermunt, thank you for your enthusiasm in my work and the technical insights into specific topics.

I want to express my gratitude to my thesis supervisor Thijs Vlugt, from the Delft University of Technology, for the graduation assignment. He guided me throughout the process and gave constructive feedback on my work.

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Wietse Schaefer

ABSTRACT

The thesis discusses how alternative heat generation for furnaces can be implemented on the Shell Netherlands Refinery to become CO_2 neutral by 2050 or sooner. The research analyses the current knowledge, and future alternatives for furnace heat generation and underlines the need for alternative solutions with net-zero emission impact. Furnaces are the equipment that heat process streams before the reactor or distillation column. Hydrogen firing, electrification, biofuel combustion, and heat pumps are the four main topics of alternative technologies that are discussed. The result is a roadmap including all relevant information for the applicability of technologies, developments, value drivers and credible scenarios.

Revamping all Pernis' fired heaters for hydrogen firing is a suitable option and has TRL 6. The ultra-low NOx burners are operational, but hydrogen is not integrated yet as a fuel, and combustion analysers are not field-tested. The blue hydrogen will not be 100% pure, so not all CO_2 can be abated. Besides, switching between RFG and hydrogen can cause flame instabilities and a higher thermal NOx emission. The normalised CO_2 abatement price against RFG operation, the cost of not emitting a tonne of CO_2, is 13 /tCO_2.

Electrification, such as impedance and immersion heaters, have TRL 7 and are limited to relatively small duties, single-phase, and clean service. Radiant heaters can heat process streams with two-phase and coking services having TRL 2. The concept is proven, but no prototype is tested. Electrical heaters have high efficiencies and might have a yield benefit. However, the showstopper is the plot space availability of the refinery. The normalised CO_2 abatement price against RFG operation for electrical heaters is 21 /tCO_2.

Upgrading biofuel to biomethane allows the gas to be interchangeable with natural gas. Suitable for combustion without any adjustment on the furnace if biomethane is injected into the national natural gas grid. Biomethane combustion, having TRL 7, only impacts the sites emission, and it seems to be an administrative solution, where trading in certificates will be dominating the market. The normalised CO_2 abatement price against RFG operation for biomethane is 21 /tCO_2.

Heat pumps are used in refineries, and they can be used to reduce the furnace load but not to replace the furnace. The potential for replacing fired heaters with TRL 7 heat pumps is low since the maximum operating temperature is 160 °C [1].

The development scenarios showing the energy consumption expects that low carbon-intense electricity will expand most, suggesting that electrification is the step forward for SNR. The usage and production of hydrogen tend to increase after 2050, and the amount of biomass is small and will most probably not be an available option for Pernis. Four credible scenarios show that it is possible to abate sufficient CO_2. With electrification only, it is impossible to achieve the vision of 2050 due to the plot space constraint. The hydrogen and electrification scenarios are combined in a hybrid scenario, where most CO_2 is abated. The net-zero CO_2 operation of furnaces requires significant investments and technical developments.

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NOMENCLATURE

Acronyms

AD	Anaerobic Digestion
BWT	Bridge Wall Temperature
CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CH	Cabin Heater
COP	Coefficient of Performance
CVB	Convection Bank
EU ETS	European Union Emissions Trading System
FIT	Furnace Inlet Temperature
FOT	Furnace Outlet Temperature
GHG	Green House Gas
HHV	Higher Heating Value
IH	Induction Heating
IHP	Industrial Heat Pumps
ILUC	Indirect Land Use Change
LHV	Lower Heating Value
MOD	Money Of the Day
NPV	Net Present Value
OPEX	Operating Expenditures
PSA	Pressure Swing Adsorption
PSV	Project Steering Value
RFG	Refinery Fuel Gas
SNR	Shell Netherlands Refinery
SRF	Standard Refinery Fuel
ToR	Terms of Reference
TRL	Technical Readiness Level
VIR	Value Investment Ratio

Symbols

A	Cross sectional area of the pipe	[m^2]
D	Internal diameter of the pipe	[m]
f	Friction factor	[–]
L	Length of pipe	[m]
M	Molar weight	[kg/mol]
P	Electric potential	[W]
P'	Absolute pressure	[Pa]
ΔP	Pressure drop	[Pa]
R	Gas constant	[J/mol K]
T	Temperature	[K]
v	Velocity	[m/s]
V	Voltage	[V]
$\overline{V}$	Specific volume of fluid	[m^3/kg]
w	Rate of flow	[kg/s]
Z	Compressibility factor	[–]
Ω	Element's resistance	[Ω]

1. INTRODUCTION

The oil and gas industry started at the beginning of the 20th century and has a high energy demand, which is traditionally fulfilled by fired heaters. The tubes inside the furnace are heated by a direct-fired burner that uses residual refinery gas streams as fuel. Processes evolved as well as associated environmental legislation, and consequently, there is a variety of furnaces throughout a refinery and the world. Shell Netherlands Refinery (SNR) is one of Europe's largest refineries and processes about 400.000 barrels of oil per day in more than 50 different process units. The site's total annual energy consumption is 50 PJ, and the total CO_2 emission is 4.200 kton. Shell Pernis is one of the major CO_2 emitters in the Netherlands and has developed a CO_2 reduction program to achieve the 2030 ambitions of both the Shell group and the Netherlands. Furnaces are responsible for over 40% of SNR's CO_2 emissions, and alternative heat generation reduces the sites carbon footprint and copes with the expected stricter legislation in the future.

1.1. Shell's footprint

1.1.1. Shell and climate change

Climate change is a combination of global warming caused by greenhouse gas (GHG) emissions and the shift in weather patterns [2]. The greenhouse effect is the earth's warming due to the re-radiation of energy by greenhouse gases trapped in the atmosphere, such as H_2O, N_2O, CH_4, and CO_2. Due to human activities, the earth's natural greenhouse effect changes; by burning fossil fuels, the CO_2 concentration in the atmosphere has increased. The consequences of these changes include the warming of the world, extremer weather conditions (rain and drought), rising sea levels due to an increase in seawater temperature, and a negative effect on food production [3]. Crops can increase yield while the nutrient level, soil moisture, and water must be available. Warmer temperatures could affect fish and animals' habitat changes, disrupting the ecosystems [4].

As an energy and petrochemical company, Shell is one of the contributors to the earth's current situation; it brought the comfort and importance of energy while it supported the growth and prosperity in the world. It is underlining the challenge to provide more energy while reducing carbon emissions. Therefore, it is necessary to invest in new oil and gas production to meet society's increasing energy demand to support growth and prosperity for the coming decades. The GHG Protocol Corporate Standard classifies GHG emissions into three scopes [5]:

1. The scope one emissions are direct emissions from the companies' owned sources.
2. The scope two emissions are indirect emissions from imported generated energy.
3. The scope three emissions include all other indirect emissions in the companies' value chain, e.g., combustion of purchased fuels by a customer.

In the long term, the ambition is to halve the Net Carbon Footprint of the energy products sold, resulting in a change in the products' portfolio. The aim is to enable, inform, and accelerate the policy, technology, and societal changes for a successful transition by collaborating and sharing knowledge with different parties [6].

1.1.2. Shell and the Dutch 'Klimaatakkoord'

Shell intends to thrive as the world transitions to lower-carbon energy. One crucial way to do this is by reducing the Net Carbon Footprint of producing energy products [6]. The Rutte-III government's coalition agreement states that the Dutch emission should drop by 49% in 2030 with respect to 1990. Subsequently, the Dutch Climate Agreement, 'Klimaatakkoord,' states that in 2050 the industry should be circular, meaning that the emissions should be net-zero [7]. SNR supports this commitment and aims to be emission neutral by 2050. The impact will be on all three GHG scopes; the aim is to get all scope one emissions to net-zero, resulting in a lower carbon footprint of the products, scope three emissions. Shell's responsibility is to be consistent in the transition and actively pursue a low carbon footprint of the purchased energy, scope two emissions.

1.1.3. Shell Netherlands Refinery

Shell Pernis is a petrochemical process plant, part of the Royal Dutch Shell, located at the Vondelingenplaat in Pernis, and started in 1936 with processing 1 Mton crude oil per year. The refinery processes crude oil into usable products such as petrol, kerosene, diesel, mogas, and raw materials for the chemical industry. The breakdown depends on the type of crude oil and the market value. The target is to maximise products such as mogas and diesel and minimise low-value fuel production. An averaged mass breakdown is shown in Figure 1-1.

Pipelines connect Shell's factories to the Maasvlakte Oil Terminal, Europoort Terminal, Shell Moerdijk and others. The refinery part that receives, storages, and pumps the crude oil, and Moerdijk is a branch of Shell Netherlands Chemie B.V. SNR is the largest refinery in Europe and one of the largest in the world.

The refinery exists out of multiple factories, like a crude distiller, high vacuum distillation, or a hydrocracker, ensuring a maximum conversion of a crude oil barrel into valuable products; see Figure 1-2. After several distillation steps, the products are cracked, separated and purified. Other products besides fuels are asphalt, wax, lubricants and petrochemicals. The lighter products are gained at the distillation columns, and the heavier products are refined after cracking.

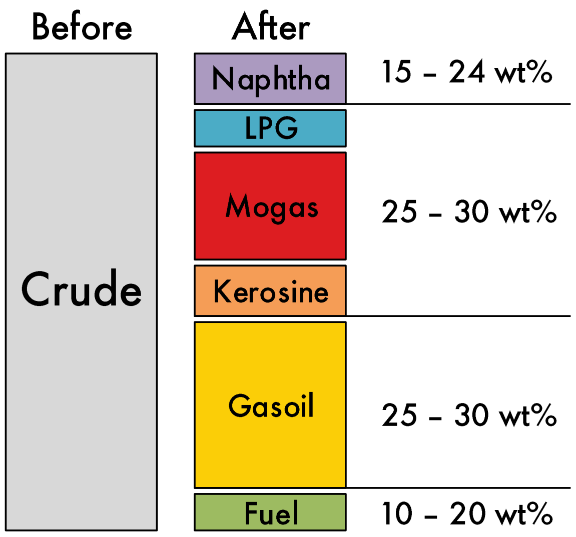

Figure 1-1: Averaged mass break down of products refined out of a barrel of crude oil on the Shell Netherlands Refinery (SNR). The refinery processes crude oil into usable products such as petrol, kerosene, diesel, and raw materials for the chemical industry. The breakdown depends on the type of crude oil and the market value. The target is to maximise products such as mogas and diesel and minimise low-value fuel production.

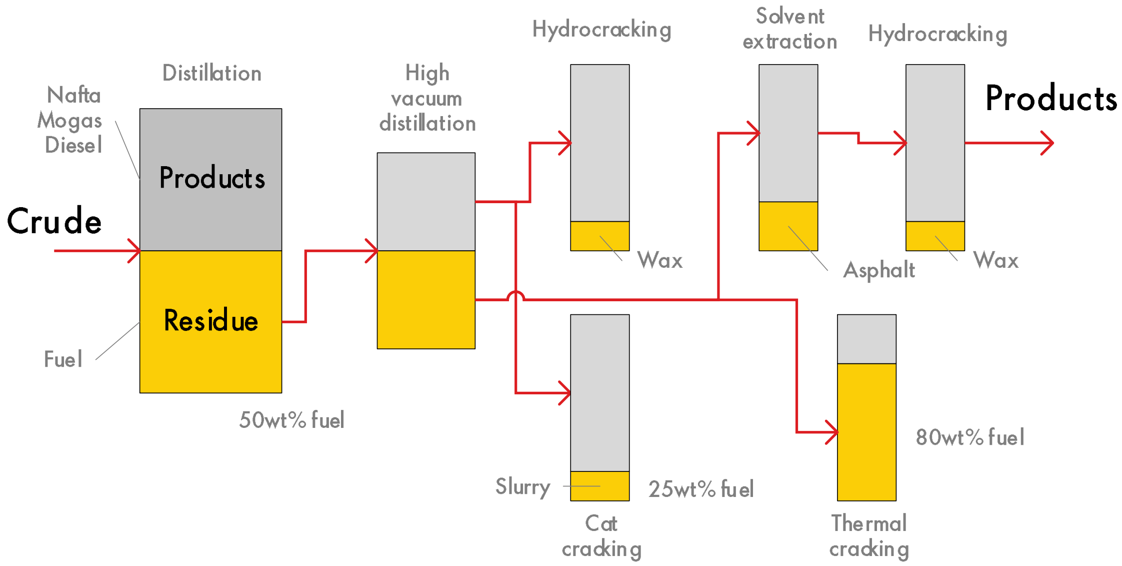

Figure 1-2: Flowchart of a typical refinery from crude oil to products. Crude oil is transformed and refined into useful products at an industrial process plant such as SNR. An oil refinery typically consists of several factories, like a crude distiller, high vacuum distillation or a hydrocracker, ensuring a maximum conversion of a crude oil barrel into valuable products. After several distillation steps, the products are cracked, separated and purified. Other products besides fuels are asphalt, wax, lubricants and petrochemicals. The lighter products are gained at the distillation columns, and the heavier products are refined after cracking.

1.1.4. Shell's emission reduction projects

SNR contributes to multiple projects which aim to reduce CO_2 emissions. Two examples are Porthos and H-vision.

Porthos

The Porthos project is an agreement with four companies to capture, transport and store CO_2 in the Port of Rotterdam. The companies will supply their CO_2 that will be compressed and transported offshore to an empty gas field beneath the North Sea. Carbon Capture Storage (CCS) helps to achieve the Dutch Climate Agreement, with relatively low cost [8].

H-vision

Large-scale blue hydrogen production will allow the industry in the Port of Rotterdam to reduce CO_2 emissions, anticipating the arrival of green hydrogen. H-vision is becoming the seed of a new hydrogen economy. Blue hydrogen is produced during autothermal reforming from Natural Gas (NG) or Refinery Fuel Gas (RFG), while the CO_2 is captured and stored in the North Sea. Green hydrogen is produced with renewable energy by electrolysis. [9], [10].

1.2. Background information on furnaces

A furnace is a device in which the fuel's chemical energy converts into heat, and it is used to raise the temperature or vaporise a feedstock; the refinery process streams. The process streams pass through steel tubes, which receive heat on the outside surface. Heat is conducted through the steel wall and then transferred to the process stream by convective heat transfer [11].

1.2.1. Fired heaters

Fired or tube still heaters are used in the petrochemical and hydrocarbon industries to heat fluids in tubes for further processing. Fluid flows through an array of tubes located inside a furnace or heater, and a direct-fired burner heats the tubes. The layout of a furnace is discussed in the next paragraph, and a schematic overview is provided in Figure 1-4. The fuel gas composition differs per furnace as the refinery has multiple and widespread fuel gas networks. The two main contributors are the imported natural gas and the by-products from the plant processes, known as off-gas streams. The produced fuels, which mainly exist out of hydrocarbons, depends on the crude oil composition and the unit's cooling capacity. When the ambient temperature is high, the cooling will be less effective, resulting in more non-condensables, hence more fuel-gas. On-site, there are multiple fuel gas streams. Depending on the location in the network, the composition can vary [12].

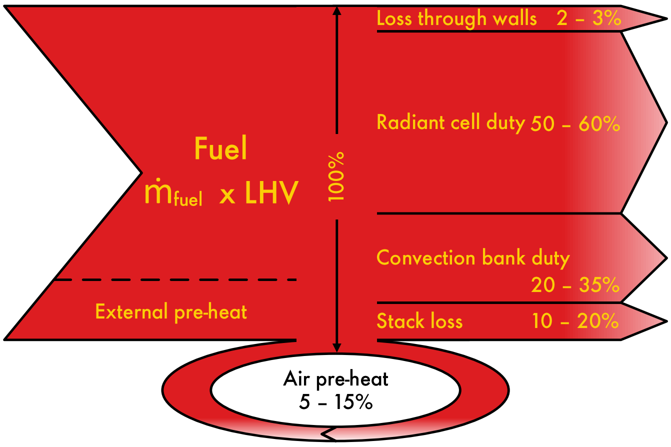

Figure 1-3: The Sankey diagram provides an overview of the furnace energy flows [13]. The incoming energy is mainly by the fuel's combustion, determined by the Lower Heating Value and the fuel's mass flow. The incoming process stream might also be pre-heated by an external pre-heater. The majority of the energy is transferred to the process stream by the radiant cell and convection bank. The losses are through the walls and via the stack. An air pre-heater recovers some of the heat from the flue gas by heating air before the combustion.

Combustion is the controlled release of heat from a chemical reaction between the fuel and an oxidiser. The Higher Heating Value (HHV) minus the energy in the flue gas going out of the stack is the available heat in a process [14]. The difference is the energy available to do work. Some energy is lost by conduction, some by radiation through openings and some by adsorption by air. Since the mass flow of air is much larger than the mass flow of fuel, it is more effective to pre-heat the air than the fuel, resulting in higher furnace efficiency, under the condition that the air and fuel pre-heat temperature are the same [14]. The Lower Heating Value (LHV) is used to determine the duty of a furnace, as the stack temperature stays above the temperature at which water vapour is condensed [14]. There is a correlation between the density and speed of sound in the fuel that determines the molar weight. Another correlation between a fixed calorific value and the fuel's weight is the Standard Refinery Fuel (SRF). SRF is used for energy monitoring and forms a basis for comparing fuel consumption among units regardless of the fuel quality [12].

The primary heat output is the heat transferred to the process side. Other outputs of a furnace are the heat losses through the walls and the stack. A Sankey diagram of a fired heater visualises the heat in- and outputs; see Figure 1-3.

1.2.2. The layout of a furnace

Figure 1-4 shows a schematic overview of a fired heater. The burners are inside the radiant section or radiant cell. Here, the flue gas temperatures are high. The outflow flue gas temperature of the radiant cell, also known as the Bridge Wall Temperature (BWT), is a good measure of its average flue gas temperature. Heat transfer is mostly by radiation, emitted by a high-temperature source through electromagnetic waves [15].

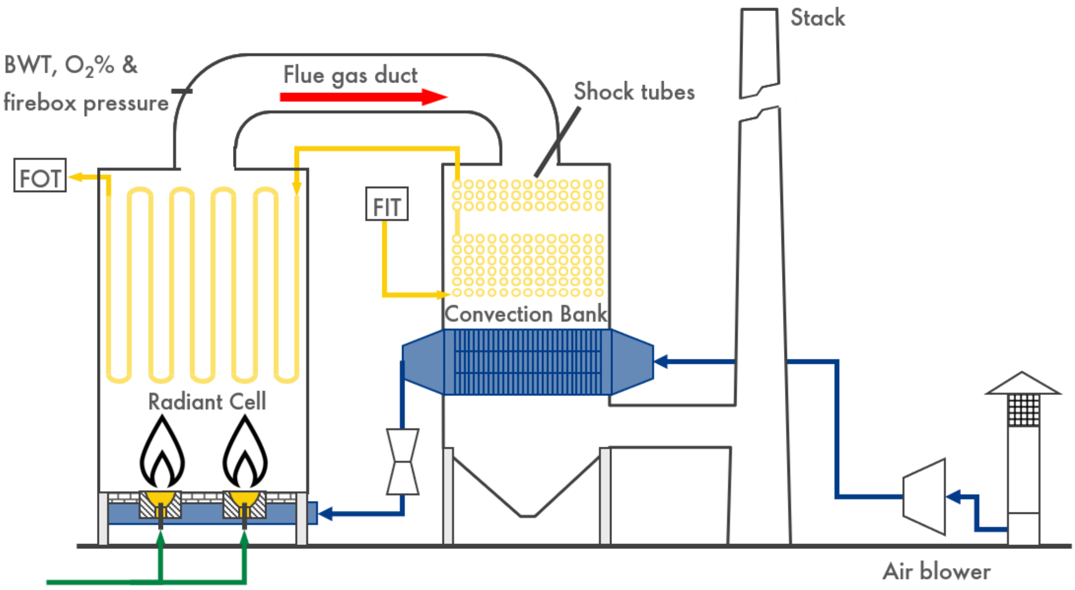

Figure 1-4: The vertical box layout forced draught fired furnace with an air pre-heater and a side-mounted convection bank. The process stream is first heated by the convection bank, after which it flows through the radiant cell. Air blowers induce forced draught, and the air is pre-heated in the convection bank. The Bridge Wall Temperature (BWT), O_2% and the pressure are measured in the flue gas duct, indicating the furnace performance. The Furnace Inlet Temperature (FIT) is where the process stream enters the furnace and should be heated until the desired Furnace Outlet Temperature (FOT).

The convection section is the part of the furnace where the flue gases flow across banks of tubes and where the heat is transferred mainly by convection, created by a 'brushing' action of the hot gases when flowing past the tubes. Heat transferred by radiation from the flue gases can still be significant at the convection section entrance, particularly the first tube rows, known as 'shock tubes'; see Figure 1-4. The radiative heat transfer reduces rapidly as the flue gas temperature falls [15].

The stack serves to discharge the furnace flue gases to the atmosphere and provides draught to draw the flue gases through the convection section, overcoming the pressure drops from the tube banks [16].

The burner is the device that combusts the fuel with air to convert the chemical energy in the fuel into thermal energy. The burners can reduce some emissions, which is needed considering new and more stringent environmental regulations. Staged combustion uses over-air fire technology, introducing the combustion air at multiple burner sections [11]. Staging reduces the flame's peak temperature, which reduces NOx production and has a more uniform heat distribution. However, staging may increase CO production [11].

1.3. Alternative heat generation

Refinery processes are driven by heat from hydrocarbons. Carbon-free fuels can provide a solution to reduce CO_2 emissions. Besides, alternative forms of energy could also contribute to furnace efficiency and reduction of emissions. The following section presents four primary energy sources and their technologies.

To properly assess each technical opportunity's development and feasibility, the Technical Readiness Level (TRL) is discussed [17]. TRL is a method to estimate the maturity of a technology. Table 1 provides Shell's implementation of the TRLs on a scale of 0, unproven concept, until 7, field-proven system.

