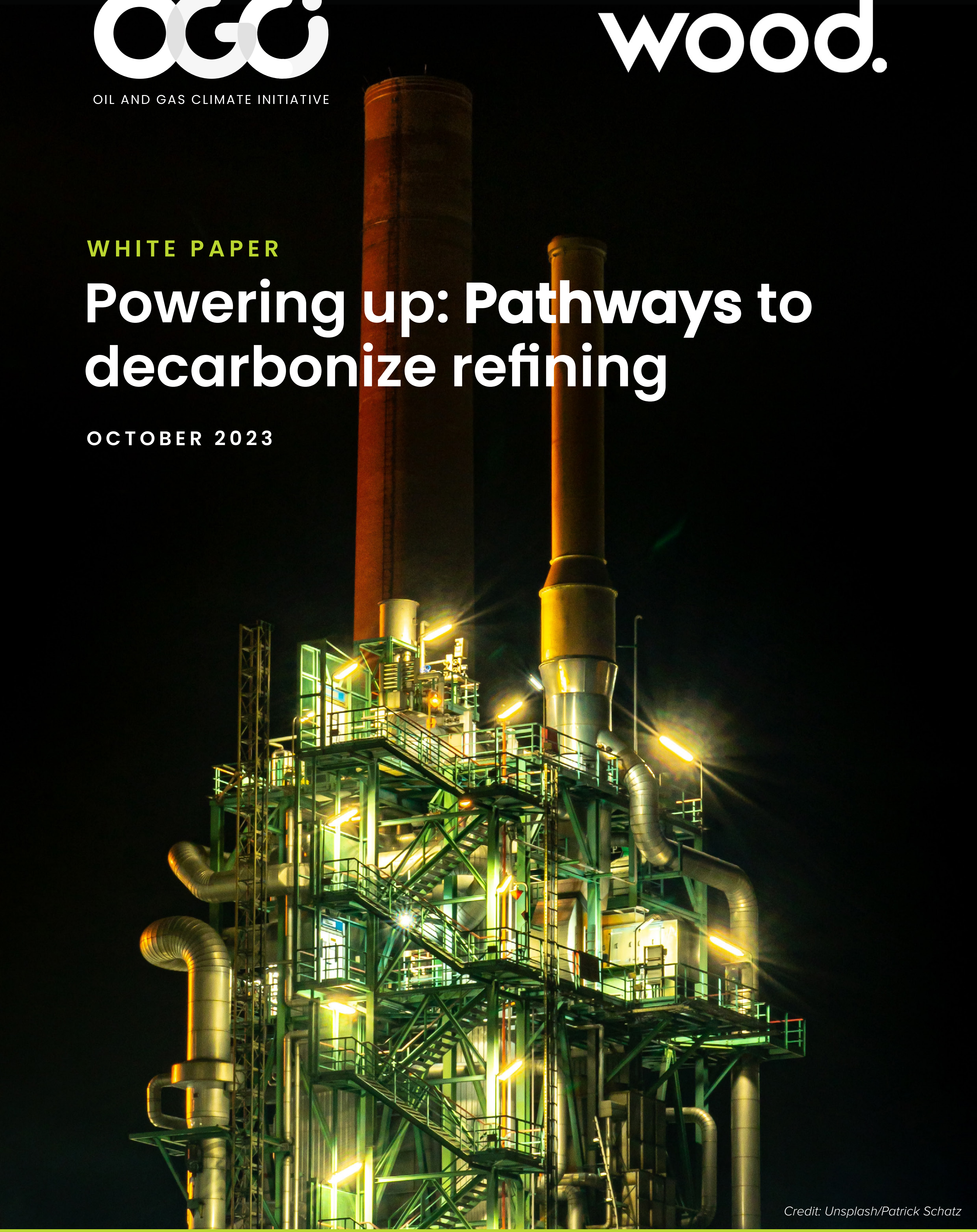
OIL AND GAS CLIMATE INITIATIVE

WHITE PAPER

Powering up: Pathways to decarbonize refining

OCTOBER 2023



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A ROADMAP TO DECARBONIZE REFINING

Executive summary

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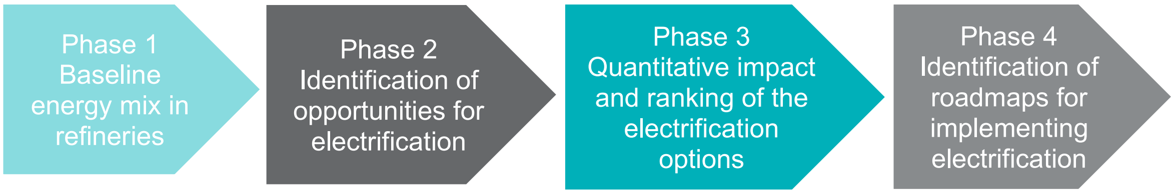
1. Background and Objectives

The Oil and Gas Climate Initiative ("OGCI") Energy Efficiency in Industry Workstream (EEI WS) has formed a working group with the purpose of developing a long-term roadmap to electrification based on technology, economics, and carbon reduction potential. This work aims to inform OGCI members of the potential for electrification to contribute to carbon intensity reductions. The first stage for the development of this roadmap consists of the identification of opportunities and barriers for electrification of refineries.

The EEI WS has appointed Wood as independent consultant to assess the potential of electrification as a greenhouse gas emissions reduction lever for the refining industry.

The study focused on application of electrification to existing, generalised sites as opposed to greenfield development opportunities, capturing the difficulties and opportunities inherent in existing facilities for electrification technologies, before applying electrification to a range of scenario roadmaps. The four study phases are shown below.



Refining Industry Electrification Study Phases

2. Phase 1: Baselining

The current energy consumption by unit and by major equipment was assessed for three representative refinery complexities, chosen to embody the most common refining configurations:

- A high complexity refinery including full upgrading via coking and fluidised catalytic cracking (FCC)
- A medium complexity refinery with a focus on hydrogen addition via vacuum gasoil upgrading via a hydrocracker
- A low complexity topping refinery with no upgrading of atmospheric residue

The three refineries were configured to produce Euro-V specification transport fuels and utilised natural gas imports as marginal fuel.

Utilities systems were also configured alongside the process units, including steam, power, water and other systems. Complexity of the steam systems followed the process units, with the high complexity utilities including a cogeneration plant and steam turbine generators. The medium complexity utilities included steam turbine generators with no cogeneration, and the low complexity configuration included let-down desuperheaters only.

The process units and utilities considered for the base case equipment energy consumption were based on a well-operated typical current configuration, hence some investment opportunities remain to reduce energy demand, but operation and maintenance was assumed to prioritise energy efficiency. Although not considered as part of the study, poorly operated sites where there is significant scope for energy savings should have an initial focus on low-investment energy efficiency improvement, followed by electrification and larger energy efficiency projects in an integrated road map.

3. Phase 2 & 3: Opportunity Identification and Analysis

The objective of Phase 2 was to identify electrification options available to refineries with high level assessment, in order to provide screening of these options. Phase 3 provided further analysis detail of cost, plot, schedule and requirements for supporting electrical infrastructure.

The fuel gas composition for the sites, typical natural gas composition and typical CO_2 equivalent emissions of natural gas supply were included in the CO_2 reduction calculations. Life-cycle emissions from the low-carbon electricity imports were utilised, based on a mix of wind, solar and nuclear generation.

3.1 Technology Assessment and Ranking

Relevant refinery electrification technologies were reviewed to quantify the following:

- Scale of facility CO_2 emissions savings, utilising major equipment consumptions
- High level capital cost efficiency
- Emissions reduction per unit of additional low-carbon electricity utilised

The following criteria were reviewed by specialists to provide qualitative impacts:

- Technology Readiness Level (TRL) was used to identify the maturity of a technology.
- Ease of implementation. This included the ability to install the technology alongside ongoing operation and tie-in within a typical turnaround window. Plot space was also considered.
- Reliability, availability, maintainability and operations impact. This included risk to operations due to single mode of failure (power), inherent reliability of the technology, and operational difficulty.
- Health, safety, security and environmental impact. This included potential major incident impacts of power outage scenarios, as well as any other identified HSSE impacts.

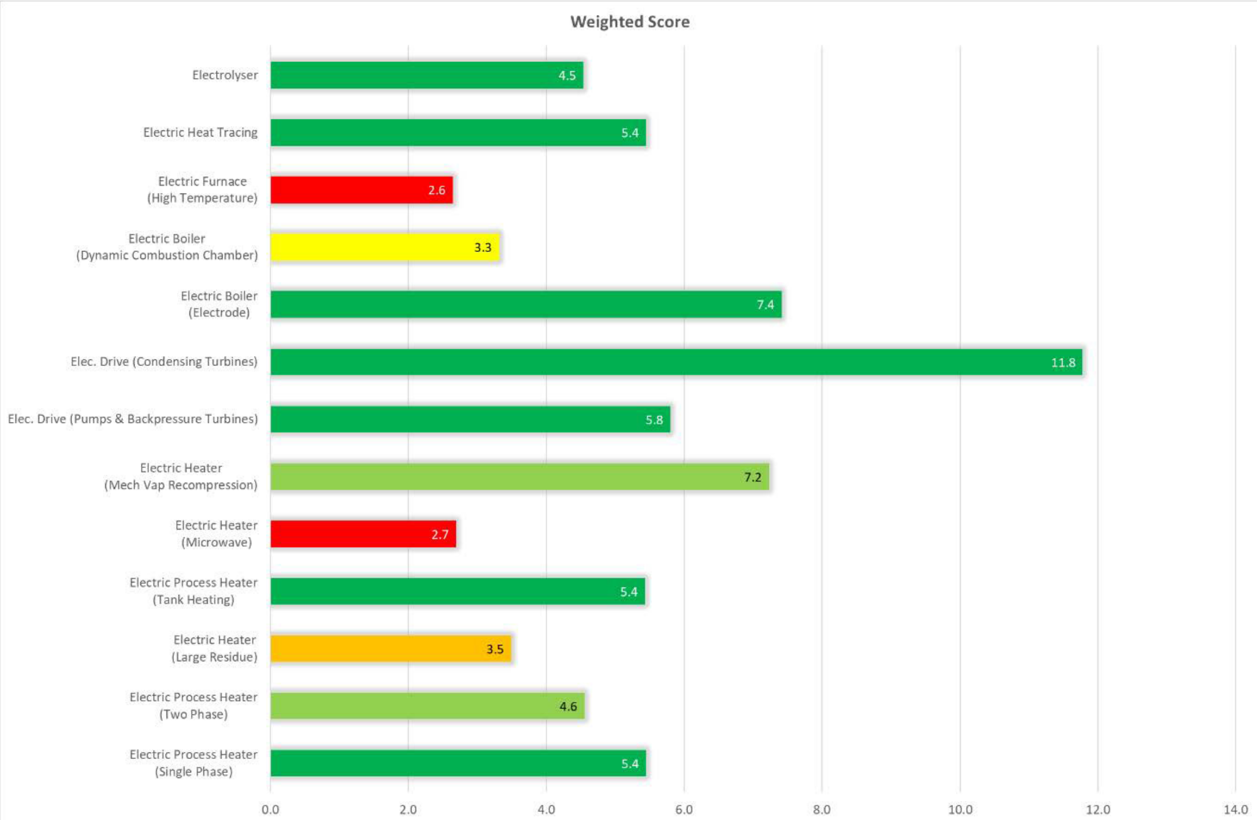
Electric boilers and electric drives applied to condensing turbines were shown to be the highest priority technologies for implementation due to a blend of efficiency improvement, high TRL and relatively few implementation issues. Mechanical Vapour Recompression (MVR) in distillation is also a very effective technology where it can be applied efficiently, strengthened by its high power utilisation efficiency.

Electric process heaters were shown to be a higher priority for simpler and lower duty services, with additional complexities and lower TRL reducing their score for high temperature and large residue heaters. In comparison, microwave heating scored poorly due to low TRL and relatively low efficiency of power utilisation.

Electrolysers scored well for replacement of current hydrogen generation technology and are preferred to high temperature electric heater implementation. Electrolysis capital cost efficiency and efficiency of power utilisation are currently lower than other electrification technologies. However, both cost and efficiency are expected to continue to improve, hence future case sensitivities will be important.

Electric heat tracing is a strong opportunity initiative, though unlikely to produce significant short-term benefits.

Review of the applicability of the electrification technologies was carried out from multiple perspectives, including overall weighted scoring as shown below.



Technology Weighted Score. Colour denotes TRL (Green = High; Red = Low).

3.2 Electrification Projects Analysis

Electrification of specific equipment was assessed in further detail encompassing the breadth of technologies and scales, including the following aspects:

- Project equipment scope, capital cost, footprint, and schedule
- Supporting electrical infrastructure impacts at site, unit and consumer levels with relevant cabling
- Relevant non-energy operating costs

Plot space is a key concern for the electrification revamps occurring within the process units such as MVR, electric drives and large electric heaters. Large substation and transformer requirements are also anticipated to be infeasible for some sites where adjacent space is not available.

The potential for disruption of refinery operations is greater for process area revamps such as MVR and large heater replacements. Technologies applied to the steam or hydrogen system should cause much less disruption as they can be constructed in new plots and tied into refinery mains during shutdowns.

Scheduling of significant investments with standard contracting strategies and decision gates gives implementation schedules from FEED to Ready for Start-up of around 3 years for most process unit revamps. Large compressor driver replacements are expected to take 2.5 years including electrical infrastructure, whilst the large electrolyser-based technologies are expected to take 3-4 years.

Related topics relevant to implementation strategy can be found in the full report, including:

- Energy storage synergies and utilities system turndown potential
- Fuel gas reduction measures and non-combustion fuel gas uses
- Breakeven carbon intensity of imported power

4. Phase 4: Representative Site Roadmaps

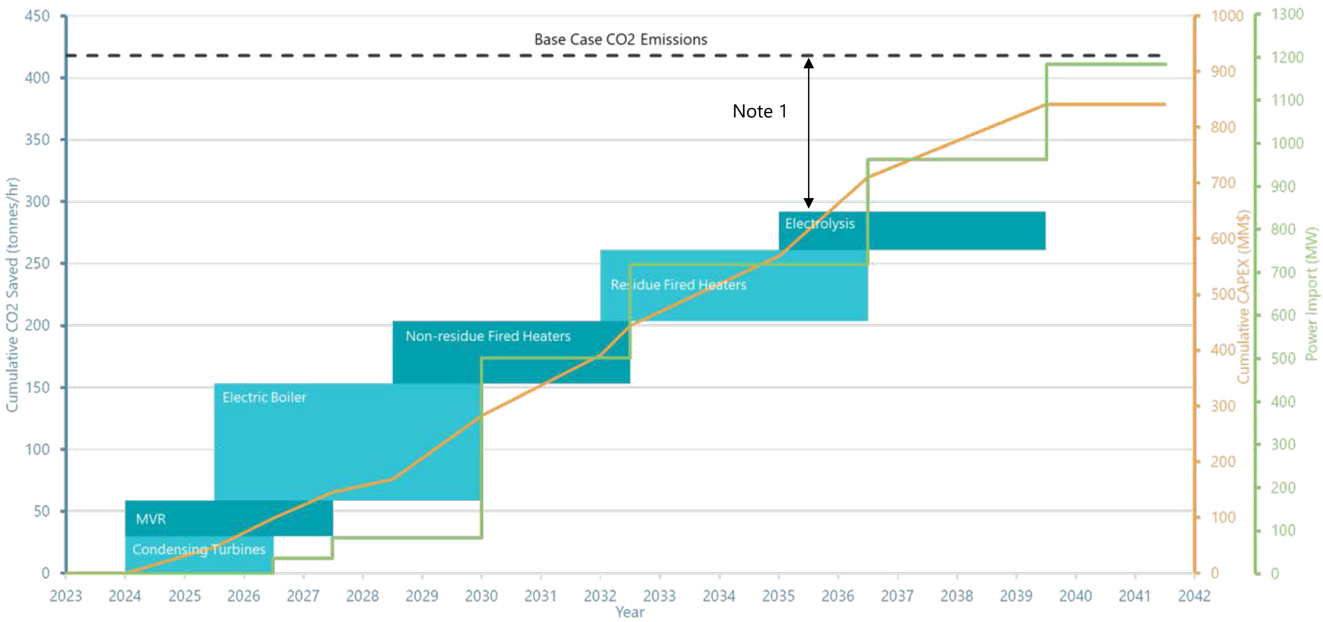
For each refinery complexity a suggested phased implementation plan was developed based on:

- Technology readiness level of each opportunity
- Interactions and synergistic effects between opportunities
- Low carbon power availability
- Major impacts on produced fuel routing
- Long lead items and project implementation timescales

4.1 Primary High Complexity Roadmap

The primary roadmap was based on maximising the capital cost efficiency of CO_2 abatement. This resulted in a plan for phased investment that prioritised replacement of the existing fired boilers with electric boilers and maintaining the existing steam consumers. Other technologies required for fired duty replacement were implemented in order of decreasing cost efficiency through the roadmap, with the exception of highly power efficient projects such as mechanical vapour recompression, which could be implemented beneficially prior to large-scale low-carbon power being available. Electrification was found to enable decarbonisation of the great majority of the Scope 1 and 2 emissions from the sites, with the main unmitigated emissions being from FCC coke combustion in the high complexity case.

The quantity of excess fuel gas at the end of the roadmap is greater than that expected to be reduced by operational changes and LPG recovery from fuel gas. This excess fuel gas requires an alternative destination for the final electrification steps taken to be effective, or alternative final steps should be considered as described in the roadblock analysis. Where large-scale low-carbon power is available by 2030, the roadmap completion is anticipated by 2040, with delays to power availability postponing the end date further.



(1) Delta between base case CO_2 emissions and cumulative CO_2 emission savings is due to FCC coke emissions, residual refinery fired emissions and electrical import CO_2 emissions (Scope 2).

Primary Roadmap – High Complexity Refinery Roadmap

4.2 Roadblock Analysis

Alternative roadmaps were developed to address potential issues that could be present for a specific site. These alternatives were driven by:

- More limited or later availability of large-scale low-carbon power
- Delay or technological infeasibility of direct electrification of large residue heaters
- Inefficient or poor condition of the existing steam system

Maintaining the cogeneration plant in operation, rather than shutting this facility down as presented in the primary roadmap, enabled a reduction in power import and reduced electric boiler spend, whilst decreasing the overall decarbonisation extent. Flexibility to respond to limited grid low-carbon power availability was also identified as an advantage, as well as reducing the issue of excess fuel gas.

Hydrogen firing in the existing large residue heaters was analysed as an alternative to avoid direct electrification of these heaters. This option resulted in a significantly greater cost and power import than the primary roadmap for similar ultimate decarbonisation.

Carbon capture of the large residue heater and steam methane reformer emissions was shown to require a similar level of investment as the primary roadmap assuming that pipeline investment is included to reach a storage location 150 km offshore. This cost is highly sensitive to the logistics of the captured CO_2. Power import requirements are significantly reduced for the carbon capture case against the primary roadmap, and the excess fuel gas product is also eliminated.

A scenario whereby the steam consumers such as reboilers, heaters and tracing are replaced by direct electrical heating was also analysed to address a situation whereby the site's steam systems have significant condition and efficiency issues. Without including the potential benefit of eliminating a very inefficient steam system, this analysis resulted in a significantly greater investment cost.

Individual alternative roadmaps, fuel balances and analyses are presented in the full report.

OGCI REFINING INDUSTRY ELECTRIFICATION

Phase 1: Baselining

Credit: Unsplash/Joshua Sun

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1 Background

The Oil and Gas Climate Initiative ("OGCI"), launched in 2014, is a voluntary, CEO-led initiative which aims to drive the industry response to climate change. OGCI explicitly supports the Paris Agreement and its aims, collaborating on actions to reduce greenhouse gas (GHG) emissions, and acting with integrity to accelerate and participate in the energy transition. OGCI brings together twelve Oil and Gas companies, which together account for over 30% of global operated oil and gas production. Member companies are Aramco, bp, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Shell and TotalEnergies.

OGCI members leverage their collective strength to lower the carbon footprint of the energy, industry, and transportation value chains via engagements, policies, investments and deployment. This includes actions and knowledge-sharing across several key areas of impact on GHG. The OGCI is currently composed of six workstreams (WS), working on the following topics: CCUS, Role of Gas (and methane leakage), Energy Efficiency in the Industry, Transport, Natural Climate Solutions and Low Emission Opportunities.

The Energy Efficiency in Industry Workstream (EEI WS) has formed a working group with the purpose of developing a long-term roadmap to electrification based on technology, economics, and carbon reduction potential. This work aims to inform OGCI members of the potential for electrification to contribute carbon intensity reductions. The first stage for the development of this roadmap consists of the identification of opportunities and barriers for electrification of the O&G assets.

Electrification encompasses a range of complex opportunities for oil and gas operations, requiring a roadmap that describes and assesses the choices available in specific locations, ranging from electricity-driven rotating equipment, electric heaters, electric boilers, heat pumps and battery storage solutions through to fully electric facilities supplied from electrical grid systems, as well as optimal sequencing and timing in the overall asset life cycle. Electrification offers a powerful lever for efficiency gains, associated carbon reduction and offers the potential for zero scope 1 emissions from oil and gas facilities, meaning the topic is key to OGCI objectives.

In this context, the OGCI EEI WS has appointed Wood as independent consultant to assess the potential of electrification, a GHG emissions reduction lever, for the Refining Industry.

The study will focus on application of electrification to existing, generalised sites as opposed to greenfield development opportunities, capturing the difficulties and opportunities inherent in existing facilities.

2 Objectives

The primary objective of the Phase 1 is to establish a "typical refinery" baseline for the current energy mix for three refinery complexities. This will then form the basis for the next study phase aimed at identifying the opportunities for electrification of refineries.

Low complexity, mid-complexity and high-complexity baseline refineries have been established in close collaboration with the OGCI EEI WS stakeholders. Phase 1 objectives for each configuration are as follows:

- Provide a feasible, representative unit-level material balance for the configurations.
- Provide overall balance of steam, fuel and power to enable assessment of the site impacts of electrification options in later Phases.
- Provide a simplified, unit-level model of each representative site's utilities demands and production to enable assessment of impact of electrification options on each unit's major consumers.
- Highlight current major non-electrical energy consumers in each unit to provide potential applications for electrification technology.

Quantification of the potential of technologies for electrification will be carried out during Phases 2 and 3 where the major non-electrical energy consumers identified in Phase 1 will be targeted for electrification.

3 Abbreviations

Abbreviation	Description
ALK	Alkylation Unit
ARU	Amine Recovery Unit
BFW	Boiler Feed Water
CCR	Continuous Catalytic Regenerative Reformer Unit
CDU	Crude Distillation Unit
CKR	Coker Unit
DHT	Distillate Hydrotreater Unit
FCC	Fluid Catalytic Cracking Unit
FG	Fuel Gas
FO	Fuel Oil
HCU	Hydrocracker Unit
HP	High Pressure
HPU	Hydrogen Production Unit
HSFO	High Sulphur Fuel Oil
ISM	Isomerisation unit
KHT	Kerosene Hydrotreater Unit
KMU	Kerosene Merox Unit
KMX	Kerosene Merox Unit
LGO	Light Gas Oil
LP	Low Pressure
MTBE	Methyl Tertiary Butyl Ether
MP	Medium Pressure
NHT	Naphtha Hydrotreater
SGP	Saturated Gas Plant/ LPG Treater & Recovery
SRU	Sulphur Recovery Unit
SWS	Sour Water Stripping Unit
UGP	Unsaturated Gas Plant/ LPG Treater/ C3= Splitter

Abbreviation	Description
VDU	Vacuum Distillation Unit
VGO	Vacuum Gasoil
VHT	Vacuum Gasoil Hydrotreater
VR	Vacuum Residue

4 Study Basis

4.1 Refinery Configuration Goals

Globally, refinery configurations are incredibly diverse, including many feeds, production technologies and products. Economic drivers and specific limitations vary widely, as well as site age and technology level. Capturing the full breadth of refineries is not possible in this study and would not assist clarity of results.

The goal is to provide "typical" refinery configurations for varying complexities in order to make the results from this study applicable to as many refineries as possible. Complexity is a key parameter in a site's characteristics whereby a more complex site will include more processing and upgrading steps to higher value products or from lower value feeds. More complex refineries are larger, more expensive to build and run and provide a greater value of products versus feeds. They consume greater quantities of energy to run due to the complex process units and the utilities feeding them.

The configurations have been chosen to exclude unnecessary specific features, hence are as generic as possible to allow results to be understandable and relatable to existing sites.

Deliberate differences in some unit choices have been made between configurations to allow investigation of different site balances and unit challenges. For example, a Hydrocracking configuration is expected to consume more hydrogen and produce less fuel gas than a site based around Fluidised Catalytic Cracking.

Configurations represent current and near-future fuels specifications aligned with the Euro-V specifications to ensure relevance to the refineries that will be running in the medium-term. As part of the material balance, streams are blended to product pools to stay within these specifications.

4.2 Key Processing Decisions

4.2.1 Crude Selection and Capacity

<u>Low Complexity</u>

The low complexity refinery is based on 100,000 barrels per stream day of crude oil feed, which tends to be typical for topping refineries without heavier upgrading units.

The crude type for this complexity is split 50:50 between Arabian Light and Brent. A lighter blend is targeted to avoid excessive yield of atmospheric residue which is not upgraded. The crudes have been chosen to represent assays and properties that are well known and typical.

<u>Medium Complexity</u>

The medium complexity refinery is based on 200,000 barrels per stream day of crude oil feed, with medium complexity sites expected to be at this level of capacity.

The crude type for this complexity is split 50:50 between Arabian Light and Brent. A lighter blend is targeted to avoid excessive yield of vacuum residue which is not upgraded in this configuration, but still provides a full range of feeds for the straight-run and VGO units.

<u>High Complexity</u>

The high complexity refinery is based on 200,000 barrels per stream day of crude oil feed. The capacity of high complexity sites varies widely and can be much greater with multiple trains in operation. However, the capacity selected is considered typical for a site with single process unit trains.

The crude type for this complexity is 100% Arabian Heavy. A heavier feed is selected due to the economics of utilising the vacuum residue upgrading units available for this configuration.

4.2.2 VGO Processing

The choice of Vacuum Gasoil (VGO) processing/upgrading unit is not straightforward as the site fuel and hydrogen balance is affected significantly and both FCCs and hydrocrackers are prevalent globally.

The estimated global VGO processing capacity distribution is shown in Figure 1.   FCCs are dominant with Hydrocracking a significant proportion of units.

The High Complexity configuration includes an FCC to ensure that the specific challenges around fuel gas production, steam generation and shaft work in this unit are captured.

The Medium Complexity configuration has been deliberately chosen to include the different VGO hydrocracking configuration, which will demonstrate a different site hydrogen and fuel balance.

The Low Complexity configuration does not include VGO processing

Figure 1: Global VGO Processing Distribution

4.2.3 Vacuum Residue Processing

Vacuum Residue (VR) upgrading is limited to the High Complexity configuration. An assessment of global capacity of VR processing units is shown. Thermal processes are dominant with delayed coking being most common.

Visbreaking is also common in units known to be running or recently running globally. However, due to increased difficulty in selling high sulphur fuel oil, visbreakers are viewed as less relevant to configurations expected to be operating in the medium term.

Figure 2: Global VR Processing Distribution

4.3 Selected Configurations

A block flow diagram for each of the refinery configurations is provided in Figure 3, Figure 4 and Figure 5 for the low, medium and high refinery configurations respectively.

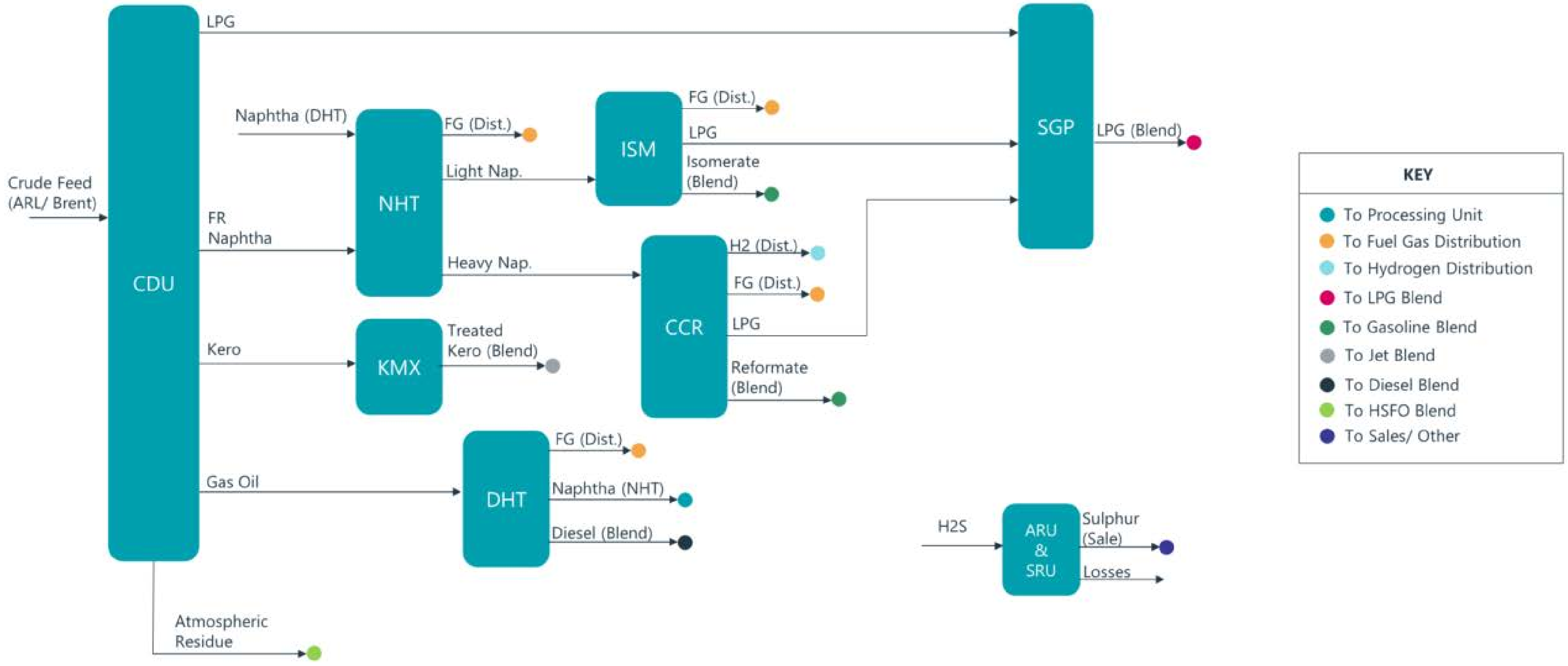

Figure 3: Low Complexity Refinery Configuration

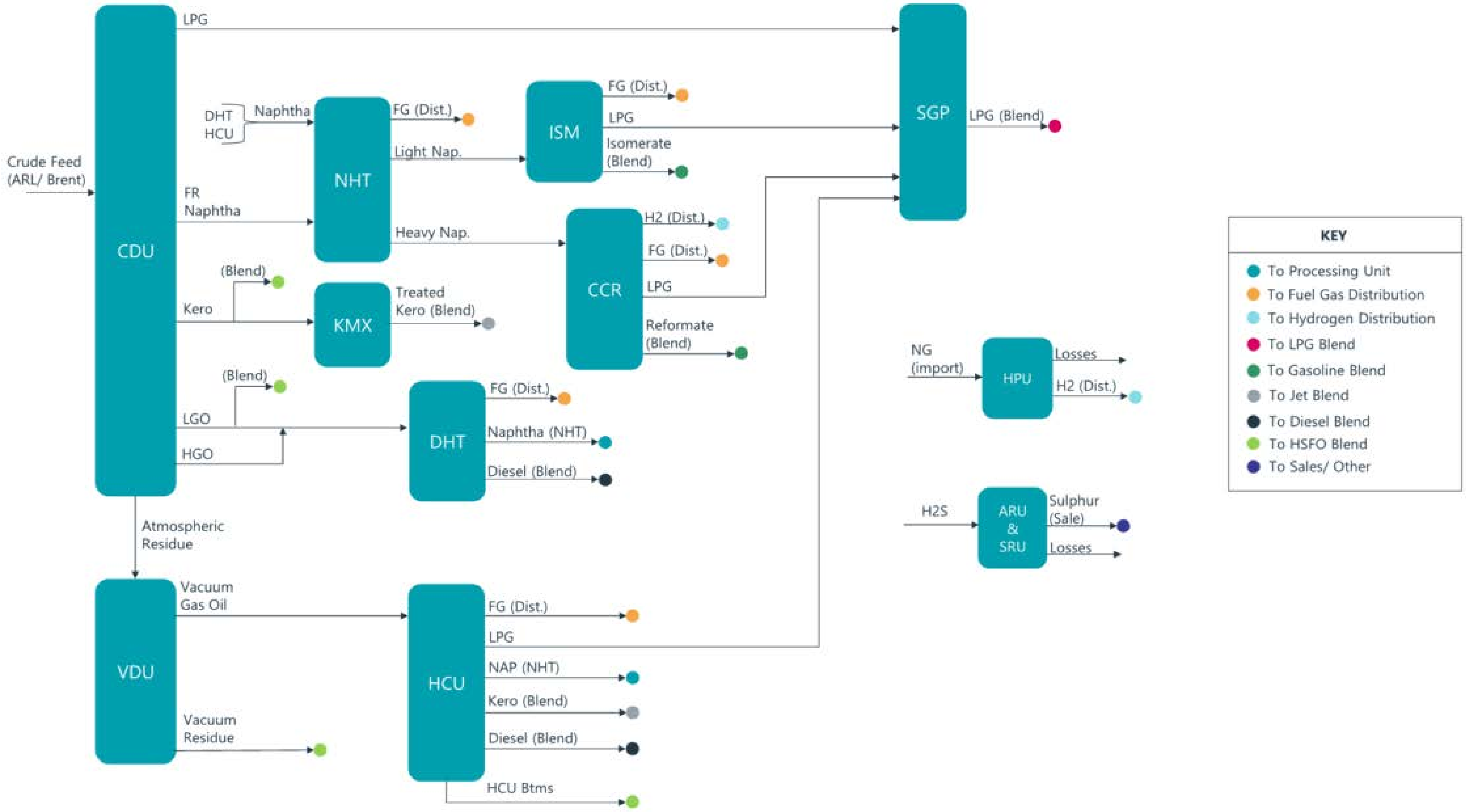

Figure 4: Medium Complexity Refinery Configuration

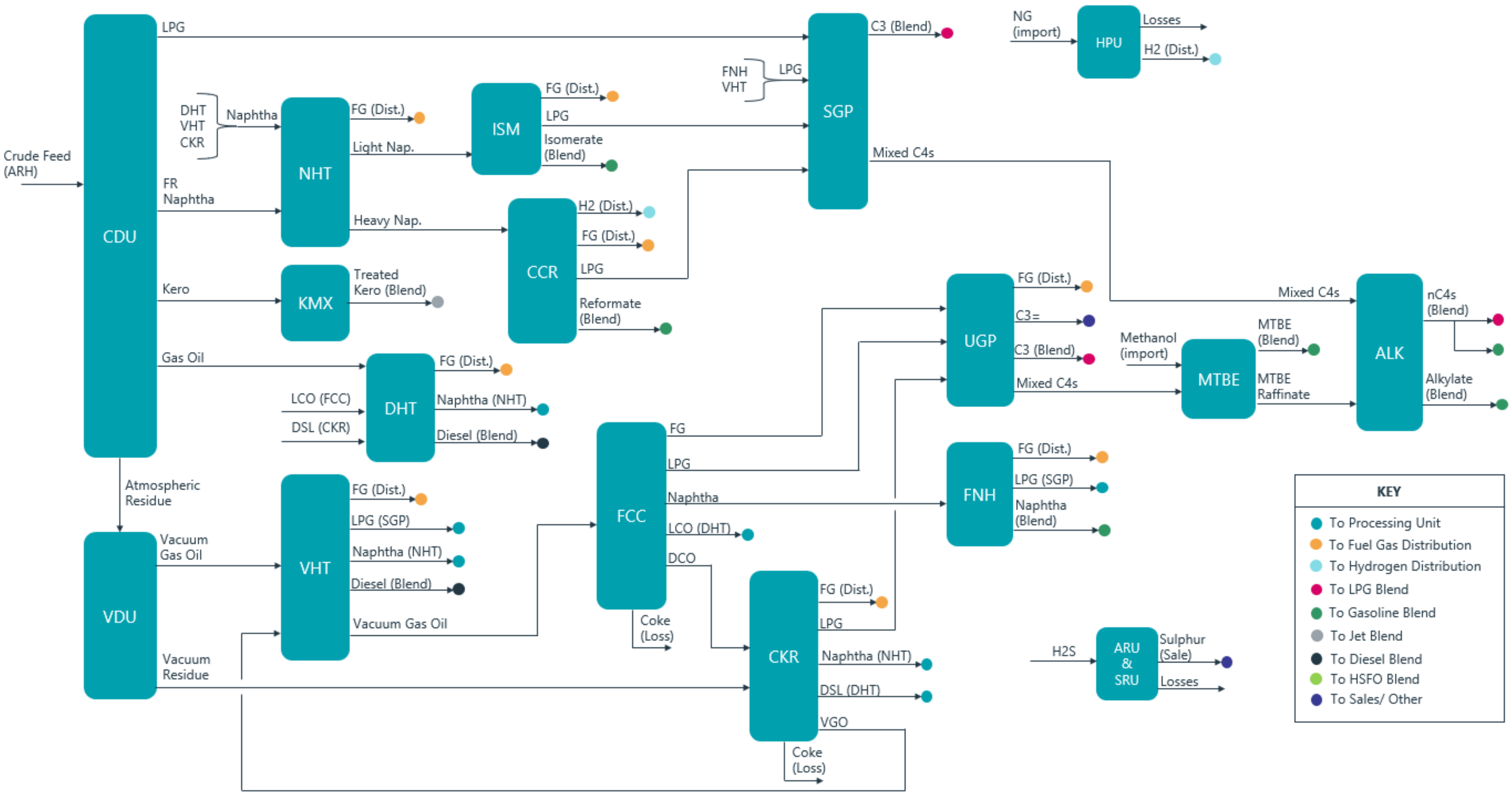

Figure 5: High Complexity Refinery Configuration

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4.3.1 Unit Operations

A summary of the unit operations considered in each of the configurations are provided in Table 1. Key differences in unit operations are a result of the extent to which each configuration processes the heavy hydrocarbons streams.

Table 1: Refinery Complexity Unit Operations

Unit Operation	Low Complexity	Medium Complexity	High Complexity	Notes
Crude Distillation Unit	✓	✓	✓	All complexities require CDU to fractionate the crude feed into useful streams
Vacuum Distillation Unit	-	✓	✓	Low complexity is a hydroskimming-type refinery that does not further fractionate atmospheric residue, hence a VDU is not included
Naphtha HDT (SR)	✓	✓	✓	Naphtha hydrotreating, isomerisation and reforming is included for all configurations to facilitate Euro-V, high octane gasoline product.
Naphtha Splitter	✓	✓	✓	
C5/C6 Isomerisation Unit	✓	✓	✓	
Continuous Catalytic Reformer	✓	✓	✓	
Kero Merox Unit	✓	✓	✓	Kerosene Merox units are included assuming current Jet specifications
Distillate HDT	✓	✓	✓	Diesel hydrotreatment is included to provide Euro-V quality product.
Hydrocracker	-	✓	-	A Hydrocracking unit is included within the medium complexity configuration to produce a high hydrogen demand configuration. Inclusion of the HCU also boosts jet and diesel production compared to the low complexity case
VGO HDT	-	-	✓	Configured to treat VGO and remove sulphur in advance of the FCC to improve reactor yield in the high complexity case.

Unit Operation	Low Complexity	Medium Complexity	High Complexity	Notes
Fluid Catalytic Cracker	-	-	✓	FCC included in the high complexity case to process hydrotreated VGO to lighter products.
FCC Naphtha HDT			✓	Required to treat FCC Naphtha prior to Gasoline blending for Euro-V sulphur specification
Saturated Gas Plant	✓	✓	✓	Required for separation and treatment of gas and LPG
Saturated LPG Merox	✓	✓	✓	
C3/C4 Splitter	-	-	✓	Included as a standalone operation in the high complexity case as there is a requirement to separate the C3's and C4's due to inclusion of alkylation unit
Unsaturated Gas Plant	-	-	✓	Only required by the high complexity case due to inclusion of FCC/Coker that produce unsaturated gas
Unsaturated LPG Merox	-	-	✓	Required for high complexity case light ends.
Unsaturated LPG Separation/ Propylene Splitter	-	-	✓	C3s and C4s are separated to provide and mixed C4 stream to MTBE unit and Alkylation. Propylene splitter included to recover valuable propylene and provide an additional unit operation not already covered in the other cases
MTBE	-	-	✓	Due to availability of iso-butene produced from FCC, MTBE unit included to provide useful gasoline blending component and another unit operation not covered in the other cases.
H2SO4 Alkylation Unit	-	-	✓	Another unit operation common to this configuration due to inclusion of FCC
Coker	-	-	✓	Coker included to increase complexity and is a widely used vacuum residue upgrading unit

Unit Operation	Low Complexity	Medium Complexity	High Complexity	Notes
Hydrogen Plant	-	✓	✓	Required by medium and high complexity cases due to high hydrogen demands from units such as the HCU and VGO HDT not found in the low complexity case
Amine Unit/ SWS/ SRU	✓	✓	✓	Required by all cases in processing of H2S and recovery of sulphur

4.3.2 Other Considerations

The following key results and decisions are given for each configuration.

Low Complexity

For the purposes of this study, atmospheric residue is routed to fuel oil. In reality, many surviving topping refinery sites export this residue to other sites as a feed for upgrading without blending to fuel oil grade, though this has little impact on the study basis. As much of the sulphur content of the crude is contained within this residue fraction, sulphur production is limited.

MTBE is imported to meet gasoline pool octane specification.

A natural gas import is required to meet the process unit fuel gas demands.

Medium Complexity

Vacuum residue is routed to fuel oil; there are other potential destinations for this residue such as sales to bitumen or upgrading. Again, alternative routing would have little impact on the study basis. By itself, this stream does not meet the fuel oil specification. Consequently kerosene & light gasoil from the CDU are blended to meet the specification.

MTBE is imported to help meet the gasoline fuel specification.

A natural gas import is required to meet the process unit fuel gas demands.

High Complexity

The processing of VGO and VR to higher value products allows fuel oil production to be avoided and maximises gasoline and diesel product.

This case produces MTBE due to the availability of isobutene from the FCC and unsaturated gas plant. The produced MTBE is blended with gasoline to meet the octane specification. Methanol import is required for this case to produce the MTBE.

There is a margin on Reid Vapour Pressure specification in the gasoline pool, which enables a small quantity of butane to be blended to boost gasoline production economics.

A natural gas import is required to meet the process unit fuel gas demands.

4.4 Utilities and Offsite Configuration

Typical utility configurations have been developed for each of the three refinery complexity cases

Table 2 describes the basis for each refinery complexity. This is supported by configuration schematics of the steam, water and power systems on subsequent pages.

Table 2: Utility basis for varying refinery complexities

Area	Low Complexity	Medium Complexity	High Complexity	Discussion
Steam Levels	HP, MP & LP	VHP, HP, MP & LP	VHP, HP, MP & LP	Each configuration requires three steam levels (high pressure, medium pressure and low pressure). The medium and high complexity case also considers a very high pressure steam level, maximising efficient power generation from steam turbines
Steam Production	Boilers	Boilers	Cogeneration + Boilers	Cogeneration is considered for the high complexity case where a gas turbine is employed to generate power with the waste heat recovered to raise steam. Boilers are used to provide the balance of steam supply.
Boiler Fuel	Fuel Gas + Natural Gas	Fuel Gas + Natural Gas	Fuel Gas + Natural Gas	Boiler Fuel is fuel gas supplemented with marginal natural gas
Power	Import	STG + Import	GT + STG + Import	Power system complexity increases with refinery complexity. For medium and high complexities, a Steam Turbine Generator is used to generate power when letting steam down between pressure levels. The high complexity case uses a gas turbine to generate power with waste heat recovered via steam production
Boiler Feed Water	Electric & steam turbine drive	Electric & steam turbine drive	Electric & steam turbine drive	BFW pumps are generally large and sometimes driven by steam turbine for increased reliability. Each complexity considers a mix of drives
Cooling Water	Once Through	Once Through	Once Through	Once through CW system considered for all complexities. This simplifies approach as the main utility demand is power irrespective of cooling water system configuration.
Imported Water	Raw Water	Raw Water	Raw Water	Raw water considered as import; no desalination requirements considered
Instrument Air	Electric & steam turbine drive	Electric & steam turbine drive	Electric & steam turbine drive	Instrument air is a critical system. It is common to split drives across compressors to support safe operation should there be a failure in one of the utility systems.

Area	Low Complexity	Medium Complexity	High Complexity	Discussion
Flare	Fuel gas purge & steam for flare tips	Fuel gas purge & steam for flare tips	Fuel gas purge & steam for flare tips	Fuel gas purge for flare headers and steam for dispersion at the flare tips
Fuel Firing	Fuel Gas	Fuel Gas	Fuel Gas	100% fuel gas firing is considered. This is typical of many facilities although it is recognised that refineries can and do use liquid fuels such as fuel oil. Choice of fuel is not expected to impact the results of this study as whether fuel gas or fuel oil fired the intention is to replace with an electric option.

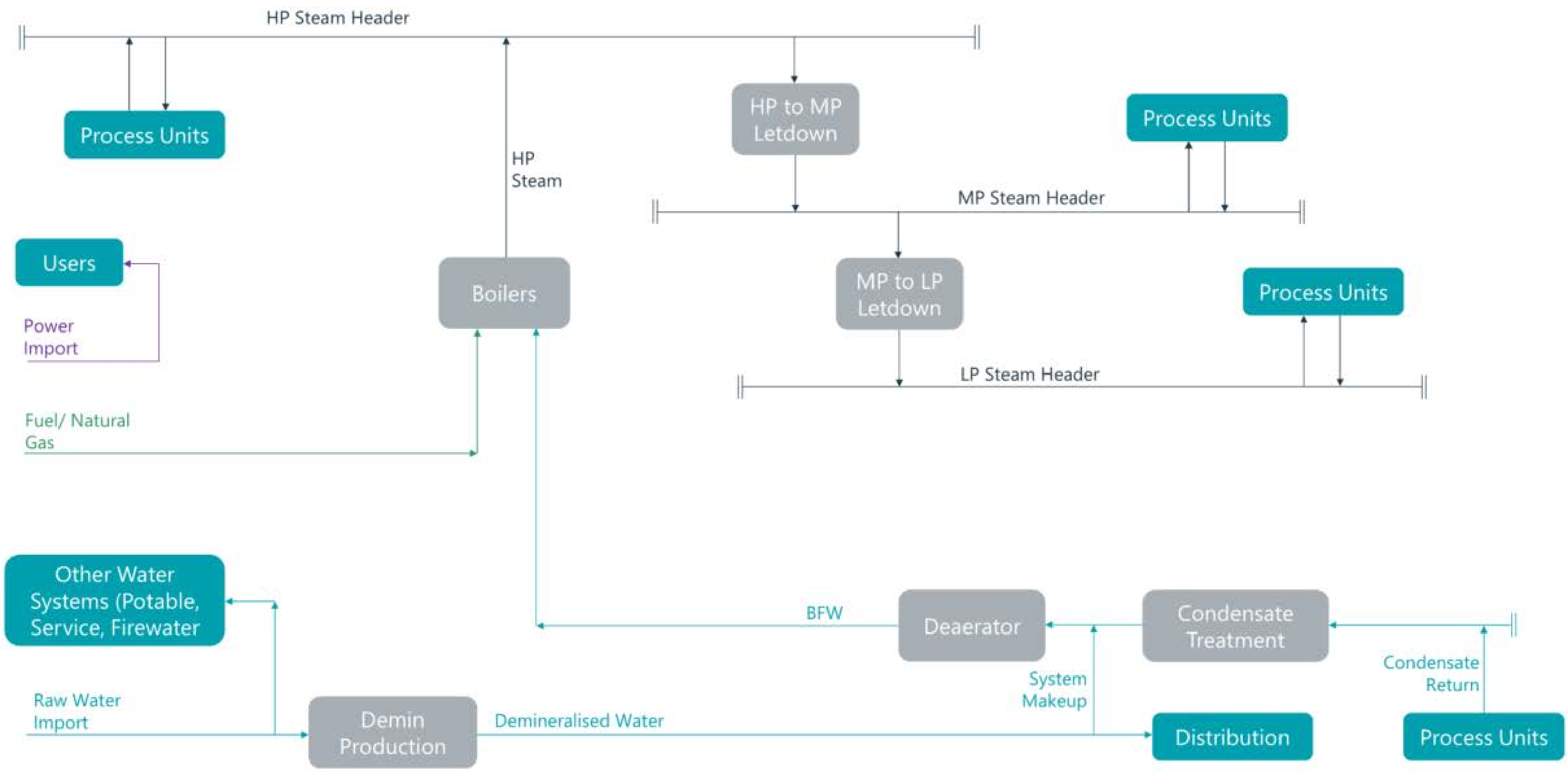

Figure 6: Low Complexity Steam & Power Configuration

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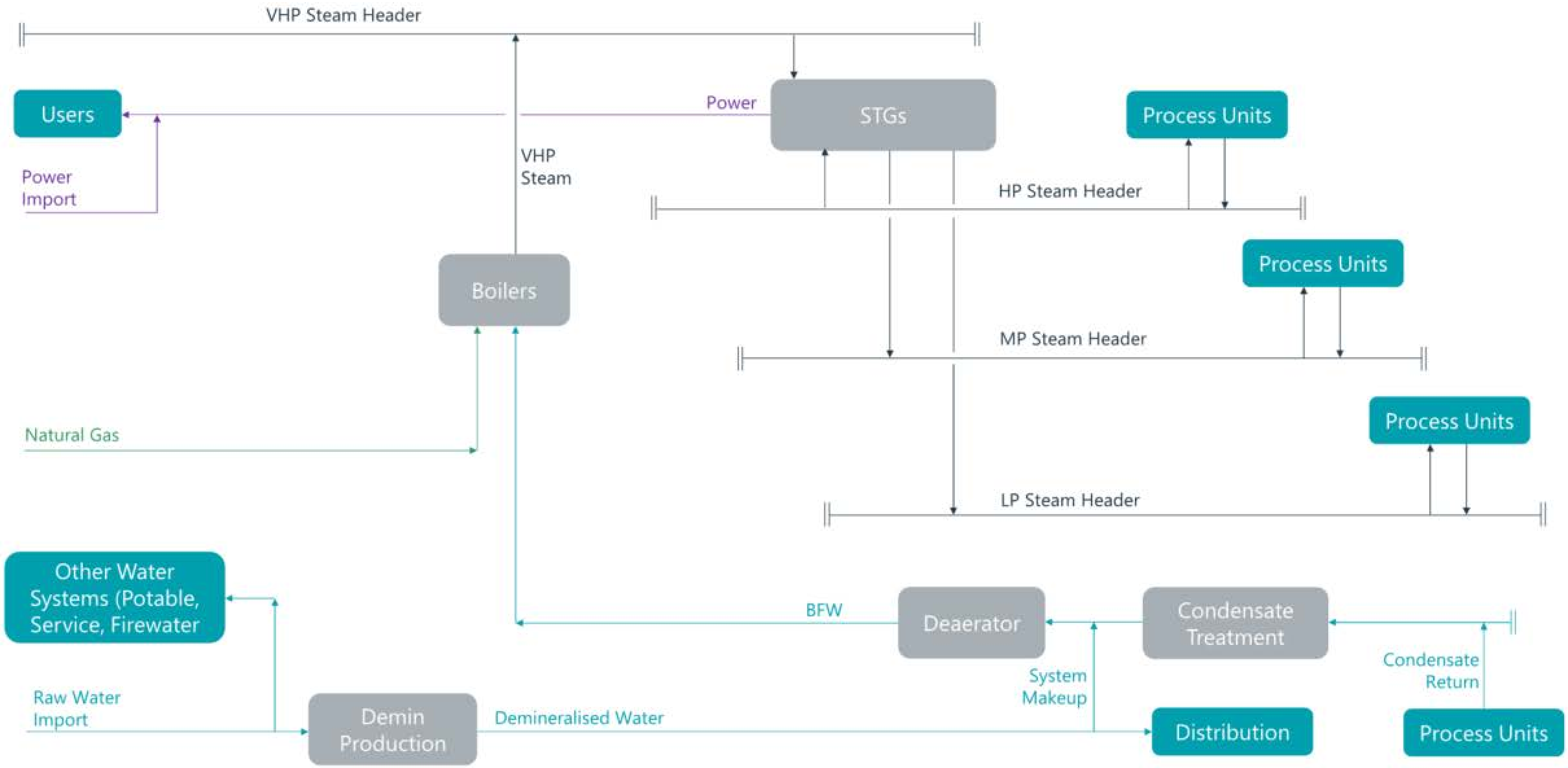

Figure 7: Medium Complexity Steam & Power Configuration

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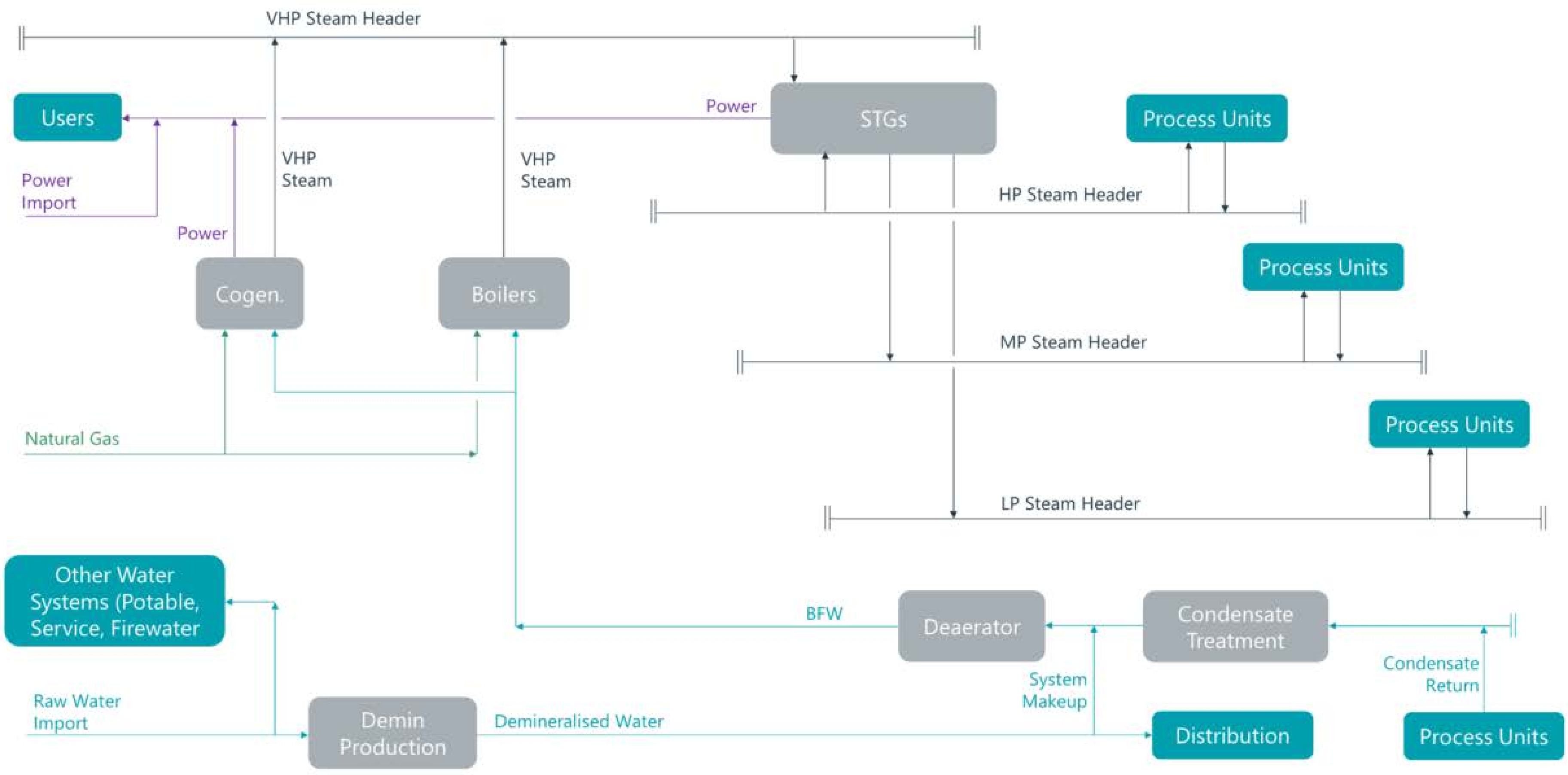

Figure 8: High Complexity Steam & Power Configuration

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5 Material Balance

5.1 Crude Oil Feedstocks

Following the crude and capacity selection exercise, Table 3 summarises the capacity and crude slate that have been selected as a basis for the three levels of refinery complexities.

Table 3: Utility basis for varying refinery complexities / Crude feedstocks

Feedstock	Unit	Low Complexity	Medium Complexity	High Complexity
Crude oil	kBPSD	100	200	200
Composition:				
Arabian Light	Vol%	50	50	-
Brent	Vol%	50	50	-
Arabian Heavy	Vol%	-	-	100

5.2 Refinery Products

Table 4 provides the product quantities for each of the three refinery complexities. The low complexity case produces significantly lower product quantities due to the lower overall refinery throughput. Sulphur product is also significantly lower for this case as the heavy portion of the crude feed that contains the majority of the sulphur is not processed in this configuration but instead routed to fuel oil.

Unlike the low complexity case the medium complexity case processes atmospheric residue in a VDU for further upgrading of VGO. This boosts the production of higher value product. The production of fuel oil for the medium complexity case is approximately the same as the low complexity case despite processing double the quantity of crude feed. The Vacuum Residue from the VDU is not processed and is instead sent to fuel oil. In order to meet HSFO specification additional components are required to be blended. In this instance kerosene and LGO from the CDU are blended to bring the HSFO pool on specification.

The high complexity case goes a step further than the medium complexity case in processing the heavy streams. Whereas the medium complexity case routes the vacuum residue to fuel oil the high complexity case processes this stream via a Delayed Coker Unit, boosting diesel production and in doing so removing the production of fuel oil. The high complexity case also includes an FCC unit that boosts gasoline production. Propylene is also produced by the FCC which is a valuable chemical product and so it is recovered and routed to sales. The high complexity cases produces the greatest amount of sulphur due to the processing of a heavier crude feed and the upgrading of vacuum residue where a large proportion of sulphur is found. This releases sulphur as H_2S and the sulphur is recovered via the SRU. Coke is also produced as a byproduct form the Delayed Coker.

Table 4: Product slate

Product	Unit	Low Complexity	Medium Complexity	High Complexity
LPG	BPSD	4,380	13,090	12,710
Gasoline	BPSD	21,930	55,950	71,570
Jet	BPSD	17,350	49,990	27,550
Diesel	BPSD	17,220	50,720	73,210
HSFO	BPSD	38,990	39,660	0
Propylene	TPSD	0	0	558
Sulphur	TPSD	21	159	578

The overall material balance for each refinery configuration is provided in Attachment 1.

6 Utility Summary

6.1 Overall Utility Balances

Table 5 quantifies the utility demands for each refiner complexity. The figures include the utility requirements from the process units as well as those from the offsites and utility systems such as storage, cooling water, instrument air, etc.

It can be observed that with increasing complexity the utility demands increase. The utility demands for the low complexity case are significantly lower compared to the medium and high complexity cases due to the reduced number of energy-intensive unit operations and their associated utilities and offsites as well as a lower overall refinery crude throughput.

There is a surplus of HP steam produced in the medium and high complexity cases. This is because there are few users of HP steam in the refinery configurations and the significant quantities of HP steam produced from the CCR and HPU that is greater than demand. The excess HP steam is routed to a steam turbine to generate power for these cases.