1.3.1. Hydrogen firing

Hydrogen is an example of a carbon-free fuel. Retrofitting hydrogen fuel is a suitable option and has been explored [18], [19], [20]. According to CFD simulations, using hydrogen instead of RFG has a minimal impact on the furnace's overall performance [18]. Moreover, the heating efficiency can slightly increase [19]. The heat transferred to the process tubes should be as uniform as possible, avoiding flame impingement preventing coke formation inside the tubes [20]. Coking is hard carbon deposits built upon on the inside of the tube's wall, limiting the cross-sectional area and, consequently, throughput [21]. Besides, the tube skin temperature will rise due to the coke layer's extra thermal resistance, which threatens to cause the tube skin temperature to exceed the allowable skin metal temperature [21].

As the hydrogen flame speed and the adiabatic flame temperature are higher than RFG gas, the flame may be shorter, consequently reducing flame impingement [18], [20]. NOx emissions will increase as the NO formation is temperature dependent due to the Zeldovich mechanism [20], [22]. By implementing ultra-low NOx burners, the mixing of combustion air and fuel gas increases, lowering the flame temperature. Hydrogen has a lower mass density but a higher LHV than natural gas or RFG. Therefore, increasing the volumetric flow rate with a factor of three keeps the same firing duty for pure hydrogen. A replacement or modification on the fuel gas line-up between the skid and the burner is needed to implement the new fuel.

As hydrogen flame speed is higher than hydrocarbon fuels, it can flashback more heat to the source at higher hydrogen concentrations. A flashback is the flame's upstream propagation, and it occurs when the flame velocity exceeds the gas velocity due to flame propagation or instabilities [23], [24]. A flame arrestor, a device that limits fuel combustion by absorbing the flame's heat [25], might be required to maintain safe operation.

The flue gas flow rate will be lower considering the same firing duty. The LHV of hydrogen is higher than RFG, and the stoichiometric air requirement of hydrogen combustion is also higher than RFG combustion. The consequences are that the plume can be stuck in the stack and cannot flow into the atmosphere, known as a downwash. The effect depends on the stack to which the furnace is connected. If the flue gas flow rate is unacceptably low, a reducer, cone, could be installed on top of the stack to decrease the cross-sectional area and increase the flue gas exit velocity, as per the stack effect [26].

Hydrogen combustion also has higher flammability compared to RFG. The excess oxygen level is limited to prevent afterburning and to increase efficient furnace operation. The air fan on the turndown capabilities is limited for forced draught furnaces [27].

In general, hydrogen combustion increases flame stability and does not have critical showstoppers [19]. The retrofitting is limited to the burner and air fan replacement, burner management system adaption, fuel gas network modification, and a check on the flue gas flow rate. Hydrogen firing has a TRL of 6, and the Pernis refinery operates some furnaces with ultra-low NOx burners already. However, hydrogen is not fully integrated into the system as a fuel. Combustion analysers, such as flame detectors and O_2/CO analysers, are commercially available but not field tested in furnaces. Ultra-low NOx burners for industrial forced draught furnaces are commercially available [19] by Callidus [28], John Zink [29], and Zeeco [30].

Revamping an existing furnace for hydrogen firing will be technically possible for all Pernis' forced draught fired heaters. The main challenge is the production and distribution of hydrogen.

Table 1: Shell's implementation of Technical Readiness Levels (TRL) [31]. A method to estimate the technology maturities to assess each technical opportunity's development and feasibility properly.

4D Model	API RP 17N	Development Stage Completed	Definition of Development Stage
D1 DISCOVER	TRL 0	**Unproven Concept** (Basic R&D, paper concept)	Basic scientific/engineering principles observed and reported, paper concept, no analysis or testing completed, no design history.
D2 DEVELOP	TRL 1	**Proven concept** (Proof of concept as a paper study or R&D experiments)	a) Technology concept and/or application formulated. b) Concept and functionality proved by analysis or reference to features familiar with/to existing technology. No design history, nearly a paper study not involving physical models but may include R&D experimentation.
	TRL 2	**Validated Concept** (Experimental proof of concept using physical model tests)	A physical model validates concept design or novel features of the design, a system mocks up, or dummy and functionally testes in a laboratory environment, no design history, no environmental tests, material testing and reliability testing is performed on key parts or components in a testing laboratory before prototype construction.
D3 DEMONSTRATE	TRL 3	**Prototype Tested** (System function, performance and reliability tested)	a) Item prototype is a built and put through (generic) functional and performance tests, reliability tests are performed including reliability growth tests, accelerated life tests and robust design development test program in relevant laboratory testing environments, tests are carried out without integration into a broader system. b) The extent to which application requirements are met are assessed, and potential benefits and risks are demonstrated.
	TRL 4	**Environmental Tested** (Pre-production system environment tested)	Meets all requirements of TRL 3, designed and built as production unit (or full-scale prototype) and put through its qualification program in a simulated environment (e.g. hyperbaric chamber to simulate pressure) or actual intended environment (e.g. subsea environment) but not installed or operating, reliability testing limited to demonstrating that prototype function and performance criteria can be met in the intended operating condition and external environment.
	TRL 5	**System Tested** (Production system interface tested)	Meets all the requirements of TRL 4, designed and built as production unit (or full-scale prototype) and integrated into the intended operating system with a full interface and functional test outside the intended field environment.
D4 DEPLOY	TRL 6	**System Installed** (Production system installed and tested)	Meets all the requirements of TRL 5, production unit (or full-scale prototype) built and integrated into the intended operating system, full interface and function test program performed in the intended (or closely simulated) environment and operated for less than three years, at TRL 6 new technology equipment might require additional support for the first 12 to 18 months.
	TRL 7	**Field Proven** (Production system field-proven)	Production unit integrated into the intended operating system, installed and operating for more than three years with acceptable reliability, demonstrating the low risk of early life failures in the field.

1.3.2. Electrical heaters

Electrical based heaters use electric currents or electromagnetic waves to heat materials. Three groups can be distinguished.

1. Direct heating takes places within the material, either by a current passing through the material, inducing an eddy current or exciting an atom or molecule within the material with electromagnetic energy.
2. Indirect heating takes place outside the material. Heat is generated externally and is transferred onto the material by either convection, conduction or radiation.
3. Hybrid systems are a combination of direct and indirect heaters. These systems combine a heat-transfer mechanism, reducing heating time and therefore increasing heating efficiency.

The critical question which defines the possibilities is the feasibility of the electrical technology at an industrial scale and conditions. Choosing between technologies is also a matter of associated Capital Expenditures (CAPEX) and Operating Expenditures (OPEX). Revamping an existing furnace into an electrical heater is, in most cases, not possible.

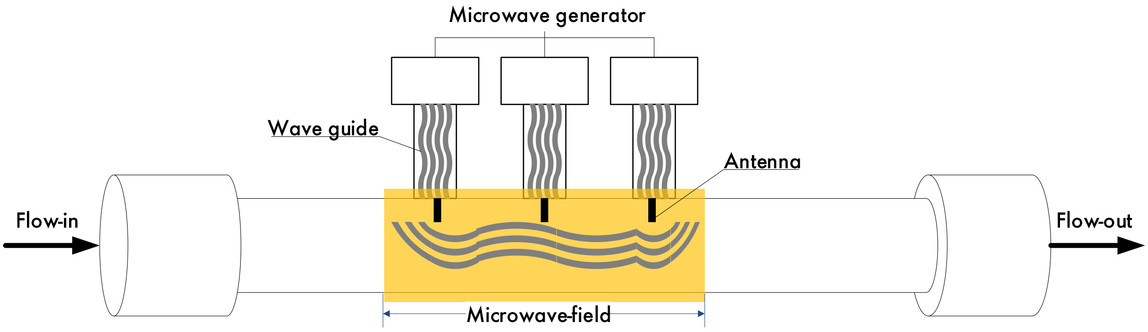

Figure 1-5: Microwave generators create waves that result in a microwave field in the process pipe. Microwave heating is direct heating by rotating polar molecules, creating friction within the material producing heat. The most critical challenges are the scale-up, non-uniform temperature profiles, temperature measurements constraints due to the interaction between the thermometer and the waves, impacts on the reaction kinetics and safety aspects [32], [33]. Commercialised, industrial size, microwave heating for a refinery application is not yet available and is still a basic engineering principle and has TRL 1.

Microwave heating

Microwave heating is a direct heating technology that heats dielectric materials with energy in the form of high-frequency (300 – 300.000 MHz) electromagnetic waves; see Figure 1-5. Microwave generators create waves that result in a microwave field in the process pipe. Microwaves heat the materials by rotating polar molecules, which create friction in the materials that produce heat. Lower frequencies, also known as radio frequencies, heat by conductive currents within the material due to ionic movement. Microwave heating is a well-known technology in industrial processing, for example, in the food processing industry for applications such as drying and processing [34], [35], [36]. Besides, microwave methods for the petrochemical industry exist mainly for cracking applications [35], [37]. More recent literature showed that there are opportunities for direct heating of refinery process streams by using microwaves. The most critical challenges are the scale-up, non-uniform temperature profiles, temperature measurements constraints due to the interaction between the thermometer and the waves, impacts on the reaction kinetics and safety aspects [32], [33]. Porch et al. [35] showed that the oil's mass density limits the oil's heating rate and that there is a correlation between the oil properties and the dielectric constant. Heavy petroleum oils are low microwave absorbing materials that have low interaction with electromagnetic waves. Added microwave receptors such as silicon carbide or carbon absorb the waves and produce heat. A significant disadvantage is the formation of local hot spots [33]. At local hot spots, the temperature increases, resulting in coke formation. Commercialised, industrial size, microwave heating for a refinery application is not yet available and is still a basic engineering principle and has TRL 1. According to the available information of vendors (MKS Instruments [38], Sairem [39], Thermex [40]) for industrial microwave generators, the current maximum capacity is 100 kW. Using this technology today will result in too many generators, hence a high CAPEX and OPEX due to maintenance requirements.

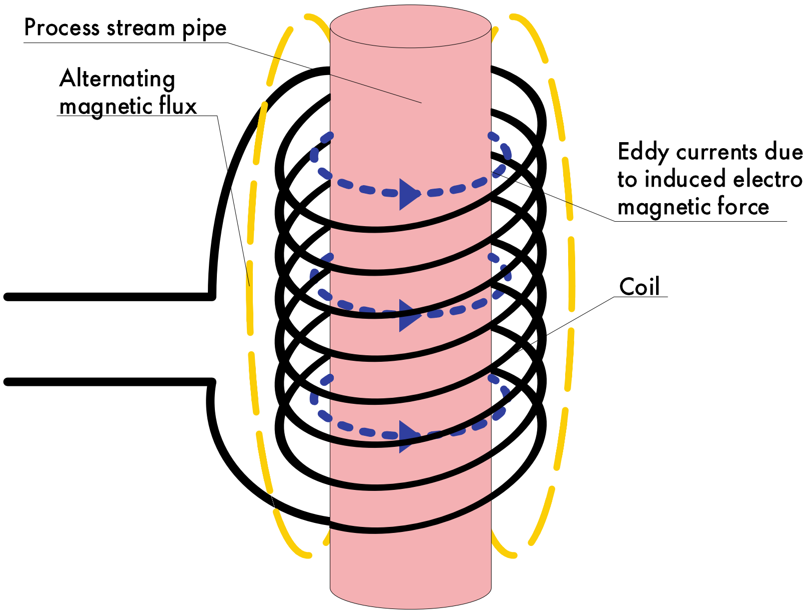

Figure 1-6: Induction heating consists of a process stream pipe surrounded by a coil, and heating is based on the Joule effect. The material to be heated, the pipe, is inside an alternating magnetic field induced by alternating currents in the coil. Eddy currents are produced and circulated within the material, and the current flows against the electrical resistivity. There is no further development of inline induction heating due to scale-up and limitation issues. Therefore, this technology has TRL 1.

Induction heating

The second possible option for an electrical heater is indirect heating by induction heating; see Figure 1-6. Induction heating consists of a process stream pipe surrounded by a coil. The principle builds upon electromagnetic induction and the Joule effect. Inside an alternating magnetic field is the material to be heated. Eddy currents are induced and circulated within the material. The current flows against the metal's electrical resistivity, generating heat, known as the Joule effect. Induction heating can be used in the petrochemical industry as it involves no contact between the to be heated material and the heat source [34], [41]. The main applications for induction heating are heat treatment, coating and melting applications [42], [43]. These systems are commercially available by EFD [44], Plustherm [45], and Radyne [46]. Unfortunately for refinery applications, there is no further development for inline induction heating due to scale-up problems and limitations. It is still a basic engineering principle with TRL 1 [33].

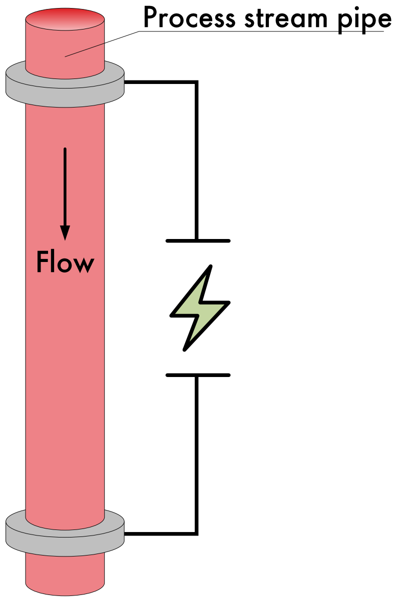

Figure 1-7: Impedance heating consists of a process stream pipe connected directly to a power source. During impedance pipe heating, a low voltage is applied across the pipe's length. Heat is nearly uniform generated by the Joule effect on the pipe's wall. Systems are commercially available for single-phase, clean service and can heat process streams over 1000 °C. Therefore, the technology has TRL 7.

Indirect heating elements made of high resistance materials exist in two types for industrial applications, (1) convective resistance impedance heaters and (2) convective resistance immersion heaters.

Impedance heating

Impedance determines the heating rate and the electrical resistivity, influenced by magnetic permeability and current density [47]. A process stream pipe is connected directly to a power source. Most commonly, across the pipe's length, there is a low voltage AC potential applied. Heat is generated nearly uniform by the Joule effect on the pipe's wall [48], [49]; see Figure 1-7. Generated from the difference in AC potential in the outside of the pipe are the eddy currents. The current in the pipe tends to concentrate at the pipe's outer surface, also known as the skin effect. The proximity effect, the current distribution within the material, increases this concentration [50]. Another effect of the produced magnetic field is magnetic hysteresis of the pipe's ferromagnetic materials, producing a significant fraction of the heat [50]. The permeability drops when reaching the material's saturation, which occurs at critical high currents [50]. Due to small radiant, contact and transformer losses, impedance heating has a higher efficiency than fired furnaces, saving energy. Other advantages are low oxidation of the workpieces, small footprint, lower risk of coke formation due to high controllability of the temperature and high turndowns [49], [51]. Impedance pipe heaters are commercially available by vendors (Armstrong [52], Chromalox [53], Heatrex [54], Indeeco [55]) and can heat process streams over 1000 °C. Systems are available for single-phase only and have a maximum of a few MW per unit. The problem with two-phase flows is the hydrodynamics' irregularity and heat transfer intensity, resulting in local peak temperatures, hence coke formation [56]. This phenomenon is only partially understood, and vendors must continue to research this before applying it on an industrial scale.

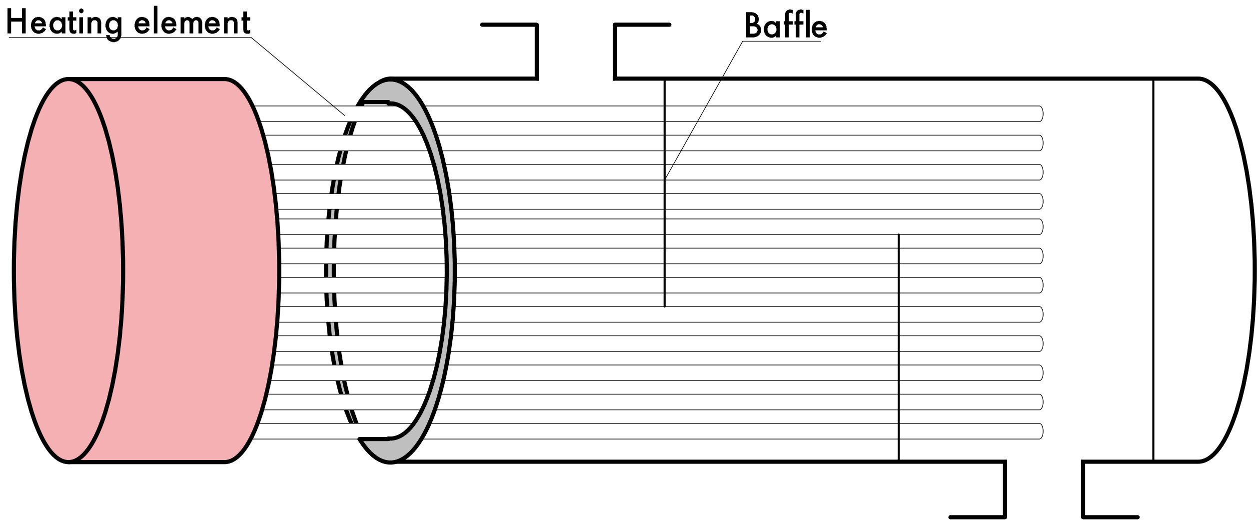

Figure 1-8: Convective resistance immersion heaters resemble a shell and tube heater, where the tubes are replaced with heating elements. Heat transferred to the process stream is generated by the Joule effect inside the tubes and mainly depends on the applied voltage. Systems are commercially available for single-phase, clean, and high-pressure operations; therefore, the technology has TRL 7.

Immersion heating

Convective resistance immersion heaters resemble a shell and tube heat exchanger, where the tubes are replaced with heating elements; see Figure 1-8. Encased inside the metal tubes are the electrical resistance heaters. The heat transferred to the process stream is generated by the Joule effect inside the tubes. For electrical heaters, the power input limits the heat flux [W/m^2]. It will depend mainly on the applied voltage, $P = \frac{V^2}{\Omega}$, where P is the potential (W), V the applied voltage (V) and Ω the element's resistance (Ω) [49]. If the heat transfer coefficient is low either because of low fluid velocities or fouling, the element's temperature will rise until the element burns out. High voltage operation (above 1000 V) decreases the cost significantly due to a reduction in step-down transformers and complex wire runs. Besides, OPEX will drastically reduce due to higher efficiencies at higher voltage as per Ohm's law [57]. Immersion heating is commercially available (Chromalox [58], Watlow [59], Wattco [60], Schniewindt [61]) for duties up to 10 MW and pressures up to 700 bar, single-phase and clean service.

Both resistance heaters have high efficiency, and vendors stated that the overall heating efficiency is approaching 99%. As these technologies are field-proven for single-phase and non-coking services, they are deployed and have TRL 7. Other significant advantages of resistance heating are the minimal maintenance requirements and precise temperature control.

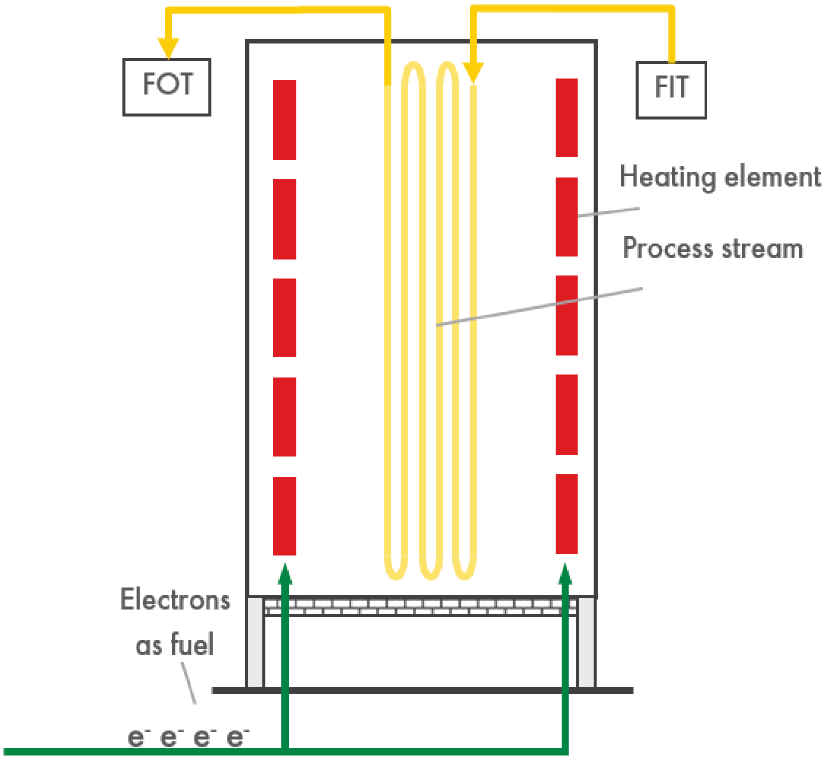

Figure 1-9: The radiative heater powered by electricity has heating elements surrounding the process stream. The Joule effect heats the elements until red-hot temperatures. Most of the heat transfer is by radiation. The concept is proven; however, no prototype is tested. Radiant heaters have TRL 2.