Though the medium complexity case generates power from the letdown of steam between pressure levels via steam turbines. However, the power produced is insufficient to cover the full requirements and so an import of power is also required.

The high complexity case utilises a gas turbine to generate power, followed by steam raised from the waste heat. The power produced from the gas turbine and the letdown of steam via the steam turbines is sufficient to meet the case power demands. There is however a shortfall in the availability of steam. To makeup for this shortfall, steam boilers are utilised, fired on natural gas import and the site fuel gas to supplement the steam supply.

Utility demands on a unit level are recorded in Attachment 2.

Table 5: Overall utility balances for varying refinery complexities

Utility	Units	Low Complexity	Medium Complexity	High Complexity
Cooling Water	m^3/hr	3,150	11,920	19,840
HP Steam	t/hr	30	114	175
MP Steam	t/hr	23	-5.8	231
LP Steam	t/hr	5	50	329
LP Cond	t/hr	-65	-235	-795
Electric Power	MW	31	89	128
Fuel Gas Fired	GJ/hr	765	2,550	4,705
BFW	m^3/hr	87	323	1,017

(1) Positive figures indicate consumption, negative figures indicate production.

wood.

6.2 Refinery Energy Consumption Distribution

To provide an overview of major energy demands are in a refinery complex the steam, power and fuel gas are converted to energy units to allow comparison between the three. The steam conditions used for determining energy requirements are presented in Table 6.

Table 6: Steam Condition Basis for Heat Value

Steam Condition	Units	HP	MP	LP
Pressure	barg	43	18	5
Temperature	°C	390	290	180

Figure 9 provides a comparison between the three complexity cases looking at the overall facility energy demands, whereas Figure 10, Figure 11 and Figure 12 illustrate the energy demands for low, medium and high complexity refinery configurations and how this energy is consumed/ distributed between the various unit types. For simplicity the units are grouped into similar families on the following basis:

- Separation Units
- Hydrotreaters
- Gasoline Components
- VGO and VR Upgrading
- Auxiliary Units
- O&U Systems

From Figure 9 it can be seen that fuel gas accounts for the majority of energy demand for all three refinery configurations. This is an important consideration when looking at electrification as it demonstrates the potential scale of electrification required. For the low and medium complexity cases, power is imported whereas for the high complexity configuration no power is imported. This is because for the high complexity case all facility power demands are met by the on-site cogeneration system.

It can be seen from Figure 10, Figure 11 and Figure 12 that for all complexity cases the offsite and utility energy demands contribute a significant proportion of the overall demand demonstrating that it is not just process units but also the support facilities that can have a major impact on the extent of electrification requirements.

The major equipment items that contribute to the energy demand for each unit are described in Section 7.

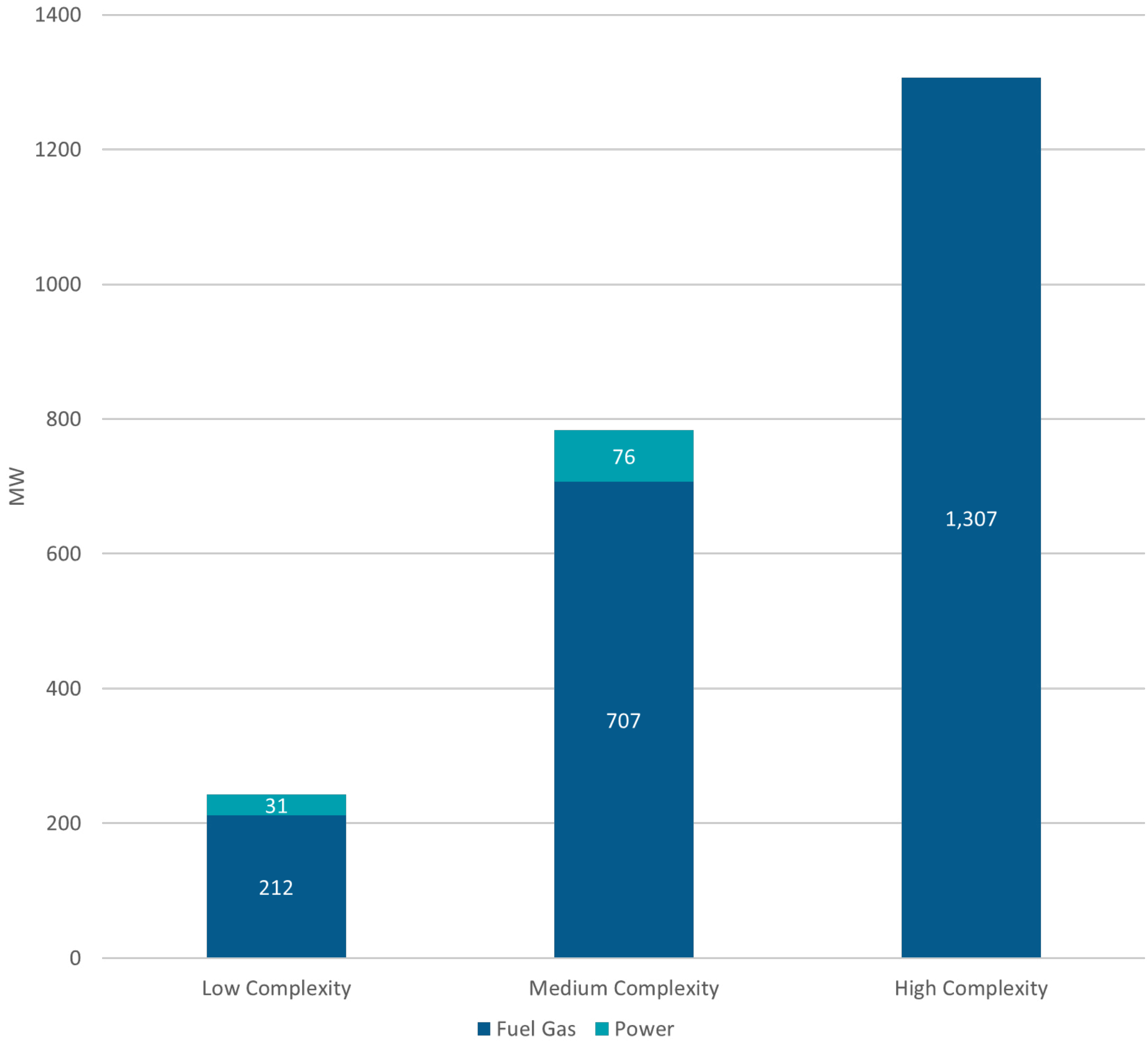

Figure 9: Energy Demand Comparison

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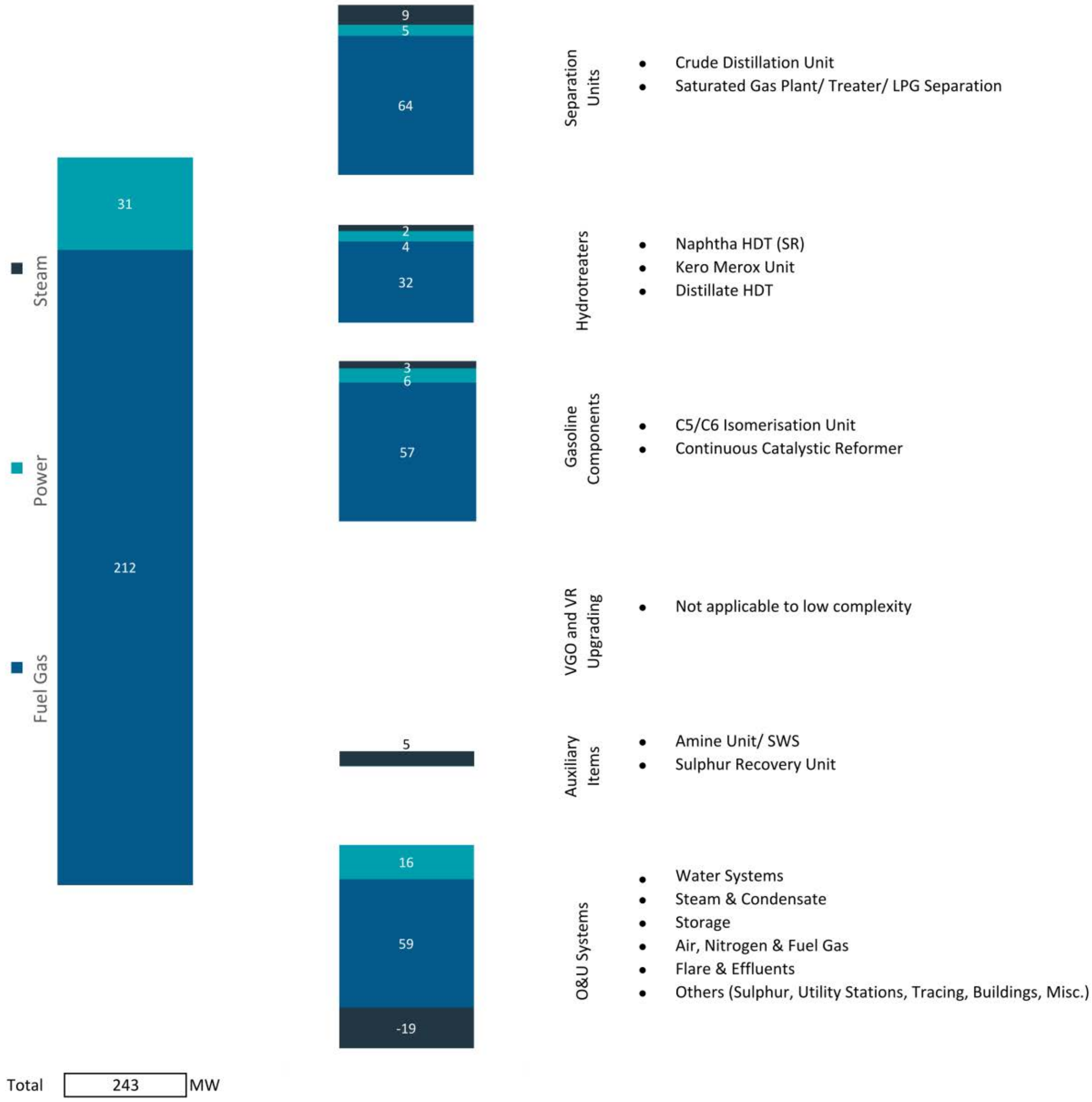


Figure 10: Low Complexity Energy Demand Distribution (Units MW)

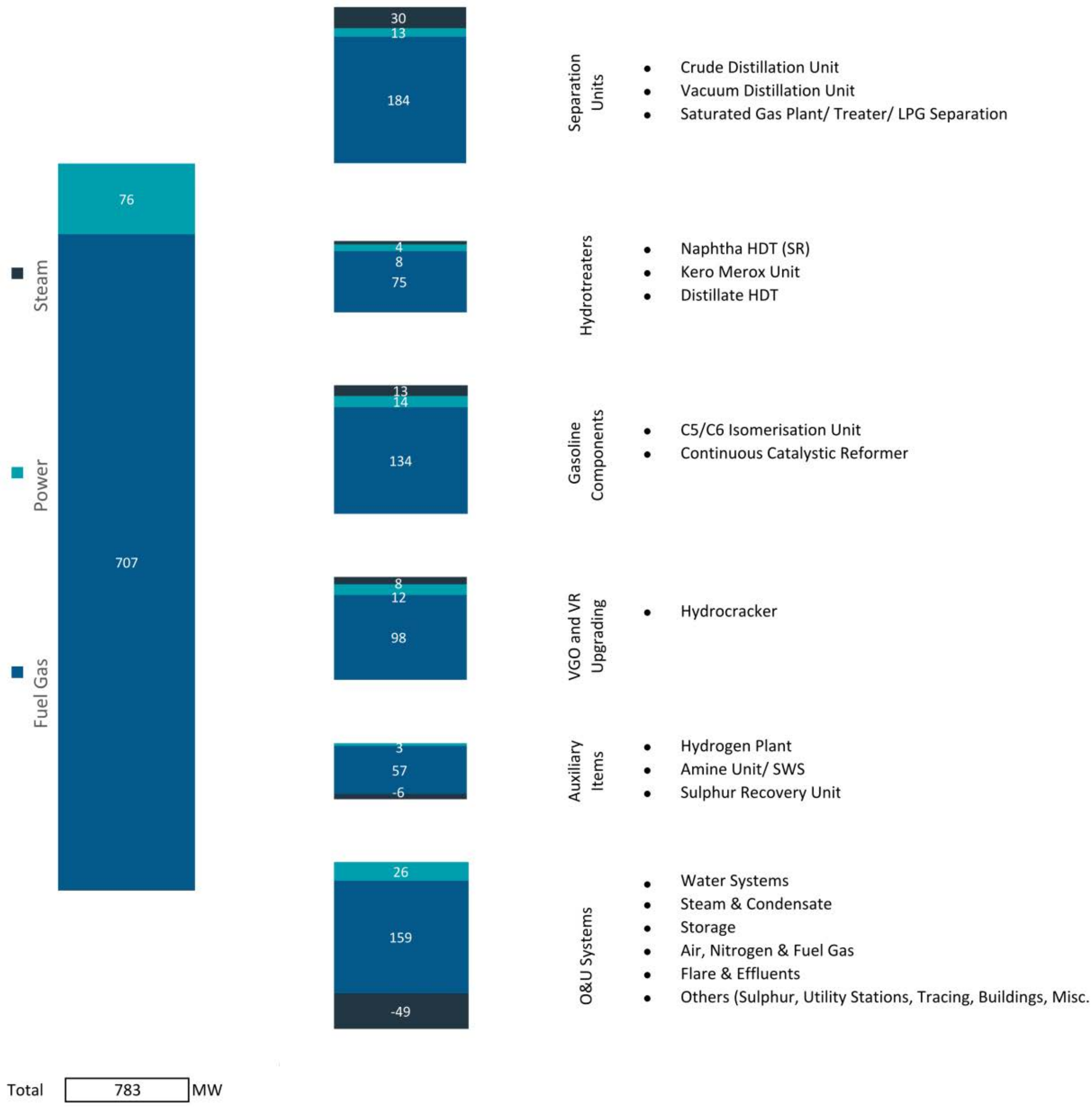


Figure 11: Medium Complexity Energy Demand Distribution (Units MW)

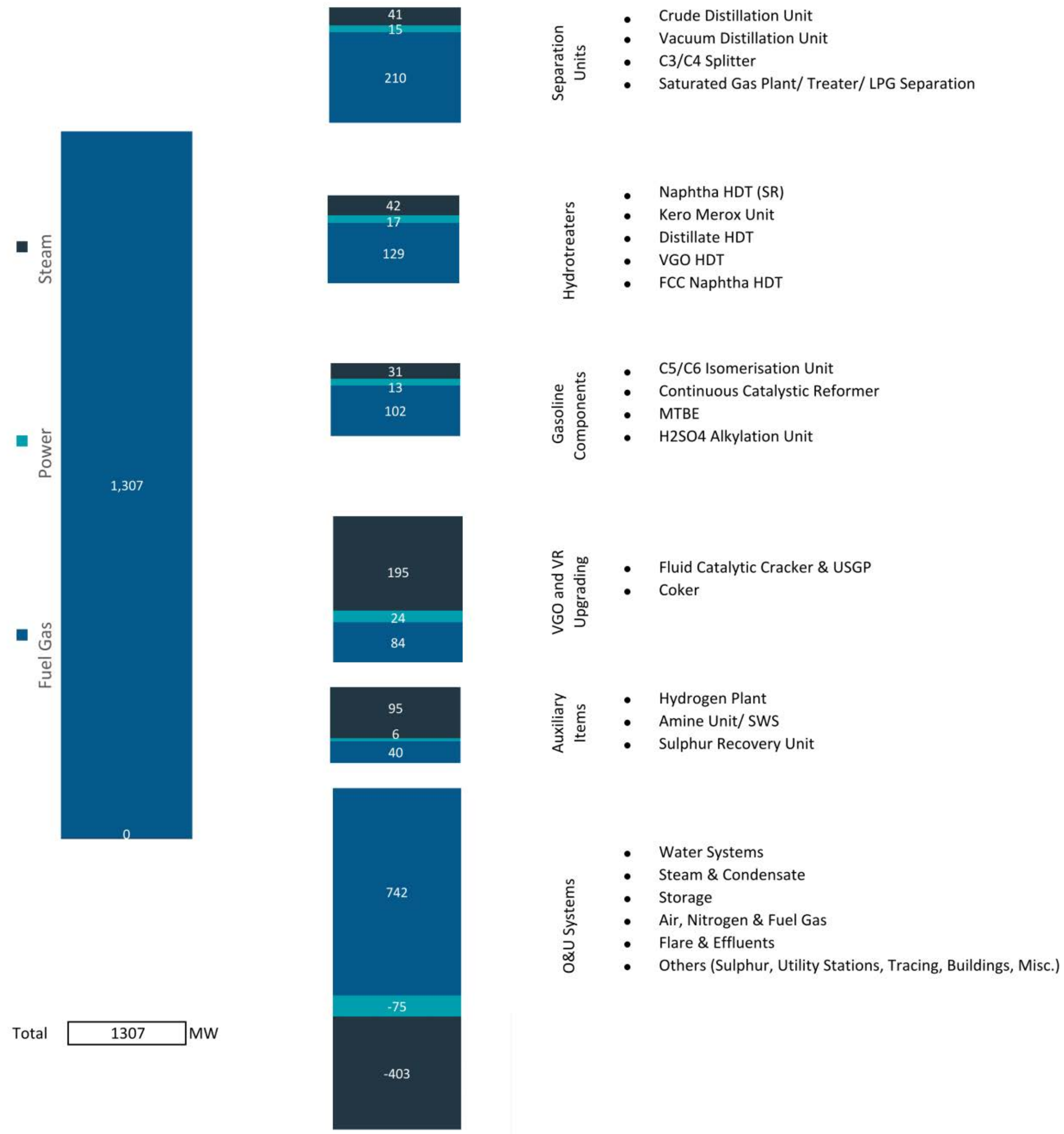


Figure 12: High Complexity Energy Demand Distribution (Units MW)

7 Identified Non-Electrical Energy Consumers

This section identifies the areas within the refinery and utilities and offsites areas where significant non-electrical utilities are consumed and the equipment where this occurs.

7.1 Separation Units

Table 7 describes the non-electrical utility consumers of separation units within the refinery configurations and the key items of equipment where consumptions occur.

The CDU and VDU heaters are significant fuel gas consumers. These units also require a large quantity of direct injection steam (condensate not recovered) to avoid coking, improve fractionation and in the vacuum overheads with current designs. LPG treatment and separation utilizes steam as a reboiling heat source.

Table 7: Non Electrical Energy Consumers – Separation Units

Unit	Utility	Equipment/Operations
Crude Distillation Unit	Fuel gas	Charge heater Naphtha debutaniser reboiler
	Steam	Fractionation column base and side strippers
Vacuum Distillation Unit	Fuel gas	Charge heater
	Steam	Column base stripping steam Heater coil steam Vacuum overheads ejectors
C3/C4 Splitter	Steam	Fractionation column reboiler
Saturated Gas Plant/ treater/ LPG separation	Steam	Fractionation column reboiler
Unsaturated Gas Plant/ treater/ separation / PP splitter	Steam	Fractionation column reboilers

7.2 Hydrotreaters

Table 8 describes the non-electrical utility consumers of hydrotreaters within the refinery configurations and the key items of equipment where consumptions occur.

The various hydrotreating units each include at least one fired heater to heat the process fluid prior to reaction or distillation. Steam is required for fractionation in reboilers or direct injection strippers. For larger hydrogen recycle flows such as with a VGO Hydrotreater, shaft work may be steam driven.

Table 8: Non Electrical Energy Consumers – Hydrotreaters

Unit	Utility	Equipment/Operations
Straight Run Naphtha Hydrotreater and Naphtha Splitter	Fuel Gas	Feed heater
	Steam	Naphtha splitter reboiler
Distillate HDT	Fuel Gas	Feed heater
	Steam	Stripping/Fractionation
VGO HDT	Fuel Gas	Feed heater Fractionation heater
	Steam	Recycle gas compressor driver Stripping in fractionator
FCC Gasoline HDT	Fuel Gas	Feed/Reactor heater
	Steam	Reboiler in fractionation column

7.3 Gasoline Component Units

Table 9 describes the non-electrical utility consumers of gasoline related units within the refinery configurations and the key items of equipment where consumptions occur.

Steam use in the fractionation column reboilers is common across these units, with some fractionators utilizing fired reboilers.

The Continuous Catalytic Reformer includes large compressors which are often steam driven. This unit is also a major fuel gas consumer in the reactor heaters. These heaters also produce a significant quantity of HP steam.

Table 9: Non Electrical Energy Consumers – Gasoline Component Units

Unit	Utility	Equipment/Operations
C5/C6 Isomerisation Unit	Steam	Process heaters and fractionation reboiler(s)
Continuous Catalytic Reformer	Fuel gas	Process heaters Stabiliser reboiler
	Steam	Recycle and net gas compressor drivers
MTBE	Steam	Fractionation reboilers
H2SO4 Alkylation Unit	Fuel Gas	Fractionation reboiler
	Steam	Fractionation reboiler

7.4 VGO and VR Upgrading Units

Table 10 describes the non-electrical utility consumers of the VGO and VR upgrading units within the refinery configurations and the key items of equipment where consumptions occur.

The Hydrocracker and FCC differ in their impact on the fuel and steam balance. The FCC produces a large quantity of steam but typically uses this for injection and to drive the Main Air Blower and the downstream Wet Gas Compressor. The Hydrocracker consumes fuel gas in its heaters and often consumes steam to drive the recycle gas compressor.

The Delayed Coker consumes a large amount of fuel in its heater and can generate steam from cooling of the fractional distillation.

Table 10: Non Electrical Energy Consumers – VGO and VR Upgrading Units

Unit	Utility	Equipment/Operations
Hydrocracker	Fuel Gas	Feed heater Fractionation heater
	Steam	Recycle gas compressor Stripping in fractionation
Fluid Catalytic Cracker	Steam	Main Air Blower driver Riser injection Catalyst stripping Main column strippers
Coker	Fuel Gas	Feed heater
	Steam	Purges Stripping in fractionation

7.5 Hydrogen and Treatment Units

Table 11 describes the non-electrical utility consumers of the hydrogen production and treatment units within the refinery configurations and the key items of equipment where consumptions occur.

The hydrogen plant is a net producer of high pressure steam despite consuming a significant quantity as part of the reaction feed whilst the Amine regeneration and Sour Water Stripping columns typically use steam to drive separation.

The Sulphur Recovery Unit produces steam from the outlet of the reaction furnace, but consumes different levels of steam in its reheaters.

Table 11: Non Electrical Energy Consumers – Hydrogen and Treatment units

Unit	Utility	Equipment/Operations
Hydrogen Plant	Fuel Gas	Reaction feed and furnace firing
	Steam	Generation in rundown and consumption in feed
Amine Unit/ SWS	Steam	Stripping/fractionation
Sulphur Recovery Unit	Steam	Generation and consumption in waste heat boiler and reheaters

7.6 Utilities and Offsites

Table 12 describes the non-electrical utility consumers of the refinery utilities and offsites and the key items of equipment where consumptions occur.

Table 12: Non Electrical Energy Consumers – Utilities and Offsites

Unit	Utility	Equipment/Operations
Steam boilers including condensate system	Fuel Gas	Boilers
	Steam	Deaeration steam BFW pump drivers Boiler fans
Tracing and tank heating	Steam	ISBL and offsites steam tracing Steam coils for tank heating
Firewater	Diesel	Emergency diesel backup/duty drivers for firewater pumps
Instrument air	Steam	Steam turbine compressor driver
Sulphur storage	Steam	Heating of stored material
Flare	Fuel gas	Fuel gas purge
	Steam	Dispersion steam at flare tip

8 Conclusions & Next Steps

The primary objective of the Phase 1 was to determine a baseline for the current energy mix in the representative refineries.

Key to this stage has been the definition of representative refining configurations, where three levels of complexities have been mutually agreed with the Workstream Stakeholders

These three representative process configurations, covering a variety of complexities and technologies, have then been modelled using Wood extensive in-house projects database, and a typical mapping of the corresponding energy demands and producers has then been developed.

The supporting utilities and offsites systems have also been assessed along with a high-level steam balance.

Utility demands have been calculated for each unit/area and for the refineries overall, allowing later phases to measure the specific impacts of electrification.

Specific equipment has been identified across the process units, utilities and offsites that represent significant non-electrical energy consumers. These will be used to provide potential applications for electrification technologies in Phase 2.

9 Attachments

Attachment 1: Material Balances

Attachment 2: Unit Level Utility Summaries

Negative values indicate production, positive values indicate consumption.

Low Complexity Case Utility Summary

Unit	Cooling water (m^3/hr)	HP Steam (t/hr)	MP Steam (t/hr)	LP Steam (t/hr)	LP Cond (t/hr)	Power (kW)	Fuel Gas (GJ/hr)	BFW (m^3/hr)
Crude Distillation Unit	297	7	0	4	-11	2535	231	0
Naphtha HDT (SR)	312	0	0	0	0	2282	98	0
C5/C6 Isomerisation Unit	169	2	20	0	-21	670	0	0
Continuous Catalytic Reformer	315	12	0	-30	0	5179	204	26
Kero Merox Unit	357	0	0	0	0	79	0	0
Distillate HDT	86	0	3	0	-3	1665	17	0
Saturated Gas Plant	71	0	1	0	-1	2513	0	0
Saturated LPG Merox	1	0	0	0	0	1	0	0
Amine Unit/ SWS	10	0	0	4	-4	77	0	0
Sulphur Recovery Unit	62	0	-1	3	-3	97	0	1
Offsites & Utilities	1463	10	0	23	-20	15685	214	59
Total	3143	30	23	5	-65	30784	763	86

Medium Complexity Case Utility Summary

Unit	Cooling water (m^3/hr)	HP Steam (t/hr)	MP Steam (t/hr)	LP Steam (t/hr)	LP Cond (t/hr)	Power (kW)	Fuel Gas (GJ/hr)	BFW (m^3/hr)
Crude Distillation Unit	593	13	0	9	-22	5071	462	0
Vacuum Distillation Unit	2951	0	37	-17	-41	1669	200	0
Naphtha HDT (SR)	779	0	0	0	0	5700	244	0
C5/C6 Isomerisation Unit	471	4	55	0	-60	1868	0	0
Continuous Catalytic Reformer	747	30	0	-72	0	12283	483	62
Kero Merox Unit	655	0	0	0	0	144	0	0
Distillate HDT	132	0	5	0	-5	2554	26	0
Hydrocracker	1514	87	-96	15	-6	12211	353	48
Saturated Gas Plant	166	0	3	0	-2	5859	0	0
Saturated LPG Merox	2	0	0	0	0	2	0	0
Hydrogen Plant	92	-42	-3	0	0	1630	205	42
Amine Unit/ SWS	76	0	0	33	-31	578	0	0
Sulphur Recovery Unit	462	0	-6	26	-25	732	0	6
Offsites & Utilities	3271	22	0	56	-42	39067	573	164
Total	11912	114	-6	50	-235	89369	2547	322

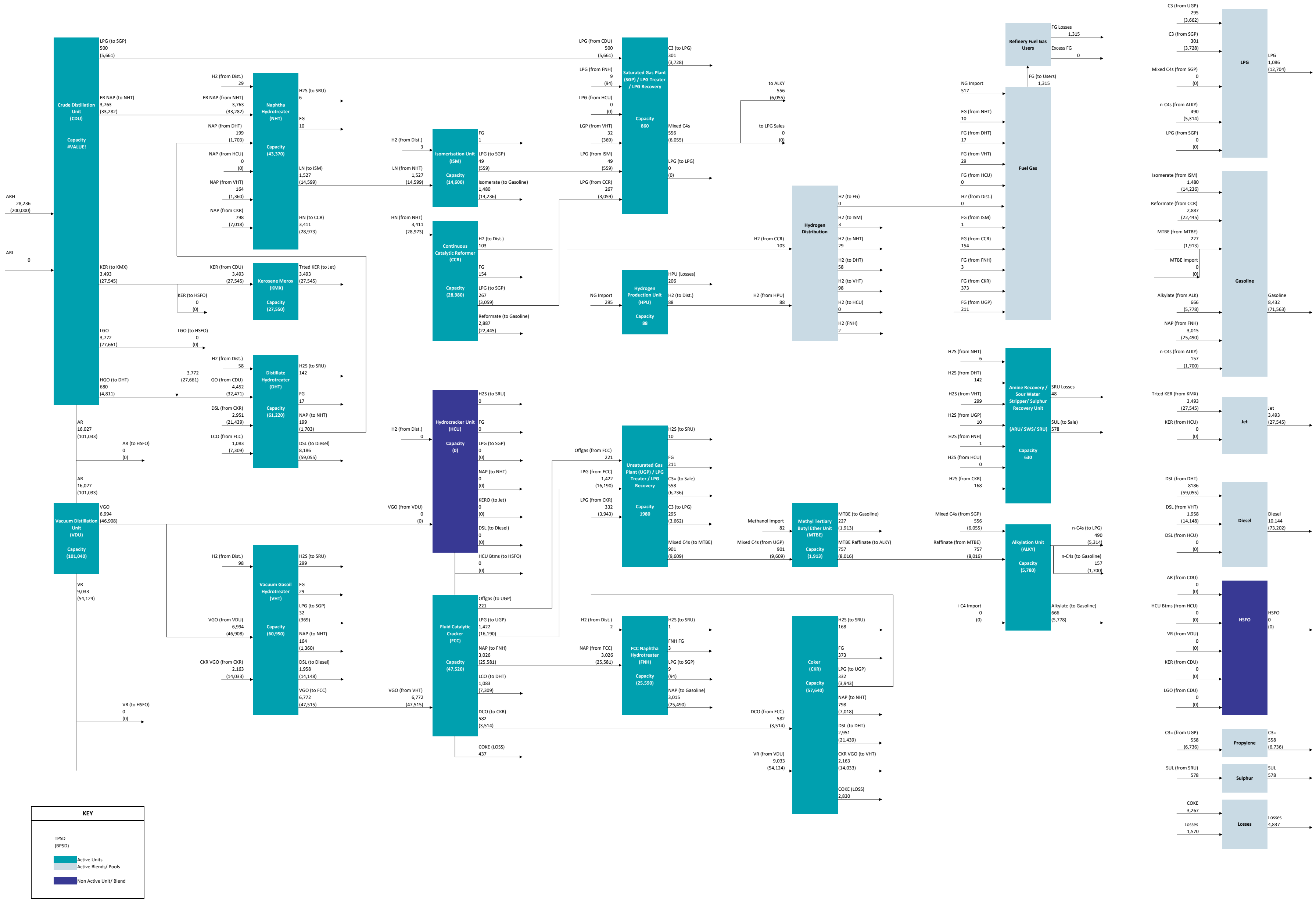
High Complexity Case Utility Summary

Unit	Cooling water (m^3/hr)	HP Steam (t/hr)	MP Steam (t/hr)	LP Steam (t/hr)	LP Cond (t/hr)	Power (kW)	Fuel Gas (GJ/hr)	BFW (m^3/hr)
Crude Distillation Unit	624	14	0	9	-24	5328	486	0
Vacuum Distillation Unit	4013	0	50	-24	-56	2270	272	0
Naphtha HDT (SR)	556	0	0	0	0	4068	174	0
C5/C6 Isomerisation Unit	308	3	36	0	-39	1220	0	0
Continuous Catalytic Reformer	555	22	0	-54	0	9135	359	46
Kero Merox Unit	564	0	0	0	0	124	0	0
Distillate HDT	304	0	11	0	-11	5869	60	0
VGO HDT	1282	79	0	-58	-20	4319	191	0
Fluid Catalytic Cracker	1776	34	129	136	-337	14281	0	155
FCC Naphtha HDT	56	15	0	0	-15	2392	41	0
Saturated Gas Plant	217	0	3	0	-3	7655	0	0
Saturated LPG Merox	1	0	0	0	0	1	0	0
C3/C4 Splitter	0	0	7	0	-6	126	0	0
MTBE	136	0	8	0	-7	84	0	0
H2SO4 Alkylation Unit	2109	0	26	0	-25	2679	7	0