Radiant heating

The last electrical heating method is indirect heating using radiation. Radiant furnaces (or infrared furnaces) consist of a heating coil to contain the fluid, surrounded by electric radiant heating elements; see Figure 1-9. The Joule effect heats the heating elements in the electric furnace by using almost all conductive materials. The furnace efficiency depends on the material's resistance. The lifetime depends on the material's robustness. When heated in the air, most metals oxidise and become brittle. The material selection, when heated to red-hot temperatures, is vital for this heat generation. Recent literature discusses four suitable materials. At first Nichrome (NiCr), at high temperatures, the chromium oxidises over the material, becoming stable and protecting the element from further oxidising [62]. For Kanthal (FeCrAl), the aluminium oxidises, forming the wire's protective layer [63]. Molybdenum disilicide ($MoSi_2$) is a ceramic material with a high melting point. At high temperatures, silicon dioxide protects the material from further oxidation. However, this material is brittle at room temperature and ductile at high temperatures [64]. Lastly, Silicon Carbide (SiC) has a high hardness and corrosion resistance. SiC can reach up to 1500 °C before oxidising [65].

The heat transfer is mostly by radiation; however, this is more complicated. The heating elements radiate towards the process coil, re-radiation from the walls and gases in the furnace has a relatively small contribution. Convection due to the circulation of gases also contributes. The radiant furnaces are not commercially available, the concept is proven, but there is no prototype tested for industrial applications; therefore, radiant heaters have TRL 2.

1.3.3. Biofuel combustion

Biomass is one of the primary renewable energy sources, and the share in the energy market is growing. Most scenarios that align with the Paris Agreement strongly rely on biomass as an energy source [66], [67]. Different technologies exist for biomass conversion. The most economical and efficient is the biological breakdown of organic material in the absence of oxygen, known as Anaerobic Digestion (AD). AD is commonly used for wastewater treatment systems [68]. Micro-organism digest the feedstock to a gas containing 50 – 65 % methane [69], [70], [71]. Biogas is a mixture that consists mainly out of methane and CO_2, which has a low heating value, higher density, and it contains impurities. Table 2 provides a typical composition of biogas and natural gas. The gas is upgraded or purified by absorption, adsorption or separation methods to biomethane containing over 90% methane in the gas. Beil et al. [72], Xie et al. [73], and Sarker et al. [74] comprehensively describe these upgrading methods. Biomethane has then similar properties to natural gas, including the Wobbe index. As defined in ISO 6976, the Wobbe index indicates the ratio between the heating value and the gas's specific gravity, the ratio between the gas's molar mass and the molar mass of air, and compares gasses' interchangeability. When the Wobbe index of two gasses is the same, gasses can easily be interchanged and therefore burn inside the furnace without modification. Even if the Wobbe index is lower than that of RFG, the gas is suitable as fuel. However, it requires a higher mass flow which may be limited by existing piping.

Governmental policy influences biogas production, and ultimately, there is a limited amount of sustainable feedstock available. The European Union council states that Indirect Land Use Change (ILUC) occurs when biofuels are produced on existing agricultural land as an alternative to food and feed crops and implemented this change in their GHG calculations [75]. When considering the environmental impact of ILUC and gas or feedstock transportation over long distances, it can be controversial. Biogas has the advantage of allowing greater control over timing and generation by the feedstock supply and storage of gas.

The usage of biomethane is expected to be around 60% in 2030 for heat production or electricity generation [76]. Generally, biomethane is injected into the existing natural gas grid. Likewise, one does not know if the consumed molecules are green or grey as they are practically indistinguishable for electricity. The GHG emission impact depends on the feedstock, transportation, production process, product and calculation method. What can be concluded is that the usage of biofuels reduces emissions significantly compared to fossil fuels. Combining biomethane's combustion with post Carbon Capture Storage (CCS) could result in negative net CO_2 emissions [77].

Table 2: Properties of biogas and natural gas [76]. Biomass is one of the primary renewable energy sources available. Different technologies exist for biomass conversion. The most economical and efficient is the biological breakdown of organic material in the absence of oxygen, known as Anaerobic Digestion (AD). Micro-organism digest the feedstock to a gas containing 50 – 65 % methane [69], [70], [71]. The gas is upgraded or purified by absorption, adsorption or separation methods to biomethane containing over 90% methane in the gas. Biomethane has then similar properties to natural gas, including the Wobbe index. As defined in ISO 6976, the Wobbe index indicates the ratio between the heating value and the gas's specific gravity, the ratio between the gas's molar mass and the molar mass of air, and compares gasses' interchangeability. When the Wobbe index of two gasses is the same, gasses can easily be interchanged and therefore burn inside the furnace without modification. Biomethane has a TRL of 7.

Substance	Biogas from anaerobic fermentation	Natural Gas
Methane	50 – 85 wt%	83 – 98 wt%
Carbon dioxide	15 – 50 wt%	0 – 1.4 wt%
Nitrogen	0 – 1 wt%	0.6 – 2.7 wt%
Oxygen	0.01 – 1 wt%	-
Hydrogen	Traces	-
Hydrogen sulphide	Up to 4,000 ppmV (parts per million by volume)	-
Ammonia	Traces	-
Ethane	-	Up to 11%
Propane	-	Up to 3%
Siloxane	0 - 5 mg/m^3	-
Wobbe index	4.6 - 9.1	11.3 - 15.4

Firing biogas in a furnace was investigated by Leicher et al. [78]. Due to the lower heating values and the denser gas, a much larger mass flow of fuel is required, and a reduced amount of excess air is needed. Pure natural gas has a higher adiabatic temperature due to the different fuel-air mixing ratio. The furnace efficiency decreases resulting from the shift in temperature distribution and the changes in flow rates. In successive research, Fiehl et al. [79] studied biogas co-firing with natural gas without making any modifications. Experimental research pointed out that co-firing is technological possible on an industrial scale. The increase in CO_2 content in the furnace atmosphere does not significantly impact the radiant cell duty. CFD simulations should provide if the increase in concentration influences the flue gas losses.

Because the expected prices are high and the feedstock's availability is not guaranteed, there is a need for a system for the industry's stable and long-term growth, which includes governmental policies. It is clear that biogas contributes to the energy system's decarbonisation, but the production scale cannot cope with natural gas demand [76]. Firing biomethane will not form any problems as the gas is interchangeable with the current RFG and natural gas. In conclusion, biomethane has a TRL 7.

1.3.4. Heat pumps

A heat pump transfers energy to a thermal reservoir in the opposite direction of spontaneous heat transfer, and a schematic overview is provided in Figure 1-11. Heat is taken from a cold reservoir and released in a warmer one, making the source colder and the sink warmer. The main application is waste heat recovery. (Pre)heating process streams, hence reducing the factory's energy footprint significantly [80]. There is a difference between open and closed systems. Open systems are mechanical or thermal vapour recompression, and they compress the waste gas to high-pressure steam. For closed systems such as compression heat pumps and sorption systems, at first, the refrigerant is compressed by either an electric or gas-driven compressor. After releasing the heat, the refrigerant is expanded, shown in Figure 1-11. The absorption heat pumps use the increased boiling point temperature of a mixture and a pure component's volatility, which could have a more beneficial temperature curve for its application [80], [1].

The closed-cycle compression heat pump is commercially available and implemented on an industrial scale. The performance of a vapour-compression system is illustrated in a T-S diagram in Figure 1-10. The vapour is isentropically compressed when flowing from state one into state two. After the compressor (state 2), heat is transferred, at constant pressure, by condensing the vapour. The saturated liquid that exits the condenser (state 3) flows through an expansion valve. A source at constant pressure heats the two-phase mixture (state 4) until supersaturated vapour (state 1) [81].

Evaluating heat pumps' potential application is done by analysing the heat demand and the available sources' temperature levels using process integration methods such as a pinch analysis or EINSTEIN expert system [80]. The difference between these two methods is that the pinch analysis is a methodology for minimising energy consumption. In contrast, EINSTEIN seeks to optimise the thermal energy supply by increasing efficiency and process integration [80]. A well-integrated heat pump recovers heat below the pinch point and upgrades this above this point. The Coefficient of Performance (COP) is one of the most important thermodynamic parameters defining the ratio between the energy available over the energy input [80].

Arpagaus et al. [1] have conducted state-of-the-art market research on available heat pumps for industrial applications, reaching capacities up to 20 MW and temperatures up to 160°C. Refrigerants have a crucial role in heat pumps, having a critical temperature that defines the maximum capacity and the pressure, defining the maximum material effort. Selection criteria for refrigerants come down to thermal suitability, environmental compatibility, safety, efficiency and availability.

According to Schlosser et al. [82], there is still a technology gap for Industrial Heat Pumps (IHP) and the lack of technical expertise on performance and implementation. In their research, they review applications and economic feasibility for large-scale industrial heat pumps. For very high-temperature heat pumps, as required for refinery applications, a higher temperature lift is needed to overcome the pinch temperature at the cost of efficiency and economic feasibility.

Short payback times could be possible, depending on the COP and electricity cost [83]. Active heat recovery increases the temperature of the waste heat, which is useful for adjacent processes. So, IHP could recover energy which passive heat recovery cannot do [84]. Typical furnace temperatures are above current operating temperatures for IHP. Therefore, the implementation for IHP on a refinery would be only suitable to (pre)heat low-temperature process streams. Since industrial heat pumps are commercially available up to 160°C [1], this technology has a TRL of 7.

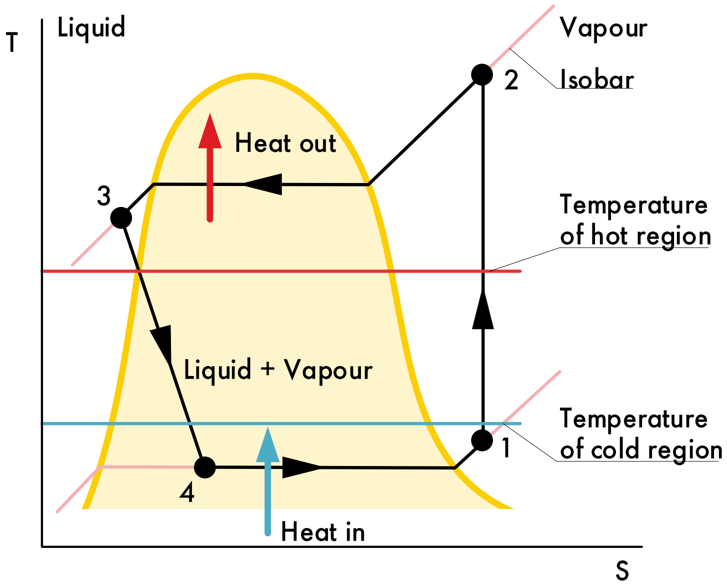

Figure 1-10: The performance of a vapour-compression system is illustrated in a T-S diagram. The vapour is isentropically compressed when flowing from state one into state two. After the compressor (state 2), heat is transferred, at constant pressure, by condensing the vapour. The saturated liquid that exits the condenser (state 3) flows through an expansion valve. A source at constant pressure heats the two-phase mixture (state 4) until supersaturated vapour (state 1) [81].

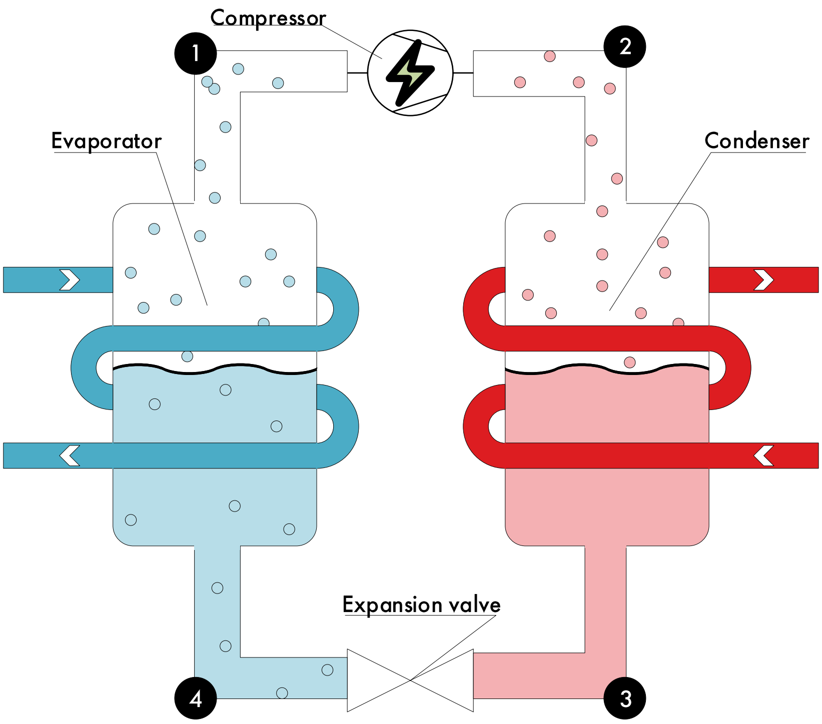

Figure 1-11: Process scheme of a closed-cycle vapour compression heat pump. Heat pumps upgrade waste heat to a higher energy level, useful for adjacent processes, reducing the total energy footprint. The numbers 1 – 4 correspond to the states as per Figure 1-10. Refinery furnaces are typically above IHP temperatures. Implementation would only be suitable to (pre)heat low-temperature process streams. Commercially available are IHP up to 160 °C with TRL 7 [1].

1.4. Problem statement

This thesis is part of three central emission reduction themes that Shell Pernis is developing.

- Furnace Heat Generation. The primary CO_2 emitters are the furnaces, where fuel burns to heat the process streams. Alternative heat generation could be the solution to reduce emissions.
- Fuel Gas Allocation. Alternative solutions for the off-gas streams produced by process units and used as fuel gas in furnaces. Relocating and re-evaluating the valuable, unused gas streams that residual of the production processes.
- Steam and Power Generation. Reduction of CO_2 by evaluating the steam and power production and demand.

The industry needs to decarbonise to achieve climate goals and minimise the effects of climate change. Alternative heat generation contributes to a lower carbon intense industry. Therefore, the following research question is raised:

How can alternative heat generation for furnaces be implemented on the Shell Netherlands Refinery to become CO_2 neutral by 2050 or sooner?

The project aims to develop an overview of the current situation and future alternatives that contribute to the roadmap for the transition of the SNR furnace portfolio, by selecting and grouping furnaces based on their plant data and process conditions and workshops with Subject Matter Experts both within as outside Shell. Several sub-questions are raised:

1. What are the possible alternatives for furnace heat generation which are suitable for the SNR furnaces?
    a. How does the alternative affect the current furnace construction, and how does this influence the process side?
    b. What are the requirements to determine if a furnace is suitable for the alternative solution?
    c. What are the site's requirements and limitations to determine if an alternative technology can be implemented?
    d. How does the alternative influence the emission of the site?
    e. What combinations of alternative forms of heat generation are available?
2. What are possible scenarios for the transition of the SNR furnace portfolio?
    a. What is the overall impact of the scenario for the site's requirements, such as infrastructure, CO_2 emissions, CAPEX and OPEX?
    b. Should mid-term solutions be considered to optimise the long-term scope?
    c. What is the CO_2 reduction cost per technology?
    d. What is the technical feasibility of the reduction plan?
    e. How does the utility availability influence the scenario?

1.5. Scope

SNR has over 55 furnaces, and these furnaces are grouped during a previous assessment, which can be seen in Table 3 [13]. The selection is based on several criteria: duty, throughput, temperatures, pressure and stream properties. Resulting in a shortlist of six furnace groups, limiting the scope of work. The SNR plot is divided into multiple geographical sections. The two sections where the furnaces are located are known as the ABC and KLM area. As maintained in this thesis, an overview of the site can be found in Figure 1-13.

Opportunity framing workshop

Hydrogen firing, electrification and heat pumps and heat networks were the three themes of the opportunity framing workshops. The workshops were necessary to kick start the project, inform all stakeholders of the latest information, and frame the technical options' opportunities. Besides, it is technically and economically challenging to convert all fired heaters of a refinery, and the feasibility of this study is essential for the upcoming energy transition. The workshop aimed to discuss the topic as an alternative option for Pernis' fired heaters with subject matter experts within Shell. Depending on the subject, heat transfer engineers, combustion engineers, technologists or electrical engineers were participating. During the workshop, selection criteria, requirements, and determining if it will be feasible to revamp the furnace were discussed based on the available information. Besides, a particular furnace case study challenged the selection criteria and feasibility. The workshops resulted in an opportunity matrix for the furnace groups, as seen in Table 4. The matrix provides information on retrofitting alternative technologies on the furnace group [13].

Roadmap

The scope of this thesis is to create a roadmap based on the approach of L. Simonse [85]. A roadmap is a visual portrayal of technology innovation elements plotted on a timeline [85]. The roadmap will include all relevant information for the applicability of an alternative solution. It will show the development of market trends and the value drivers such as utility pricing and availability based on Shell scenarios that envision the futures energy supply. The roadmap will include several scenarios based on the utility source, defining uniform details such as CO_2 savings and cost per technology to create a valuable roadmap. A reduction plan and a scope per technology should be defined to compare the technologies. The high-level reduction plan will include a cost estimate. A feasibility study concludes the size of the selected scope and the feasibility of implementation.

Timeline

Figure 1-12 provides a timeline of the project Furnace Heat Generation. First, the furnaces and alternative heat generation methods are identified. In a series of several workshops, the opportunities are framed. Multiple reduction plans resulted, and a scope per technology is defined for a cost estimate, including the Terms of References (ToR). The research concludes with a feasibility study on the reduction plan and discusses possible midterm optimisations.

Table 3: List of typical refinery fired heaters. The process duty is the duty required to heat the process stream, excluding furnace efficiency. The temperatures and phases are indicated, as well as the CO_2 emissions.

No.	Unit	Process Duty [MW]	Efficiency [%]	FIT [°C]	FOT [°C]	Inlet phase	Outlet phase	Fouling	CO_2 emission [kton/y]
1	Naphtha Platformer	150	85	400	550	Gas	Gas	No	200
2	Crude Distiller	125	80	250	350	Liquid	2 phase	Yes	175
3	High Vacuum Distillation	25	90	300	400	Liquid	2 phase	Yes	40
4	Hot Oil	15	90	250	350	Liquid	Liquid	Yes	30
5	Hydrodesulfurization	10	80	250	400	2 phase	2 phase	No	25
6	Hydrogen Conversion Unit	10	85	250	400	Liquid	2 phase	No	20

Figure 1-12: Timeline of the project Furnace Heat Generation. First, the furnaces and alternative heat generation methods are identified. In a series of several workshops, the opportunities are framed. Multiple reduction plans resulted, and a scope per technology is defined for a cost estimate, including the Terms of References (ToR). The research concludes with a feasibility study on the reduction plan and discusses possible midterm optimisations.

Table 4: Opportunity matrix for furnace groups. [1]Hydrogen firing is possible for all Pernis' fired heaters, but some modification is required. [2]Radiative heaters only have TRL 2. [3]There are no technical implications for biomethane. The main challenge is the availability of biomethane.

No.	Unit	Hydrogen	Electrification			Biogas	Heat pumps	Legend
		Hydrogen Firing	Impedance	Immersion	Radiative[2]	Biomethane[3]	IHP	
1	Naphtha Platformer	Yes, but[1]	High duty	High duty			Temperature	Possible
2	Crude Distiller	Yes, but[1]	2-phase	2-phase			Temperature	
3	High Vacuum Distillation	Yes, but[1]	2-phase	2-phase			Temperature	Possible, but there is a constraint
4	Hot Oil	Yes, but[1]	High duty	High duty			Temperature	
5	Hydrodesulfurization	Yes, but[1]	2-phase	2-phase			Temperature	Not possible, reason indicated
6	Hydrogen Conversion Unit	Yes, but[1]	2-phase	2-phase			Temperature	

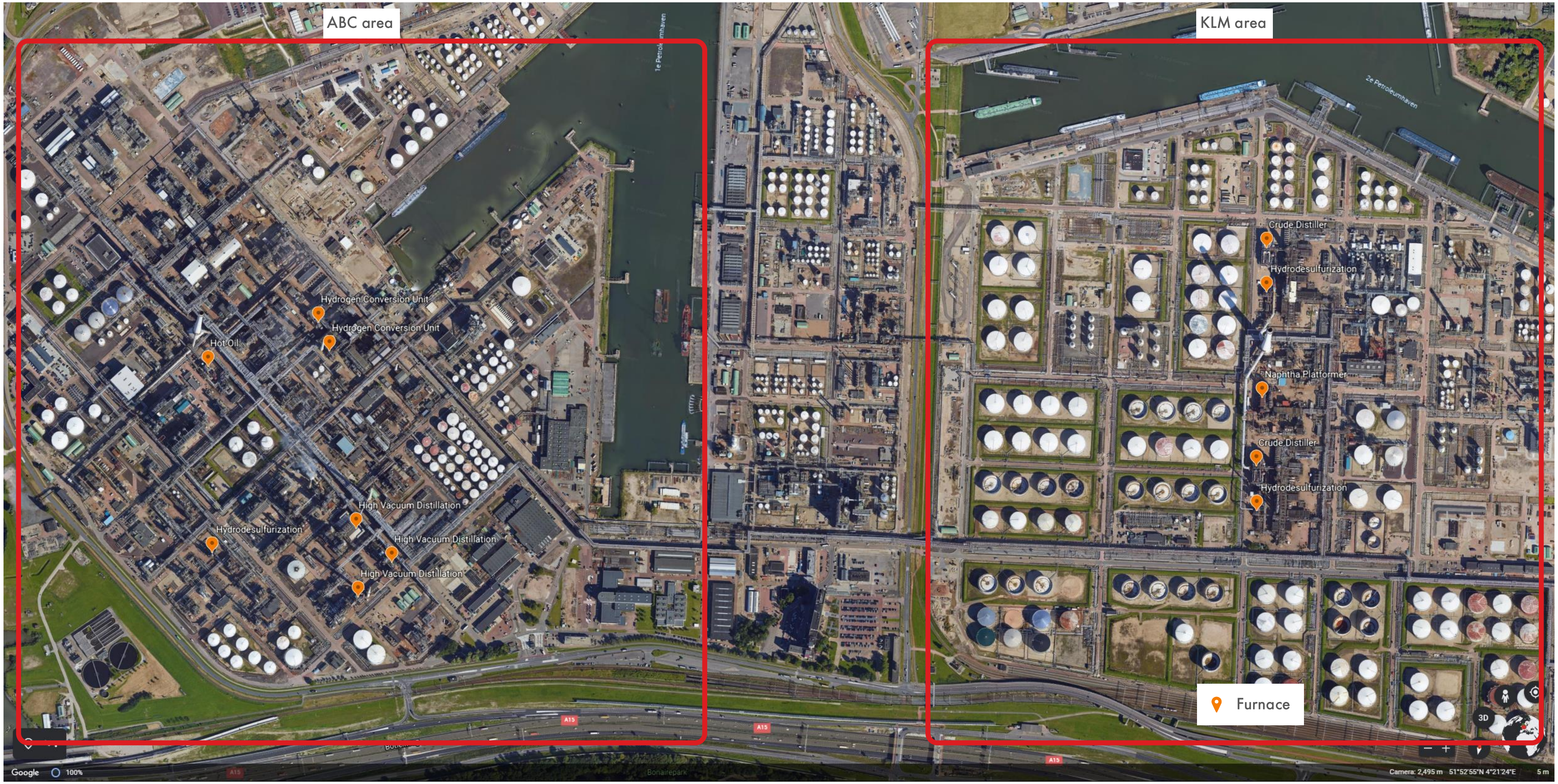

Figure 1-13: Plot plan of the Shell Netherlands Refinery. Twelve typical furnaces are modelled and considered for this thesis. The two sections where the furnaces are located are known as the ABC and KLM area.