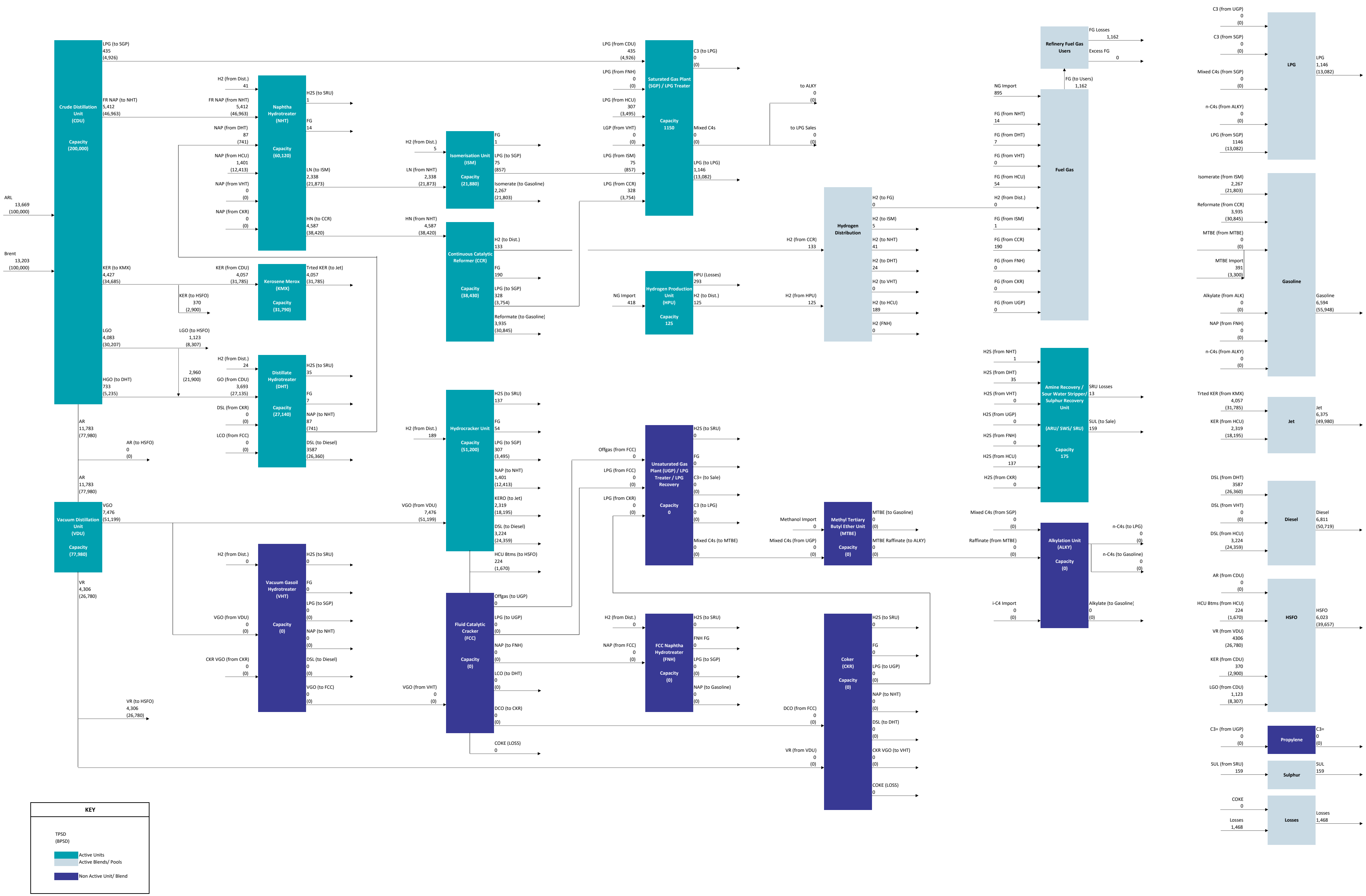
wood.

Unit	Cooling water (m^3/hr)	HP Steam (t/hr)	MP Steam (t/hr)	LP Steam (t/hr)	LP Cond (t/hr)	Power (kW)	Fuel Gas (GJ/hr)	BFW (m^3/hr)
Coker	153	3	-15	0	-1	9684	301	29
Hydrogen Plant	65	-29	-2	0	0	1150	145	29
Amine Unit/ SWS	275	0	0	118	-112	2089	0	0
Sulphur Recovery Unit	1670	0	-21	93	-90	2660	0	21
Offsites & Utilities	5172	34	0	107	-48	52704	2670	735
Total	19837	175	231	329	-795	127838	4705	1016

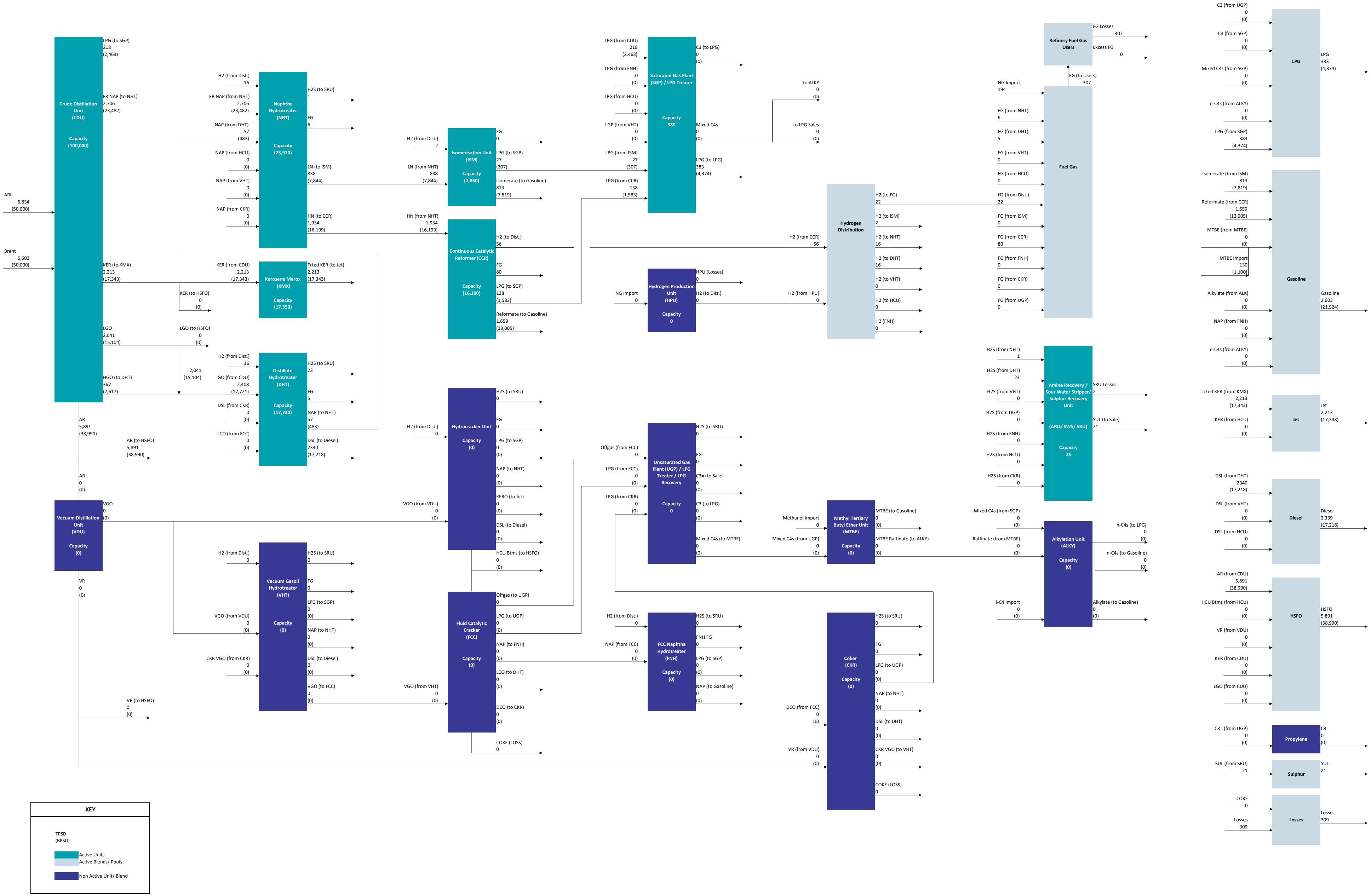
wood.



Crude Distillation Unit (CDU)
Capacity #VALUE!
ARH 28,236 (200,000)
ARL 0
LPG (to SGP) 500 (5,661)
FR NAP (to NHT) 3,763 (33,282)
KER (to KMX) 3,493 (27,545)
LGO 3,772 (27,661)
HGO (to DHT) 680 (4,811)
AR 16,027 (101,033)
AR (to HSFO) 0 (0)
AR 16,027 (101,033)
Naphtha Hydrotreater (NHT)
Capacity (43,370)
H2 (from Dist.) 29
FR NAP (from NHT) 3,763 (33,282)
NAP (from DHT) 199 (1,703)
NAP (from HCU) 0 (0)
NAP (from VHT) 164 (1,360)
NAP (from CKR) 798 (7,018)
H2S (to SRU) 6
FG 10
LN (to ISM) 1,527 (14,599)
HN (to CCR) 3,411 (28,973)
Kerosene Merox (KMX)
Capacity (27,550)
KER (from CDU) 3,493 (27,545)
KER (to HSFO) 0 (0)
Trted KER (to Jet) 3,493 (27,545)
LGO (to HSFO) 0 (0)
3,772 (27,661)
Distillate Hydrotreater (DHT)
Capacity (61,220)
H2 (from Dist.) 58
GO (from CDU) 4,452 (32,471)
DSL (from CKR) 2,951 (21,439)
LCO (from FCC) 1,083 (7,309)
H2S (to SRU) 142
FG 17
NAP (to NHT) 199 (1,703)
DSL (to Diesel) 8,186 (59,055)
Isomerisation Unit (ISM)
Capacity (14,600)
H2 (from Dist.) 3
LN (from NHT) 1,527 (14,599)
FG 1
LPG (to SGP) 49 (559)
Isomerate (to Gasoline) 1,480 (14,236)
Continuous Catalytic Reformer (CCR)
Capacity (28,980)
HN (from NHT) 3,411 (28,973)
H2 (to Dist.) 103
FG 154
LPG (to SGP) 267 (3,059)
Reformate (to Gasoline) 2,887 (22,445)
Saturated Gas Plant (SGP) / LPG Treater / LPG Recovery
Capacity 860
LPG (from CDU) 500 (5,661)
LPG (from FNH) 9 (94)
LPG (from HCU) 0 (0)
LGP (from VHT) 32 (369)
LPG (from ISM) 49 (559)
LPG (from CCR) 267 (3,059)
C3 (to LPG) 301 (3,728)
Mixed C4s 556 (6,055)
LPG (to LPG) 0 (0)
to ALKY 556 (6,055)
to LPG Sales 0 (0)
Hydrogen Production Unit (HPU)
Capacity 88
NG Import 295
HPU (Losses) 206
H2 (to Dist.) 88
H2 (from CCR) 103
H2 (from HPU) 88
Hydrogen Distribution
H2 (to FG) 0
H2 (to ISM) 3
H2 (to NHT) 29
H2 (to DHT) 58
H2 (to VHT) 98
H2 (to HCU) 0
H2 (FNH) 2
Refinery Fuel Gas Users
FG Losses 1,315
Excess FG 0
FG (to Users) 1,315
Fuel Gas
NG Import 517
FG (from NHT) 10
FG (from DHT) 17
FG (from VHT) 29
FG (from HCU) 0
H2 (from Dist.) 0
FG (from ISM) 1
FG (from CCR) 154
FG (from FNH) 3
FG (from CKR) 373
FG (from UGP) 211
Hydrocracker Unit (HCU)
Capacity (0)
H2 (from Dist.) 0
VGO (from VDU) 0 (0)
H2S (to SRU) 0
FG 0
LPG (to SGP) 0 (0)
NAP (to NHT) 0 (0)
KERO (to Jet) 0 (0)
DSL (to Diesel) 0 (0)
HCU Btms (to HSFO) 0 (0)
Vacuum Distillation Unit (VDU)
Capacity (101,040)
VGO 6,994 (46,908)
VR 9,033 (54,124)
VR (to HSFO) 0 (0)
Vacuum Gasoil Hydrotreater (VHT)
Capacity (60,950)
H2 (from Dist.) 98
VGO (from VDU) 6,994 (46,908)
CKR VGO (from CKR) 2,163 (14,033)
H2S (to SRU) 299
FG 29
LPG (to SGP) 32 (369)
NAP (to NHT) 164 (1,360)
DSL (to Diesel) 1,958 (14,148)
VGO (to FCC) 6,772 (47,515)
Fluid Catalytic Cracker (FCC)
Capacity (47,520)
VGO (from VHT) 6,772 (47,515)
Offgas (to UGP) 221
LPG (to UGP) 1,422 (16,190)
NAP (to FNH) 3,026 (25,581)
LCO (to DHT) 1,083 (7,309)
DCO (to CKR) 582 (3,514)
COKE (LOSS) 437
Unsaturated Gas Plant (UGP) / LPG Treater / LPG Recovery
Capacity 1980
Offgas (from FCC) 221
LPG (from FCC) 1,422 (16,190)
LPG (from CKR) 332 (3,943)
H2S (to SRU) 10
FG 211
C3= (to Sale) 558 (6,736)
C3 (to LPG) 295 (3,662)
Mixed C4s (to MTBE) 901 (9,609)
FCC Naphtha Hydrotreater (FNH)
Capacity (25,590)
H2 (from Dist.) 2
NAP (from FCC) 3,026 (25,581)
H2S (to SRU) 1
FNH FG 3
LPG (to SGP) 9 (94)
NAP (to Gasoline) 3,015 (25,490)
Methyl Tertiary Butyl Ether Unit (MTBE)
Capacity (1,913)
Methanol Import 82
Mixed C4s (from UGP) 901 (9,609)
MTBE (to Gasoline) 227 (1,913)
MTBE Raffinate (to ALKY) 757 (8,016)
Coker (CKR)
Capacity (57,640)
DCO (from FCC) 582 (3,514)
VR (from VDU) 9,033 (54,124)
H2S (to SRU) 168
FG 373
LPG (to UGP) 332 (3,943)
NAP (to NHT) 798 (7,018)
DSL (to DHT) 2,951 (21,439)
CKR VGO (to VHT) 2,163 (14,033)
COKE (LOSS) 2,830
Amine Recovery / Sour Water Stripper/ Sulphur Recovery Unit (ARU/ SWS/ SRU)
Capacity 630
H2S (from NHT) 6
H2S (from DHT) 142
H2S (from VHT) 299
H2S (from UGP) 10
H2S (from FNH) 1
H2S (from HCU) 0
H2S (from CKR) 168
SRU Losses 48
SUL (to Sale) 578
Alkylation Unit (ALKY)
Capacity (5,780)
Mixed C4s (from SGP) 556 (6,055)
Raffinate (from MTBE) 757 (8,016)
i-C4 Import 0 (0)
n-C4s (to LPG) 490 (5,314)
n-C4s (to Gasoline) 157 (1,700)
Alkylate (to Gasoline) 666 (5,778)
LPG
C3 (from UGP) 295 (3,662)
C3 (from SGP) 301 (3,728)
Mixed C4s (from SGP) 0 (0)
n-C4s (from ALKY) 490 (5,314)
LPG (from SGP) 0 (0)
LPG 1,086 (12,704)
Gasoline
Isomerate (from ISM) 1,480 (14,236)
Reformate (from CCR) 2,887 (22,445)
MTBE (from MTBE) 227 (1,913)
MTBE Import 0 (0)
Alkylate (from ALK) 666 (5,778)
NAP (from FNH) 3,015 (25,490)
n-C4s (from ALKY) 157 (1,700)
Gasoline 8,432 (71,563)
Jet
Trted KER (from KMX) 3,493 (27,545)
KER (from HCU) 0 (0)
Jet 3,493 (27,545)
Diesel
DSL (from DHT) 8186 (59,055)
DSL (from VHT) 1,958 (14,148)
DSL (from HCU) 0 (0)
Diesel 10,144 (73,202)
HSFO
AR (from CDU) 0 (0)
HCU Btms (from HCU) 0 (0)
VR (from VDU) 0 (0)
KER (from CDU) 0 (0)
LGO (from CDU) 0 (0)
HSFO 0 (0)
Propylene
C3= (from UGP) 558 (6,736)
C3= 558 (6,736)
Sulphur
SUL (from SRU) 578
SUL 578
Losses
COKE 3,267
Losses 1,570
Losses 4,837
KEY
TPSD (BPSD)
Active Units
Active Blends/ Pools
Non Active Unit/ Blend



ARL
13,669
(100,000)
Brent
13,203
(100,000)
Crude Distillation Unit (CDU)
Capacity (200,000)
LPG (to SGP) 435 (4,926)
FR NAP (to NHT) 5,412 (46,963)
KER (to KMX) 4,427 (34,685)
LGO 4,083 (30,207)
HGO (to DHT) 733 (5,235)
AR 11,783 (77,980)
AR (to HSFO) 0 (0)
AR 11,783 (77,980)
H2 (from Dist.) 41
FR NAP (from NHT) 5,412 (46,963)
NAP (from DHT) 87 (741)
NAP (from HCU) 1,401 (12,413)
NAP (from VHT) 0 (0)
NAP (from CKR) 0 (0)
Naphtha Hydrotreater (NHT)
Capacity (60,120)
H2S (to SRU) 1
FG 14
LN (to ISM) 2,338 (21,873)
HN (to CCR) 4,587 (38,420)
KER (from CDU) 4,057 (31,785)
KER (to HSFO) 370 (2,900)
Kerosene Merox (KMX)
Capacity (31,790)
Trted KER (to Jet) 4,057 (31,785)
LGO (to HSFO) 1,123 (8,307)
2,960 (21,900)
H2 (from Dist.) 24
GO (from CDU) 3,693 (27,135)
DSL (from CKR) 0 (0)
LCO (from FCC) 0 (0)
Distillate Hydrotreater (DHT)
Capacity (27,140)
H2S (to SRU) 35
FG 7
NAP (to NHT) 87 (741)
DSL (to Diesel) 3587 (26,360)
H2 (from Dist.) 5
LN (from NHT) 2,338 (21,873)
Isomerisation Unit (ISM)
Capacity (21,880)
FG 1
LPG (to SGP) 75 (857)
Isomerate (to Gasoline) 2,267 (21,803)
HN (from NHT) 4,587 (38,420)
Continuous Catalytic Reformer (CCR)
Capacity (38,430)
H2 (to Dist.) 133
FG 190
LPG (to SGP) 328 (3,754)
Reformate (to Gasoline) 3,935 (30,845)
LPG (from CDU) 435 (4,926)
LPG (from FNH) 0 (0)
LPG (from HCU) 307 (3,495)
LGP (from VHT) 0 (0)
LPG (from ISM) 75 (857)
LPG (from CCR) 328 (3,754)
Saturated Gas Plant (SGP) / LPG Treater
Capacity 1150
C3 (to LPG) 0 (0)
Mixed C4s 0 (0)
LPG (to LPG) 1,146 (13,082)
to ALKY 0 (0)
to LPG Sales 0 (0)
NG Import 418
Hydrogen Production Unit (HPU)
Capacity 125
HPU (Losses) 293
H2 (to Dist.) 125
H2 (from CCR) 133
H2 (from HPU) 125
Hydrogen Distribution
H2 (to FG) 0
H2 (to ISM) 5
H2 (to NHT) 41
H2 (to DHT) 24
H2 (to VHT) 0
H2 (to HCU) 189
H2 (FNH) 0
H2 (from Dist.) 189
Hydrocracker Unit
Capacity (51,200)
H2S (to SRU) 137
FG 54
LPG (to SGP) 307 (3,495)
NAP (to NHT) 1,401 (12,413)
KERO (to Jet) 2,319 (18,195)
DSL (to Diesel) 3,224 (24,359)
HCU Btms (to HSFO) 224 (1,670)
Vacuum Distillation Unit (VDU)
Capacity (77,980)
VGO 7,476 (51,199)
VGO (from VDU) 7,476 (51,199)
VR 4,306 (26,780)
VR (to HSFO) 4,306 (26,780)
H2 (from Dist.) 0
VGO (from VDU) 0 (0)
CKR VGO (from CKR) 0 (0)
Vacuum Gasoil Hydrotreater (VHT)
Capacity (0)
H2S (to SRU) 0
FG 0
LPG (to SGP) 0 (0)
NAP (to NHT) 0 (0)
DSL (to Diesel) 0 (0)
VGO (to FCC) 0 (0)
VGO (from VHT) 0 (0)
Fluid Catalytic Cracker (FCC)
Capacity (0)
Offgas (to UGP) 0
LPG (to UGP) 0 (0)
NAP (to FNH) 0 (0)
LCO (to DHT) 0 (0)
DCO (to CKR) 0 (0)
COKE (LOSS) 0
Offgas (from FCC) 0
LPG (from FCC) 0 (0)
LPG (from CKR) 0 (0)
Unsaturated Gas Plant (UGP) / LPG Treater / LPG Recovery
Capacity 0
H2S (to SRU) 0
FG 0
C3= (to Sale) 0 (0)
C3 (to LPG) 0 (0)
Mixed C4s (to MTBE) 0 (0)
H2 (from Dist.) 0
NAP (from FCC) 0 (0)
FCC Naphtha Hydrotreater (FNH)
Capacity (0)
H2S (to SRU) 0
FNH FG 0
LPG (to SGP) 0 (0)
NAP (to Gasoline) 0 (0)
Methanol Import 0 (0)
Mixed C4s (from UGP) 0 (0)
Methyl Tertiary Butyl Ether Unit (MTBE)
Capacity (0)
MTBE (to Gasoline) 0 (0)
MTBE Raffinate (to ALKY) 0 (0)
DCO (from FCC) 0 (0)
VR (from VDU) 0 (0)
Coker (CKR)
Capacity (0)
H2S (to SRU) 0
FG 0
LPG (to UGP) 0 (0)
NAP (to NHT) 0 (0)
DSL (to DHT) 0 (0)
CKR VGO (to VHT) 0 (0)
COKE (LOSS) 0
Refinery Fuel Gas Users
FG Losses 1,162
Excess FG 0
FG (to Users) 1,162
NG Import 895
FG (from NHT) 14
FG (from DHT) 7
FG (from VHT) 0
FG (from HCU) 54
H2 (from Dist.) 0
FG (from ISM) 1
FG (from CCR) 190
FG (from FNH) 0
FG (from CKR) 0
FG (from UGP) 0
Fuel Gas
H2S (from NHT) 1
H2S (from DHT) 35
H2S (from VHT) 0
H2S (from UGP) 0
H2S (from FNH) 0
H2S (from HCU) 137
H2S (from CKR) 0
Amine Recovery / Sour Water Stripper/ Sulphur Recovery Unit (ARU/ SWS/ SRU)
Capacity 175
SRU Losses 13
SUL (to Sale) 159
Mixed C4s (from SGP) 0 (0)
Raffinate (from MTBE) 0 (0)
i-C4 Import 0 (0)
Alkylation Unit (ALKY)
Capacity (0)
n-C4s (to LPG) 0 (0)
n-C4s (to Gasoline) 0 (0)
Alkylate (to Gasoline) 0 (0)
C3 (from UGP) 0 (0)
C3 (from SGP) 0 (0)
Mixed C4s (from SGP) 0 (0)
n-C4s (from ALKY) 0 (0)
LPG (from SGP) 1146 (13,082)
LPG
LPG 1,146 (13,082)
Isomerate (from ISM) 2,267 (21,803)
Reformate (from CCR) 3,935 (30,845)
MTBE (from MTBE) 0 (0)
MTBE Import 391 (3,300)
Alkylate (from ALK) 0 (0)
NAP (from FNH) 0 (0)
n-C4s (from ALKY) 0 (0)
Gasoline
Gasoline 6,594 (55,948)
Trted KER (from KMX) 4,057 (31,785)
KER (from HCU) 2,319 (18,195)
Jet
Jet 6,375 (49,980)
DSL (from DHT) 3587 (26,360)
DSL (from VHT) 0 (0)
DSL (from HCU) 3,224 (24,359)
Diesel
Diesel 6,811 (50,719)
AR (from CDU) 0 (0)
HCU Btms (from HCU) 224 (1,670)
VR (from VDU) 4306 (26,780)
KER (from CDU) 370 (2,900)
LGO (from CDU) 1,123 (8,307)
HSFO
HSFO 6,023 (39,657)
C3= (from UGP) 0 (0)
Propylene
C3= 0 (0)
SUL (from SRU) 159
Sulphur
SUL 159
COKE 0
Losses 1,468
Losses
Losses 1,468
KEY
TPSD (BPSD)
Active Units
Active Blends/ Pools
Non Active Unit/ Blend