2. METHODOLOGY

Implementing new technologies at an operational refinery can be challenging. It is theoretically possible to operate all furnaces CO_2 neutrally, but this becomes more complicated in practice. It is needed to determine each technique's work scope for revamping or replacing the furnace and infrastructure to determine a high-level CO_2 abatement price.

To ensure that all sites within the Shell Group of Companies make uniform calculations, Shell Global Solutions International B.V. set up Design and Engineering Practice (DEP) guidelines. The guidelines are followed in this thesis. DEPs are confidential, and some sections will be explained where needed.

2.1. Hydrogen firing

As stated before, all Pernis' fired heaters are forced draught. Revamping the existing furnaces for hydrogen firing is, therefore, a suitable option.

2.1.1. Scope of work

The work scope for revamping a furnace for hydrogen firing comes down to the furnace conversion and the fuel gas line modification.

Furnace conversion

The furnace conversion scope includes the following, as discussed in section 1.3.1.

- State-of-the-art ultra-low NOx high-capacity burners. These burners are designed for low NOx emissions and have a higher turndown ratio due to increased flame stability.
- Air fan replacement, the high hydrogen flammability window limits the excess oxygen level in the flue gas. Unburnt hydrogen might be a risk. Air fans need to have increased turndown capability.
- The flow rate of the flue gas will be lower. Therefore, a confirmation is needed. Depending on the stack and the draught flow rate, a reducer on top of the stack might be needed.
- Burner Management System adaption, this includes furnace and fuel gas system instrumentation. Furnace instrumentation includes:
    - Up-to-date air and fuel flow measurements.
    - Installing oxygen and CO analysers.
    - Upgrading the flame detector to be capable of handling with H_2 and RFG.
    - Installing a pressure alarm for a broader range of fuel gas.
    - Installing a pressure sensor to monitor the flue gas flow and guarantee the draught.
- Fuel gas system instrumentation:
    - Upgrading the molecular weight instrument as pure hydrogen has a lower molecular weight than the currently used instrumentation. The instrument exists out of an ultrasonic, pressure, temperature and volumetric flow sensor.

Fuel gas line modification

There are two strategies for fuel gas line modification.

- Furnace by furnace approach, choose (a cluster of) furnaces that are most suitable for hydrogen firing. A new and separate hydrogen network is needed to provide pure hydrogen.
- Increase the hydrogen content in the fuel gas network. It comes down to upgrading the entire RFG network to be suitable for high hydrogen content and replacing the weakest link until the desired content is reached. All components in the network, such as pipes and valves, must be suitable for hydrogen operation.

Besides the research question: "How should hydrogen be provided to the furnace?" another question that arises is: "How will the hydrogen be implemented?" Two strategies are possible.

- Hydrogen blending approach. Increase the mass percentage of the hydrogen content in the burner or the fuel gas network. The main advantage is the usage of the current fuel gas network and that a furnace could abate CO_2 even if there is a shortage of hydrogen. An increase in the percentage of hydrogen results in a higher CO_2 abatement. However, only a limited amount of hydrogen can be blend into the current fuel gas network.
- Fuel switching approach. Again, two strategies apply (1) slow change from RFG to H_2. It is expected that a slow change will result in fewer problems of, e.g. flame instabilities and controllability issues. (2) A fast change could be a direct switch between RFG to H_2. Maintaining flame stability will be more complex than a slow change, and control systems to monitor the air to fuel ratio stability is needed.

There are several challenges in upgrading the existing RFG network. First, the complete network, including valves, fittings, and instrumentation, must be upgraded for pure hydrogen operation. Besides RFG residuals from production processes, the produced gas is put on the network and consumed by others, such as fired heaters. Increasing the hydrogen content in the RFG network will result in a higher volume flow since the producers remain operational. At a certain point, the physical aspects of the piping will limit the hydrogen content. A significant benefit is that one could directly abate a small part of the total CO_2 footprint. However, there is a high volume% of hydrogen in the RFG, limiting operation already at some furnaces.

The hydrogen blending approach could be made right in front of the furnace or the network. The benefit is that all compositions between RFG and pure hydrogen are possible. In case that there is a hydrogen shortage, one could still reduce CO_2 emissions. However, it is seen as less feasible for burners to operate on all possible compositions due to differences in the Wobbe index and airflow. Further research is needed to confirm this.

The furnace by furnace approach is the most likely option and abates most CO_2. Just before the knock-out drum, there will be a fuel-switching approach. It is yet unclear if this will be a slow or fast change. During a turnaround of the hydrogen production plant or a hydrogen trip, the refinery could always fall back on the RFG system, increasing the furnace's reliability.

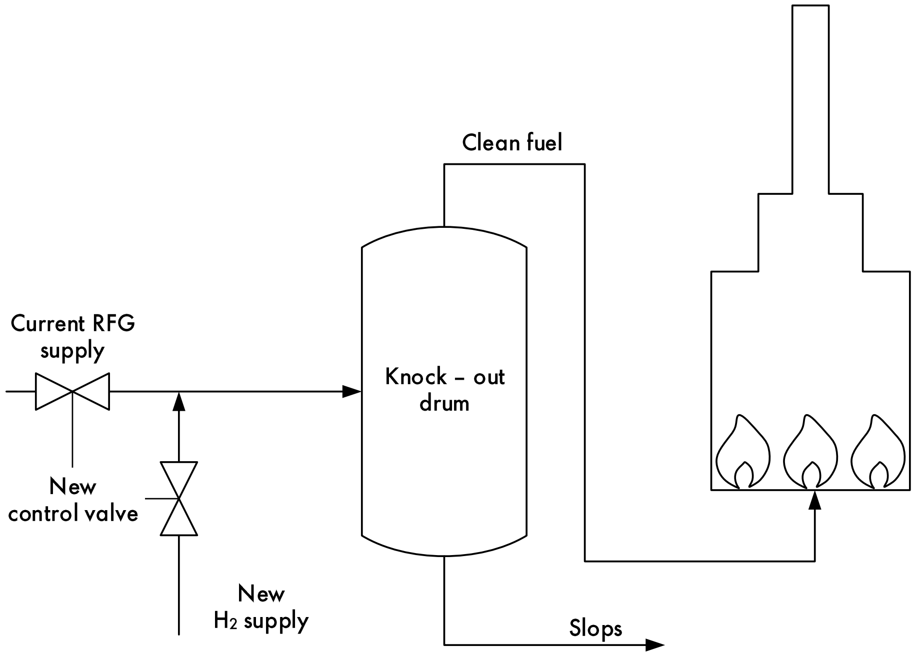

Figure 2-1: High-level schematic overview of the current fuel gas supply and the possible hydrogen connection, known as a tie-in. Modification of the fuel gas line-up between the skid and burner is required for hydrogen operation. Both RFG and hydrogen supply lines need a control valve for the transition between RFG and hydrogen fuel. The slops are filtered out at the knock-out drum just before the clean gas enters the burners.

Replacement or modification of the fuel gas line-up between the skid and burner is therefore required. There must be a hydrogen connection, known as a tie-in, in the network just before the knock-out drum, which filters out the unwanted slops. Besides adaption to the fuel gas control skid, a control valve is also needed on both lines. A high-level schematic representation of the tie-in is provided in Figure 2-1.

Some furnaces already have Ultra-Low NOx burners suitable for hydrogen firing. The scope for those furnaces is limited to the furnace instrumentation and the fuel gas line modification.

2.1.2. Infrastructure

As discussed shortly in the previous section, a furnace by furnace approach is the best option, influencing the site-wide infrastructure. This approach demands a new hydrogen network.

Import and export station to a blue hydrogen facility

First, there must be enough hydrogen available. Currently, there is no blue or green hydrogen facility at SNR or in the Port of Rotterdam. During this thesis, it is assumed that the hydrogen is provided from a supplier outside the refinery; this is feasible as stated in section 1.1.4, where H-vision is anticipating green hydrogen arrival. Blue hydrogen is produced out of RFG during a reforming process. The assumption is made that the import station of hydrogen and the export station of RFG are at the same location. Hydrogen will be provided under high pressure, and the RFG should be exported under high pressure to a blue hydrogen production plant.

Hydrogen network

Hydrogen is a critical component of a refinery and is used for hydrotreating, hydrocracking or hydro desulphurisation. Therefore, there is already an existing feedstock hydrogen network. Feedstock hydrogen is almost pure hydrogen gained after an extra purification step. This last step is cost-intensive and not a necessity for hydrogen firing in furnaces. It is assumed that blue hydrogen will be 55wt% or 95v% pure, having a lower purity than the feedstock hydrogen. Therefore, a new hydrogen network across the plant is needed. An example of a possible network is provided in Figure 2-2. The network exists out of a 'backbone' and branches from the backbone towards the furnaces. There is a distinction made between the two lines to determine the pipe sizing. The backbone has a higher volumetric flow rate than the branches. The line sizing is discussed later.

RFG network

The assumption is made that the blue hydrogen will be reformed out of RFG. The main benefit is that all RFG can be exported to the blue hydrogen factory. Firing hydrogen will impact the sites fuel gas balance, and reallocation of this gas is a necessity. A new network is needed to export the RFG, including tie-ins into the existing RFG network.

Composition of the gasses

The gas compositions are of vital importance to design the new network. In practice, the composition of RFG changes throughout the refinery and time. During this thesis project, the simplified possible composition of blue hydrogen [9], [86], [87] and RFG [12], [13] as per Table 5 are used as an example. The properties of these gas streams are calculated using UniSim Design, and the results can be found in Table 6. The assumption is made that RFG and hydrogen demands are interchangeable at the hydrogen factory. The total firing duty of 650 MW, as per the example given in Figure 2-2, includes the furnace efficiency and will be exported or imported.

Compressor

The formation of blue hydrogen is under high pressure. The assumption is that hydrogen will enter the site at high pressure. The RFG network is under low pressure, and compressors are needed to export the gas.

Considering a Rotating Equipment Engineer's expertise, a compressor is chosen by the pressure and mass flow. Piston compressors have a low mass flow (2.000 to 3.000 m^3/h) but high-pressure ratios, while centrifugal compressors have a high mass flow (10.000 – 100.000 m^3/h) but a smaller pressure ratio. Rotary-screw compressors are used as a middle mode between the piston and centrifugal compressors.

The compressor is simulated using UniSim Design, providing the gas properties and defining the piping limits. The results can be found in Table 7. The pressure ratio is low, while the mass flow is high. Therefore, a centrifugal compressor should be considered. Piping limitations will define whether an aftercooler is needed.

Table 5: Possible composition of blue hydrogen [9], [86], [87] and RFG [12], [13]. The composition of RFG changes in practice throughout the refinery and time. During this thesis project, the following simplified compositions are used as an example.

	Blue H_2		RFG	
Component	**Weight %**	**Mole %**	**Weight %**	**Mole %**
CH_4	10	2	45	31
C_2H_6	0	0	10	4
C_3H_8	0	0	15	4
N_2	15	2	15	6
O_2	20	2	2	1
CO_2	0	0	3	1
H_2	55	94	10	54

Table 6: Properties of the gas compositions as per Table 5 at standard conditions calculated by UniSim Design. [15°C, 1 atm]

Properties	Firing duty	LHV	Flow rate	Molar weight	Density
	[MW]	[MJ/kg]	[kg/s]	[g/mol]	[kg/m3]
H2	650	71,01	9,16	3,44	0,15
RFG	650	46,22	14,06	10,98	0,46

Table 7: UniSim Design compressor simulation input and results. A compressor is needed to export the low-pressure RFG to a blue hydrogen factory. The compressor is simulated using UniSim Design, providing the duty, gas properties and defining the piping limits.

	Compressor input							Result	
Type	**Adiabatic efficiency**	**Inlet Pressure**	**Inlet Temperature**	**Mass flow**	**Volume flow**	**Outlet Pressure**	**Pressure ratio**	**Duty**	**Outlet Temperature**
[–]	[%]	[barg]	[°C]	[kg/h]	[m^3/h]	[barg]	[–]	[MW]	[°C]
Centrifugal	75	2	15	50627	55150	10	5	8,1	192

Pipelines

The pipelining scope is limited to some basic assumptions. As seen in Figure 2-2, the pipe length is determined by using Google Earth.

Line sizing is determined by assuming that the flow in the pipe is compressible and completely isothermal. For ease of calculation and following Crane Flow of Fluids [88], the following assumptions are also made:

- Isothermal and steady flow;
- No mechanical work is done by or on the system;
- Perfect gas law obeys, the velocity is the average cross-section velocity;
- Constant friction factor;
- Straight pipeline and horizontal between the start and end.

Equation 1 verifies that the pressure drop at the corresponding pipe diameter is within its limits. The formula assumes a straight and horizontal pipeline. To include pressure drop other than a straight pipe, all elbows and side flow tie-ins are included with their equivalent length as per the DEP and following Crane [88]. Their equivalent length adds to the pipe's length. Table 8 provides information on the equivalent length (L_e) of fittings, where D is the nominal pipe diameter.

$$w^2 = \left[\frac{A^2}{\bar{V}_1\left(\frac{fL}{D} + 2\,log_e\frac{P_1'}{P_2'}\right)}\right]\left[\frac{(P_1')^2 - (P_2')^2}{P_1'}\right] \tag{1}$$

$$\begin{aligned}
w &= \text{Rate of flow } \left[{}^{\text{kg}}/_{\text{s}}\right] \\
\bar{V}_1 &= \text{Specific volume of fluid } \left[{}^{\text{m}^3}/_{\text{kg}}\right] \\
A &= \text{Cross sectional area of the pipe } [\text{m}^2] \\
f &= \text{Friction factor } [-] \\
L &= \text{Length of pipe } [\text{m}] \\
D &= \text{Internal diameter of pipe } [\text{m}] \\
{P_1}' &= \text{Absolute inlet pressure } [\text{Pa}] \\
{P_2}' &= \text{Absolute outlet pressure } [\text{Pa}]
\end{aligned}$$

The friction factor is defined as per the Weymouth friction factor; see Equation 2.

$$f = \frac{0{,}094}{(1000\ D)^{1/3}} \tag{2}$$

$$\begin{aligned}
f &= \text{Friction factor } [-] \\
D &= \text{Internal diameter of pipe } [\text{m}]
\end{aligned}$$

It is more complex in practice, but as stated before, these assumptions fall within the boundaries set for this high-level study.

Table 8: List of equivalent length of fittings, where D is the nominal pipe diameter in meter. To include pressure drop other than a straight pipe, all elbows and side flow tie-ins are added to the pipe's length with their equivalent length as per the Design and Engineering Practice (DEP) and following Crane [88].

Type of fitting	Equivalent length L_e [m]
Tee	65 D
45° Elbow	16 D
90° Elbow	20 D

The exit velocity is determined by using the compressibility factor and can be calculated by using Equation 3. The DEP indicates the maximum allowable velocity of gases and other fluids. At the end of the pipe, the pressure drop is the largest and the gas velocity maximum. By iteration of different pipe diameters, it is confirmed that a pipe size is suitable. The branches are designed for their maximum length and corresponding duties rounded up. Details are provided in Table 9.

$$v_{\text{exit}} = \frac{w\ Z\ R\ T}{\Delta P\ M\ A} \tag{3}$$

$$\begin{aligned}
v_{\text{exit}} &= \text{Exit velocity } [\mathrm{m}/\mathrm{s}] \\
w &= \text{Rate of flow } \left[\mathrm{kg}/\mathrm{s}\right] \\
Z &= \text{compressibility factor } [-] \\
R &= \text{Gas constant; } 8{,}314\ \left[\mathrm{J}/\mathrm{mol\ K}\right] \\
T &= \text{Temperature } [\mathrm{K}] \\
\Delta P &= \text{Pressure drop } [\mathrm{Pa}] \\
M &= \text{Molar weight } \left[\mathrm{kg}/\mathrm{mol}\right] \\
A &= \text{Cross sectional area of the pipe } [\mathrm{m}^2]
\end{aligned}$$

Table 9: Details and calculation results for the pipelines indicated in Figure 2-2. Using Equation 1, Equation 2, Equation 3, it is confirmed that the pipe diameter and corresponding pressure drop and exit velocity are within limits. By iteration of different pipe diameters, it is confirmed that a pipe size is suitable. All suitable different pipe sizes are provided in the table.

Line		**Blue H_2**	**Blue H_2**	**Blue H_2**	**Blue H_2**	**Return RFG**	**Return RFG**	**Return RFG**
Location		**Import station**	**Backbone**	**Branch ABC**	**Branch KLM**	**Export station**	**Backbone**	**Branch ABC**
Firing duty	[MW]	650	500	150	250	650	500	150
Flow rate	[kg/h]	32.959	25.349	7.605	12.674	50.627	38.944	11.683
Flow rate	[kg/s]	9,16	7,04	2,11	3,52	14,06	10,82	3,25
Upstream pressure	[bara]	40,00	40,00	40,00	40,00	10,00	10,00	10,00
Mole weight	[kg/kmol]	3,44	3,44	3,44	3,44	10,98	10,98	10,98
Compressibility	[–]	1,01	1,01	1,01	1,01	0,99	0,99	0,99
Cp/Cv	[–]	1,43	1,43	1,43	1,43	1,35	1,35	1,35
Temperature	[°C]	15,00	15,00	15,00	15,00	15,00	15,00	15,00
Density	[kg/m^3]	5,67	5,67	5,67	5,67	4,61	4,61	4,61
Pipe internal diameter	[inch]	8	8	6	6	12	12	8
Pipe internal diameter	[mm]	203	203	152	152	305	305	203
Pipe straight length	[m]	50	2.700	1.000	280	50	2.700	1.000
Elbows	[–]	1	5	3	3	1	5	5
Red. bore ball valves	[–]	0	1	0	0	0	1	0
Tees (side flow)	[–]	0	4	5	1	0	1	0
Total equivalent length	[m]	54	2.776	1.059	299	56	2.755	1.020
Velocity upstream	[m/s]	49,8	38,3	20,4	34,0	41,8	32,2	21,7
Friction factor	[–]	0,016	0,016	0,018	0,018	0,014	0,014	0,016
Pressure drop	[bar]	0,30	10,50	1,48	1,15	0,11	3,74	0,99
Exit velocity	[m/s]	50,2	51,9	21,2	35,0	42,3	51,4	24,1

Piping class

The piping class is needed for cost estimation. Besides the pipe sizing, material selection is critical. Suitable materials are Carbon Steels, Stainless Steels or Low alloy Steels. Carbon steel is chosen as it is the most cost-efficient and fulfils all the fuel gas requirements for the hydrogen network. According to the ASME B16.5-2013 standard [89], the pressure-temperature ratings are as per Table 10. In Table 11, the maximum operating pressure and temperature are stated, and the pipe's material and class are indicated. The exit stream of the compressor is at 10 bar at 192 °C. The piping class of 150 psi indicates at 200 °C a pressure of 13.8 bar. Therefore, there is no aftercooler needed if piping class 150 psi is chosen.

Table 10: List of piping class temperature - pressure rating as per ASME B16.5-2013 rating [89]. The exit stream of the compressor is at 10 bar, 192 °C without an aftercooler. The piping class of 150 psi indicates at 200 °C a pressure of 13,8 bar. Therefore, a piping class of 150 psi is a suitable option.

	Class [bar]					
Temp., °C	**150 psi**	**300 psi**	**600 psi**	**900 psi**	**1500 psi**	**2500 psi**
-29 to 38	19,6	51,1	102,1	153,2	255,3	425,5
50	19,2	50,1	100,2	150,4	250,6	417,7
100	17,7	46,6	93,2	139,8	233,0	388,3
150	15,8	45,1	90,2	135,2	225,4	375,6
200	13,8	43,8	87,6	131,4	219,0	365,0

Table 11: Piping material and class of pipelines indicated in Figure 2-2, needed for an infrastructure cost estimation. Suitable materials are Carbon Steels, Stainless Steels or Low alloy Steels. Carbon steel is chosen as it is the most cost-efficient and fulfils all the requirements for the hydrogen network.

Line name		**8″ H_2**	**6″ H_2**	**12″ RFG**	**8″ RFG**
Maximum temperature	[°C]	35	35	192	192
Maximum pressure	[bar]	45	45	10	10
Material	[–]	Carbon steel	Carbon steel	Carbon steel	Carbon steel
Class	[psi]	300	300	150	150

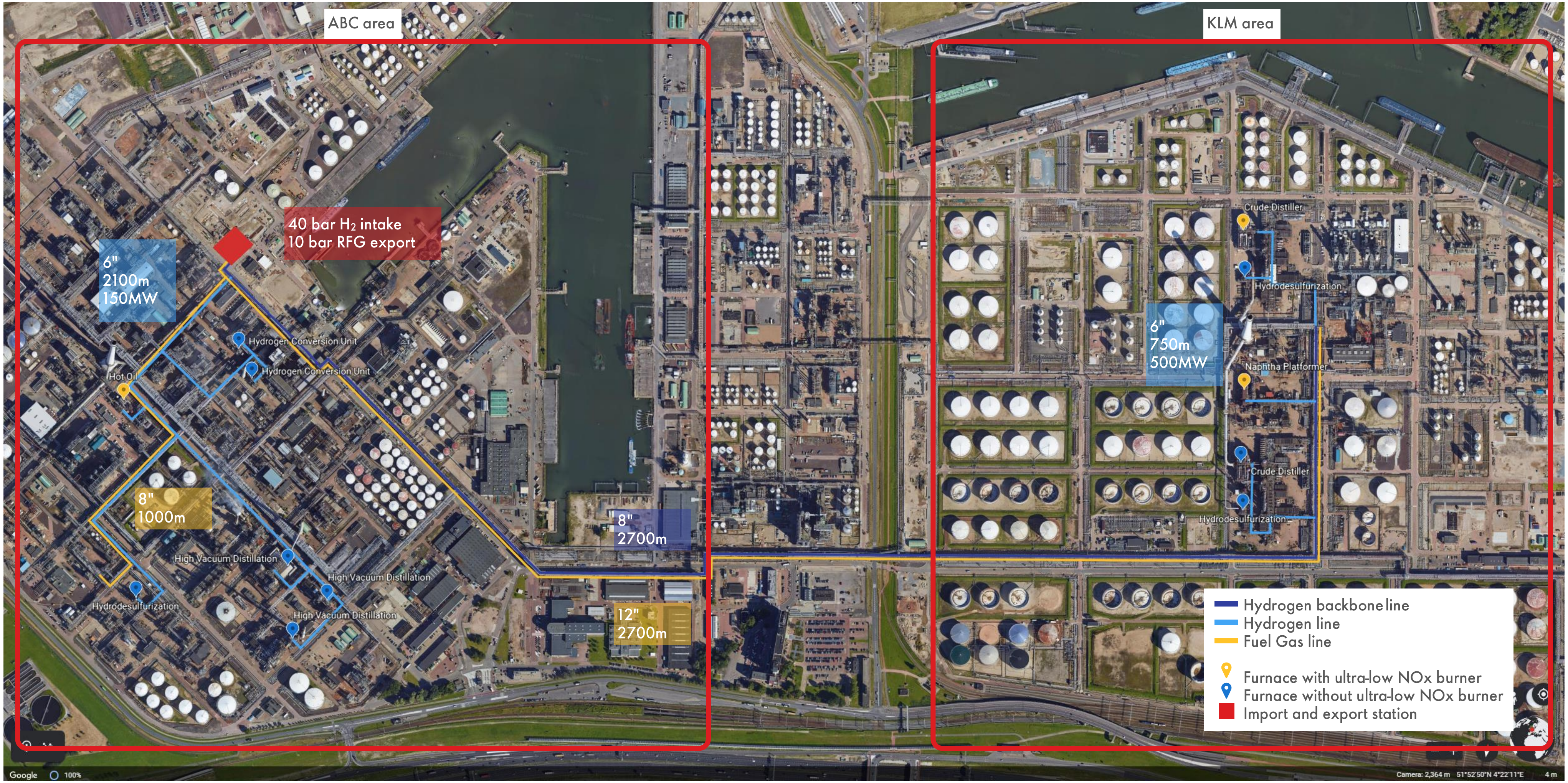

Figure 2-2: Shell Pernis modelled furnaces and possible hydrogen network. The indicated rounded duties are the firing duties, including furnace efficiency. The fuel gas is collected at a mixing station and is compressed at the export station.

2.2. Electrical heaters

There are several options to electrify a fired heater, depending mainly on the process stream's properties. Currently, the only commercially available options, impedance and immersion heaters, are single-phase and non-fouling services. It is assumed that the industry is developing radiant heaters for multi-phase and fouling services and that these heaters will be available in the coming decade. Microwave and induction heaters with TRL 1 have severe scale-up problems, and no pilot projects are known yet. It is not feasible that these technologies will be de-risked, tested and deployed in the coming decade. For the rest of this thesis, it is assumed to have three options for electrification: impedance, immersion and radiant heating.

2.2.1. Scope of work

Revamping an existing furnace into an electrical heater is not seen feasible. New technologies are implemented in an operational refinery. Revamping a furnace can only be done when a factory's operation is stopped or when it would have a spare furnace. The downtime of a unit is cost-intensive and should always be limited to the minimum. It is therefore not seen feasible to revamp an existing fired heater within the turnaround time window.

Moreover, the design of the electrical heater is entirely different from that of a fired heater. It will be more efficient to build a new unit with a longer lifetime than revamping the old asset. Besides, it might be desirable to fall back on the fired heater if there would be a power shortage.

A furnace-by-furnace approach is needed to identify the benefits and constraints of electrification. Some furnaces are currently forming a production bottleneck as they are operating above their design capacity due to evolutions over time. Besides, some furnaces could have a yield benefit due to the higher heat transfer controllability. CFD simulations must be done to confirm the possible yield benefit.

The work scope for the electrification of a fired heater comes down to placing a new asset and connecting it to the current infrastructure.

Plot space availability

As stated before, electrical heaters should be built next to the existing fired heater. A critical showstopper is the plot space availability. The refinery plot is entirely occupied, so there is not always space for a new heater. As seen in the example of Figure 2-4, not all fired heaters are connected to the electrical network due to the plot space constraints.

2.2.2. Infrastructure

The major challenge for electrification is the infrastructure and the availability of renewable electricity. Assumed is that TenneT, responsible for power transmission services as the grid operator, has sufficient capacity to supply the refinery with the high electricity demand. TenneT should upgrade its current network to achieve this. The connection to TenneT's services can be found in Figure 2-4. The infrastructure consists out of an import station, substations and connections to the electrical heaters. These transformer stations are needed to keep the voltage as high as possible to minimise electrical losses. A representation can be found in Figure 2-3

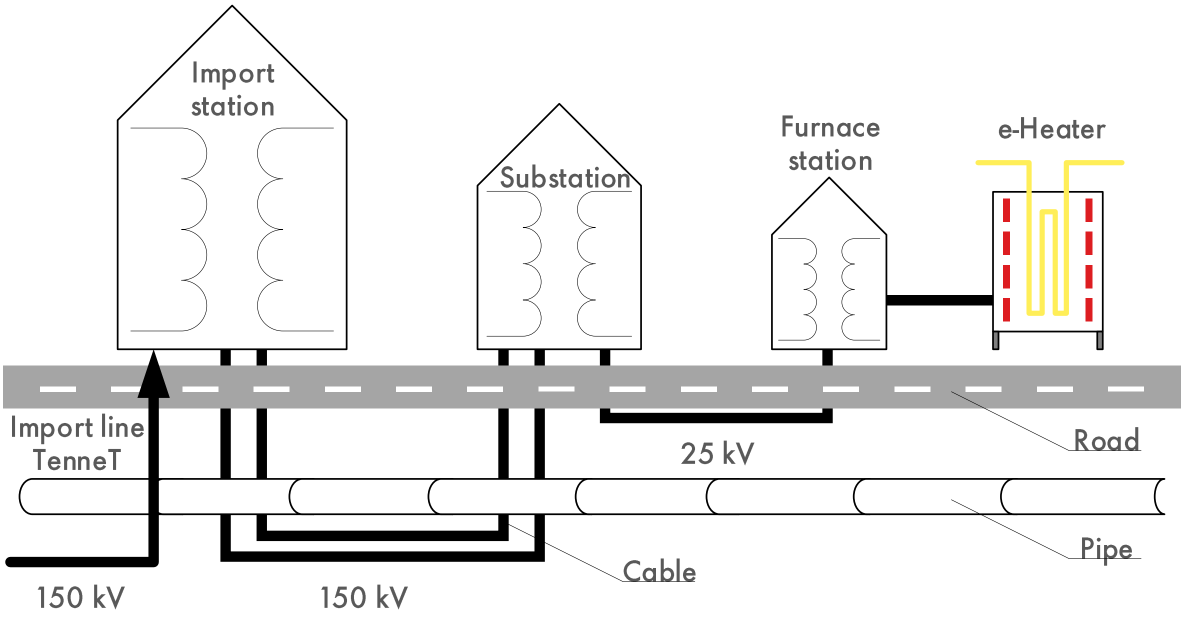

Figure 2-3: Schematic representation of the onsite electrical network. The major challenge for electrification is the infrastructure and the availability of renewable electricity. Assumed is that TenneT, responsible for power transmission services as the grid operator, has sufficient capacity to supply the refinery with the high electricity demand. TenneT should upgrade its current network to achieve this. The infrastructure consists out of an import station, substations and connections to the electrical heaters. These transformer stations are needed to keep the voltage as high as possible to minimise electrical losses. The voltage of the furnace depends on the technology and the desired heat transfer. High-voltage lines (150 kV) are drilled underground, below current piping, and lower-voltage lines (25 kV) are placed under the road.

The import station

The import station is the place where TenneT's services stop and internal infrastructure is needed. Electricity is provided under high voltage by TenneT, 150kV. From this place, underground cables will supply substations. The number of underground cables is doubled to ensure high reliability.

Substations

The substations are the connection between the import station and the station next to the furnace. Here the voltage is reduced to 25 kV and further distributed over several furnaces. Unlike the cables to the substation connected by drilling tunnels to minimise the distance, cables are placed under the road.

Furnace stations

Close to the electrical heater is the last transformer. Here the high voltage is reduced to the desired voltage for operation. The voltage differs per electrical heater.

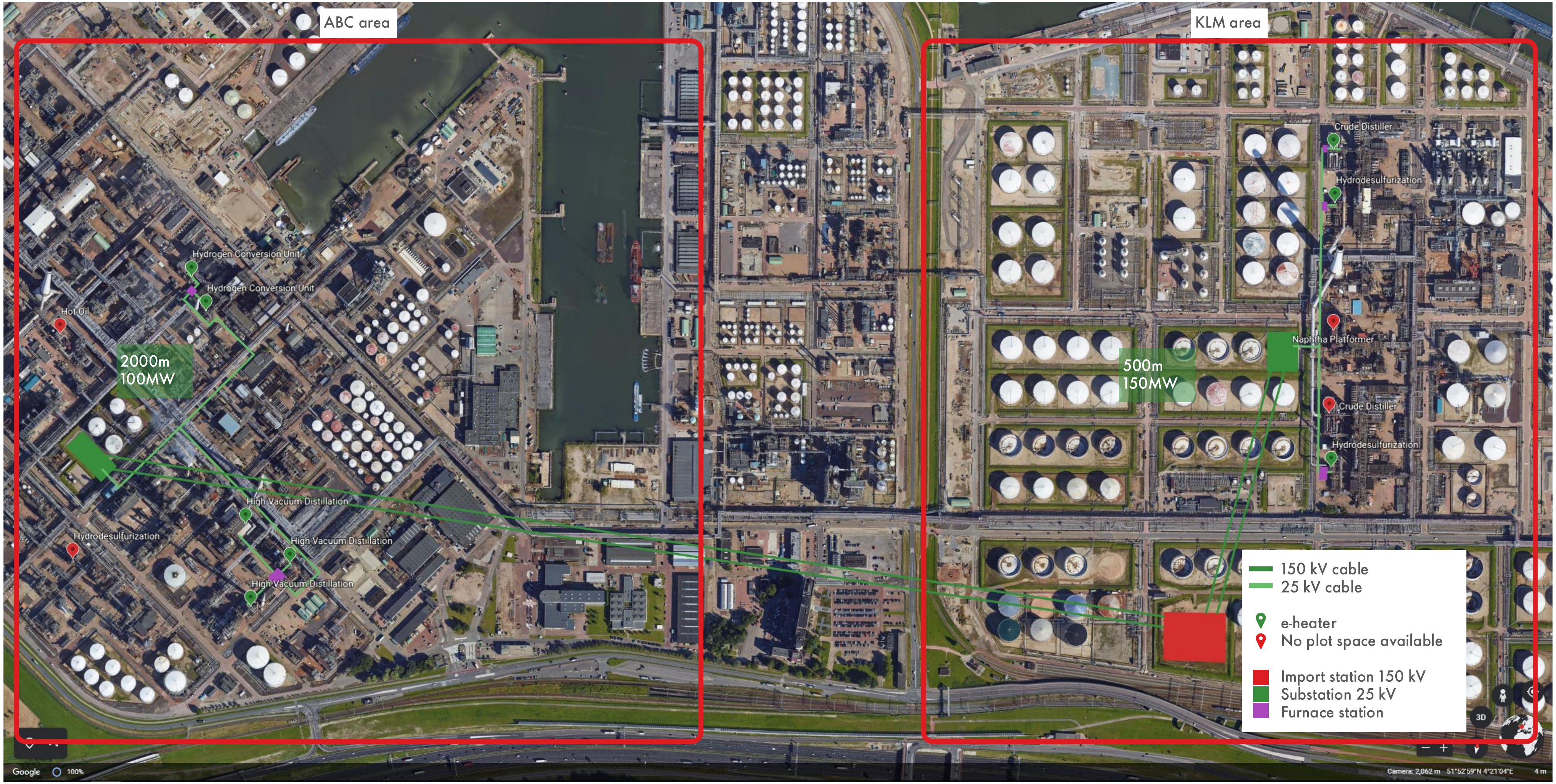

Figure 2-4: Shell Pernis modelled furnaces with possible e-heaters and infrastructure. The indicated duties are electrical duties, including furnace efficiency. The electrical heaters are assumed to have an efficiency of over 98%.

2.3. Biofuel combustion

The purified or upgraded biogas to biomethane can be used as fuel for combustion. Implementing biomethane to the current network should only impact the emissions. As for green energy, biomethane combustion seems to be an administrative solution where trading in certificates will be dominating the market.

2.3.1. Scope of work

Biomethane, which contains over 90% methane, is interchangeable with natural gas, as stated in section 1.3.3. There is no extra scope of work for biomethane combustion in the existing fired heaters.

2.3.2. Infrastructure

There is no significant scope of work for the infrastructure. Of course, there must be a tie in the refinery fuel gas network to import the biomethane. The tie can be the current natural gas supply when the biomethane is injected into the national natural gas grid.

2.4. Heat pumps

Heat pumps are used in refineries. They can be used to reduce the furnace load, not to replace the furnace. A heat pump could replace a sub-160°C furnace, and it is clear, considering Table 3, that the potential for replacing fired heaters with heat pumps is low. Other possibilities are to place a heat pump in front of a furnace or within a pre-heat train. The source and sink can be decoupled when using the existing steam network. The energy flows within Pernis should be mapped to identify the opportunities of heat pumps. A site-wide pinch analysis will provide the ideal utility transfer. Because the analysis will exceed this thesis project's goal and that fired heaters' potential is low, it has been decided not to go into heat pumps and further possibilities.

2.5. Carbon Capture and Storage

Carbon Capture and Storage (CCS) is already applied in the industry on a large scale, and it will not be an option to replace an existing furnace. There where the CO_2 flows into the atmosphere, the furnace stack, CCS can be implemented. As it is not a source for alternative furnace heat generation, no further research is done on CCS in this thesis. However, it is included in the roadmap to compare with alternative technologies. The technique used to capture the CO_2 is not specified, and it is assumed to have a capture rate of 90wt%.

3. RESULTS

The thesis's scope is to create a roadmap based on the approach of L. Simonse [85]. As stated before, a roadmap is a visual portrayal of technology innovation elements plotted on a timeline. The roadmap aims to create a clear overview with relevant information of the technologies, developments, value drivers, and credible scenarios. Decision-makers can use the roadmap to develop a long-term strategy for the energy transition that is ahead. Figure 3-11 represents the roadmap for the transition of Pernis' furnace portfolio. Note that the roadmap is based on the scenarios presented earlier in this thesis.

3.1. Technological options

The first section of the roadmap provides an overview of the technical options discussed in Chapter 2 Methodology. Key indicators give a clear picture per technology so that a trade-off can easily be made for a specific type of furnace. The applicability indicates where technology can be used. As stated before, not all process streams can be heated by alternative technologies. The constraints indicate the limitations of the concept.

The economics is divided into three parts: CAPEX, OPEX and CO_2 abatement price. The prices are normalised against the current operation with RFG. Therefore, the OPEX of regular operation is set to one and is scaled to the other technologies.

CAPEX

The Capital Expenditures is calculated as per the scope of work in Chapter 2 Methodology. The CAPEX for hydrogen firing consists of three parts, infrastructure, fuel gas line modification and furnace conversion. The infrastructure is installed at once, and a cost estimator provided a high-level total cost of the new hydrogen network. The fuel gas line modification is a standard cost, regardless of the furnace's size, so equal for all furnaces. The furnace conversion is only for furnaces without ultra-low NOx burners. As stated in Table 12, the total average cost for hydrogen firing as per the scenario of Figure 2-2 is 11.000 per MW.

CAPEX calculations for other technologies are based on the same principle as hydrogen firing. However, the CAPEX of electrical heaters is also based on vendor quotations. The infrastructure cost is added to the initial investment cost as for hydrogen firing. Biomethane does not need any furnace or infrastructure modification, assuming that biomethane is injected into the national natural gas grid. The CCS CAPEX is based on internal Shell references. As for hydrogen and electrification, the infrastructure cost is added to the initial investment.

OPEX

The Operating Expenditures are based on Shell internal Project Steering Values. OPEX is not expected to be constant but to increase gradually due to inflation, supply and demand. OPEX is averaged over 2030 until 2050. For calculations such as the CO_2 abatement price, fluctuating OPEX is considered.

Table 12: CAPEX calculation for hydrogen firing. All costs are normalised against the OPEX of regular RFG operation. The CAPEX for hydrogen firing consists of three parts, infrastructure, fuel gas line modification and furnace conversion. The infrastructure is installed at once, and a cost estimator provided a high-level total cost of the new hydrogen network. The fuel gas line modification is a standard cost, regardless of the furnace's size, so equal for all furnaces. The furnace conversion is only for furnaces without ultra-low NOx burners. CAPEX calculations for other technologies are based on the same principle.

Key numbers	Duty	650	MW
	Furnaces with ultra-low NOx burner	3	
	Furnaces without ultra-low NOx burner	9	
Infrastructure	Total cost	5.000	X 1.000
	Cost per MW firing duty	7	X 1.000/MW
Fuel gas line modification	Cost per furnace	50	X 1.000/furnace
	Total cost all furnaces	600	X 1.000
	Cost per MW firing duty	1	X 1.000/MW
Furnace conversion		3	X 1.000/MW
Total without furnace conversion		8	X 1.000/MW
Total with furnace conversion		12	X 1.000/MW
Weighted average total		11	X 1.000/MW

CO_2 abatement price

The CO_2 abatement price is the cost per tonne of abated CO_2, which is CO_2 not emitted to the atmosphere. Accordingly, it is the benefit of using the alternative heat generation method and the marginal value of preventing a tonne of CO_2 emissions. The CO_2 abatement price indicated on the roadmap is calculated as per the simplified model in Figure 3-1, showing the example of the hydrogen scenario.

The CO_2 abatement price, as per Equation 4, is calculated per year and therefore fluctuates over time. The average CO_2 abatement price from 2030 to 2050 is shown on the roadmap. The CO_2 abatement price is calculated over a scenario, as in section 3.4. According to the model, CCS has the lowest abatement cost, followed by hydrogen firing. Electrical heaters and biofuel combustion are comparable.

$$\mathrm{CO_2\ abatement\ price} = \frac{\mathrm{Annual\ cash\ flow}}{\mathrm{Annual\ abated\ CO_2}} \tag{4}$$

The total cash flow is the difference between the revenue and the expenditures. The revenue comes from the possible sale of RFG and the savings on the costs of CO_2. The expenditures are the CAPEX, OPEX and Tax. For simplification, tax and revenue expenditures, such as maintenance cost, are not considered.