Crude Distillation Unit (CDU)
Capacity (100,000)
ARL 6,834 (50,000)
Brent 6,602 (50,000)
LPG (to SGP) 218 (2,463)
FR NAP (to NHT) 2,706 (23,482)
KER (to KMX) 2,213 (17,343)
LGO 2,041 (15,104)
HGO (to DHT) 367 (2,617)
AR 5,891 (38,990)
AR (to HSFO) 5,891 (38,990)
AR 0 (0)
Naphtha Hydrotreater (NHT)
Capacity (23,970)
H2 (from Dist.) 16
FR NAP (from NHT) 2,706 (23,482)
NAP (from DHT) 57 (483)
NAP (from HCU) 0 (0)
NAP (from VHT) 0 (0)
NAP (from CKR) 0 (0)
H2S (to SRU) 1
FG 6
LN (to ISM) 838 (7,844)
HN (to CCR) 1,934 (16,199)
Kerosene Merox (KMX)
Capacity (17,350)
KER (from CDU) 2,213 (17,343)
Trted KER (to Jet) 2,213 (17,343)
KER (to HSFO) 0 (0)
LGO (to HSFO) 0 (0)
2,041 (15,104)
Distillate Hydrotreater (DHT)
Capacity (17,730)
H2 (from Dist.) 16
GO (from CDU) 2,408 (17,721)
DSL (from CKR) 0 (0)
LCO (from FCC) 0 (0)
H2S (to SRU) 23
FG 5
NAP (to NHT) 57 (483)
DSL (to Diesel) 2340 (17,218)
Isomerisation Unit (ISM)
Capacity (7,850)
H2 (from Dist.) 2
LN (from NHT) 838 (7,844)
FG 0
LPG (to SGP) 27 (307)
Isomerate (to Gasoline) 813 (7,819)
Continuous Catalytic Reformer (CCR)
Capacity (16,200)
HN (from NHT) 1,934 (16,199)
H2 (to Dist.) 56
FG 80
LPG (to SGP) 138 (1,583)
Reformate (to Gasoline) 1,659 (13,005)
Saturated Gas Plant (SGP) / LPG Treater
Capacity 385
LPG (from CDU) 218 (2,463)
LPG (from FNH) 0 (0)
LPG (from HCU) 0 (0)
LGP (from VHT) 0 (0)
LPG (from ISM) 27 (307)
LPG (from CCR) 138 (1,583)
C3 (to LPG) 0 (0)
Mixed C4s 0 (0)
LPG (to LPG) 383 (4,374)
to ALKY 0 (0)
to LPG Sales 0 (0)
Hydrogen Production Unit (HPU)
Capacity 0
NG Import 0
HPU (Losses) 0
H2 (to Dist.) 0
Hydrogen Distribution
H2 (from CCR) 56
H2 (from HPU) 0
H2 (to FG) 22
H2 (to ISM) 2
H2 (to NHT) 16
H2 (to DHT) 16
H2 (to VHT) 0
H2 (to HCU) 0
H2 (FNH) 0
Refinery Fuel Gas Users
FG Losses 307
Excess FG 0
FG (to Users) 307
Fuel Gas
NG Import 194
FG (from NHT) 6
FG (from DHT) 5
FG (from VHT) 0
FG (from HCU) 0
H2 (from Dist.) 22
FG (from ISM) 0
FG (from CCR) 80
FG (from FNH) 0
FG (from CKR) 0
FG (from UGP) 0
Amine Recovery / Sour Water Stripper/ Sulphur Recovery Unit (ARU/ SWS/ SRU)
Capacity 25
H2S (from NHT) 1
H2S (from DHT) 23
H2S (from VHT) 0
H2S (from UGP) 0
H2S (from FNH) 0
H2S (from HCU) 0
H2S (from CKR) 0
SRU Losses 2
SUL (to Sale) 21
Hydrocracker Unit
Capacity (0)
H2 (from Dist.) 0
VGO (from VDU) 0 (0)
H2S (to SRU) 0
FG 0
LPG (to SGP) 0 (0)
NAP (to NHT) 0 (0)
KERO (to Jet) 0 (0)
DSL (to Diesel) 0 (0)
HCU Btms (to HSFO) 0 (0)
Vacuum Distillation Unit (VDU)
Capacity (0)
VGO 0 (0)
VR 0 (0)
VR (to HSFO) 0 (0)
Vacuum Gasoil Hydrotreater (VHT)
Capacity (0)
H2 (from Dist.) 0
VGO (from VDU) 0 (0)
CKR VGO (from CKR) 0 (0)
H2S (to SRU) 0
FG 0
LPG (to SGP) 0 (0)
NAP (to NHT) 0 (0)
DSL (to Diesel) 0 (0)
VGO (to FCC) 0 (0)
Fluid Catalytic Cracker (FCC)
Capacity (0)
VGO (from VHT) 0 (0)
Offgas (to UGP) 0
LPG (to UGP) 0 (0)
NAP (to FNH) 0 (0)
LCO (to DHT) 0 (0)
DCO (to CKR) 0 (0)
COKE (LOSS) 0
Unsaturated Gas Plant (UGP) / LPG Treater / LPG Recovery
Capacity 0
Offgas (from FCC) 0
LPG (from FCC) 0 (0)
LPG (from CKR) 0 (0)
H2S (to SRU) 0
FG 0
C3= (to Sale) 0 (0)
C3 (to LPG) 0 (0)
Mixed C4s (to MTBE) 0 (0)
FCC Naphtha Hydrotreater (FNH)
Capacity (0)
H2 (from Dist.) 0
NAP (from FCC) 0 (0)
H2S (to SRU) 0
FNH FG 0
LPG (to SGP) 0 (0)
NAP (to Gasoline) 0 (0)
Methyl Tertiary Butyl Ether Unit (MTBE)
Capacity (0)
Methanol Import 0
Mixed C4s (from UGP) 0 (0)
MTBE (to Gasoline) 0 (0)
MTBE Raffinate (to ALKY) 0 (0)
Alkylation Unit (ALKY)
Capacity (0)
Mixed C4s (from SGP) 0 (0)
Raffinate (from MTBE) 0 (0)
i-C4 Import 0 (0)
n-C4s (to LPG) 0 (0)
n-C4s (to Gasoline) 0 (0)
Alkylate (to Gasoline) 0 (0)
Coker (CKR)
Capacity (0)
DCO (from FCC) 0 (0)
VR (from VDU) 0 (0)
H2S (to SRU) 0
FG 0
LPG (to UGP) 0 (0)
NAP (to NHT) 0 (0)
DSL (to DHT) 0 (0)
CKR VGO (to VHT) 0 (0)
COKE (LOSS) 0
LPG
C3 (from UGP) 0 (0)
C3 (from SGP) 0 (0)
Mixed C4s (from SGP) 0 (0)
n-C4s (from ALKY) 0 (0)
LPG (from SGP) 383 (4,374)
LPG 383 (4,374)
Gasoline
Isomerate (from ISM) 813 (7,819)
Reformate (from CCR) 1,659 (13,005)
MTBE (from MTBE) 0 (0)
MTBE Import 130 (1,100)
Alkylate (from ALK) 0 (0)
NAP (from FNH) 0 (0)
n-C4s (from ALKY) 0 (0)
Gasoline 2,603 (21,924)
Jet
Trted KER (from KMX) 2,213 (17,343)
KER (from HCU) 0 (0)
Jet 2,213 (17,343)
Diesel
DSL (from DHT) 2340 (17,218)
DSL (from VHT) 0 (0)
DSL (from HCU) 0 (0)
Diesel 2,339 (17,218)
HSFO
AR (from CDU) 5,891 (38,990)
HCU Btms (from HCU) 0 (0)
VR (from VDU) 0 (0)
KER (from CDU) 0 (0)
LGO (from CDU) 0 (0)
HSFO 5,891 (38,990)
Propylene
C3= (from UGP) 0 (0)
C3= 0 (0)
Sulphur
SUL (from SRU) 21
SUL 21
Losses
COKE 0
Losses 309
Losses 309
KEY
TPSD (BPSD)
Active Units
Active Blends/ Pools
Non Active Unit/ Blend

A ROADMAP TO
DECARBONIZE REFINING

Phase 2 & 3 Report: Opportunity identification and analysis

Credit: Unsplash/Yusen Sun

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1. Background

The Oil and Gas Climate Initiative ("OGCI"), launched in 2014, is a voluntary, CEO-led initiative which aims to drive the industry response to climate change. OGCI explicitly supports the Paris Agreement and its aims, collaborating on actions to reduce greenhouse gas (GHG) emissions, and acting with integrity to accelerate and participate in the energy transition. OGCI brings together twelve Oil and Gas companies, which together account for over 30% of global operated oil and gas production. Member companies are Aramco, bp, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Shell and TotalEnergies.

OGCI members leverage their collective strength to lower the carbon footprint of the energy, industry, and transportation value chains via engagements, policies, investments and deployment. This includes actions and knowledge-sharing across several key areas of impact on GHG. The OGCI is currently composed of six workstreams (WS), working on the following topics: CCUS, Role of Gas (and methane leakage), Energy Efficiency in the Industry, Transport, Natural Climate Solutions and Low Emission Opportunities.

The Energy Efficiency in Industry Workstream (EEI WS) has formed a working group with the purpose of developing a long-term roadmap to electrification based on technology, economics, and carbon reduction potential. This work aims to inform OGCI members of the potential for electrification to contribute carbon intensity reductions. The first stage for the development of this roadmap consists of the identification of opportunities and barriers for electrification of the O&G assets.

Electrification encompasses a range of complex opportunities for oil and gas operations, requiring a roadmap that describes and assesses the choices available in specific locations, ranging from electricity-driven rotating equipment, electric heaters, electric boilers, heat pumps and battery storage solutions through to fully electric facilities supplied from electrical grid systems, as well as optimal sequencing and timing in the overall asset life cycle. Electrification offers a powerful lever for efficiency gains, associated carbon reduction through low-carbon electricity and offers the potential for zero Scope 1 emissions from oil and gas facilities, meaning the topic is key to OGCI objectives.

In this context, the OGCI EEI WS has appointed Wood as independent consultant to assess the potential of electrification, a GHG emissions reduction lever, for the Refining Industry.

The study will focus on application of electrification to existing, generalised sites as opposed to greenfield development opportunities, capturing the difficulties and opportunities inherent in existing facilities.

2. Objectives

2.1 Phase 2 and 3 Objectives

This report represents a combination of previous Phase 2 and 3 reports and results have been further updated for consistency between the Phases.

The primary objective of Phase 2 was to identify electrification options available to refineries with high level assessment and provide screening of these options. Phase 3 provided further analysis of cost, plot, schedule and requirement for supporting electrical infrastructure. The resulting costs, schedule and efficiencies are utilised in Road Map scenarios in Phase 4 where the technologies are applied to representative configurations.

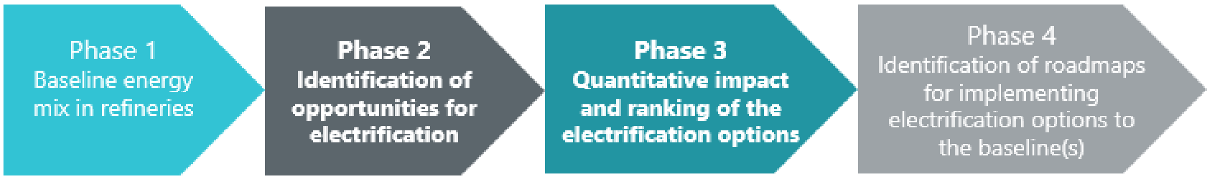

Figure 1: Refining Industry Electrification Study Phases

Relevant refinery electrification technologies have been reviewed to provide assessment in the following areas:

- Scale of application, utilising quantified major equipment consumptions for a representative configuration
- Potential emissions savings across a representative configuration
- High level capital cost efficiency
- Emissions reduction efficiency per unit of additional low-carbon electricity utilised
- Technology Readiness Level (TRL)
- Ease of implementation
- Reliability, availability, maintainability and operations impact
- Health, safety, security and environmental impact

Opportunity sources of electricity generation are also reviewed, including waste heat. Emissions expected to be produced by low-carbon electricity imports are included in the benefit workings.

A screening structure was agreed with OGCI to discuss and prioritise opportunities based on the above criteria.

Specific electrification projects, for example replacing a specific item of equipment, are assessed in further detail encompassing the breadth of technologies and scales, including:

- Project equipment scope, capital cost, footprint, and schedule
- Supporting electrical infrastructure impacts at a process unit and consumer level
- Relevant non-energy operating costs

Other topics relevant to the later Phase 4 decisions are also summarised in the current report, including:

- Energy storage
- Fuel gas reduction measures
- Non-combustion fuel gas uses
- Utilities system turndown potential
- Breakeven carbon intensity of imported power

2.2 Focus and Boundaries for Opportunity Identification

The investigation has focused on the identified major consumers of fuel and steam, across the process and utilities areas.

Some early-stage technologies are included where a specific need has been identified and no alternative is available. However, in general, technologies have been included where research has progressed to demonstration plant or vendor feasibility work to avoid very high uncertainty in purely theoretical solutions.

This report focuses on electrification of individual items of equipment rather than the site wide impacts that will be assessed in Phase 4. This report includes electrical infrastructure which is estimated assuming only one project or item of equipment is implemented without combination of projects into fewer substations.

The analysis remains conceptual and at /-50% accuracy, despite higher accuracy with more detailed sizing being utilised where possible.

3. Abbreviations

Abbreviation	Description
AEC	Alkaline Electrolysis Cells
AEM	Anion Exchange Membrane
CAPEX	Capital Cost Estimate
ARU	Amine Recovery Unit
C_3/C_4	Hydrocarbon fraction composed of 3-carbon and 4-carbon based molecules
C_5/C_6	Hydrocarbon fraction composed of 5-carbon and 6-carbon based molecules
CDU	Crude Distillation Unit
CO_2	Carbon Dioxide
COP	Coefficient of Performance
CRV	Capital Replacement Value
DCC	Direct Combustion Chamber
EHT	Electric Heat Tracing
EPC	Engineering, Procurement and Construction
FEED	Front End Engineering Design
FCC	Fluid Catalytic Cracker
FID	Final Investment Decision
GHG	Greenhouse Gas
H_2SO_4	Sulphuric Acid
H_2	Hydrogen
HDT	Hydrotreater
HP	High Pressure (Steam)
HPU	Hydrogen Production Unit
HSSE	Health, Safety, Security, and Environment
LHV	Lower Heating Value
LLI	Long Lead Item
LPG	Liquefied Petroleum Gas
MAB	Main Air Blower
MTBE	Methyl Tertiary Butyl Ether
MW	Megawatt
MWh	Megawatt hour
MVR	Mechanical Vapour Recompression

Abbreviation	Description
O2	Oxygen
O&M	Operations and Maintenance
OCM	Oxidative Coupling of Methane
OPEX	Operating Cost Estimate
ORC	Organic Rankine Cycle
PEM	Proton Exchange Membrane
PP	Polypropylene
RAM	Reliability, Availability, Maintainability
SIMOPS	SIMultaneous OPerationS
SMR	Steam Methane Reformer
SOEL	Solid Oxide Electrolyser
SWS	Sour Water Stripper
TA	Turn Around
TIC	Total Installed Cost
TPSD	Tonnes Per Stream Day
TRL	Technology Readiness Level
UPS	Uninterruptible Power Supply
USGC	United States Gulf Coast (Location basis)
VDU	Vacuum Distillation Unit
VR	Vacuum Residue
VSD	Variable Speed Drive

4. Assessment Methodology

4.1 Emissions Savings Calculation Methodology

4.1.1 General Assumptions

The following assumptions have been made regarding the analysis of individual technologies:

- High-level assessment of boiler emissions has been performed using enthalpy and efficiency-based duty calculation to avoid utilising the more complex utility model.
- At this stage, the efficiency of equipment (both process and utility systems) has been kept unchanged when applying electrification.
- Complete combustion is considered for CO_2 emissions from fuel gas fired and other CO_2 equivalent emissions are not considered from combustion.
- The ratio of imported gas to produced fuel gas is unchanged and based on the high complexity Phase 1 Baseline balance.
- Imported gas is pure methane transported via pipeline. LNG facility and transportation emissions will not be considered.
- A unit's equipment duty is linearly proportional to the unit's throughput where differing unit capacity data has been utilised. Summaries of unit throughput for the High, Medium and Low Complexity cases from Phase 1 are included in the Phase 1 report.

4.1.2 Site Energy Efficiency

The process units and utilities considered for the base case equipment energy consumptions are intended to be based on a well-operated typical current configuration. This will mean that some investment opportunities are present to reduce energy demand, but operation and maintenance is considered to prioritise energy efficiency.

Design of the process units is based on typical configurations found on existing sites, rather than the newest designs with high energy efficiency design criteria. For example, some large condensing turbine compressor drivers are included, as are many fired reboilers. In general, improving the energy performance from the base case considered for a typical site is assumed to require significant investment.

Efficiency of fired equipment is also assumed to be equivalent to a well operated, existing plant but not aligned with the most energy efficient recent designs that would require significant expenditure to retrofit.

The utility system is assumed to be optimised with respect to steam levels and let downs/turbine generators in all cases.

Opportunities for waste heat utilisation as an improvement from the base case are presented in Section 6.4.

Although not considered as part of the study, poorly operated sites where there is significant scope for energy savings have an initial focus on low-investment energy efficiency improvement, followed by electrification and larger energy efficiency projects. This would ensure that the increased power import requirement for electrification is minimised and expenditure is optimised.

4.1.3 Fuel Gas & Natural Gas

The components of the produced refinery fuel gas have been grouped into separate categories based on carbon atoms in the below table. Individual molar ratios of CO_2 to fuel gas burned are shown for complete combustion.

Table 1: Fuel Gas Composition and Natural Gas Import Data

Species	Total mol%	Amount of C atoms in the molecule	Mol of CO_2 emissions per mol of species' group
Produced Refinery Fuel Gas			
Water, Nitrogen, Helium, Argon, and Hydrogen	11.330	0	0
Carbon Dioxide and Methane	71.806	1	0.718
Ethane and Ethylene	13.087	2	0.262
Propane and Propylene	2.252	3	0.068
i-Butane, n-Butane and Butene	1.315	4	0.053
i-Pentane and n-Pentene	0.147	5	0.007
C6 Hydrocarbon	0.063	6	0.004
Total	100	-	1.112
Molecular Weight	18.1		
LHV (kcal/kg)	11,446		
NG Import (100% Methane)			
Molecular Weight	16		
LHV (kcal/kg)	11,985		

(1) Data in above table is specific to high and medium complexity refinery cases. For the low complexity case there is an excess of hydrogen produced that is routed to fuel gas. In this instance the produced fuel gas molecular weight is 7.1 kg/kmol and the LHV is 14,765 kcal/kg

The mass balance between produced fuel gas (FG) and imported natural gas (NG) and their respective Lower Heating Value (LHV), shown in the below table, yields the mixed LHV used for process heating. Mixed LHV is calculated through Equation 1 below.

$$Mixed\ LHV = \frac{FG\ (TPSD) \times (FG\ LHV) + (NG\ Import) \times (NG\ Import\ LHV)}{Total\ (TPSD)} \tag{1}$$

Table 2: Mass Balance of produced FG and NG Import for Baseline High Complexity Configuration

Variable	Units	High Complexity	Medium Complexity	Low Complexity
FG	TPSD	798	266	113
NG Import	TPSD	1,252	575	184
TOTAL	TPSD	2,050	841	297
Mixed LHV	Kcal/kg	11,775	11,814	13,042

Equation 2 below represents the fired CO_2 emissions per unit energy released. This is used to calculate the carbon emissions of equipment from the heat duty required.

$$Fired\ Carbon\ Intensity = \frac{(CO_2\ from\ FG\ and\ NG\ \ combustion)}{(Heat\ provided\ by\ combustion)} \tag{2}$$

In addition to fired emissions, those related to NG Import Scope 3 emissions are also included. The NG supply carbon intensity considers pre-production, extraction, processing and logistics/transport. Transportation over long distances by Liquified Natural Gas is not factored into this calculation due to a lack of transparency in the carbon emission data and in order to utilise the most conservative basis for benefit calculation.

The sources of CO_2 emissions in NG supply are from three areas:

1) Supply chain combustion emissions. Heat and electricity are required in various stages of the supply chain, usually provided by the combustion of natural gas for equipment.
2) Vented and flare emissions. Intentional disposal of surplus gas or due to maintenance/incident.
3) Fugitive emissions. Leakages in pipelines or during extraction.

The table below provides the fired carbon intensity for each of the three refinery complexity cases. Given that the low complexity cases has a higher level of hydrogen in the fuel gas the carbon intensity is lower compared to the other cases.

Table 3: CO_2 Emissions from Fuel Gas/ Natural Gas Firing

Variable	CO_2 Emissions [g(CO_2)/kWh]		
	Low Complexity	Medium Complexity	High Complexity
Fired Carbon Intensity FG	126.9	203.1	203.1
Fired Carbon Intensity NG	197.4	197.4	197.4
Supply Carbon Intensity NG (1)	43.6	43.6	43.6
Total Carbon Intensity NG	240.9	240.9	240.9
Total Carbon Intensity FG/NG Firing Combined	191.8	229.3	226.6

(1) Total estimated median Scope 3 emissions without LNG transportation routes (Ref. 45).

In reality, each electrification project would achieve a saving of natural gas imports, produced refinery fuel gas or a mixture depending on whether the site is fuel gas long or short. For the purposes of the CO_2 savings in the current Phase, the total refinery fuel gas mixture has been used as a weighted average.

4.1.4 Electricity

Renewable electricity carbon intensity is utilised from published life cycle assessments (Ref. 10). Considering the intent of this initiative to decarbonise the refining industry via electrification, a typical low-carbon blend of new investment sources has been used. For simplicity, this has been assumed to be from equal parts nuclear, solar photovoltaic and wind. Emissions savings of electrification are calculated on the basis of using entirely low-carbon electricity.

Table 4: Electricity Carbon Intensity

Source	Lifecycle Electricity Carbon Intensity [g(CO2)/kWh]
Biomass	230
Geothermal	38
Hydro	24
Nuclear	12
Solar PV	48
Wind (Onshore and Offshore)	11-12
Average Used (Wind, Solar PV, Nuclear)	24

(1) Lifecycle emissions from Ref. 10 provide a range of data. For the purposes of this study median emissions are considered.

4.1.5 Fired Heaters Including Boilers

The CO_2 emission from fired heaters is the product of the fired duty required and total carbon intensity from fuel burning, given in Table 3. The fired duty is the actual amount of heat needed to be produced by combustion, whereas the absorbed duty is the heat required by the process or utility stream, defined by the below efficiency.

$$Efficiency = \frac{Absorbed\ Duty}{Fired\ Duty} \tag{3}$$

In reality, efficiency is unique to each heater due to design, operation and mechanical degradation. An efficiency of 85% (Lower Heating Value basis) has been applied across these heaters.

4.1.6 Steam Consuming Heaters

Steam serves as an intermediate medium for heat distribution throughout the refinery, as well as being used for direct injection. The absorbed heat of an item of equipment has been approximated by the enthalpy change between inlet and outlet steam and condensate levels. Heat loss through the steam system is assumed at a typical 10C of superheat and the efficiency of the boilers is set at 85%.

4.1.7 Steam Turbines

Steam turbines extract energy from pressurised steam. Calculation of emissions due to steam turbine operation is carried out similarly to Steam Consuming Heaters, whereby the enthalpy difference across the turbine is utilised along with steam supply efficiencies.

For condensing turbines, additional duty is required due to the heat lost in condensing the steam exiting the turbines.

Efficiency of larger turbines such as the FCC wet gas compressor condensing turbine or a large recycle gas compressor backpressure turbine are assumed to be 80%. Smaller backpressure turbines for pumps and small compressors are assumed to be 70% efficient.

4.1.8 Steam Methane Reformer

The CO_2 emissions from an SMR requires consideration of the fired emissions to provide heat to the reformer as well as the process emissions. The fired heat duty and CO_2 emission from combustion are obtained through similar manner to a fired heater, however SMR produces additional CO_2 from the reaction; in the case of methane feed, for every four moles of H_2 produced, one mole of CO_2 is released. The fired duty is provided by the combustion of waste gas from reaction to the reformer furnace. The reformer furnace has been assumed to have a typical efficiency across a range of equipment ages and operation of 85%.

4.2 Qualitative Assessment Methodology

Technology Readiness Level (TRL) is used to provide a recognised and consistent approach to identifying the maturity of a technology for electrifying current refinery assets. The description of the different TRL levels is given below.

Table 5: TRL Definitions (European Research Council)

TRL	European Union Definition
1	Basic principles observed
2	Technology concept formulated
3	Experimental proof of concept
4	Technology validated in lab
5	Technology validated in relevant environment (industrially relevant environment in the case of key enabling technologies)
6	Technology demonstrated in relevant environment (industrially relevant environment in the case of key enabling technologies)
7	System prototype demonstration in operational environment
8	System complete and qualified
9	Actual system proven in operational environment (competitive manufacturing in the case of key enabling technologies; or in space)

The following criteria have been reviewed by specialists in the relevant areas to provide expected qualitative impacts:

- Ease of implementation. This includes the ability to install the technology alongside ongoing operation and tie-in within a typical 8-week turnaround (TA) window. Plot space requirements are also considered.
- Reliability, availability, maintainability (RAM) and operations impact. This includes risk to operations due to single mode of failure (power), inherent reliability of the technology, and operational difficulty above the current technology.
- Health, safety, security and environmental impact. Includes potential major incident impacts of power outage scenarios, as well as any other identified HSSE impacts.

5. Technology Elaboration Methodology

The following areas have been assessed in further detail for each technology where maturity and knowledge within the industry allows:

- Process and other equipment
- Electrical infrastructure
- Capital cost (CAPEX)
- Footprint of equipment and electrical infrastructure
- Operating cost (OPEX)
- Schedule

For each technology, one or more representative items of equipment is assessed as examples.

Electrical infrastructure includes control, cabling to the equipment, substations and transformers and high-voltage supply cabling.

Any expected significant non-energy operating cost changes are noted, with a percentage of capital cost applied.

5.1 Cost Estimating Basis and Methodology

CAPEX estimates have been developed from several different resources. In some instances, vendors have been approached for input on specialist technology and in others sized equipment has been developed and costed along with the use of in-house information. The CAPEX basis for each individual electrification technology is described in the following sections whilst generic considerations are discussed below.

- Total Installed Cost (TIC) Factors are applied to equipment costs to produce a TIC for the equipment item. TIC factors are dependent on location, market conditions, local working conditions/ productivities. TIC factors include for all bulk materials and construction associated with the equipment item to which they are applied, such as piping, instrumentation, civils, steel work. An important exclusion from this is the electrical costs associated that are also normally included with the TIC factor. In this instance, given the significance that electrical costs present when electrifying a facility, these have been calculated separately and the contribution to the TIC factor removed. Allowance has also been made within the TIC factors used to account for the fact that these electrification opportunities are generally for brownfield applications and the additional cost this would entail over greenfield.
- United States Gulf Coast (USGC) location is assumed as a basis for the TIC factors
- All CAPEX figures presented are on Q4 2022 basis. Where cost information has been obtained for an earlier time period costs have been inflated to the Q4 2022 basis.
- CAPEX figures presented in this report are the total installed costs (TIC)
- A 10% design margin has been included within the equipment capacity for equipment CAPEX.
- CAPEX figures presented are based on equipment requirements for the high complexity refinery configuration case.

5.2 Electrical Infrastructure Basis and Methodology

The electrical infrastructure required to supply power to the new equipment items is an important input to both the overall cost and the feasibility with respect to plot space and constructability.

This assessment covers the following areas:

- Any required controllers such as heater voltage controllers and variable speed drives that are not packaged with the equipment costs from the vendor
- Cabling from the electrical consumer(s) or controllers back to the substation. Cable size and number are optimised on cost, with voltage set by the equipment requirement. The length of cabling is assumed to be 450 metres for an adjacent plot.
- New unit substation within a new building and outdoor transformers, where these are required by the duty. As the electrification projects are intended to be applied to brownfield sites which have often had revamps applied, only very low power increases such as a pump motor replacing a backpressure turbine are considered to fit within the existing substation capacity. Requirements for number of switchgear tiers, switchboards and transformers are calculated based upon present day manufacturing limits, resulting in the substation and transformer plot area. A typical 10 kVA uninterruptible power supply unit (UPS) and two HV circuit breakers are also included for all new substations.
- Cabling from the site receiving substation area to the unit transformer and substation area. Cable size, number of cables and voltage level are optimised on cost. The length of cabling is assumed to be 2000 metres to traverse the site.
- Site receiving substation and transformer additions where the project would increase the overall site power demand significantly.
- A nominal allowance for 10 km of high voltage overhead lines outside the site boundary is also included in the electrical infrastructure estimate.

Cost estimates are made considering areas calculated for transformers and substations, as well as costs for installed key equipment and cables. Other cost basis assumptions are aligned with Section 5.1.

10% design margin is expected to be included within the sizing of the electrical infrastructure.

Electrical losses from the site boundary to the consumer are expected to be within 4%, whereby transformers are ca. 99 % efficient, main power cables are sized to restrict losses to a max of 1% and the final cable to the user may lose a further 2%.

5.3 Operating Cost Basis and Methodology

Operating cost has been considered at a high level for relevant cost components using the basis described below.

5.3.1 Labour

For the projects studied, numbers of operations personnel, technical staff, management and support are not anticipated to change. Revamps and equipment additions to existing units would not result in a noticeably increased operations or technical workload. The larger utility projects such as electrolysers and electrode boilers may require different manning, though these will replace existing large utilities/hydrogen units hence the net impact is not known to be significant at this level of detail.

5.3.2 Maintenance

The annual total cost of maintenance, including materials, staff and contract maintenance employees and contract services, is typically estimated as a percentage of plant Capital Replacement Value (CRV). This method enables the contributions of routine and shutdown maintenance activities to be represented as an average annual figure. Note that labour requirements for staff maintenance roles are not included, but are not expected to change as discussed in Section 5.3.1.

The percentage of plant CRV is based on the location, the complexity, the agreed maintenance philosophy and degree of automation for the facility. Maintenance costs will be significantly higher in turnaround years than non- turnaround years. As the turnaround schedule for the representative sites is not fixed, an annualised average figure for maintenance has been estimated.

A typical figure of 2% of the project capital cost has been used to represent maintenance costs

Spares cost is included within the capital cost estimation.

5.3.3 Utilities

Utility costs are excluded from this analysis due to the dependence on future power, fuel and CO_2 pricing. Emissions changes and electrical imports quantities are given for the technologies and cases studied.

5.3.4 Insurance

Insurance cost for a facility is typically composed of the following components:

- Property. This is based on the declared value of the asset. For the projects considered, this can be estimated based on their capital cost at a typical $0.10 per year per $100 of declared value.
- Business Interruption. This is based on the value of indemnity, often assumed to be a maximum of 365 days of business interruption. As total gross revenue differential for the projects is not known this has been excluded.
- General Liability. The impact of the project on general liability is not known but is unlikely to be significant and is excluded.

5.3.5 Catalysts and Chemicals

For the technologies studied, operating cost due to catalysts and chemicals is not expected to be significant.

5.3.6 Land Rental

Land rental could be relevant to the larger scale utilities options that require significant adjacent plot space. This value is highly dependent on local factors, hence it is assumed that plot space from decommissioning or spare land is available at no cost difference.

5.4 Project Planning and Schedule Basis and Methodology

The following assumptions have been taken across all major projects, considered to reflect a typical approach for brownfield execution without special considerations.

5.4.1 Overall Project Attributes

No special considerations for project scale are deemed appropriate. No modularisation, i.e. on-purpose remote prefabrication to avoid stick-building on site, is assumed for this project as this is usually driven by special site attributes rather than cost.

5.4.2 Contracting Strategy and Design Execution

A typical investment gate process is assumed to be followed through Pre-FEED, FEED and EPC with no rollover between phases. A 6-month EPC bid period has been allowed, including 3 months overlap with FEED. 6 months is then assumed to be required for review, EPC final investment decision (FID) and finance alignment. These periods are specific to an organisation and are based on typical experience.

Typical periods have been used for engineering design activities throughout the design phase. No licensed technologies are present, hence these activities are excluded.

The typical critical path optimisation between LLIs, piping/bulks arrival and foundation execution has been reviewed in the schedule for each type of project.

5.4.3 Site Access Timing and Logistics

Access to the site for any ground preparation, construction and electrical infrastructure is assumed to be available alongside operating plant with relevant hot work and other measures taken. Seasonal weather or local labour delays are not considered.

Turnaround timing has not been set within the schedule and is assumed to be coincident with the project required timing.

The required port facilities, major roads and physical access to the site are assumed to be in place as the project will be built at an existing industrial complex.

A specific construction camp and its timing is not anticipated to be required for this scale of project, whereby accommodation and amenities are assumed to be available in the local area. However, site space is assumed to be available for temporary expansion of the site canteen, changing, control of work, project organisation and other functions.

5.4.4 Site Preparation

As a brownfield project location is assumed, no levelling or stabilisation of the plot is anticipated. Risks concerning existing underground cables, pipes and civil structures are inherent within this type of plot and have been accounted for in the schedule. No decommissioning is included within the schedule.