			NPV	Sum		2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Furnace		MW				-	156	333	333	333	333	333	333	489	489	489	489	506	533	589	601	626	650	650	650	650
CO2	Price	MOD/ton			**PSV**	6,43	6,48	6,53	6,58	6,63	6,68	6,73	6,78	6,83	6,88	6,93	6,98	7,03	7,08	7,13	7,17	7,22	7,27	7,32	7,37	7,42
	Emitted	kton/y	10.587	10.587		815	651	463	463	463	463	463	463	298	298	298	298	270	232	157	134	91	49	49	49	49
	Total abated	kton/y	10.603	10.603		-	165	353	353	353	353	353	353	517	517	517	517	545	583	658	682	724	766	766	766	766
Revenue	Fuel gas	MOD/MWh			**PSV**	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00	1,00
	Fuel Gas Revenue	mln MOD				-	1,37	2,92	2,92	2,92	2,92	2,92	2,92	4,29	4,29	4,29	4,29	4,43	4,68	5,16	5,27	5,49	5,70	5,70	5,70	5,70
	CO2 revenue	mln MOD				-	1,07	2,30	2,32	2,34	2,35	2,37	2,39	3,53	3,56	3,58	3,61	3,83	4,12	4,69	4,89	5,23	5,57	5,61	5,65	5,69
	Total Revenue	**mln MOD**	27,54	158,53		-	2,44	5,22	5,24	5,25	5,27	5,29	5,31	7,82	7,84	7,87	7,89	8,26	8,80	9,85	10,16	10,71	11,27	11,31	11,35	11,38
CAPEX	**Total Capex**	**mln MOD**	3,66	6,98		4,77	0,53	0,60	-	-	-	-	-	0,53	-	-	-	0,06	0,09	0,19	0,04	0,08	0,08	-	-	-
OPEX	Blue hydrogen	MOD/MWh			**PSV**	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50	3,50
	Total Opex	**mln MOD**	67,52	293,64		-	4,80	10,22	10,22	10,22	10,22	10,22	10,22	15,01	15,01	15,01	15,01	15,52	16,38	18,08	18,47	19,21	19,96	19,96	19,96	19,96
Tax	**Total Tax**	**mln MOD**	-	-																						
Cashflow	**Total Cashflow**	**mln MOD**	(27,21)	(142,08)		-4,77	-2,89	-5,60	-4,98	-4,96	-4,94	-4,93	-4,91	-7,73	-7,17	-7,15	-7,12	-7,32	-7,67	-8,42	-8,35	-8,58	-8,77	-8,65	-8,61	-8,57
			NPV	*Average*																						
	CO2 abatement price	**MOD/ton CO2**	-2,57	-13,40		-	-17,58	-15,88	-14,13	-14,08	-14,03	-13,98	-13,93	-14,95	-13,87	-13,82	-13,77	-13,42	-13,16	-12,80	-12,25	-11,85	-11,45	-11,29	-11,24	-11,19
			VIR	(7,44)																						

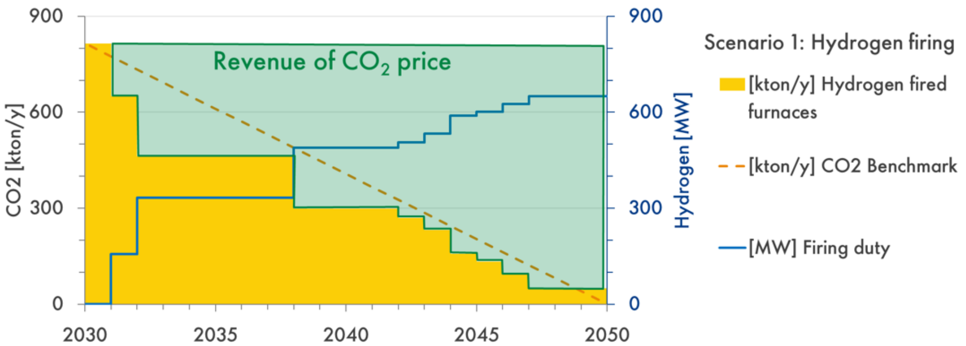

Figure 3-1: Simplified CO_2 abatement price calculation model for scenario 1, hydrogen firing. The CO_2 abatement price is calculated per year and therefore fluctuates over time. The average CO_2 abatement price from 2030 to 2050 is shown on the roadmap. The total cash flow is the difference between the revenue and the expenditures. The revenue comes from the possible sale of RFG and the savings on the costs of CO_2. The expenditures are the CAPEX, OPEX and tax. For simplification, tax and revenue expenditures, such as maintenance cost, are not considered. The Money Of the Day (MOD) values are nominal values in terms of money, which is not adjusted for inflation, compared to real-term values adjusted for inflation.

3.2. Development

The next section of the roadmap shows market trends of (renewable) electricity, hydrogen and biomass. The scenarios describe what could happen rather than what will happen. The diagram, also depicted in Figure 3-7, indicates the energy type's percentage of heavy industry energy consumption in the Netherlands, as per the Shell Sky Scenario [90]. A comparison is made with the BP Energy Outlook [91] and the World Energy Council European Regional Perspective scenario [92] to verify the Shell Sky Scenario.

Shell Sky Scenario [90]

The most ambitious energy scenario of Shell is Sky. The scenario illustrates a technically possible but challenging pathway consistent with global warming below 2°C from pre-industrial levels. In February 2021, the Sky-1.5 Scenario was launched, including the pandemic's potential impact [93]. Comparing the Sky and Sky-1.5 Scenario for the heavy industry on world level by energy carrier, there is only less than one per cent of the energy demand difference. The difference is mainly from 2020 until 2025. It has been predicted that in the future, the effects of the pandemic will be eliminated. Figure 3-2 illustrates the increasing energy usage in the future. Since the data of Sky-1.5 is only available on a world level, an in-depth research is done with the Sky Scenario with data from both Europe as the Netherlands. Figure 3-3 shows the total final energy consumption of Europe by three energy carriers: electricity, hydrogen and biomass. Energy carriers such as hydrocarbon fuels (69% in 2020) and heat (4% in 2020) have been omitted from the graph.

BP Energy Outlook: 2020 edition [91]

The BP Energy Outlook: 2020 edition Net Zero Scenario is BP's most ambitious scenario limiting global warming to 1,5 °C, and it includes the pandemic. Global carbon emissions from energy use fall over 95% by 2050. Due to increasing energy efficiency measurements, the global energy demand will increase slower than it used to be; see Figure 3-4. In Figure 3-5, the total final energy consumption of Europe by three energy carriers: electricity, hydrogen and biomass are provided. Energy carriers such as hydrocarbon fuels (55% in 2020) have been omitted from the graph.

World Energy Council: European Regional Perspective 2019 [92]

The World Energy Council is the United Nations accredited global energy body, promoting an affordable, stable and environmentally sensitive energy system for the most significant benefit for all. The council consist of governments, corporations, non-governmental organisations, academia and other stakeholders to represent the entire energy spectrum. The Unfinished Symphony Scenario is the most ambitious. It describes a world where more intelligent and sustainable economic growth emerges as the world aspires to a low carbon, renewable energy system. Figure 3-6 provides an overview of the final energy consumption, again by three energy carriers. Energy carriers such as hydrocarbon fuels (68% in 2020) and heat (7% in 2020) have been omitted from the graph.

Comparison of the three scenarios

The decision is made to compare the Shell scenario with a competitor and an independent third party. Figure 3-2 and Figure 3-4 indicate that both Shell and BP have the same trend in the total final energy demand. The global primary energy demand differs from different assumptions such as population growth, gross domestic product, efficiency gains in the industry, and calculation method. Europe's energy demand is comparable, and all three scenarios show the same slightly negative trend in energy demand. Especially BP expects a rapid phasing out of fossil fuels. When comparing Figure 3-3, Figure 3-5 and Figure 3-6, they all have the same trend in doubling the electricity share in the total final energy consumption. The amount of biomass does not increase or hardly increases over the years in all three expectations. Regardless of green or blue, the share of hydrogen will only increase after 2040 in the BP and Shell scenario and will be very limited. Therefore, one could conclude that the scenario teams do not expect any blue hydrogen plant in Europe soon.

Because all three scenarios are reasonably aligned and do not contradict each other, it has been decided to continue with the available data from the original Shell Sky Scenario of the Netherlands. This data provides the best insight into what the expected energy sources are in the future for Pernis. It can provide an eye-opener into the energy transition period until 2050 and might help SNR decision-makers.

Sky Scenario: Energy Consumption of Heavy Industry in the Netherlands

Figure 3-7 indicates the Sky Scenario results of the energy consumption of heavy industry in the Netherlands. The furnaces of SNR are responsible for around 10% of the heavy industry's annual energy consumption in the Netherlands, as per the Sky Scenario. As stated before, hydrogen is expected around 2050, indicating that a project such as H-vision is seen less visible by the scenarios team. The share of blue hydrogen will not rise as fast as is hoped. The amount of biomass is also expected to be minor, confirming the previous statements in the thesis. Biomass will most probably not be an available large-scale option for a refinery such as Pernis. According to the Sky Scenario, electrification will be the future's dominant energy carrier by over 50% in the early 2050s. Low carbon electricity includes green electricity and nuclear power. Fossil fuels produce high carbon intense electricity. The graph suggests that the step forward for SNR furnaces is by electrification.

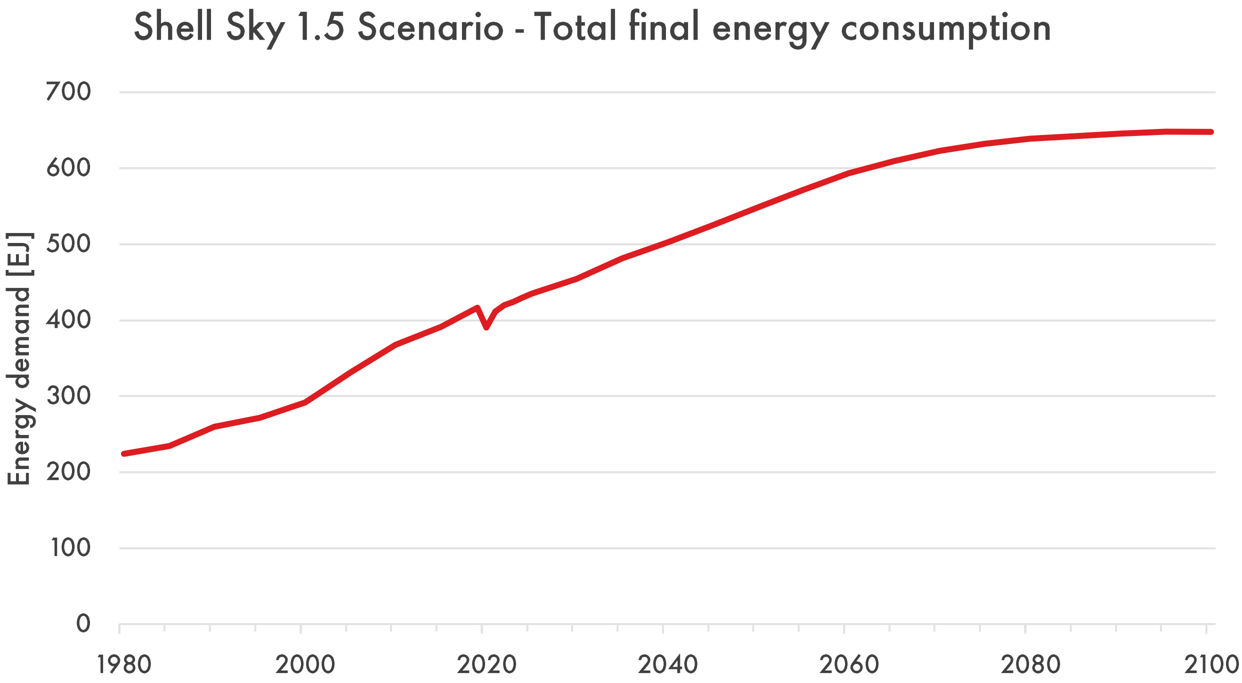

Figure 3-2: Total final consumption of energy as per the Shell Sky 1.5 Scenario [93]. The prediction of increasing future energy usage on the world level. The most ambitious energy scenario of Shell is Sky. The scenario illustrates a technically possible but challenging pathway consistent with global warming below 2°C from pre-industrial levels. The Sky-1.5 Scenario was launched, including the pandemic's potential impact [93]. Comparing the Sky and Sky-1.5 Scenario for the heavy industry on world level by energy carrier, there is only less than one per cent of the energy demand difference. The difference is mainly from 2020 until 2025. It has been predicted that in the future, the effects of the pandemic will be eliminated.

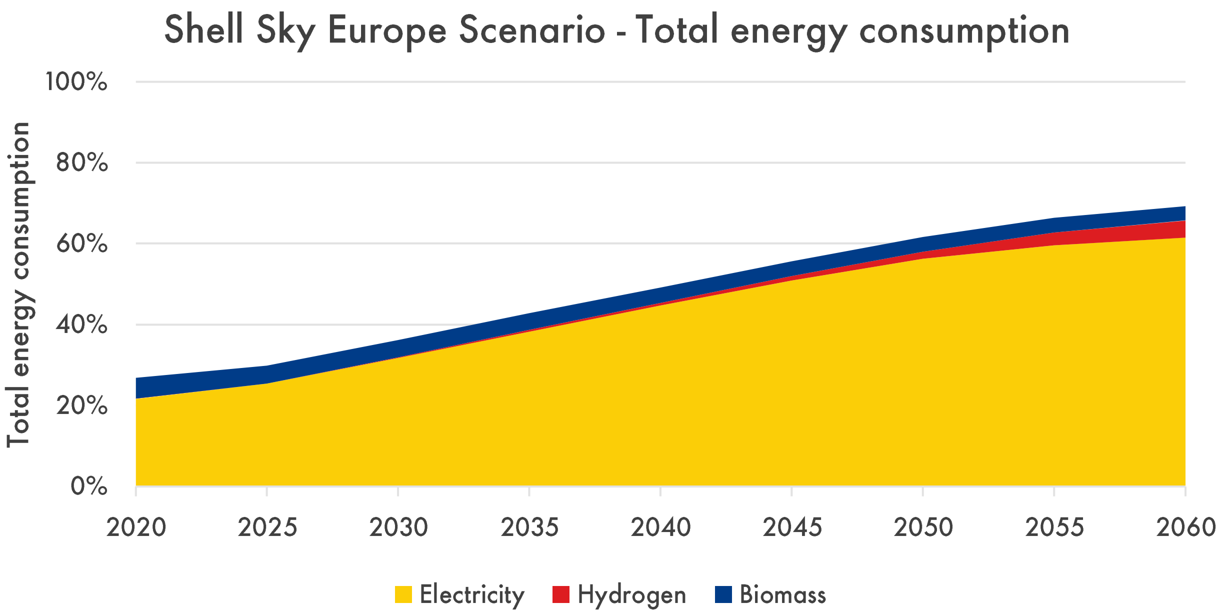

Figure 3-3: Shell Sky Europe Scenario, the share of total energy consumption by a carrier. Energy carriers such as hydrocarbon fuels (69% in 2020) and heat (4% in 2020) have been omitted from the graph.

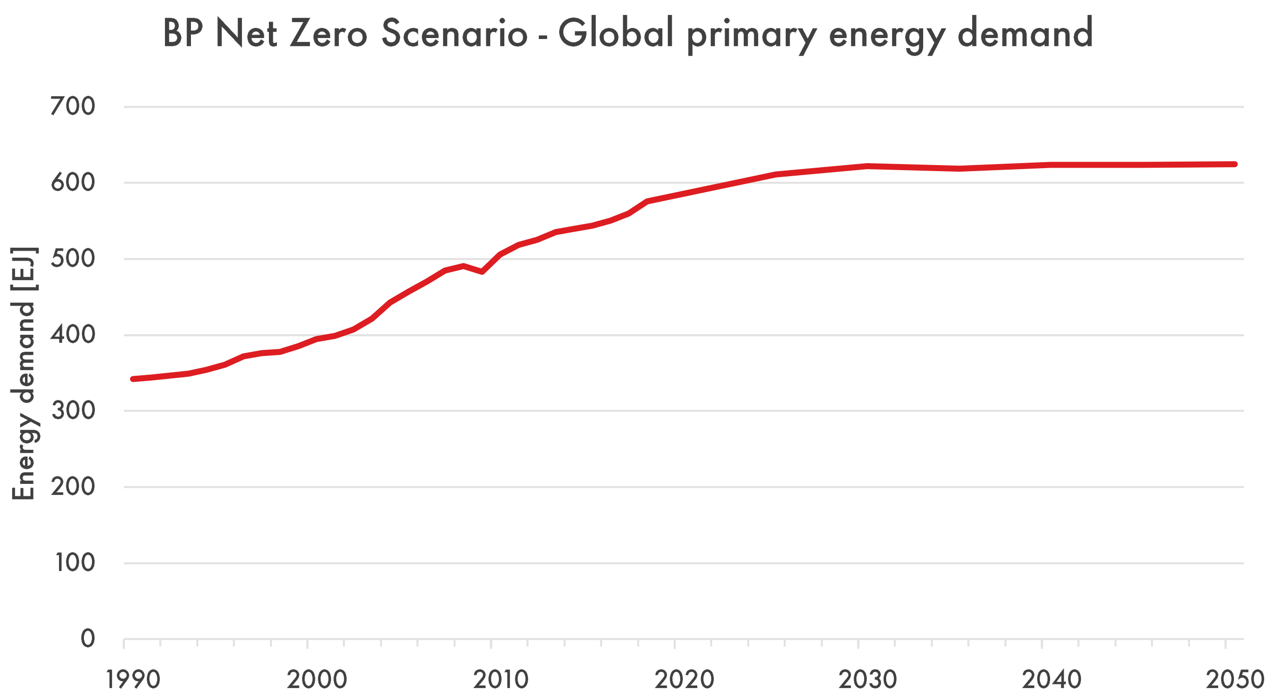

Figure 3-4: The global primary energy demand as per the BP energy Outlook: 2020 edition [91]. The BP Energy Outlook: 2020 edition Net Zero Scenario is BP's most ambitious scenario limiting global warming to 1,5 °C, and it includes the pandemic. Global carbon emissions from energy use fall over 95% by 2050. The global energy demand will increase slower than it used to be due to increasing energy efficiency measurements.

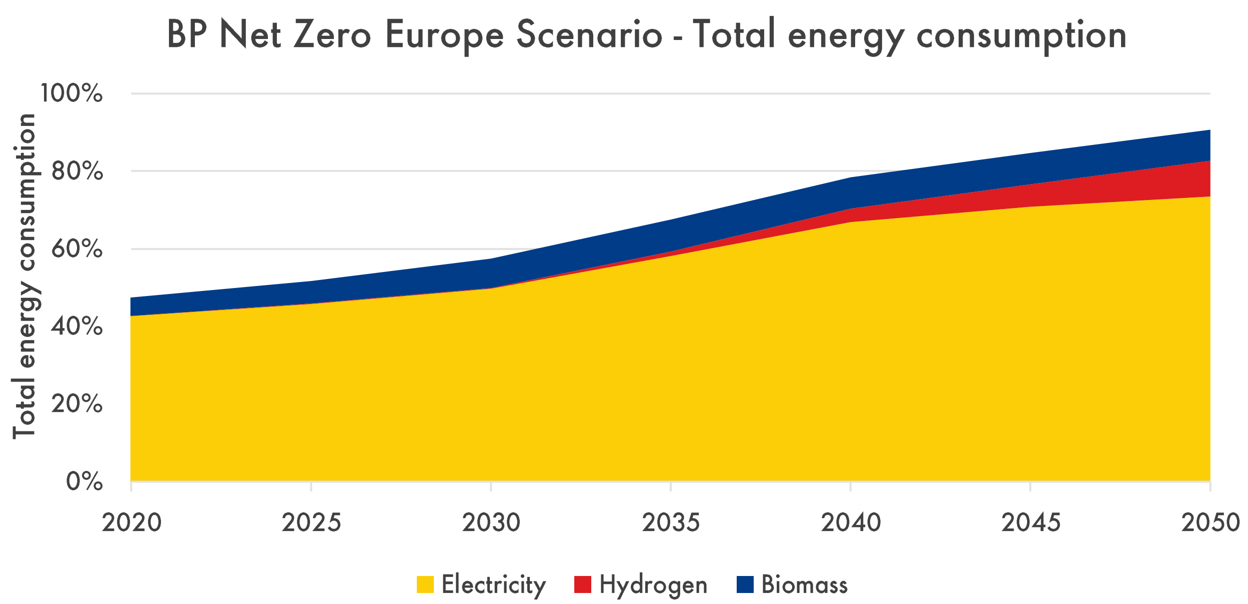

Figure 3-5: BP Energy Outlook: 2020 edition Net Zero Europe Scenario, the share of total energy consumption per carrier. Energy carriers such as hydrocarbon fuels (55% in 2020) have been omitted from the graph.

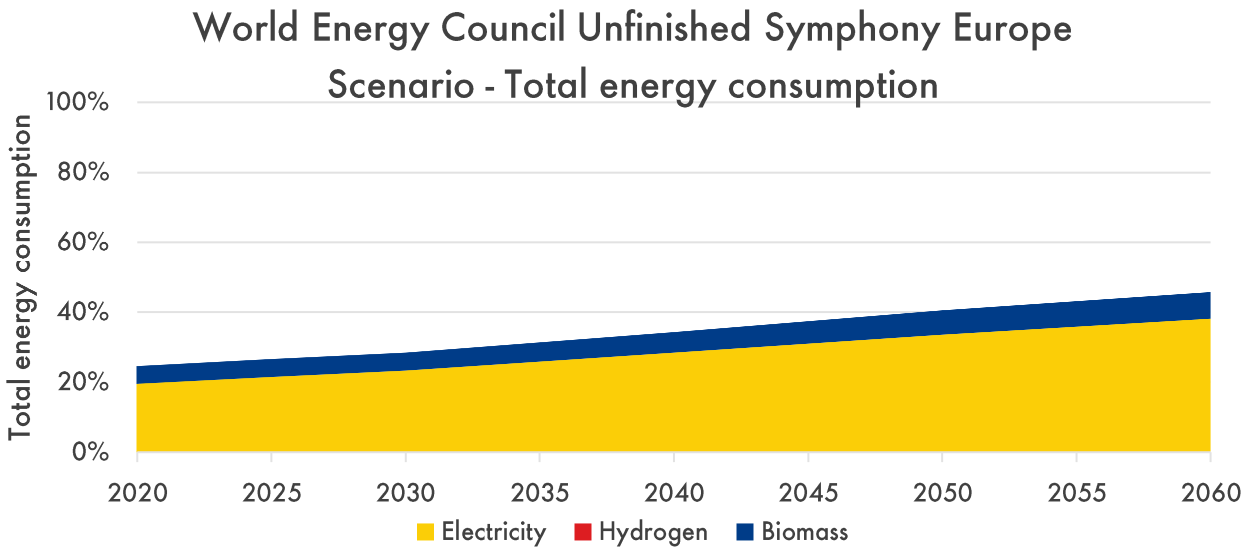

Figure 3-6: World Energy Council European Regional Perspective Unfinished Symphony Scenario, the share of total energy consumption per carrier. Energy carriers such as hydrocarbon fuels (68% in 2020) and heat (7% in 2020) have been omitted from the graph. The World Energy Council is the United Nations accredited global energy body, promoting an affordable, stable and environmentally sensitive energy system for the most significant benefit for all. The council consist of governments, corporations, non-governmental organisations, academia and other stakeholders to represent the entire energy spectrum. The Unfinished Symphony Scenario is the most ambitious. It describes a world where more intelligent and sustainable economic growth emerges as the world aspires to a low carbon, renewable energy system.