5.4.5 Example Project Schedules

The three example project schedules below have been produced to represent three types of projects, utilising the basis discussed above. For ease of reference, the projects analysed in Section 6 correspond to the following example schedules:

- Large Electric Driver with New Electrical Infrastructure
    - FCC Main Air Blower driver replacement with electric motor
- Process Unit Revamp with New Electrical Infrastructure
    - CDU Charge Heater replacement with electric heater
    - Debutaniser Reboiler replacement with electric heater
    - MVR installation on propylene splitter
    - Indirect electrical tank heating with circulating hot oil
- Large Utilities Unit with New Electrical Infrastructure
    - Electric steam boilers to replace existing boilers
    - DCC to replace existing boilers
    - Electrolysis to replace hydrogen production

The following projects do not have specific schedules as they are considered minor projects with minor electrical system changes and no long-lead items:

- Heat tracing replacement with electric tracing
- CDU Bottoms pump driver replacement with electric motor
- Heat pumps for waste heat and ORC. Note: These are expected to be minor projects when each unit application is considered as the projects will be applied to streams dispersed across the site.

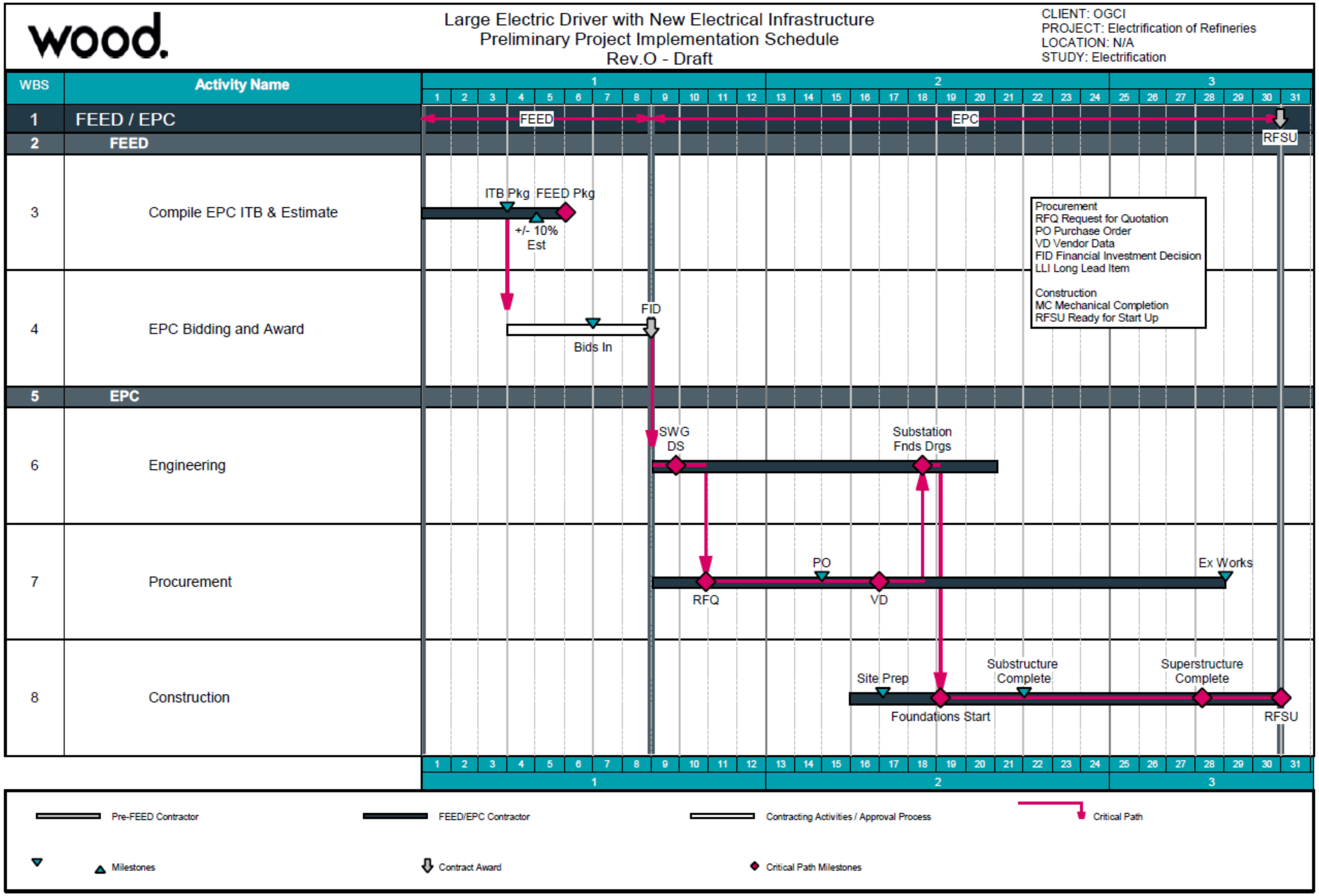

Figure 2: Large Electric Driver with New Electrical Infrastructure

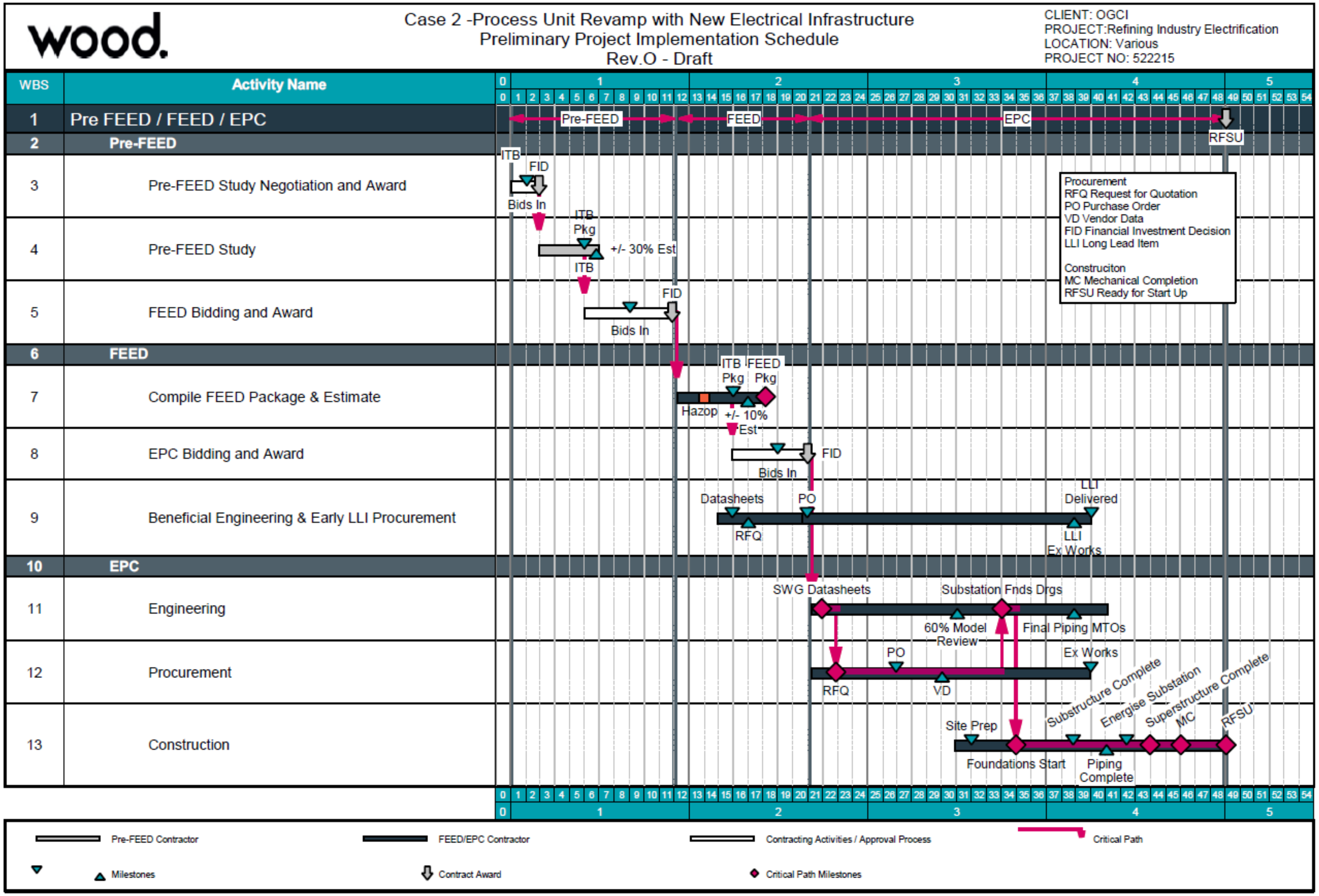

Figure 3: Process Unit Revamp with New Electrical Infrastructure

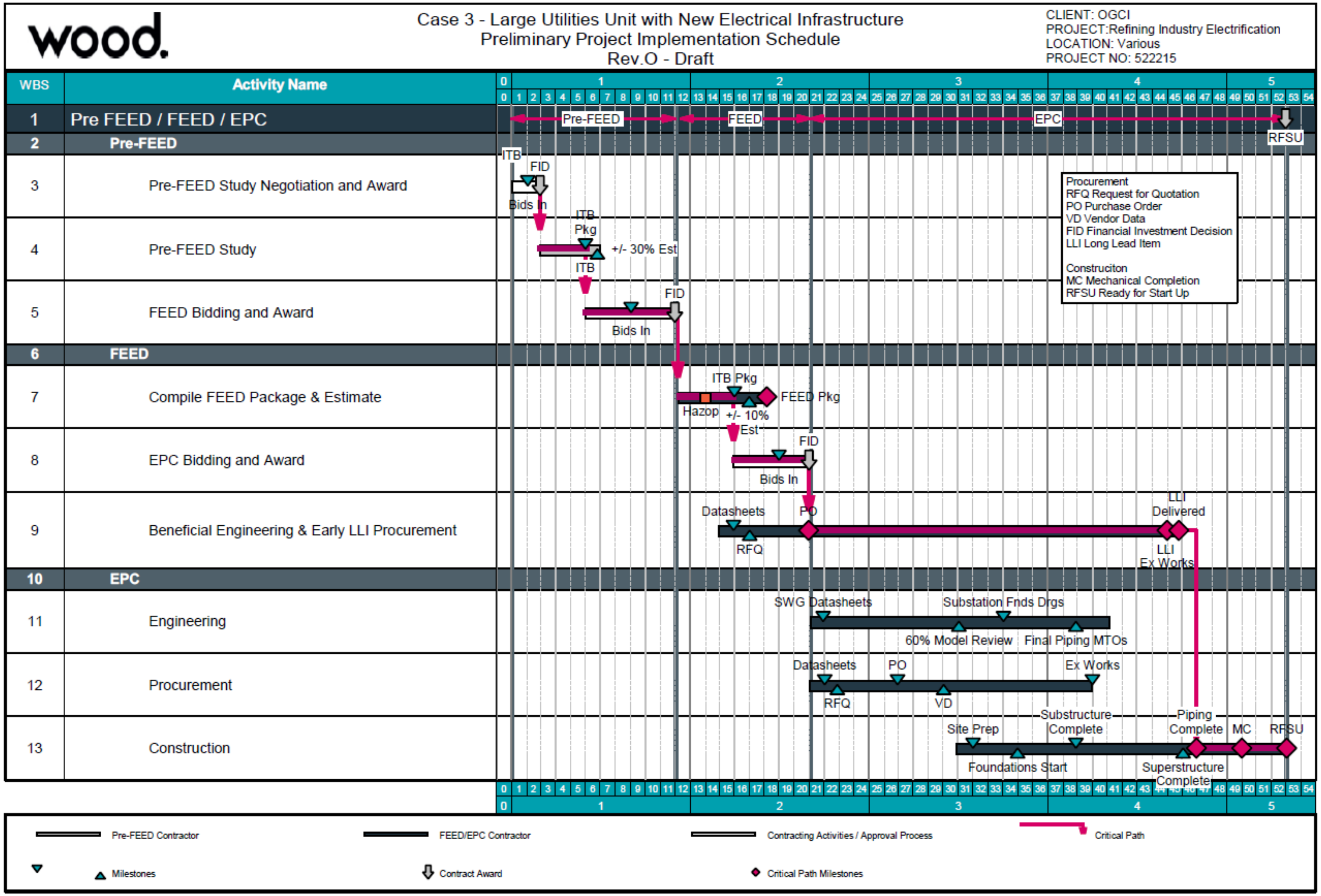

Figure 4: Large Utilities Unit with New Electrical Infrastructure

6. Assessment of Electrification Technologies

Each technology is discussed in turn in the below sections. The table below provides a summary of the electrification technologies and which significant fuel and steam consumers they are applied to.

Table 6: Summary of Technologies' Application to Fuel and Steam Consumers

Technology	Equipment Replaced or Modified	Utility Replaced
Electric Process Heater (Single Phase)	FCC Gasoline Hydrotreater Diolefin Reactor Heater Isomerisation Reactor Heater Naphtha Reformer Heaters Alkylation Unit Air Preheaters MTBE Feed Preheater	Fuel Gas/Steam
Electric Process Heater (Two Phase)	All reboilers and feed heaters not included in Single Phase or Large Residue	Fuel Gas/Steam
Electric Heater (Large Residue)	CDU, VDU and Coker Charge Heaters	Fuel Gas
Electric Process Heater (Tank Heating)	All tanks currently heated by steam coils, sulphur storage heating	Steam
Electric Heater (Microwave)	All Heaters within Single Phase, Two Phase and Large Residue categories	Fuel Gas/Steam
Electric Heater (Mechanical Vapour Recompression)	Reboilers associated with columns with close boiling point range such as propylene splitter	Steam
Electric Boiler (Electrode)	All steam production via boilers	Fuel Gas
Electric Boiler (Dynamic Combustion Chamber)	All steam production via boilers	Fuel Gas
Electric Drive	All identified steam turbine drivers of shaft work	Steam
Electrolyser	Hydrogen Production Unit replacement	Fuel Gas
Electric Heat Tracing	Site wide steam tracing	Steam
Electric Furnace (High Temperature)	Steam Methane Reformer	Fuel Gas

6.1 Electric Process Heaters

6.1.1 Description and Application

6.1.1.1 Single-Phase Applications

Electric heaters for low heat duties, low voltage and for single phase heating are extensively applied in industry. These units appear similar to a shell and tube exchanger, where the bundle is replaced with electrical elements. Around 5 MW per shell is possible, leading to multiple shells for higher duties. Retrofit into existing shells for steam exchangers would also be possible.

The current technology is capable of heating to 650 °C reliably, which covers the operating conditions of most processes within a refinery. Designs include stacking exchangers and manifolding to achieve similar heat flux and residence time profiles to their fired heater equivalents. This also allows pressure drop to be managed. The heater units can be mounted horizontally or vertically depending on process requirements.

Electric heaters have a very high efficiency as all heat is generated in the heating elements and transferred to the fluid or gas. Heat flux control is also an advantage of electrical heaters, either through specific design features such as increasing heating coil density or in some case by controlled heating zones. Baffle design can be used to increase turbulence and decrease fouling at the hot end.

20 year lifespans are generally expected for the heaters. A schematic of a typical electric heater is presented below.

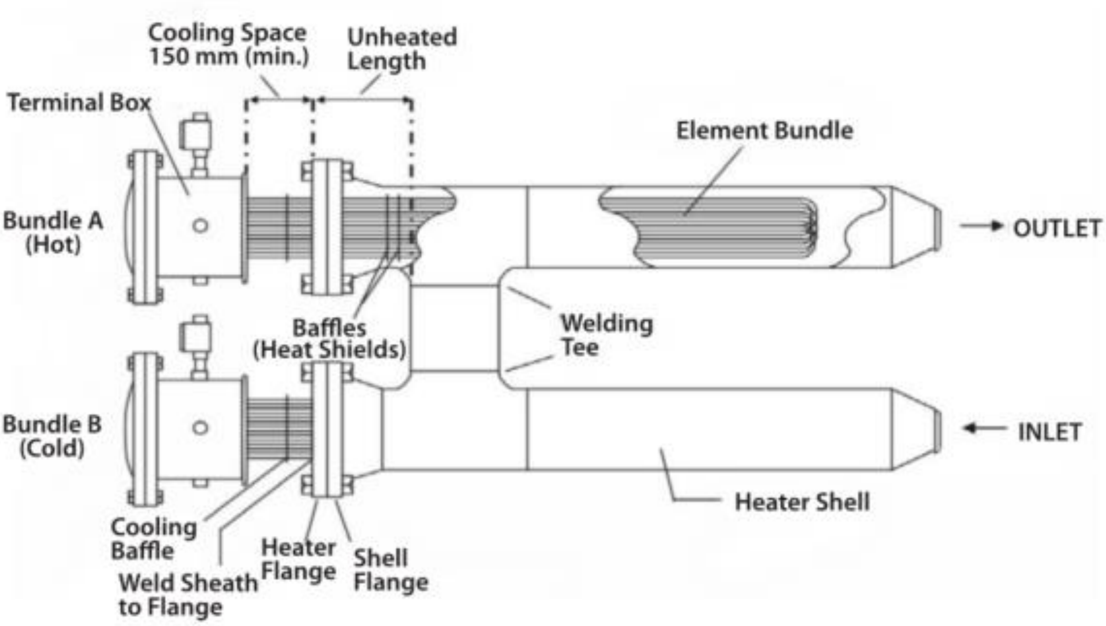

Figure 5: Electric Heater Schematic (Source: Watlow)

6.1.1.2 Two-Phase Applications

Two phase applications include reboilers and vapourising charge heaters not included in the Large Residue Heater designation below. The design of heaters in two-phase applications is much more complex due to the requirement for validating the performance under different boiling regimes, which would affect the actual heat flux density.

Physically, current designs of electric reboilers at >10 MW capacity resemble the single phase varieties with arrangements of shells containing heating elements.

Industrial electric process heaters have only been widely applied to single phase services. However, vendors have well understood reboiler designs that are in operation at ca. 5 MW scale, with application of medium voltage at MW scale expected in 2023.

6.1.1.3 Large Residue Heaters

Large residue heaters in units such as the CDU, VDU and Coker charge heaters are very high duty and are susceptible to coke formation due to the heavy aromatics/asphaltene content of the process stream. Design methodology for these heaters has been developed over decades of industry experience to enable predictable run lengths of heaters between decoking and maintenance shutdowns.

Electric heaters similar to the technology described above, where shells are arranged with resistance elements providing heat, have not been designed or trialled with these high duty and high fouling services. Potential issues regarding heat flux, dead zones and high vapour velocities have not been mitigated by proven design features. However, electric heaters have inherent advantages with respect to control of the heating elements and design of baffle arrangements.

Medium voltage design at around 4 kV is expected to be required for this duty, which is not evidenced in refinery applications but electrical control equipment is available at this voltage.

Considering the potential issues and feasibility of tying into outlet pipework with respect to hydraulics for large lines, modification of the existing fire box to include electrical heaters acting on the existing tubes may be a preferred option. This technology is in conceptual development, hence should be assessed as technology matures.

6.1.1.4 High Temperature Applications

Process heaters capable of high-temperature reactions in the range of 800-1000 °C are a required for cracking and high temperature reforming reactions. In refining, this applies to Steam Methane Reforming (SMR) where the optimal SMR temperature is around 800-900 °C, which is higher than the upper ceiling of available electric heaters.

The first high temperature electric furnace is to commission by 2025 for olefins production. BASF is developing an electrical furnace capable of >850 °C that could produce olefins, aromatics, and lighter hydrocarbons scheduled for 2025. (Ref. 6). Shell and Dow are undergoing a study on electric furnace through their recently completed e-cracking furnace experimental unit. (Ref. 14)

6.1.2 Technology Readiness Level

6.1.2.1 Single Phase Applications

Industrial electric heaters providing process temperatures up to 650 °C are supplied by multiple vendors for single phase and low duty. The current technology would require multiple units in series/parallel for processes with high heat duty. TRL is assessed as 9.

6.1.2.2 Two Phase Applications

The electric heaters in this application are determined to have a TRL of 6. There is no known operating experience at above 10 MW and medium voltage, though the component technologies have been applied. Requires multiple units in a series for processes with high heat duty.

6.1.2.3 Large Residue Heaters

The key components of large residue electric heaters have been proven in the industry. However, assembling those technologies to a heater for a high duty, high fouling/coking tendency process has not been realised and specific concerns surround this application. Therefore, this category is given a TRL of 5.

6.1.2.4 High Temperature Applications

A TRL of ca. 4 is expected for high-temperature electric furnaces. An experimental unit has been completed and is under evaluation. Commissioning of a pilot plant using electric furnaces is anticipated by 2025, hence the application at large scale is not imminent.

6.1.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting to electric process heater technology from fired heaters and steam exchangers.

Table 7: CO_2 Emission Savings for Electric Process Heaters

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Crude Distillation Unit	Crude Heater	Fuel Gas	24.39
	Debutaniser Reboiler Heater	Fuel Gas	3.36
Vacuum Distillation Unit	Charge Heater	Fuel Gas	15.52
C3/C4 Splitter	Fractionation Column Reboiler	MP Steam	1.17
Saturated Gas Plant/ Treater/ LPG separation	Fractionation Column Reboiler	MP Steam	0.59
Straight Run Naphtha Hydrotreater and Splitter	Feed Heater	Fuel Gas	2.41
	Stripper Reboiler	Fuel Gas	3.43
	Naphtha Splitter Reboiler	Fuel Gas	4.1
Distillate HDT	Feed Heater	Fuel Gas	3.46
Vacuum Gas Oil Hydrotreater	Feed Heater	Fuel Gas	2.97
	Fractionator Heater	Fuel Gas	7.93

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
FCC Gasoline HDT	HDS Reactor (Feed) Heater	Fuel Gas	0.35
	Naphtha Splitter Reboiler	Fuel Gas	1.98
	Splitter Reboiler	HP Steam	1.43
	Reactor pre-heater	HP Steam	0.08
	Stabilizer Reboiler	HP Steam	0.63
C5/C6 Isomerisation Unit	Charge Heater Exchanger	HP Steam	0.52
	Regenerant Vapouriser	MP Steam	0.27
	Stabilizer Reboiler	MP Steam	2.23
	Raffinate Column Reboiler	MP Steam	2.48
	Extract Column Reboiler	MP Steam	1.19
Continuous Catalytic Reformer	Process Heaters	Fuel Gas	19.89
	Stabiliser Reboiler	Fuel Gas	0.62
MTBE	Feed Preheater	LP Steam	0.07
	Fractionation Reboiler	MP Steam	0.92
	Methanol Recovery Column	MP Steam	0.37
H2SO4 Alkylation	Process Air Heaters	Fuel Gas	0.08
	Depropaniser Reboiler	LP Steam	0.07
	Deisobutaniser Reboiler	MP Steam	3.36
	Debutaniser Reboiler	MP Steam	1.07
Hydrocracker (2)	Feed Heater	Fuel Gas	5.69
	Fractionator Heater	Fuel Gas	14.74
Fluid Catalytic Cracker	Stripper Steam Reboiler	LP Steam	5.67
	Debutanizer Reboiler	MP Steam	19.74
	Fractionation Column Reboilers	MP Steam	1.34
	C3= Splitter LPS Reboiler	LP Steam	21.57
Coker	Feed Heater	Fuel Gas	17.18

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Hydrogen Plant	SMR	Fuel Gas	11.8
Amine Unit (SWS)	ARU Regen Reboiler	LP Steam	15.26
	SWS Regen Reboiler	LP Steam	3.29
Sulphur Recovery Unit	LPS TGTU Regen Reboiler	LP Steam	7.27

(1) Figures in the table are based on the high complexity refinery configuration

(2) The hydrocracker is not present in the high complexity configuration, instead, it is included in the medium complexity configuration. However, data is included in the above table for comparison.

6.1.4 Operations, Reliability and Safety Impact

6.1.4.1 Ease of Implementation

As process heaters are usually located within or close to process unit plot areas, electric process heaters replacing existing conventional heaters will require careful consideration to simultaneous Operations (SIMOPS) and the ease of access and construction in the vicinity of live plant. Parallel heating may result in a manifold and is fairly complicated to implement.

Electric process heaters need to be installed in the vicinity of existing fired heaters and inlet and outlet process stream distribution headers to enable tie ins during a turnaround. Should plot space in the vicinity of existing fired heaters be an issue, then parallel build and required connection hydraulics may be problematic.

6.1.4.2 RAM and Operations Impact

Electric process heaters will remove the requirement for conventional fired heater convection sections as there will no longer be a need for flue gas residual heat recovery. Conventional process heaters are susceptible to flue gas side tube fouling and dew point corrosion mechanisms that often arise during abnormal upset periods. With removal of the convection section thanks to the use an electric process heater, fouling and corrosion issues are expected to reduce. There will be fewer operator and maintenance field interventions as a result.

For conventional fired heaters, operators and inspection teams monitor furnaces to check refractory condition and wall / tube hotspots that can impact on furnace reliability and unscheduled outages. With removal of direct firing for electric heaters, refractory and tube integrity issues will be significantly reduced.

Heater 'bundle' pulling and high pressure jet washing is similar to regular shell and tube bundle cleaning from vendor correspondence.

With removal of direct fired process heaters, fuel, combustion air and flue gas flow control, burner, flue gas O2 control, heater box pressure control management will be eliminated, thus making start-up, normal operation and shutdown of boilers less complicated with potential OPEX savings.

The potential common mode failures of steam supply at same time as power supply to units would require study on individual equipment to evaluate the extent of impacts on conventional fired versus electric process heaters.

For two phase fired process heaters, a critical operating parameter is the management of process stream flows through tube banks, along with controlling fired burner flame patterns to achieve a desired heat distribution and vapourisation profiles within the radiant sections. Effective control of vapourisation profiles within electric process heaters will be different, and potentially more difficult for operators to control with parallel shells. Operating and maintenance teams will require training to operate new unfamiliar electric process heaters.

Decoking of radiant tubes in fired heaters, particularly in coker heaters, is a carefully managed process of on-line spalling of coke from inside the furnace tube walls utilising steam or boiler feed water. Care must be taken in the design of an on-line spalling procedure to assure safety, to protect equipment, to protect piping, and to complete a good spall. Such a process will be difficult to achieve in multiple electric coker heaters without specific design features.

Emergency shut off of heat is not expected to be very different to the base case, as electrical elements can be switched off quickly so only the thermal mass of the bundles remains to be cooled by the process fluid.

6.1.4.3 HSSE Impact

The requirement for operators to be in a close proximity to fired heaters to manage burners, flame patterns and flame tube impingement brings the inherent risk of exposure to flue gas releases. Electric heaters and boilers can eliminate many of these risks.

Fewer operations and maintenance interventions for higher reliability electric process heaters also reduces health and safety exposure risks.

Heavy residue and coker fired heaters require experience and proven methods to prevent tube hot spots and associated tube ruptures causing major safety incidents occurring, often leading to serious injuries and fatalities. Control of hot spots in electric process heaters is an unknown and thus will potentially increase safety risks until sufficient operating data is gained.

6.1.5 Example Project Application

Two example projects have been analysed in further detail:

- 2-phase heater: 15.3 MW Debutaniser Reboiler representing a smaller duty with change of phase.
- Large residue heater: 110 MW CDU Charge Heater representing the largest duty process fired heater.

6.1.5.1 Process Equipment

An economic maximum of 10 MW per heater unit is achievable at present with electric heater designs. Consequently, for the large duty equipment such as the CDU Crude Heater, multiple units will be required with specific manifolding for hydraulic and heat profile considerations.

The design duty of the high complexity refinery CDU Crude Heater is 110 MW, thus 11 x 10 MW units are required. The design duty of the Debutaniser Reboiler is approximately 15 MW which may be feasible in one unit or two reboiler units in parallel.

6.1.5.2 Electrical Infrastructure

The electrical infrastructure required for the two studied electrical process heaters is of a similar design, though at very different scale.

The CDU Heater and the Debutaniser Reboiler both require electrical feed at 6-7 kV medium voltage. One heater control unit is required per 2-3 MW, which provides an additional constraint on reduction of the number of cables to the equipment. To supply the heaters with cable which affords an ease of installation whilst remaining relatively economic, a cable size of 300 mm^2 was selected for both applications. 52 cables are required for from the substation to the consumers for the large CDU Heater; 8 cables are required for the Debutaniser Reboiler.

Both applications are expected to require new substations and transformers. The CDU Heater requires a total of 63 off medium voltage tiers feeding 3 off transformers to maintain a maximum switchgear current of 5000 A and redundancy. Associated high and low voltage switchboards and transformers are also allowed for. This results in a new substation building of ca. 660 m^2 and a new transformer area of ca. 153 m^2. The Debutaniser Reboiler is estimated to require a total of 14 off medium voltage tiers feeding 2 off transformer, which require an area of 175 m^2 for the substation and 108 m^2 for the transformer.

Power supply to the substation and transformer area is assumed to be at 33 kV with 8 off 300 mm^2 cables required for the CDU Heater and 2 off 300 mm^2 cables required for the Debutaniser Reboiler.

Additions to the site receiving substation and transformers are also expected to be required for the CDU Heater due to the additional duty required. Area required for these additions is estimated to be 649 m^2 for the substation and 178 m^2 for the transformers.

6.1.5.3 Capital Cost

The TICs for the electric heater options have been developed from vendor supplied equipment cost information, then applying a specific TIC factor. However, given that detailed equipment quotations for these applications have not been performed, the vendor was unable to provide exact cost figures, instead providing ranges to cover various complexities of application.

Equipment costs can vary significantly depending upon the following key features.

1) Watt Density. High watt density results in fewer elements and a smaller vessel/flange per MW.
2) Materials of Construction. Depending on process conditions and the fluid being heated, materials of construction can have a significant impact on cost. Those systems suitable for carbon steel provide the cheaper options whilst those requiring stainless steel and higher metallurgy tubing are at the high end of equipment costs.
3) Pressure drop allowance. Systems sensitive to pressure drop drive short elements in a large vessel which results in a greater number of elements and larger vessel sizes, increasing costs.