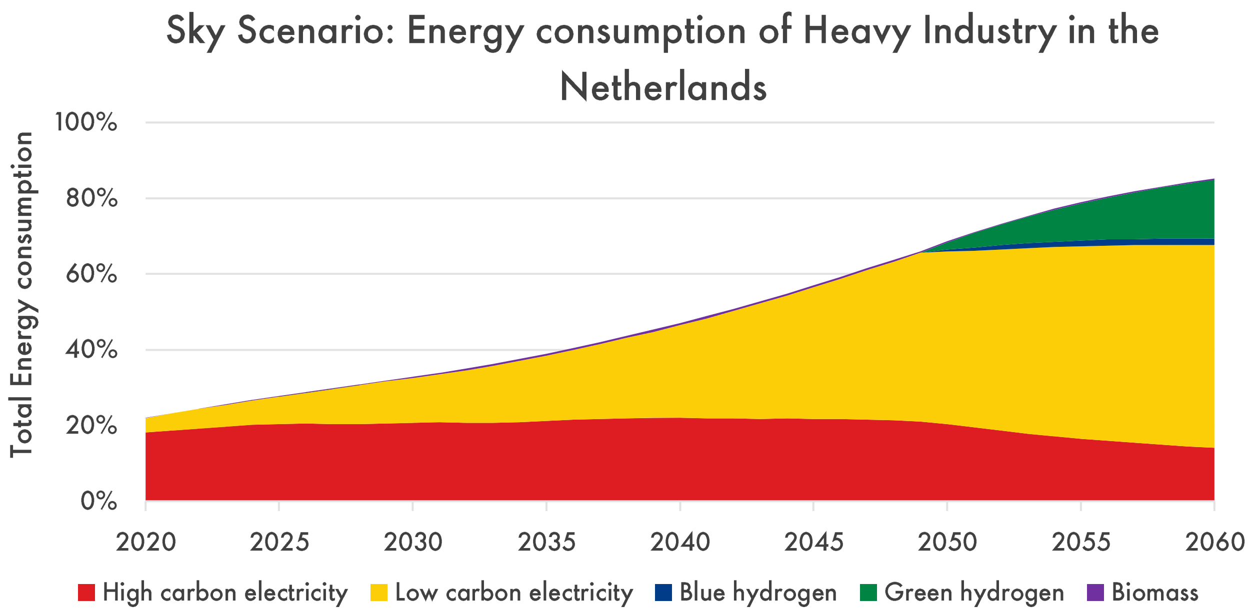

Figure 3-7: Sky Scenario: Energy consumption of heavy industry in the Netherlands, share of total energy consumption per carrier. Hydrogen is expected around 2050, indicating that a project such as H-vision is seen less visible by the scenarios team. The share of blue hydrogen will not rise as fast and at all as is hoped. The amount of biomass is also expected to be minor. According to the Sky Scenario, electrification will be the future's dominant energy carrier by over 50% in the early 2050s. Low carbon electricity includes green electricity and nuclear power. Fossil fuels produce high carbon intense electricity.

3.3. Value drivers

A value driver increases its value to customers, differentiating it from those of competitors—providing a competitive advantage being the upper hand in the industry using state-of-the-art technology. Some value drivers considered are displayed on the roadmap and provide additional insight into when it might be interesting to apply a particular technology.

Project Steering Values

Value drivers such as utility pricing and CO_2 prices are essential indicators to indicate whether a technology will be interesting. Project Steering Values (PSV) are uniform guidance throughout the company so that all related projects use the same assumptions. The PSVs used are shown in Figure 3-8 and are based on the assumed contributions as per Figure 3-9. It is assumed that gasses' futures value remains the same considering Money Of the Day (MOD) values. MOD values are nominal values in terms of money, which is not adjusted for inflation, compared to real-term values adjusted for inflation. A prediction has been made about the value of the PSV in the future. The normalised cost is shown in the MOD value.

The biomethane market is end-use, pathway and subsidy dependent. There is no Shell internal PSV for the combustion of biomethane in Pernis' furnaces. Biomethane is around double the cost of the natural gas price in Europe in 2018 [67]. The cost includes biogas production, upgrading to biomethane and an additional cost to inject into the national natural gas grid. The IEA outlook for biogas and biomethane estimated the global average biomethane production price in 2020, including grid connection costs [67]. The report states that due to the increased availability of feedstock, the biomethane price will fall over time, while natural gas prices will increase.

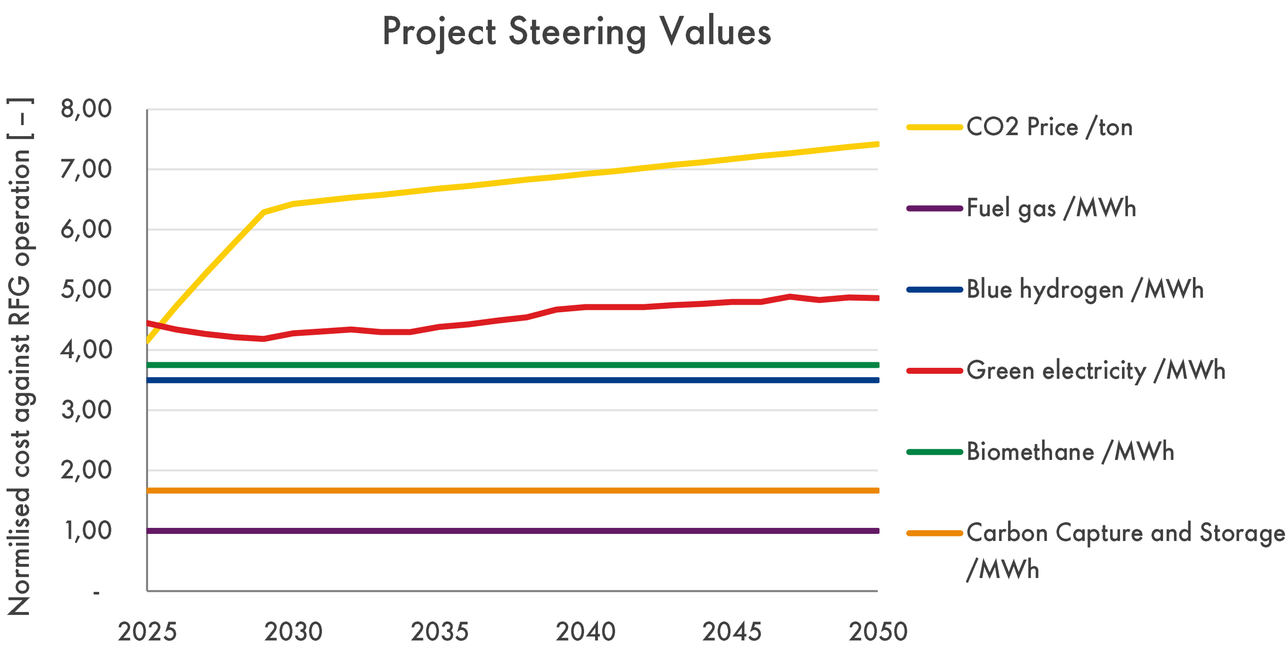

Figure 3-8: Project Steering Values used for the project Furnace Heat Generation. Value drivers such as utility pricing and CO_2 prices are essential indicators to indicate whether a technology will be interesting. Project Steering Values (PSV) are uniform guidance throughout the company so that all related projects use the same assumptions. The PSVs used are based on the assumed contributions as per Figure 3-9. It is assumed that gasses' futures value remains the same considering MOD values. A prediction has been made about the value of the PSV in the future. The normalised cost is shown in the MOD value.

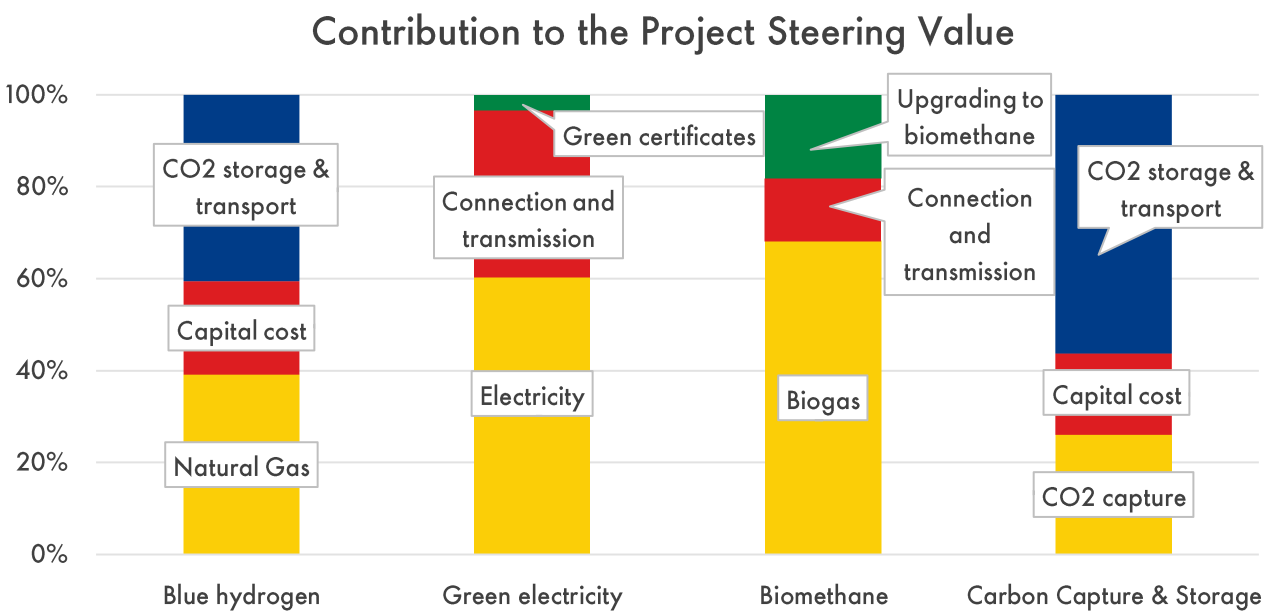

Figure 3-9: Assumed contribution of costs to the project steering value, averaged 2025 until 2050. The biomethane market is end-use, pathway and subsidy dependent. There is no Shell internal PSV for the combustion of biomethane in Pernis' furnaces. Biomethane is around double the cost of the natural gas price in Europe in 2018 [67]. The cost includes biogas production, upgrading to biomethane and an additional cost to inject into the national natural gas grid. The IEA outlook for biogas and biomethane estimated the global average biomethane production price in 2020, including grid connection costs [67].

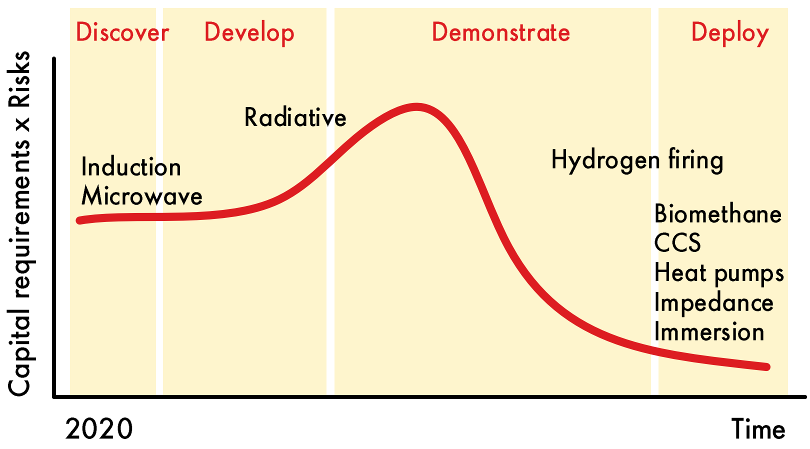

Figure 3-10: Capital requirements to de-risk technology over time. A technology is suitable for implementation in the deploy phase. The value drivers CAPEX and the Value Investment Ratio (VIR) indicate the total capital investment needed and the ratio of payoff to investing in a new project. The VIR is the ratio between the Net Present Value (NPV) of the total cash flow and the initial investment. The NPV is the difference between the present value of cash in and outflows over a set time. To de-risk new technologies, capital investment is required. The lower the capital investment and the lower the furnace's operating cost, the higher the VIR will be, the likelier a project will succeed.

De-risking new technologies

The value drivers CAPEX and the Value Investment Ratio (VIR) indicate the total capital investment needed and the ratio of payoff to investing in a new project. The VIR is the ratio between the Net Present Value (NPV) of the total cash flow and the initial investment. The NPV is the difference between the present value of cash in and outflows over a set time. A profitability index of one indicates a break-even. A lower value indicates that the present value is less than the initial investment. Therefore, a higher VIR profitability index would suggest the higher financial attractiveness of the project. To de-risk new technologies, capital investment is required. Figure 3-10 indicates the relative investment is needed to get the technology to the deploy phase. The lower the capital investment and the lower the furnace's operating cost, the higher the VIR will be, the likelier a project will succeed.

Shared value drivers

Shared value drivers refer to public opinion and governmental subsidies. The values are of importance to succeed with the energy transition. Public opinion affects the government, which grants companies subsidies to implement projects, such as this energy transition project. These value drivers are not shown in graphs but must also not be forgotten, given the government's indispensable value.

Moreover, the shared values are also crucial for the company's reputation. One of the largest emitters in the Netherlands can also make the most impact. The impact is accompanied by the customer focus that wants a transition in their energy carbon footprint.

3.4. Transition scenarios

The last part of the roadmap shows four different credible scenarios. The scenarios include either hydrogen firing or electrification, as these options are deemed the most feasible. The share of biomethane seems to be too low for all Pernis fired heaters. These scenarios differ in requirements and the priority list of the furnaces. The pathway shows the amount of CO_2 reduced by the projects; it is visible that the scenarios cannot abate all the emitted CO_2.

CO_2 benchmark

The CO_2 benchmark is the maximal allowable amount of CO_2 emitted in 2030 by the furnaces. It is assumed that the current linear reduction will continue in the transition period from 2030 to 2050. The European Union Emissions Trading System (EU ETS) currently combats climate change by developing the carbon trading market and is proven to drive emission reduction cost-effectively [94]. Companies receive free allowance to emit CO_2. if the allowance is insufficient for the operation extra allowance should be bought on the carbon market. The free allowance is calculated by simplified Equation 5 for post-2030.

$$\text{Free Allowance} = \text{Historical level x Benchmark x Reduction factor x Emissions} \tag{5}$$

The historical level is the mean value of the annual activity levels in a baseline period depending on the allocation period. The benchmark depends on the EU ETS phase. Phase three is from 2021 – 2025, and phase four is from 2026 – 2030. The benchmark is a fixed value and is decreased over time by the reduction factor. The benchmark value is based on the average greenhouse gas emission of the best 10% performing installations in Europe [95]. The benchmark does not vary according to the technology or fuel used, and this is equal for all fired heaters across Europe. The benchmark post-2030 is not yet published. Therefore, the assumption is based on the continuous linear reduction. Emissions is a ratio between the direct, scope one emissions, and the indirect, scope two emissions. The produced products have an allocated emission footprint.

Since the free allowances are given for a complete site, the furnaces do not have to decarbonise immediately. Other abatement projects on-site ensure sufficient reduction in the short term. The assumption to reduce linearly over time is therefore sufficient to achieve the abatement goals of furnaces within Pernis. Note that shutting down a unit, including a furnace, impacts the emissions and directly limits the complete site's free allowances.

Besides the emissions, the pathways also indicate the energy required. The scenarios are aligned with each unit's turnaround planning, limiting the flexibility of the transition year.

Scenario 1: Hydrogen

In the first scenario, all furnaces where it is technically possible are hydrogen fired. As stated before, it is possible to revamp all fired heaters of SNR. The pathway includes all 15 furnaces, as depicted in Figure 2-2. The requirement for this scenario is the sufficient availability of blue or green hydrogen. It is neglected where this hydrogen is produced and distributed on-site.

First, the furnaces with ultra-low NOx burners should be converted since spending CAPEX is always more economically attractive in the future, and they do not require new burners. After that, it is interesting to convert large scale furnaces. The bigger the project, the relatively cheaper the revamp project is. Abating the same amount of CO_2 with multiple smaller projects gives a higher NPV. The last priority is furnaces with end-of-life burners that need replacement.

Scenario 2: Electrification

In the second scenario, all furnaces where it is technically possible are electrified. As seen in Figure 2-4, not all furnaces can be electrified due to plot space constraints. The requirement for this scenario is the sufficient availability of low carbon-intense energy and a site-wide infrastructure.

The priority for electrification is to replace the furnaces that are end-of-life, as it is unnecessary to invest in upgrading units that will be replaced soon. Next are the low-efficiency furnaces and furnaces that form a constraint for the current operation, such as production bottleneck or high turndown requirements. As stated before, some furnaces might have an increase in yield, so an increase in production. The only showstopper, the plot space availability, must also be considered.

Scenario 3: Hybrid

The hybrid scenario is a combination of hydrogen firing and electrification. Electrical heaters will replace furnaces with a general benefit in electrification if the plot space allows it. All other furnaces will be hydrogen fired. The hybrid scenario seems to be the most likely option, as it combines both the advantages of hydrogen and electrification. However, the major disadvantage is the need for two types of infrastructure which entails high costs. As for the other scenarios, it is assumed that blue or green hydrogen and low carbon-intense electricity is sufficiently available.

At first, the furnaces are converted, which are hydrogen fired, so that the hydrogen infrastructure is first used optimally. Afterwards, the electrified heaters will be placed and installed with the necessary electrical infrastructure.

Scenario 4: Do nothing or do all CCS

The last scenario aims to compare the hydrogen, electrical and hybrid scenario with two obvious decisions. What if the operation is as usual without any changes (do-nothing), and what if most CO_2 is captured utilising CCS (do-all). The do-nothing scenario, where it is business as usual, does not need any modification. The RFG is included in the OPEX, and the CO_2 levy is included in the revenue.

The do-all CCS scenario follows the planning of the hydrogen scenario to compare easily. However, less CO_2 is abated due to the 90% capture rate versus the 94v% purity of blue hydrogen.

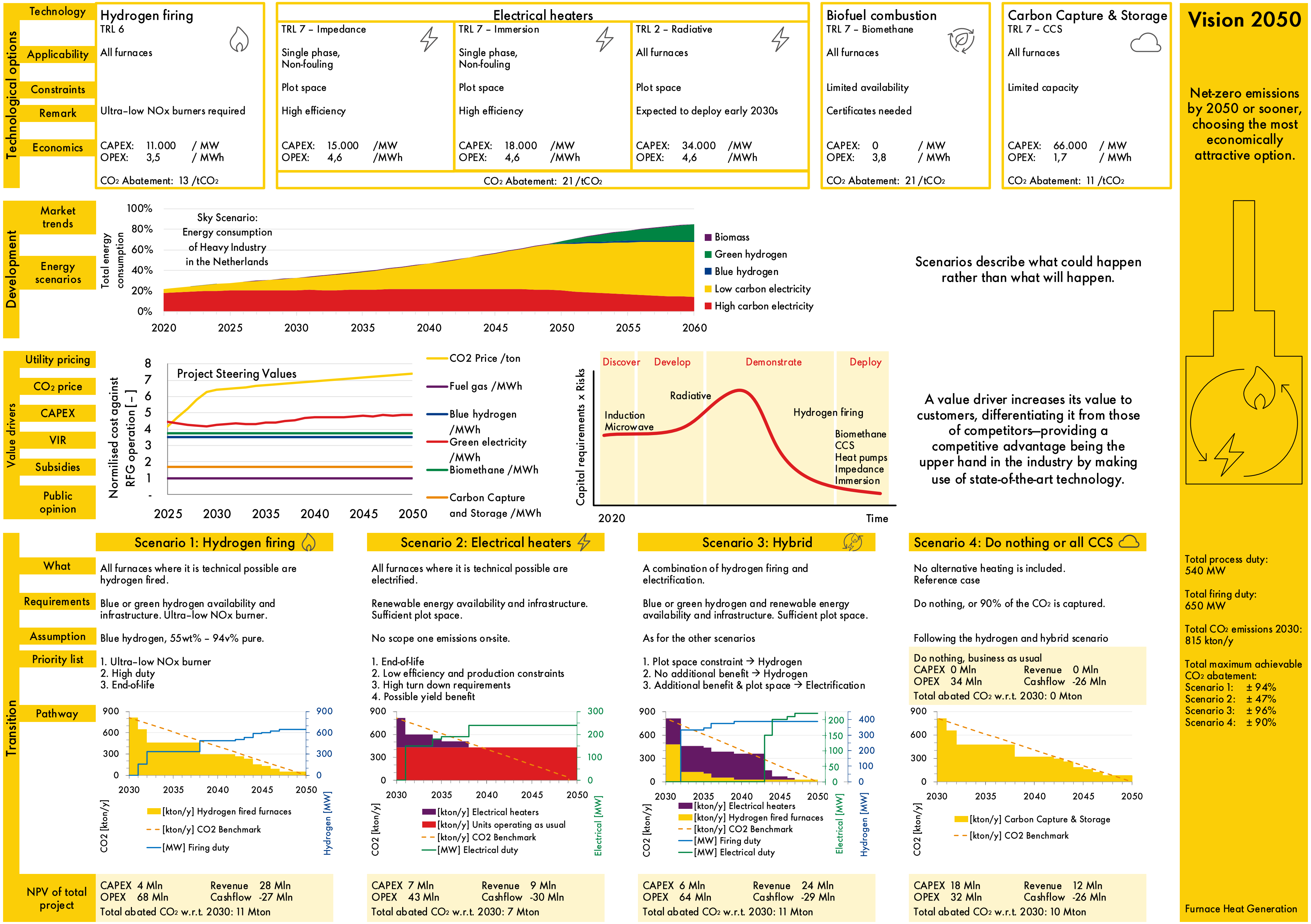

Figure 3-11: Furnace Heat Generation roadmap. The roadmap is a visual portrayal of technology innovation elements. Technological options, developments, value drivers and credible scenarios are indicated. The roadmap can be a guide for decisions for the upcoming energy transition. Note that the roadmap is based on the scenarios presented earlier in this thesis.