For this analysis, a qualitative assessment of required features was made to determine the cost per MW. The CDU Crude Heater is sensitive to pressure drop which is likely to increase equipment price. In addition, the large residue heaters are likely to require more exotic materials due to temperature and composition requirements. Although crude oil is not highly sensitive to temperature, watt density would be required to be restricted relative to water or other non-temperature sensitive fluids, which will increase cost further. The CDU Charge Heater equipment cost is therefore estimated to be towards the upper end of the vendor range.

For the Debutaniser Reboiler, lower temperatures are required and so less costly materials of construction can be selected. Watt densities are also expected to be higher compared to crude oil allowing for fewer elements and smaller vessels. However, the heater still has a relatively large duty versus industry experience and is likely to be sensitive to pressure drop, hence a mid cost is selected within the CAPEX range for this equipment item.

Equipment costs for both the CDU Crude Heater and Debutaniser Reboiler are prorated based on the vendor provided information and required design duty rather than accounting for economy of scale for the equipment. This is due to the modular nature of increasing duty for this equipment.

Table 8 provides the TIC for the two electric heater options investigated. The non-equipment costs of installation (via TIC factoring) are greater for the smaller Debutaniser Reboiler than the CDU Charge Heater due to the economy of scale for pipework, civils and other installation elements.

Table 8: CAPEX Summary - Electric Heaters

Item	CAPEX (MM$)	
	CDU Heater	Debutaniser Reboiler
Process Equipment	65.0	9.0
Electrical Infrastructure	29.0	6.1
Total Installed Cost (TIC)	94.0	15.1

6.1.5.4 Space Requirement

A summary of the plot area requirements for the two electric heater options is provided in Table 9. The crude heater requires significantly more plot space due to the greater duty and number of electric heaters, which raises concerns regarding feasibility in close proximity to the CDU column within a congested unit.

A vendor has advised that the electric heaters can be stacked allowing for a reduced plot space. For the purposes of this study it is assumed that the electric heaters are stacked two vessels high.

The required plot areas for electrical infrastructure are large and could result in layout issues if an adjacent area is not available near to the process unit.

Table 9: Plot Area Summary - Electric Heaters

Item	Plot Area (m^2)	
	CDU Heater	Debutaniser Reboiler
Process Equipment	180	25
Electrical Infrastructure	813 (1)	283
Total	993	308

(1) Unit substation and transformer area only. Excludes site receiving infrastructure additions.

6.1.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 2.0 MM$ for the CDU Charge Heater and 0.3 MM$ for the Debutaniser reboiler, in respect of maintenance cost and property insurance.

In reality, some operating cost credit could be taken for decommissioning of the existing fired heater.

6.1.5.6 Project Schedule

In either the reboiler or CDU charge heater example, the project will install a number of electrical heater vessels and electrical element bundles, as well as extensive cabling, substation and transformer infrastructure. The location will necessarily be very close to the existing heater.

Access to the site for any ground preparation, construction of the equipment and electrical infrastructure is assumed to be available alongside operating plant, but this is a significant risk to feasibility that will require specific site assessment. Tie ins to the existing process connections and substation supply electrical infrastructure will be required during a major complex turnaround.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs). The critical path optimisation shows little difference between LLIs, piping/bulks arrival and foundation execution.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and one month. Due to this being a process revamp, a Pre-FEED phase may also be required.

6.1.5.7 Other Options for Fired Heaters

Applying electric heaters as described above to very large fired heaters such as the CDU, VDU or Coker charge heaters produces numerous process and project planning issues. Process concerns include hydraulics within the multiple heater “vessels” required, new technologies required for coking mitigation, and high velocities due to steam injection or vacuum pressure. Constructability and shutdown planning also introduces the issue of plot space immediately adjacent to the existing heater and outlet manifold tie in requirements to maintain hydraulic performance.

Alternatives to this technology are:

- Revamp within the existing fire box to eliminate the process and tie-in concerns
- Fuel substitution with hydrogen produced by electrolysis
- Other non-electrification options such as carbon capture.

<u>Revamp Within Existing Fire Box</u>

Electrification of the existing firebox, utilising the existing heater tubes but replacing the burners with electrical heat, could avoid many of the issues highlighted by making minimal changes to the process side of the heater and plot.

This technology is currently at very early concept stage; key enabling technologies within the fire box have not yet been developed. Suitable radiant heater units facing the existing tubes and induction heating of the tubes are being considered during technology development, which will also focus on the balance of heating across the heater tubes.

<u>Fuel Substitution with Hydrogen</u>

Completely replacing fuel gas with hydrogen combustion in the heaters is a relatively mature technology, though specialist study and modification is required to allow for the combustion properties of hydrogen.

Electrical efficiency is lower than direct electric heating due to the efficiency of the electrolysers. However, this solution enables energy storage of this part of the refinery electrical duty as hydrogen. Fuel substitution with hydrogen will be applied as an option in Phase 4 utilising the project scopes developed in Phase 3 for electrolysis.

6.2 Electric Heaters (Tank Heating)

6.2.1 Description and Application

Tank heating for maintenance of the viscosity of fuel oil, waxes and residue is commonly achieved through steam heating coils with connection to the side of the tank. Leakage and utility system losses can be significant problems for this application of steam as the tanks are often remote from the core processing facilities.

Direct electric tank heating has efficiency benefits since it functions similarly to process electric heaters but at a lower heat demand, usually in the kW range.

Changeover of tanks to direct electrical heaters could take 10-20 years depending on maximum achievable maintenance intervals and the requirement to clean out tanks in these services. However, an alternative online retrofit option is to utilise the existing coils and heat a circulating fluid by an external electric heater. While not as efficient as direct heating, it adds flexibility for timing of installation. Mineral oils are the more popular heat-carrying mediums in indirect heating, which could be heated by a smaller scale process electric heater. These systems also subject the fluid to smaller watt density, which is helpful for temperature-sensitive inventories.

6.2.2 Technology Readiness Level

Electric heaters for this application will have lower heating demand than process heating and are believed to have been applied in industry, hence a TRL of 9 is expected.

6.2.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting to electric heaters for tank heating.

Table 10: CO_2 Emission Savings for Electric Heaters (Tank Heating)

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Tank Heating	Steam Coils for Tank Heating	LP Steam	5.04
Sulphur Storage	Heating of Stored Material	LP Steam	0.12

(1) Figures in the table are based on the high complexity refinery configuration

6.2.4 Operations, Reliability and Safety Impact

6.2.4.1 Ease of Implementation

As discussed above, direct replacement with electric elements is likely to take place over 5-10 years due to tank maintenance intervals. Installation of indirect systems would require remote electrical connection and associated equipment in the tank farm.

6.2.4.2 RAM and Operations Impact

Reliability is not expected to be a significant concern. However, operating and maintaining additional remote heating equipment for indirect heating in the tank farm is unlikely to be a focus for the site teams which may lead to degradation of this equipment over time.

6.2.4.3 HSSE Impact

Hot oil circulation is an additional hazard in the tank farm, though reduction in steam and condensate leaks and loss is a clear efficiency benefit.

6.2.5 Example Project Application

6.2.5.1 Process Equipment

The following describes the process equipment requirements for the two potential tank heating electrification options, direct electric heating and indirect hot oil heating.

Direct Electric Heating

Minimal process equipment is required for this option as it involves the replacement of the steam heating coils with a direct electric heater. Equipment sizing depends on the heating duty for each individual tank. A high level view of tank heating requirements for a refinery has been considered whereby the total tank heating duties are combined. This results in a total duty of 23 MW for the high complexity case.

Indirect Hot Oil Heating

The indirect hot oil heating option does not require direct modification of the existing tanks as it is assumed that the current heating coil will also be suitable for hot oil. Significant process equipment will be required for the hot oil system consisting of hot oil storage tanks, transfer and circulation pumps, expansion vessels, coolers and drain drums amongst other items. Efficiencies of such a system are assumed to be ca. 95% due to heat loss to surroundings. The total electrical input duty accounting for these inefficiencies is approximately 24 MW.

6.2.5.2 Electrical Infrastructure

The electrical infrastructure for direct electrical heating of each tank or heating of a centralised hot oil system is assumed to be similar based on the duty and voltage required. Cabling to each tank may be longer and more expensive depending on the tank farm in the direct tank heating case, balanced against the duty being slightly greater in the indirect case.

For both options, 8 off medium voltage cables are required from the substation to the consumer(s), where this would enable multiple individual tanks to be heated in the direct heating option.

A new substation and transformers are expected to be required for this additional power requirement. Two off 7-tier medium voltage switchboards with associated transformers are required to feed the consumer(s) with redundancy. Substation building area requirement is 175 m^2, with 108 m^2 for the transformer area.

33 kV high voltage power supply to the substation area is assumed, requiring 2 runs of 300 mm^2 cables.

6.2.5.3 Capital Cost

The CAPEX for the direct electrical heating option is developed from vendor supplied information whilst the CAPEX required for the indirect hot oil heating system has been developed from in-house information for a similar hot oil system design and vendor information for the electric heater.

Table 11 provides the CAPEX estimates for the two electrification options. It's seen that the indirect system is significantly more costly compared to the direct electric heating option due to the hot oil system required. The preferred electrification option depends on the driver for a particular facility. If the facility is able to wait for a maintenance interval and safety issues appropriately controlled, then direct electric heating offers a cost effective electrification approach compared to indirect. However, if the implementation period target does not align with facility maintenance planning, then the indirect method offers a shortened implementation timeframe.

Table 11: CAPEX Summary - Electric Heaters (Tank Heating)

Item	CAPEX (MM$)	
	Direct Electric Heating	Indirect Hot Oil Heating
Heating/Hot Oil System	8.9	19.2
Electrical Infrastructure	6.1	6.1
Total Installed Cost (TIC)	15.0	25.3

6.2.5.4 Space Requirement

A summary of the plot area requirements for the two electrification options are provided in

Table 12. The indirect hot oil heating option requires significantly more plot space to accommodate the closed hot oil heating system that would need to be installed to provide the heating duty to the tanks. Given the application of this system will be to brownfield sites that are likely to be congested, finding a suitable plot space may prove difficult and is a key disadvantage of this option.

The electrical infrastructure plot requirements are for the new common substation and transformers for either option.

Table 12: Plot Area Summary - Electric Heaters (Tank Heating)

Item	Plot Area (m^2)	
	Direct Electrical Heating	Indirect Hot Oil Heating
Heating/Hot Oil System	(1)	2700
Electrical Infrastructure	283	283
Total	283	2983

(1) Minimal impact, electric heater internal to tank

6.2.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 0.3 MM$ for the direct heating option and 0.5 MM$ for the indirect option, in respect of maintenance cost and property insurance.

Considering that most of the equipment would be in addition to existing infrastructure, the above is expected to add directly to the existing site operating cost.

6.2.5.6 Project Schedule

In the case of indirect electrical heating, the project will install an electrical heating unit, circulation equipment and pipework, as well as extensive cabling, substation and transformer infrastructure. The location will be near to the relevant tanks in the tank farm.

Access to the site for any ground preparation, construction of the equipment and electrical infrastructure is assumed to be available as installation will be within the offsites area.

Tie ins are not expected to be as dependent as other projects on turnaround timing, provided the existing steam coils can be isolated and re-used.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs), which includes the electric heater. The critical path optimisation shows little difference between LLIs, piping/bulks arrival and foundation execution.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and one month.

Direct electrical heating execution is expected to be dependent on the maintenance schedule of the relevant tanks, hence could be in the order of 10 or more years.

6.3 Electric Heaters (Microwave)

6.3.1 Description and Application

Microwave heating has been proposed for general heating purposes, replacing fired heaters or steam heat exchange. Theoretically, fast, localised, uniform heating without direct contact could resolve fouling issues over time and hence maintain heat transfer efficiency versus current technology. Use is not proven in refinery applications.

Electromagnetic wave penetration is limited, hence mixing of the process stream remains required for even temperature to be achieved. Efficiency of microwave generation is ca. 70-80%; overall efficiency is further reduced by the fraction absorbed by the process fluid. As the technology is not mature at industrial scale, this overall efficiency is unknown but could be as low as 50%.

Studies have shown that microwaves could be used to assist in the cracking of hydrocarbons, increasing yields for small volume processing or providing additional heat for endothermic processes. (Ref. 1)

Recent research showed that microwave heating could be enhanced by the addition of additives such as carbon black, water or methanol, resulting in a >95% conversion efficiency from microwave to heat energy, but only for a small laboratory volumes. (Ref. 1)

6.3.2 Technology Readiness Level

For process heating, this technology has been used successfully in other, dissimilar industries but is unproven at scale or in refining. Therefore, a TRL of <5 is estimated.

Though not applied here, the TRL for microwave hydrocarbon cracking is ca. 3 due to a lack of laboratory validation.

6.3.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting to electric heaters (microwaves) for various applications. Microwave heating for refinery processes has not been proposed for specific applications by vendors, hence theoretical application has been made to all heating requirements.

Table 13: CO_2 Emission Savings for Electric Heaters (Microwaves)

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Crude Distillation Unit	Crude Heater	Fuel Gas	22.11
	Debutaniser Reboiler Heater	Fuel Gas	3.05
Vacuum Distillation Unit	Charge Heater	Fuel Gas	14.07
C3/C4 Splitter	Fractionation Column Reboiler	MP Steam	1.06
Saturated Gas Plant/ Treater/ LPG separation	Fractionation Column Reboiler	MP Steam	0.54
Straight Run Naphtha Hydrotreater and Splitter	Feed Heater	Fuel Gas	2.19
	Stripper Reboiler	Fuel Gas	3.11
	Naphtha Splitter Reboiler	Fuel Gas	3.71
Distillate HDT	Feed Heater	Fuel Gas	3.13
Vacuum Gas Oil Hydrotreater	Feed Heater	Fuel Gas	2.69
	Fractionator Heater	Fuel Gas	7.18
FCC Gasoline HDT	HDS Reactor (Feed) Heater	Fuel Gas	0.32
	Naphtha Splitter Reboiler	Fuel Gas	1.79
	Splitter Reboiler	HP Steam	1.29
	Reactor pre-heater	HP Steam	0.07
	Stabilizer Reboiler	HP Steam	0.57
C5/C6 Isomerisation Unit	Charge Heater Exchanger	HP Steam	0.47
	Regenerant Vapouriser	MP Steam	0.25
	Stabilizer Reboiler	MP Steam	2.02

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
	Raffinate Column Reboiler	MP Steam	2.25
	Extract Column Reboiler	MP Steam	1.08
Continuous Catalytic Reformer	Process Heaters	Fuel Gas	18.03
	Stabiliser Reboiler	Fuel Gas	0.56
MTBE	Feed Preheater	LP Steam	0.06
	Fractionation Reboiler	MP Steam	0.84
	Methanol Recovery Column	MP Steam	0.33
H2SO4 Alkylation	Process Air Heaters	Fuel Gas	0.07
	Depropaniser Reboiler	LP Steam	0.06
	Deisobutaniser Reboiler	MP Steam	3.04
	Debutaniser Reboiler	MP Steam	0.97
Hydrocracker (2)	Feed Heater	Fuel Gas	5.15
	Fractionator Heater	Fuel Gas	13.36
Fluid Catalytic Cracker	Stripper Steam Reboiler	LP Steam	5.14
	Debutanizer Reboiler	MP Steam	17.89
	Fractionation Column Reboilers	MP Steam	1.21
	C3= Splitter LPS Reboiler	LP Steam	19.54
Coker	Feed Heater	Fuel Gas	15.57
Hydrogen Plant	SMR	Fuel Gas	11.49
Amine Unit (SWS)	ARU Regen Reboiler	LP Steam	13.83
	SWS Regen Reboiler	LP Steam	2.98
Sulphur Recovery Unit	LPS Heating	LP Steam	6.66
	LPS TGTU Regen Reboiler	LP Steam	6.59

(1) Figures in the table are based on the high complexity refinery configuration

(2) The hydrocracker is not present in the high complexity configuration, instead, it is included in the medium complexity configuration. However, data is included in the above table for comparison.

6.3.4 Operations, Reliability and Safety Impact

6.3.4.1 Ease of Implementation

Microwave heaters could be used to supplement electric process heaters. Consequently, microwave heaters will need to be located on plots adjacent to electric heaters. Multiple units and complex pipe manifolds will be required to achieve process duties.

6.3.4.2 RAM and Operations Impact

Operating and maintenance teams will require training to operate new unfamiliar microwave heaters.

There will be no contact between microwave heaters and process fluids, operations and maintenance interventions are therefore likely to be reduced. Lower maintenance and servicing cost are likely.

6.3.4.3 HSSE Impact

Similar to electric process heaters, elimination of fired heaters allows improvement in safety of operations personnel, though common mode failure of electricity supplies would require study.

6.3.5 Example Project Application

Due to the early technology development level of microwave heating in this application, more detailed analysis of a representative project was not carried out.

6.4 Heat Pumps

6.4.1 Description and Application

Although refineries are generally well heat integrated, including complex preheat trains, sites have plentiful waste and low-temperature energy in the form of rundown streams, columns overhead condensers and other streams exchanged with cold utilities. Typically, these streams are below 230 °C and commonly around 100 °C after heat exchange with cold process streams.

Industrial heat pumps are a form of heat recovery equipment that transforms low-quality heat to higher and more usable heat. Refrigerant undergoes a cycle of compression and expansion, alternating from the hot gaseous phase, emitting heat, to the cold liquid phase, absorbing heat. The ability to absorb heat from low temperature sources enables very high electrical to heat power efficiency of multiple times the power input.

Of the potential technologies for high temperature Power-to-Heat, heat pumps are viewed less technologically ready (Ref. 13). Demonstration of heat pump technology on an industrial scale of 2 MW has been achieved, producing a process steam between 120 °C to 150 °C from waste heat at 60 °C to 90 °C with efficiencies above 50% of the theoretical maximum (Ref. 13). Although resulting temperatures of below 150 °C are unlikely to displace a large amount of utilities at a site, the demonstration shows the scale of temperature increase and duty.

Assessment of the possibility of storing low price electricity as heat at a high temperature with a heat pump, and then producing electricity at the highest price periods has also been proposed. The stored heat can be converted to electricity by means of an Organic Rankine Cycle (ORC) heat engine. The CHESTER high temperature heat pump must reach temperatures around 140°C in order to charge the phase change material of the thermal energy store, which stores heat at 133°C. (Ref. 13)

High-grade steam production has also been proposed by vapour recompression of excess, low-pressure steam thus reducing steam boiler load. (Ref. 15)

Though not primarily an electrification technology, QPinch is a related technology utilising a chemical reaction where phosphates are polymerised in a closed loop between two reactors. In the cold reactor the phosphates are exposed to the waste heat and an endothermic reaction produces polymers and capturing energy. In the hot reactor the polymers undergo the reverse reaction which is exothermic and in doing so releases usable process heat (Ref. 34).

As well as a closed refrigeration heat pump to upgrade streams to higher temperature, this technology can be used for mechanical vapour recompression (MVR) whereby the overhead vapour is compressed prior to condensing which enables the hot vapour to condense at a high enough temperature to exchange against the reboiler, before expansion and separation into the reflux and product streams. A typical schematic is presented in Figure *6*.

MVR can therefore enable elimination of the large amounts of heat wasted via air coolers or cooling water exchangers in the column overheads, providing the boiling points of the top and bottom products are sufficiently close and compression is therefore not excessive to provide the necessary temperature difference.

Application of heat pump technology to specific fuel and steam consumers in the refinery is limited to the MVR technology. However, opportunity exists to upgrade larger waste heat streams to low pressure steam or to power via a heat engine.

MVR has been applied in LPG fractionation, specifically in propane/propylene separation where higher reflux ratios can also be achieved with MVR to enable higher quality product. Shell Pernis refinery implemented this revamp successfully in 1995. (Ref. 35)

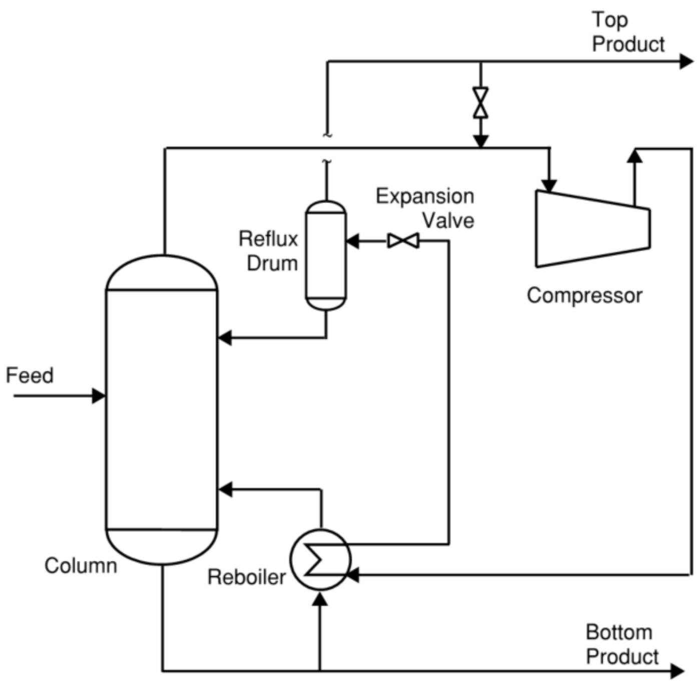

Figure 6: Typical MVR Schematic

Major equipment identified for electrification is not expected to use waste heat upgrading to replace current utilities, with the exception of MVR as discussed above. However, this could be an important technology to apply to reduce low pressure steam production by utility boilers or reduce renewable power imports.

Theoretically, waste heat streams could be upgraded to exchange against the cold end of preheat trains; this is unlikely to achieve high benefits without major investment in heat exchange area. Two ways are considered in which energy could be recovered from these streams, as LP steam or electricity.

- LP Steam: Heat pumps offer a method whereby this energy can be recovered as steam. Such systems use electrical energy to drive a system where heat is absorbed at low temperature and rejected at a higher temperature (as steam). This technology is typically suitable for heat recovery from streams in the region of 80-150 °C. A schematic of a heat pump system is presented in Figure 7.

- Electricity: Organic Rankine Cycle (ORC) systems offer a method whereby this energy can be recovered as electricity. This technology is typically used to produced power from low-medium temperature sources in the range of 80-350 °C. A schematic of an ORC system is presented in Figure 8.

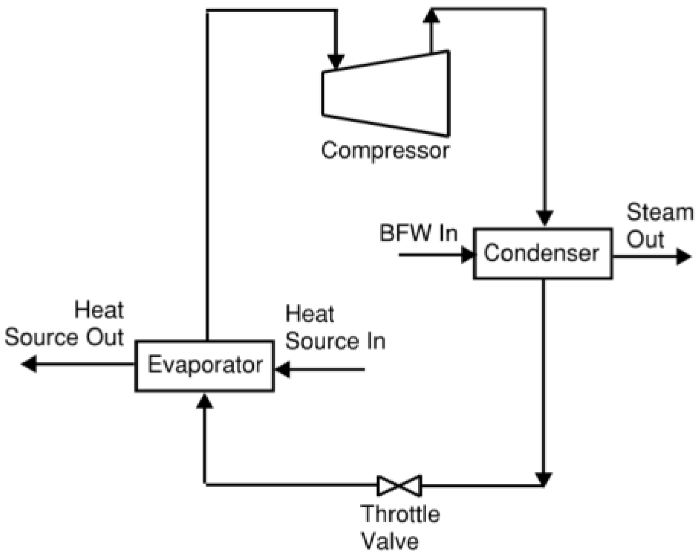

Figure 7: Schematic of Heat Pump System

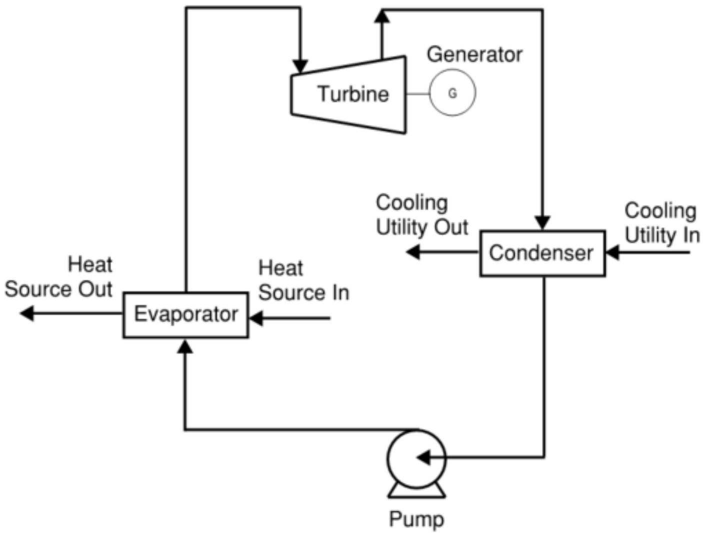

Figure 8: Schematic of Organic Rankine Cycle (ORC) System

6.4.2 Technology Readiness Level

For low grade heat sources and application of heat pumps and engines, a TRL of 9 expected for applications below 150 °C due to wide availability in industrial settings and TRL of <8 for applications above 150 °C. Pilot testing shows viability for process heating. Product temperatures of up to 230°C via technologies such as QPinch are theoretically possible with 120-150°C being more common.

Mechanical vapour recompression is proven in LPG refinery distillation applications, hence a TRL of 9 is expected.

6.4.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings for applications suitable for MVR technology as a replacement for steam reboilers. As discussed above, application has only been made to propylene/ propane splitting to avoid large boiling range products.

CO_2 savings reported in the table below are based on the propylene splitter reboiler duty being provided by LPS. Operation can be optimised through heat integration and recovery of waste heat thus reducing LPS demand which in this specific instance would mean lower CO_2 savings for this equipment item. However, for purposes of this study the assumption is that the reboiler duty is provided by LPS in its entirety to demonstrate the potential savings for this equipment item where heat integration has not been considered.

Table 14: CO_2 Emission Savings for Heat Pumps

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Fluid Catalytic Cracker	C3 Splitter LPS Reboiler	LP Steam	23.16

(1) Figures in the table are based on the high complexity refinery configuration

6.4.4 Operations, Reliability and Safety Impact

6.4.4.1 Ease of Implementation

An MVR revamp is likely to require extensive work alongside live plant prior to shutdown as well as significant work during a shutdown to tie in. Space requirements could be problematic around the base of columns that are generally located in congested process areas.

Heat pumps will require additional plot space in the vicinity of any waste heat streams to be upgraded.

6.4.4.2 RAM and Operations Impact

The reliability of an MVR, heat pump or ORC system in comparison to steam/fuel reboilers is likely to be poorer, though in the case of waste heat to utilities, this can be substituted by increased imports of power and steam generation if the utility system is sized for waste heat systems failure.

Operating and maintenance teams will require training to operate the new technologies.

6.4.4.3 HSSE Impact

Heat pump compressor equipment could give an increased risk of leak and loss of containment of hydrocarbon/refrigerant vapour.

6.4.5 Example MVR Project Application

The system identified most applicable to MVR technology is the propylene splitter due to the close boiling points of propylene and propane. The example analysed is based on the application of MVR to this system. Only the high complexity refinery case includes a propylene splitter as this refinery configuration is the only one to include an FCC for propylene production.

6.4.5.1 Process Equipment

The three main process equipment items for the MVR system are as follows.

- Overhead Compressor
- Separation Vessel
- Reboiler

The existing reboiler maybe suitable for use in the MVR system. However, differing heat transfer coefficients between steam and the overhead stream may require a different technology and it is likely that design efficiency can be improved using an exchanger with closer approach temperature. For the purposes of this study, it is assumed that the existing reboiler is replaced. When investigating such a system in detail, the thermal design of the existing reboiler should be investigated for suitability of re-use. In terms of overall cost, the reboiler has less weighting compared to the compressor and so inclusion of a new reboiler does not overly bias the results and is conservative.

Basic sizing of the MVR system for the propylene splitter was carried out by process simulation utilising in-house information. This enabled a sized equipment list to be developed from which the MVR cost is estimated. Polymer grade propylene product has been considered where propylene product is a minimum 99.5 wt% propylene, which requires a very high reflux ratio and reboiler heat duty.

The reboiler duty required is ca. 90 MW. This energy was shown to be recovered via the MVR system with a compressor at a duty of 25 MW, thus achieving a compressor COP of 3.5.

6.4.5.2 Electrical Infrastructure

The large 28 MW MVR compressor driver and associated VSD requires electrical feed at 11 kV high voltage. To supply the heaters with cable which affords an ease of installation whilst remaining relatively economic, a cable size of 300 mm^2 was selected. 14 cables are required for from the substation to the consumers.

Within the new substation and transformer area, the new 28 MW driver requires a total of 8 off high voltage tiers and associated transformers and low voltage switchboard. This results in a new substation building of ca. 151 m^2 and a new transformer area of ca. 98 m^2.

Power supply to the substation and transformer area is assumed to be at 33 kV with 7 off 300 mm^2 cables required.

6.4.5.3 Capital Cost

The CAPEX for the propylene splitter MVR system has been developed based on a sized equipment list specific for the propylene splitter of the high complexity case. Results are presented in

Table 15. The CAPEX is substantial for this option due the high duty of the propylene splitter system.

Table 15: CAPEX Summary - Heat Pumps (MVR)

Item	CAPEX (MM$)
Process Equipment	80.0
Electrical Infrastructure	5.4
Total Installed Cost (TIC)	85.4

6.4.5.4 Space Requirement

A summary of the plot area requirements for the MVR system is provided in Table 16. The plot space required is significant for a brownfield site particularly as layout is likely to have been optimised and space utilised for other applications over the lifetime of a facility. The high duty for the system means that the compressor and drum equipment are large.

The required plot area for electrical infrastructure for the large driver and VSD is also significant and could result in layout issues if an adjacent area is not available near to the process unit.

Table 16: Plot Area Summary - Heat Pumps (MVR)

	Plot Area (m^2)
Process Equipment	400
Electrical Infrastructure	249
Total	649

6.4.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 1.8 MM$, in respect of maintenance cost and property insurance. Most of the equipment is additive to the existing unit, hence the above is expected to add directly to the site operating costs.

6.4.5.6 Project Schedule

The project will install a large compressor system, large separator drum, heat exchangers and associated pipework and control, as well as extensive cabling, substation and transformer infrastructure. The location will necessarily be close to the existing distillation column.