4. DISCUSSION

A roadmap is a theoretical tool used during the energy transition of SNR's furnace portfolio. Most of the roadmap information is based on assumptions, the refinery's current operation, and Shell's future perspective. However, it is needless to state that no one can predict the future and that a lot can change in a state-of-the-art refinery like Pernis. Assumptions that now seem logical may change in the future. Therefore, it is essential to make a few comments on the roadmap to indicate that it is flexible but not all-encompassing.

4.1. Practical problems

Practical problems and objections are always there. As mentioned before, the energy transition at an operational refinery has several challenges. In addition to the obvious and practical problems such as plot space availability and cost considerations to not abate all CO_2, there are several, sometimes less obvious points.

Problems with hydrogen firing

Factors that influence the pipe diameter are the flow rate, pressure, temperature and gas composition. It is expected that blue hydrogen will not be 100% pure H_2. Impurities after reforming RFG is inevitable. Purification steps are required to upgrade blue hydrogen after reforming if a high purity grade is wanted. Suppose the purity of blue hydrogen changes, the molar mass and the LHV are influenced. The LHV of the mixture is determined by the LHV of the pure component and the corresponding mass fraction. Pure hydrogen has a high LHV, and other components have a lower LHV. Therefore, the higher the impurity of blue hydrogen, the lower the LHV. It comes down to the following: a lower hydrogen purity means a higher molar mass and a lower LHV, therefore a higher volumetric flow rate of blue hydrogen for the same amount of combustion heat. A higher volumetric flow rate than the design purity of hydrogen can be problematic for the pipe sizing, as this is limited to the internal pressure and gas velocity. When designing a final network, it must be apparent where the hydrogen comes from, under what pressure, and quality. The design of a blue hydrogen plant ultimately determines the quality and pressure of hydrogen.

The hydrogen will not be 100% pure as it is less economic interesting to abate the last amount of impurities. Pressure Swing Adsorption (PSA) is a widely used technique for separating hydrogen from other components such as CO_2 and CO. The purification method is based on adsorption in a pressure changing adsorption process [96]. The hydrogen quality extracted from the gas depends on the hydrogen purity requirements and the feed composition. Hydrogen for combustion must have the highest possible purity, but it must also outweigh economic aspects. The last PSA step is cost-intensive due to significant hydrogen losses in the off-gas. The amount of hydrogen lost must be compensated by the production, resulting in rising hydrogen production costs. The blue hydrogen will contain some impurities such as CO and CO_2. During combustion in a furnace, the CO and CO_2 will contribute to the scope one emissions, which means that hydrogen firing cannot abate all emissions considering economic aspects but will abate 94% of the CO_2 emissions.

As stated before, in section 2.1.1, blending hydrogen and RFG is another challenge that will require further research. The fuel-switching approach with a tie-in right before the knock-out drum is preferred as it seems the most feasible option. This approach has an enormous infrastructure scope, but implementing a new 'blue hydrogen with furnace quality' infrastructure is more feasible than mixing hydrogen into the current RFG network. The current RFG network has several physical limitations, such as the flow rate and the maximum permissible amount of hydrogen. All control valves and fittings must also meet the higher hydrogen safety requirements, and upgrading to a higher mass percentage of hydrogen results also in a higher volume of fuel gas in the system, limiting some sections.

Besides, switching between the two types of fuel always takes time. The main concern is how the drop in molar weight affects the burner. A slow change expects to have fewer potential flame stability and controllability issues. With a fast change, it will be more challenging to maintain flame stability and keep the correct air to fuel ratio for the control system. Slow change seems obvious, but the problem arises when a hydrogen plant trip occurs, and a fast change back to RFG will be needed. Another concern when switching between fuels is the higher thermal NOx emissions. Intelligent combustion control systems need to maintain flame stability and the desired thermal load by adjusting the airflow according to the fuel's composition.

Problems with electrical heaters

An obvious problem is fuel gas relocation. When using hydrogen as fuel, reforming hydrogen out of RFG seems a possible option. However, producing electricity out of RFG is not logical. It will be more challenging to relocate the RFG. A possible alternative might be upgrading RFG to natural gas quality and injecting it into the national grid. As fuel gas relocation is not part of this thesis, no further research is done. However, the fuel gas balance is more complicated for electrification than for blue hydrogen production.

It is more complex to build electrical infrastructure than a hydrogen network, partly due to the cables' underground installation. The bore must go extra deep into the ground to avoid unknown pipes, to exclude the risk of an accident of not appropriated documented pipes in the past. Electrical infrastructure is cost-intensive because it is the drilling of a cable and the substations needed to transform the power to a lower voltage.

4.2. Economics

The financial calculations are based on several assumptions. The infrastructure costs are high-level estimations with an uncertainty of over 50%, a standard for a project in their identification phase. The estimation is based on previous data and rough estimates of pipe or cable length, pressure, diameter, and power. It is not considered if the pipes will fit the current pipe-rack, and the infrastructure is not optimised with regards to the shortest length and ease of implementation. The electrical infrastructure is also not optimised with regards to the substations' location.

CAPEX

The CAPEX of all technologies contains several vendor quotations, implementation projects, and evenly distributed infrastructure costs. Therefore, it contains the calculation of some assumptions that can have a substantial impact on the result.

OPEX

The OPEX for gasses is assumed to be constant over time in the MOD value. Gas prices will fluctuate and are hardly predictable. Certainly applying to biogas prices, essential factors are the influence of the government and the production volumes.

Furthermore, it is interesting to see that the electrical prices will be the highest throughout the future. Mainly due to the enormous increase in the transmission cost in the coming decade. Biomethane and blue hydrogen are relatively competitive with each other when it comes to operational costs. Biomethane has the added advantage to abate all CO_2. However, CCS OPEX is by far the cheapest but does not outweigh the fact that the CAPEX is also by far the most expensive. The CCS OPEX is based on a higher CO_2 concentration than furnace flue gas, and it is expected that the OPEX will increase for lower concentrations.

CO_2 abatement price

The CO_2 abatement price, as calculated per the simplified model in Figure 3-1, makes use of MOD values. The CO_2 abatement price is calculated per year and averaged to compare with the other scenarios. The MOD values are used rather than the real-term values to exclude the inflation for ease of comparison. Moreover, similar energy transition projects also use MOD values for the CO_2 abatement price calculations.

The VIR calculation uses NPV. Therefore the infrastructure cost has been taken separately into the CAPEX and are issued the year before the first furnace is operational. NPV values have an inflation adjustment, which is calculated from MOD values. For this reason, it is essential to calculate the CO_2 abatement price from MOD values.

Furthermore, the transition scenarios influence the CO_2 abatement price, which is why it has been chosen to keep them as similar as possible.

The Dutch CO_2 levy

The EU ETS is an essential existing tool for the carbon pricing of the industry in Europe. Due to the yearly decrease in emission allowances, the price per ton of CO_2 will increase. The Dutch levy is an increase in the European carbon price path to accelerate the national carbon reduction. Because the prices are unknown after 2030, it is unknown whether there will be any additional Dutch levies beyond 2030. The CO_2 PSV is based on the European carbon price predictions and the added Dutch levies. It is clear from Figure 3-8 that the Dutch tax affects carbon prices. Assumed is that the CO_2 price will rise above a ceiling that the Dutch levies are not needed anymore. The EU ETS carbon price will then be kept high by the European industry’s supply and demand.

Subsidies

The ‘Planbureau voor de Leefomgeving’ advised the Dutch Ministry of Economic Affairs and Climate on the SDE++ subsidy scheme [97]. The subsidies have been kept out of scope for this thesis. However, note that subsidies can bring significant changes to the furnace energy transition pathway. If the government decides to continue with, for example, large scale electrification and grants subsidies, scenarios will change.

4.3. Midterm optimisation

One of the sub-questions asked in the problem statement, section 1.4, considers midterm solutions to optimise the long-term scope. Comparing the different scenarios, as stated in the roadmap, Figure 3-11 shows no need to abate faster or more. The aim is to stay as close as possible to the benchmark line to create an optimal scenario for saving CO_2 and its costs. A midterm optimisation is something that saves both emissions and cost for a short period. For example, this could be hydrogen blending in the fuel gas network or hydrogen firing before electrification. However, all scenarios show that it is possible to stay close to the benchmark line, so a midterm optimisation is not considered necessary for the time being.

4.4. Comparing the four scenarios

As depicted on the roadmap, the four scenarios show that it is possible to abate CO_2 emissions. The electrification scenario shows clearly the impact of the plot space constraint. It can be concluded that only electrical heaters will not abate all the CO_2. The do-all furnaces with CCS scenario abates 90% of the CO_2 emissions, followed by the hydrogen firing scenario, which abates 94%. The hybrid scenario has the highest maximum achievable CO_2 abatement, with 96% of the total emissions regarding 2030.

NPV of total project

The NPV of the total project shows large cash flows. Hydrogen firing has the highest cash flows but not the most losses, that is the electrification scenario. The do-nothing and CCS scenarios have the slightest loss, and the least amount of money is involved. As stated before, these scenarios are not Pernis' vision for the future but rather serve to show that the other scenarios can be engaging. For example, due to the above-expected enormous increase of CO_2 prices, the other scenarios, where less CO_2 is emitted, can be more profitable. If the CO_2 price rises by 300%, the hydrogen scenario will cost less than the CCS scenario. However, this is not seen as feasible now. Comparing the hydrogen scenario to the do-nothing scenario, an increase of 9% in CO_2 price already shows a more positive cash flow for the hydrogen scenario than the do-nothing scenario.

VIR sensitivity

Value Investment Ratio scenarios can provide valuable insight in some scenarios. Moreover, a VIR indicated the payoff to invest in new projects. For the energy transition of furnaces, the VIR standard for energy projects at Shell must be met. The less profitable a project is, the less likely the project will succeed within the company. For energy transition projects, the VIR is set to 0,5.

Consider the hydrogen scenario. For example, assume that the CAPEX and the CO_2 prices are fixed and that the upscale of a blue hydrogen plant will tend to decrease the hydrogen price. The hydrogen price can be calculated based on a VIR = 0,5 and equals 1,54 / MWh. For a price lower than 1,54 / MWh, the project will succeed by the Shell standard. Nevertheless, considering Figure 3-9, around 39% (1,4 / MWh) of the hydrogen price is natural gas, and 40% (1,4 / MWh) is CO_2 storage and transport. The same amount of natural gas is needed to produce hydrogen in the coming years, and that the same amount of CO_2 should be stored. The natural gas price and the carbon storage cost should reduce significantly to get a VIR = 0,5. The OPEX should reduce to 35%, something that seems unlikely. It can be concluded that the hydrogen should be produced differently, or burning hydrogen is not going to make money, save at most.

The electrification scenario cannot get to VIR = 0,5 by reducing the green electricity price when keeping the CO_2 price and CAPEX constant.

It can be concluded that based on the VIR, none of the scenarios will be profitable and that SNR always must invest in decarbonising its operation further. Alternative heat generation of furnaces can save costs, but it is unlikely to be cost-cutting.

Most likely scenario

Comparing the different scenarios, considering all the value drivers and the predicted development, electrification of furnaces is a logical process. However, hydrogen is needed for SNR to decarbonise all furnaces. The hybrid scenario seems the most likely scenario for the future of Pernis. A combination of hydrogen firing and electrification abates the most CO_2, a value driver that is probably most preferred by the public opinion.

The vision to have net-zero emissions by 2050 or sooner, choosing the most economically attractive option, does not quite fit the hybrid scenario. There are other options to operate the furnaces in a more economic friendly way. However, these options do not abate as much CO_2 as the hybrid scenario. Moreover, for none of the scenarios, is it possible to get to net-zero emissions. Perhaps in the future, there will be more renewable energy to make green hydrogen, or that biomethane will play a more significant role in the heavy industry. Green hydrogen and biomethane are the fuels with a net-zero footprint and can be implemented on all Pernis fired heaters.

4.5. Reflection of the scenario outlined and the actual situation

This thesis outline is compared with Pernis' actual situation to clarify how adaptable the situations are. At first, the furnace overview, the duties, efficiencies and emissions are values from typical refinery heaters, and these are not the actual values of SNR. However, the ratio between the duty and CO_2 emissions is equal and relevant for the CO_2 abatement calculations. The outline uses a reduced number of furnaces for convenience. The remaining furnaces do not reflect reality. The opportunity matrix, Table 4, is representative for both the thesis and Pernis.

The infrastructure for hydrogen and electricity are representative of Pernis. However, the exact locations may be different. The line sizing is scaled accordingly.

The prices scale with RFG prices, considering possible fluctuations in gas prices. Since the ratio between duty and emission is the same, the CO_2 abatement prices are also proportional. Price scenarios were developed for specific scenarios as depicted in this thesis, and the infrastructure cost was adjusted accordingly.

It can be concluded that the scenarios developed for this thesis can be used by decision-makers, as they are proportional to reality. The technical aspects of individual fired heaters, which does not reflect reality, do not affect the furnace portfolio's final transition. The savings in terms of cash flow and emissions are proportionate.

5. CONCLUSIONS

The industry needs to decarbonise to achieve climate goals and minimise the effects of climate change. This thesis's research focused on implementing alternative heat generation of furnaces on SNR to become CO_2 neutral by 2050 or sooner. The work aims to develop an overview of the current situation and future alternatives that contribute to the roadmap for the transition of the furnace portfolio.

Shell intends to thrive the world transition to lower-carbon energy by reducing the carbon footprint of the energy products sold. SNR is Europe's largest refinery and has over 55 furnaces. The fired heaters are responsible for 40% of the plant's emission. Therefore, alternative heating is needed. Furnaces heat process streams before entering a reactor or distillation column. Fired heaters use RFG or natural gas as an energy source. Carbon-free fuels can be the solution for alternative heat generation.

Hydrogen firing

Hydrogen is an example of a carbon-free fuel. The work scope for hydrogen firing consists of a furnace conversion project, fuel gas line modification, and a new site-wide infrastructure. The infrastructure is connected to a hydrogen plant. RFG is exported, and hydrogen is imported from the plant. It is possible to revamp all Pernis fired heaters for hydrogen firing. However, there are still some practical issues. The blue hydrogen will not be 100% pure, so not all CO_2 can be abated. Besides, switching between RFG and hydrogen can cause flame instabilities and a higher thermal NOx emission. The normalised CO_2 abatement price against RFG operation, the cost of not emitting a tonne of CO_2, is 13 /tCO_2.

Electrical heaters

There are several options to electrify a furnace, such as immersion, impedance and radiant heaters. The significant advantages of electrical heaters are the higher efficiency than fired heaters and a possible yield benefit. In all cases, it is not an option to revamp a fired heater to an electrical heater. A new unit is needed. Electrical heaters should be built next to the existing fired heater. A critical showstopper is the plot space availability as the refinery plot is entirely occupied. A new cost-intensive and complex electrical infrastructure is needed to supply all heaters with power. The network consists of several transformer stations to keep the voltage as high as possible, to minimise electrical losses. The normalised CO_2 abatement price against RFG operation, the cost of not emitting a tonne of CO_2, is 21 /tCO_2.

Biofuel combustion

One of the world's primary renewable energy sources is biomass. After converting biomass to biogas by AD and upgrading it to biomethane, it is interchangeable with natural gas. Firing gasses with the same Wobbe index as natural gas or fuel gas can be implemented on all furnaces without modification. Biomethane combustion only impacts the site's emission, and it seems to be an administrative solution where trading in certificates will be dominating the market. There is no significant implementation work scope if biomethane is injected into the national natural gas grid.

The normalised CO_2 abatement price against RFG operation, the cost of not emitting a tonne of CO_2, is 21 /tCO_2.

Heat pumps

Heat pumps are widely used in refineries, and they can be used to reduce the furnace load, not to replace the furnace. The potential for replacing fired heaters with heat pumps is low due to the high temperature requirements.

Roadmap

The roadmap aims to create a clear overview with relevant information of the technologies, developments, value drivers, and credible scenarios. The development scenario shows the energy consumption of heavy industry in the Netherlands, such as (renewable) electricity, hydrogen and biomethane. It is expected that low carbon-intense electricity will expand most, suggesting that electrification is the step forward for SNR. Hydrogen tends to increase around 2050, and the amount of biomass is small and will probably not be an available option for Pernis. The PSVs suggest that hydrogen has a lower OPEX than green electricity.

Four credible scenarios show that it is possible to abate most CO_2. With electrification only, it is not possible to achieve the vision of 2050. The hydrogen and electrification scenario are combined in a hybrid scenario, where most CO_2 is abated. The scenarios are compared to a do-nothing scenario where the operation is as usual and a CCS scenario on all furnace stacks. The cash flows are what it is all about in the end, and these show that with a significant cash flow, most CO_2 can be avoided, resulting not necessarily in the most financial losses.

To conclude, furnaces could theoretically operate with zero scope-one emissions. Several technologies exist and can be implemented for refinery heating applications. Emissions depend on the type of fuel and the associated CO_2 footprint. Decision-makers should make the final choice, and this study shows that it would be a decision between either hydrogen firing or the electrification of heaters. It would eventually become a financial decision, but that does not matter, as long as GHG emissions are reduced in any way in order to curb the effects of climate change.

6. RECOMMENDATIONS

There are several recommendations for future work, as this study is not all-encompassing. Many assumptions have been made since this study focuses on the period from 2030 to 2050. The future is uncertain, and trends are trying to predict the future.

Alternative technologies

Technology is developing rapidly, so are the alternative heat generation methods for furnaces. Only the most promising technologies, such as hydrogen firing, impedance heating, immersion heating, radiative heating and biomethane combustion, are described in section 1.3. Multiple technologies, including microwave heating and induction heating, are probably still in development. Therefore, it is recommended to reassess the possibilities every few years to keep evaluating their TRL level.

Energy efficiency improvements, how to reduce the need for high-temperature heat?

Pernis' energy flows should be mapped to identify the opportunities for heat pumps and other energy-efficiency steps. A site-wide pinch analysis will provide the ideal utility transfer. Creating a masterplan for an ideal solution for the refinery from 2030 to 2050 is then possible. The masterplan should consider different technological options for further heat integration. Besides, heat networks might be able to reduce furnace loads as well.

Utility availability

The utility availability after 2030 is uncertain. A lot is dependent on the availability of the energy supply and footprint it has. In this thesis, it is assumed that the hydrogen is produced in a blue-hydrogen factory and the green electricity is grey electricity from the grid with a guarantee of origin certificates. Green hydrogen or renewable energy, which comes directly from the source, is not considered. The Shell Sky scenario suggests that there will not be a blue hydrogen plant soon and that most of the hydrogen produced is green. The impact this has on the price scenarios is still unknown.

Shell can also push the energy producers in the direction it wants to go on. Therefore, it is recommended to further investigate their green hydrogen or green electricity production price scenarios. So, Shell can operate independently, which it prefers and can be the frontrunner in the energy transition.

Financial aspects

All financial calculations are based on high-level assumptions. The high-level infrastructure estimation is based on a sketch showing a possibility. The CAPEX is based on vendor quotations. However, this depends on the furnace process conditions and the cost of implementation. OPEX is based on known compositions of current prices and is extrapolated for this study's specific purpose. The CO_2 abatement price depends mainly on the scenario sketch and the years of implementation. It is recommended to further investigate the specific price scenarios to better understand the CAPEX and OPEX, so a more reliable estimation of the abatement price can be made. Furthermore, it should be investigated if and how different scenarios influence the abatement price.

The future of Pernis

That a refinery is going to change in the future is inevitable. In collaboration with the Dutch government and KLM, Shell recently completed a successful pilot on sustainable, synthetic kerosene [98]. Synthetic kerosene is produced out of green hydrogen and CO_2. Liquid kerosene is produced in a Fischer-Trop installation after a few process steps. The pilot test suggests that SNR might develop a new factory. The demand for renewable energy is increasing, and Shell needs to anticipate. Besides, the demand for raw materials for the chemical industry is also growing. Therefore, it is inescapable that some factories will close and that new factories will be designed. The closure and start-up of new factories, of course, affects Pernis' furnace portfolio. There will probably be more plot space available for electrical heaters, and new factories might need higher controllability of heat transfer to optimise the production.

Therefore, it is recommended to investigate credible scenarios better to understand the shift in the refinery's energy transition. Higher heat transfer controllability requires push for electrification. Nevertheless, if a blue hydrogen plant is part of the future refinery, hydrogen firing in furnaces might be more cost-effective.

Carbon Capture and Storage

CCS might not be an option to replace an existing furnace. It might be part of the solution to avoid CO_2 emissions. To thoroughly compare CCS with hydrogen firing or electrification, more in-depth research should be conducted. The most optimal technology to capture CO_2 in the stack must be determined. The stack properties' such as diameter, CO_2 concentration, and flue gas flow might influence the technology needed.

Moreover, CCS requires some significant plot space. So, what is the feasibility of capturing CO_2 on all stacks? The feasibility study should also comprise the CO_2 storage capacity.

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