Access to the site for any ground preparation, construction of the equipment and electrical infrastructure is assumed to be available alongside operating plant, but this is a significant risk to feasibility that will require specific site assessment.

Tie ins to the overheads, modifications to the reboiler and substation supply electrical infrastructure will be required during a major complex turnaround.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs). The critical path optimisation shows little difference between LLIs, piping/bulks arrival and foundation execution.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and one month. Due to this being a process revamp, a Pre-FEED phase may also be required.

6.4.6 Example Waste Heat Recovery Application

The major unit operations identified for electrification are not expected to use waste heat upgrading to replace current utilities, with the exception of MVR as discussed previously. However, this could be an important technology to reduce low pressure steam production requirements by utility boilers or reduce renewable power imports. Two ways that this could be achieved are via an Organic Rankine Cycle (ORC) to produce electricity or via a heat pump system to produce LP steam.

There are a number of low grade heat streams within a refinery complex such as distillation cuts requiring cooling, overhead condenser streams and rundown/ product streams. The number and energy content of these streams need to be understood in order to quantify the benefits in taking the energy recovery approaches. This has been estimated and reported in Table 17 below. The table illustrates the significant amount of energy available from these streams. In reality, it would not be economical to target all the waste heat streams, instead focus should be made on those few streams that offer the greatest potential.

Table 17: Potential waste stream heat recovery for high complexity case (Ref. 44)

Refinery Complexity	Capacity (BPSD)	Phase Waste Heat Stream	Potential Recoverable Energy (MW)	Stream Temperature (°C)
High Complexity	200,000	Liquid	570	80
		Gas	190	150

(1) Figures calculated assuming 10°C ambient temperature in the reference data (Ref. 44) and a hot stream (low grade heat process stream) outlet temperature of 60°C

The potential level of LP steam and electricity generation is calculated based on the available energy referred to in Table 17 for the gas and liquid low grade thermal energy streams. To illustrate a best case scenario it is assumed that all the potential energy is used to produce LP steam or electricity via the heat pump and ORC processes respectively. Results are presented in Table 18.

Table 18: Potential Electricity and LP Steam Generation from Low Grade Heat Streams

Technology	Energy Stream Produced	Waste Stream		
		Liquid	Gas	Total
Organic Rankine Cycle	Electricity (MW)	50	23	73
Heat Pump	LP Steam (tonnes/hr)	120	21	141

(1) Figures in the table assumes that the ORC heat sink is 25°C (typical ambient/cooling medium)

(2) Figures in table assumes that the heat pump heat sink is 150°C (LP steam)

CAPEX figures for these systems have been developed assuming that, for the high complexity case, all accessible waste heat is recovered. In reality, only those streams offering greater concentrations of recoverable energy are likely to be selected as smaller streams would not be cost effective.

In the case of ORC, the electrical infrastructure requirement to connect a number of ORC systems around the site to local substations has been considered. This assumes up to 38 connections to local substations from ORC generation, with associated expansion to the switchboards, an additional controller and cabling from the ORCs.

The heat pump electrical infrastructure is also expected to be distributed across multiple units with minor modifications to existing substations and including cabling to the consumer heat pump packages.

Table 19: CAPEX Summary – ORC and Heat Pump

Item	CAPEX (MM$)	
	ORC	Heat Pump
Process Equipment	193.0	270.0
Electrical Infrastructure	3.8	1.6
Total Installed Cost (TIC)	196.8	271.6

6.5 Electric Steam Boilers

6.5.1 Description and Application

Steam boilers in refining supply steam for the processes from combustion of fuel gas or fuel oil. In recent years, in an effort to decarbonise and where electricity is renewable and low cost, some industrial sites have implemented electric steam boilers at significant scale.

Electric boilers can be a complete replacement for fuel-fired steam boilers. Electric boilers have been developed with high voltage electrode boiler designs up to 60MW capacity operating at 99% efficiency. At maximum power, the electrode boiler can generate saturated steam of 85 barg at 90 tonnes/hour which is significantly above the typical refinery high pressure steam system requirement of ca. 40 barg. If superheated steam is required, additional electric superheaters can be installed with additional electricity consumption.

A smaller duty electric boiler can be an addition to the existing refinery utilities for flexible operations with existing combustion-driven boilers (provided plant area availability). This enables utilisation of the electric boiler when the power price is lower, such as during weekends or night-time, due to lower electricity demand. As an intermediate electrification measure, this would assist peak power grid demand.

The expected life expectancy of the electrodes is ten years. However, improper use outside design parameters will significantly accelerate the deterioration of electrodes, specifically pH and conductivity ranges. Electrode boiler manufacturer have claimed that electrodes will not degrade through the lifespan of the boilers if operating within design specifications (Ref. 26).

6.5.2 Technology Readiness Level

TRL 9 is expected due to electric boilers being applied in industry at high pressure (ca. 40 barg) steam levels or lower and at scale.

The TRL for higher pressure (>85 bar) or very high capacity single train steam production is lower, but not required for this application.

6.5.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting to electric steam boilers.

Table 20: CO_2 Emission Savings for Electric Steam Boilers

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Utilities	Boilers	Fuel Gas	131.6

(1) Figures in the table are based on the high complexity refinery configuration

6.5.4 Operations, Reliability and Safety Impact

6.5.4.1 Ease of Implementation

Generally, it is common for utility steam production facilities to be located close to or within process unit plot areas. Should electric steam boilers be physically replacing existing conventional boilers in a similar location, then careful consideration will need to be given to simultaneous operations and the ease of access and construction in the vicinity of live plant. If plot space in the vicinity of existing steam generation plant is an issue, then it is viable for new boilers to be located remotely via new steam headers.

6.5.4.2 RAM and Operations Impact

Electric boilers will remove the requirement for conventional fired heater convection sections as there will no longer be a need for flue gas residual heat recovery. There will be fewer operator and maintenance field interventions as a result.

Conventional boilers are susceptible to flue gas side tube fouling and dew point corrosion mechanisms that often arise during abnormal upset periods. With removal of the convection section in an electric boiler, fouling and corrosion risks are expected to be reduced.

For conventional fired boilers, operators and inspection teams monitor furnaces to check refractory condition and wall/tube hotspots that can impact on furnace reliability and unscheduled outages. With removal of direct firing for electric boilers, tube integrity issues will be significantly reduced.

With removal of direct fired boilers, fuel, combustion air and flue gas flow control, burner, flue gas O_2 control, heater box pressure control management will be eliminated, thus making start-up, normal operation and shutdown of boilers less complicated. With the elimination of boiler fired heat generation equipment (fuel, flue gas, convection sections), there are potential reductions in maintenance and operational costs.

The potential common mode failures of steam supply at same time as power supply to units needs to be studied to evaluate the extent of impacts on conventional fired versus electric boilers. For example, site flare scenarios may not currently consider simultaneous steam and power outage.

Operating and maintenance teams will require training to operate new electric boilers.

6.5.4.3 HSSE Impact

The requirement for operators to be in a close proximity to fired boilers to manage burners, flame patterns and flame tube impingement brings the inherent risk of exposure to flue gas releases (opening combustion chamber peepholes etc). Electric boilers can eliminate many of these risks.

Fewer operations and maintenance interventions for electric boilers reduces health and safety exposure risks.

6.5.5 Example Project Application

The example analysed applies electric boilers to replace the base case high-complexity refinery steam boilers that supply steam to the process and utility users.

6.5.5.1 Process Equipment

Limited process equipment scope is required other than the electric boilers and connections. The boilers can be installed, manifolded and connected up to the existing steam system with little difficulty provided there is sufficient space.

For purposes of this study, a single boiler capacity is limited to 50 MW based on vendor discussions. Higher capacities are achievable but currently at lower steam pressure levels. The steam boiler design duty is 595 MW for the high complexity refinery case which equates to a minimum 12 x 50 MW boilers being required. Sparing of the boilers will be required to cover when boilers trip or are unavailable for other reasons. Given the number of boilers it is assumed that n+2 boiler sparing is required.

The steam boiler duty is significant and presents the greatest capacity scenario where the only electrification step taken is to replace the boiler system. With other electrification steps that reduce the facility steam demand, the duty and number of electric boilers required will reduce.

6.5.5.2 Electrical Infrastructure

The electrode steam boiler equipment is expected to require electrical feed at 11 kV based on recent vendor experience. As approximately 14 x 50 MW boilers (including sparing) are anticipated to be required to supply the full duty for complete electrification of the existing steam system, cabling to each of these boilers is significant. To supply the boilers with cable which affords an ease of installation whilst remaining relatively economic, a cable size of 300 mm^2 had been selected, a total of 156 cables from the substation to the consumers is estimated to be required.

A new, large substation and transformers are required, with a total of 35 off HV tiers feeding 7 off HV/11kV transformers, to maintain a maximum switchgear current of 5000 A. This results in a new substation building of ca. 383 m^2 and a new transformer area of ca. 368 m^2.

Power supply to the substation and transformer area is assumed to be at 110 kV due to the large power demand and is likely a dedicated supply. 42 off 300 mm^2 cables are required to provide this capacity.

Additions to the site receiving substation and transformers are also expected to be required for the electric boilers due to the additional power required. Area required for these additions is estimated to be 325 m^2 for the substation and 368 m^2 for the transformers.

6.5.5.3 Capital Cost

The CAPEX for the electrode boiler has been developed based on vendor information and is presented in Table 21 for the high complexity refinery case.

Table 21: CAPEX Summary Electric Steam Boilers

Item	CAPEX (MM$)
Boiler Equipment	94.0
Electrical Infrastructure	47.6
Total Installed Cost (TIC)	141.6

6.5.5.4 Space Requirement

A summary of the plot area requirements for the electric steam boilers is provided in Table 22 for the high complexity refinery case.

The required plot areas for electrical infrastructure are large but are expected to be feasible considering the boilers will be built on an adjacent plot.

Table 22: Plot Area Summary – Electric Steam Boilers

	Plot Area (m^2)
Boiler Equipment	1,030
Electrical Infrastructure	751 (1)
Total	1,781

(1) Unit substation and transformer area only. Excludes site receiving infrastructure additions.

6.5.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 3.0 MM$, in respect of maintenance cost and property insurance.

If the existing boilers are decommissioned, the above operating cost impact could be reduced significantly.

6.5.5.6 Project Schedule

The project will install multiple electrode boilers on an unoccupied brownfield plot with extensive cabling, substation and transformer infrastructure. Complexity of this project is relatively low, though the number of boilers and plot area required is significant.

Access to the site for any ground preparation, construction of the boilers and electrical infrastructure is assumed to be available alongside operating plant as this will be performed on an adjacent plot.

Tie ins to the steam mains and site supply electrical infrastructure will be required during a major complex turnaround.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs). The longest lead items are anticipated to be the electrode boilers at ca. 15-18 months delivery. The critical path optimisation shows LLIs, piping/bulks arrival and foundation execution are approximately aligned if LLIs are expedited as above.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and one month.

6.6 Dynamic Combustion Chamber

6.6.1 Description and Application

Dynamic Combustion Chamber technology is a process to generate steam via direct combustion of hydrogen in a boiler system. The closed-loop system utilises an electrolyser to produce and capture both hydrogen and oxygen, which are reacted in the boiler to produce steam. A schematic of a Dynamic Combustion Chamber system is presented in Figure *9*.

The current design maturity is only able to produce steam up to 40 barg at 28 tonnes/hr. The electrical efficiency of this technology is very low when coupled with electrolyser technology, though emergent electrolyser technologies at higher efficiency would assist economics considerably.

The key advantage of the DCC is the ability to store hydrogen and oxygen as an intermediate and hence utilise excess renewable power from the grid when available.

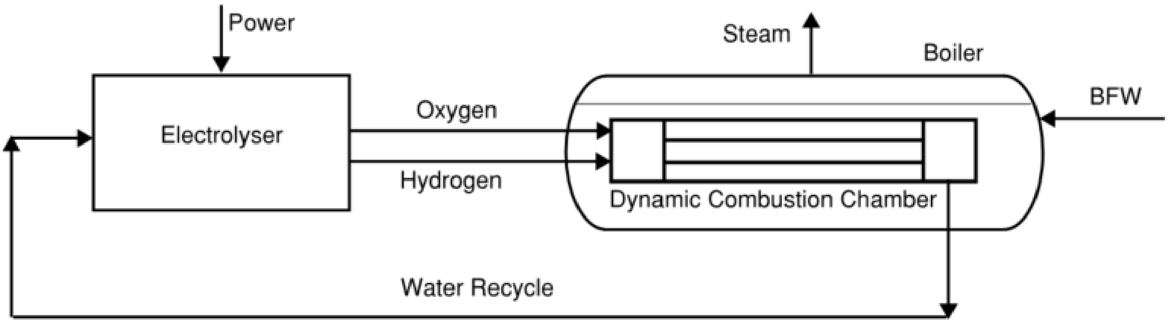

Figure 9: Schematic of Dynamic Combustion Chamber System

6.6.2 Technology Readiness Level

The TRL for DCC is expected to be 6 since the component technologies (electrolysers and hydrogen boilers) are both relatively mature technologies.

6.6.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting to dynamic combustion chamber technology from fuel gas fired steam boilers.

Table 23: CO_2 Emission Savings for DCC technology

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Utilities	Boilers	Fuel Gas	121.9

(1) Figures in the table are based on the high complexity refinery configuration

6.6.4 Operations, Reliability and Safety Impact

6.6.4.1 Ease of Implementation

Three areas of equipment are anticipated to be required for DCC application: electrolysis, storage of hydrogen and oxygen, and the hydrogen boiler. This is a significant multi-zone application with connecting pipework which will require significant planning outside of a shutdown.

6.6.4.2 RAM and Operations Impact

Impacts are expected to be similar to the electrolyser technology discussed in Section 6.8.4 . Storage and combustion is expected to be relatively simple versus existing fired boilers.

This technology is new and has multiple elements new to refinery operations.

6.6.4.3 HSSE Impact

Hydrogen and oxygen storage, compression and logistics operations are likely to be new to a site and will require specific new safety measures and control.

6.6.5 Example Project Application

6.6.5.1 Process Equipment

The key parts to the dynamic combustion chamber system are the electrolyser that produces the hydrogen and oxygen and the steam boiler where steam is raised from the reaction of hydrogen with oxygen. Due to the quantity of steam production required in the high complexity case, direct replacement with the DCC technology results in significant power demand due to the quantity of hydrogen and oxygen that is needed. The electrolyser design duty for the high complexity case is 1,040 MW which enables the required steam production rate of 580 t/hr. As with the electric boiler, discussed in Section 6.5.5.1**Error! Reference source not found.**, this presents the maximum power d emand scenario where the DCC technology replaces the entire existing fuel fired steam boiler with no other electrification options taken. Electrifying other equipment that require steam will reduce the overall duty and size of the DCC option.

It is assumed that low-carbon electricity supply to the facility is reliable and continuous thus hydrogen storage to buffer fluctuation in renewable energy supply has not been considered.

For purposes of this study PEM electrolysers have been considered aligned with the reasoning given in Section 6.8.5.3.

6.6.5.2 Electrical Infrastructure

The DCC electrical consumer equipment is similar to the electrolysers for SMR replacement, though at much greater scale. The power requirement for the DCC to replace fuel fired boilers is 1040 MW versus the SMR replacement requirement above of 222 MW. This results in an increase of cabling from substation to the consumers to 260 off 11kV 300 mm^2 cables. Despite 300 mm^2 cables being easier to lay than thicker specifications, this will require significant space around the rows of electrolyser modules.

A new, large substation and transformers are required, with 96 off total HV tiers feeding 12 off HV/11kV transformers, to maintain a maximum 11kV switchgear current of 5000 A. This results in a new substation building of ca. 986 m^2 and a new transformer area of ca. 618 m^2.

Power supply to the substation and transformer area is assumed to be at 240 kV due to the large power demand and is likely a dedicated supply. 39 off 500 mm^2 cables are required to provide this capacity.

Additions to the site receiving substation and transformers are also expected to be required for the DCC electrolysers due to the additional power required. Area required for these additions is estimated to be 1861 m^2 for the substation and 618 m^2 for the transformers.

6.6.5.3 Capital Cost

The CAPEX for a DCC system has been developed based on inhouse information and is presented in

Table 24. The majority of the cost associated with the DCC technology is a result of the electrolyser required to produce the hydrogen and oxygen for reaction with a smaller contribution from the steam boilers with reaction heaters. Costs for support utilities such as water treatment, cooling water,

instrument air and nitrogen have been factored as it is assumed utility systems at existing facilities will be insufficient to support an DCC system of this size.

Table 24: CAPEX Summary - DCC

Item	CAPEX (MM$)
Process Equipment	1,530.0
Electrical Infrastructure	111.0
Total Installed Cost (TIC)	1,641

As discussed in Section 6.8.5.3, the cost of electrolysers is expected to fall significantly over the coming years. Given that the majority of the DCC option CAPEX results from the electrolyser costs the figures presented in

Table 24 are expected to fall substantially.

6.6.5.4 Space Requirement

A summary of the plot area requirements for the DCC system is provided in Table 25. Significant plot space is required to accommodate DCC technology, associated electrolysers and other utilities. The majority of the plot area is associated with the electrolyser which will be based on a modular arrangement due to the required capacity.

The required plot areas for electrical infrastructure are very large and, alongside a very large area for the electrolysers, will require a large adjacent plot.

Table 25: Plot Area Summary – DCC

	Plot Area (m^2)
Process Equipment	137,000 (1)
Electrical Infrastructure	1604 (2)
Total	138,604

(1) Includes rectifiers and switchgear, support utilities (cooling water supply etc. and buildings (control room, workshop etc)

(2) Unit substation and transformer area only. Excludes site receiving infrastructure additions.

6.6.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 34.4 MM$, in respect of maintenance cost and property insurance.

If the existing boilers are decommissioned, the above operating cost impact could be reduced, though the impact on the increase in cost is likely to be small due to the scale of the DCC project.

6.6.5.6 Project Schedule

The project will install multiple electrolyser modules as well as hydrogen-fired boilers on an unoccupied brownfield plot with extensive cabling, substation and transformer infrastructure. The complexity of this project is relatively low, though the number of modules and plot area required are significant.

Access to the site for any ground preparation, construction of the electrolysers and electrical infrastructure is assumed to be available alongside operating plant as this will be performed on an adjacent plot.

Tie ins to steam mains and site supply electrical infrastructure will be required during a major complex turnaround.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs). The longest lead items are anticipated to be the electrolyser vendor supplied units at ca. 24 months delivery. The critical path optimisation shows LLIs remain on the critical path ahead of piping/bulks arrival and foundation execution.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and five months.

6.7 Electric Drives

6.7.1 Description and Application

Electric drives have been applied as an alternative to steam turbines to provide shaft power to pumps and compressors. Modern designs of process plant generally favours electrical motors, however many large steam driven machines, including condensing turbines, exist in operating sites due to historic design practices and the desire for steam and electrical drivers as differentiated spares in a single duty.

Steam turbines use thermal energy from pressurising steam to rotate shafts for mechanical work. Electric drive technology is readily available to replace steam turbines up to 100MW capacity, potentially simplifying the start-up and shutdown procedure and removing inefficient condensing turbine use. The limiting factor for replacing steam with electricity is likely to be plot constraints as variable speed facilities and the motors themselves are generally much larger than the original steam turbine.

Modern technology has reduced or eliminated the difference in reliability between steam turbines and electric motors, which should remove the argument that steam drivers are more reliable. (Ref. 12) In some cases, the existing steam turbine drive can be kept in place, in order to improve the redundancy and reliability of the plant. (Ref. 12). In the case of retrofit, electrification is a well proven and economically feasible option.

Benefits of electrifying shaft work are much greater if replacing large condensing turbine systems which have low overall thermal efficiency. Equally, strong economics are observed whereby the site has an excess of the exhaust-side steam level, such as LP steam, and this low level steam is vented or condensed.

However, replacement of back pressure turbines where the exhaust steam level remains required for the steam balance is likely to provide minimal value.

6.7.2 Technology Readiness Level

TRL 9 is expected as the technology is available up to very high power for compressor drivers.

6.7.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings for converting to steam drives to electric drives.

In a system where the backpressure turbine is replaced with an electric motor and the exhaust-pressure steam (e.g. low-pressure steam) is then made up by a let-down via a desuperheater, the low-carbon electricity can replace an amount of fuel firing in the boilers. This is the scenario presented in the table below and the ranking results. However, where spare steam turbine generator capacity is available between the steam mains and will be utilised to produce the exhaust-pressure steam in the electrified scenario, the benefit will be negligible as the steam let down will simply occur via a turbine, generator and motor rather than the backpressure turbine in the base case.

Table 26: CO_2 Emission Savings for Electric Drives

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Crude Distillation Unit	Steam Turbine	HP Steam	0.28
Vacuum Gas Oil Hydrotreater	Recycle Compressor Steam Turbine	HP Steam	2.05
Continuous Catalytic Reformer	Recycle and Net Gas Compressor Drivers	HP Steam	1.43
Hydrocracker (2)	Recycle Gas Compressor	HP Steam	1.07
Fluid Catalytic Cracker	Main Air Blower Driver	HP Steam	14.45
	Wet Gas Compressor	HP Steam	12.83
	Slurry Pump Around Pump	HP Steam	0.25
Steam boilers including condensate system	BFW Pump Drivers	HP Steam	0.43
Firewater	Steam Turbine Driver	HP Steam	0.35

(1) Figures in the table are based on the high complexity refinery configuration

(2) The hydrocracker is not present in the high complexity configuration, instead, it is included in the medium complexity configuration. However, data is included in the above table for comparison.

6.7.4 Operations, Reliability and Safety Impact

6.7.4.1 Ease of Implementation

By removing steam turbine drivers, steam network piping can be removed from often congested process area pipracks. This will ease the issue of fully loaded piperacks around pump alleys when considering revamps and expansions.

Motor drive replacement of steam turbine drives is common practice at operating refineries.

It can be possible to build alongside existing steam drive systems and tie in during a scheduled unit outage. Plot space may be a concern, however there is a degree of flexibility on location of a replacement motor driven pump and associated variable speed drive (VSD). Large VSD's require significant plot space within ca. 200m of the motor.

6.7.4.2 RAM and Operations Impact

Electric drivers reduce levels of operator and maintenance interventions, as there are less field operator interventions than with a turbine and associated steam circuits.

For critical services, a detailed analysis must be conducted to determine whether there is a need to retain a steam turbine driver to cover power upsets/outages. This is unlikely to be practical or cost effective for the very large rotating machines. The potential for common mode failure of steam supply at same time as power supply to units needs to be considered when contemplating replacement of a steam drive with electric drive.

With the elimination of the steam turbine driver, associated steam system and control equipment, there are potential reductions in maintenance and operational costs by switching to electric motor drives. However, large VSD's require their own specialist maintenance.

6.7.4.3 HSSE Impact

Electric drivers are generally considered safer as there is no hot turbine, steam or condensate piping in the vicinity of the pump.

Electric drivers are also quieter than steam turbine drivers, with operator safety and health benefits.

6.7.5 Example Project Application

For the purposes of this report a large condensing steam turbine drive (FCC Main Air Blower, MAB) and a smaller steam turbine driven pump (CDU Bottoms Pump) have been selected for further analysis to enable differences in scale between large and small drives to be quantified.

6.7.5.1 Motor Equipment

The required electric drives are 16.6 MW and 0.3 MW for the FCC MAB and CDU Bottoms Pump respectively.

6.7.5.2 Electrical Infrastructure

The electrical infrastructure required for the two studied electrical drives differs in that the small 0.3 MW CDU Bottoms Pump is expected to be supplied by an existing substation and is medium voltage, whereas the FCC Main Air Blower driver is expected to require a new substation and transformers and receive a high voltage supply to the consumer.

The small CDU Bottoms Pump is expected to require a Variable Speed Drive and a single 185 mm^2 supply cable, as well as addition of a new switchgear starter/tier within the existing substation.

The large FCC Main Air Blower Driver requires electrical feed at 11 kV high voltage. To supply the heaters with cable which affords an ease of installation whilst remaining relatively economic, a cable size of 300 mm^2 was selected. 8 cables are required for from the substation to the consumers. Within the new substation and transformer area, the new driver requires 8 off high voltage tiers and associated transformers, low and medium voltage switchboards. This results in a new substation building of ca. 142 m^2 and a new transformer area of ca. 68 m^2. Power supply to the substation and transformer area is assumed to be at 33 kV with 2 off 300 mm^2 cables required.

6.7.5.3 Capital Cost

The CAPEX for the electric drive options have been developed based on in-house information and are presented in Table 27.

Table 27: CAPEX Summary – Electric Drives

Item	CAPEX (MM$)	
	FCC MAB	CDU Bottoms Pump
Motor Equipment	4.6	0.2
Electrical Infrastructure	4.2	0.1
Total Installed Cost (TIC)	8.8	0.3

6.7.5.4 Space Requirement

In terms of the small electric drive option (CDU bottoms pump) it is assumed that there is existing capacity withing the facility power intake such that additional electrical infrastructure is not required. Given that the electric drive motor will replace the steam turbine overall there is negligible impact to plot space for this option.

In terms of the large electric drive option (FCC MAB), 210 m^2 is estimated to be required for the electrical infrastructure and control, in addition to the motor unit adjacent to the compressor.

The required plot area for electrical infrastructure for the large driver is significant and could result in layout issues if an adjacent area is not available near to the process unit. For the small replacement without new substation, layout is much simpler, though space for the VSD will also be required.

6.7.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the FCC MAB driver project is 0.2 MM$, in respect of maintenance cost and property insurance. No significant operating cost increase is expected for the small CDU Bottoms driver.

If the existing steam turbine and associated condensing equipment are decommissioned, site operating cost is likely to reduce overall.

6.7.5.6 Project Schedule

With respect to the large electric drive associated with the FCC MAB, the project will install a new, large motor with associated VSD in the vicinity of the existing equipment and compressor. Extensive cabling, substation and transformer infrastructure is also expected to be built. The complexity of this project is relatively low.

Access to the site for any ground preparation, construction of the electrolysers and electrical infrastructure is assumed to be available alongside operating plant, though this is a risk to feasibility and would require specific site analysis.

Physical connection to the compressor and any modifications to the existing steam turbine will be required during a major complex turnaround.

The critical path optimisation shows civils design and foundation execution, including for the substation, are on the critical pat, hence no LLI expediting has been applied.

The project duration from start of FEED to Ready for Start-up is estimated to be two years and six months. No Pre-FEED phase would be expected for this type of project.

6.8 Electrolyser

6.8.1 Description and Application

Power to hydrogen production via electrolysis of water has high potential for decarbonising current emissions from steam methane reformers (SMRs) and electrolyser systems are well proven in industry. Application has been uneconomic in the recent past due to comparative utility process and far greater capital costs for electrolysers versus SMRs. (Ref. 12) Electrolysis currently requires multiple parallel units of electrolysers to produce hydrogen flowrates similar to large SMRs.

For this analysis, it is assumed that hydrogen is produced from water electrolysis with alkaline electrolysis cells (AEC) since this technology is mature, commercially available and suitable for large-scale installations. The assumed operation parameters were based on the following representative key parameters (Ref. 4):

- Operating temperature 80 ˚C
- Conversion efficiency 0.65 MW(H_2) (LHV)/MW(e)
- Excess heat release of 0.3 MW(th)/MW(e) at 70C
- Water demand of 0.54 ton/MWh(H_2)
- Oxygen production of 0.24 ton/MWh(H_2).

The levelised cost of hydrogen by electrolysis has been calculated at ca. 5 €/kg (baseload production), which has compared unfavourably with the cost of hydrogen from natural gas at ca. 1-1.5 €/kg using the steam reforming process (Ref. 12), though this is highly dependent on electricity vs. gas price. Technology is advancing rapidly, which will drive down the lifecycle cost and improve efficiency in the next years.

A 25MW alkaline electrolyser located in Peru is the largest electrolysis plant in operation. In January 2021, Thyssenkrupp (provider of alkaline electrolysers) won a contract to build an 88MW electrolysis plant in Quebec, due to be commissioned in 2023. One of the largest advanced-stage projects is a 200-megawatt electrolyser facility in the Port of Rotterdam by Shell capable of producing 60 tonnes of hydrogen daily from renewable energy. (Ref. 18)

Proton Exchange membrane (PEM) electrolysers are currently more expensive than alkaline and use precious metals for catalyst. A 20MW PEM project at Air Liquide's site in Bécancour is presently the largest operating PEM project to date. In January 2021, ITM Power announced that a 24MW PEM electrolysis plant had been sold to Linde to be installed at a Chemical Complex in Germany, scheduled to begin production in the second half of 2022. PEM technology is favoured by operations requiring higher turndown capacity.

Anion Exchange Membrane electrolysers are potentially cheaper due to the material of the membrane but less effective and only semi-commercial at this stage.

High Temperature Solid Oxide (SOEL) electrolysers have a lower TRL than the Alkaline and PEM types. The first example use of high-temperature solid-oxide electrolysers at semi-commercial scale will be at a biofuel refinery in the Netherlands, where a 2.6MW SOEL will be utilised with significant operational feedback by 2024.

Companies such as Hysata are also attempting to develop breakthrough, very high efficiency electrolyser technology, reported to be ca. 95% efficient versus 75% for current technology. (Ref. 43)

6.8.2 Technology Readiness Level

TRL is expected to be 9 for Alkaline and PEM types. Up to 20MW hydrogen plants are built worldwide with upcoming projects with higher output.

TRL of ca. 4 is expected for AEM. Early research is ongoing and proven to work in lab environment. SOEL technology is estimated at ca. TRL 7.

6.8.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings considering Electrolyser technology to produce hydrogen rather than SMR. Hydrogen production of 88 tonnes per stream day is aligned with this high complexity case.

Table 28: CO_2 Emission Savings for Electrolyser technology

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Hydrogen Plant	Electrolysis	Fuel Gas	30.3

(1) Figures in the table are based on the high complexity refinery configuration

6.8.4 Operations, Reliability and Safety Impact

6.8.4.1 Ease of Implementation

High volume hydrogen demands will require multiple modular electrolyser units & plot space.

Should plot space be a premium, then the demolition of part or all of the steam methane reformer (SMR) being replaced will be necessary. This will be a challenge as the SMR is a critical unit providing hydrogen to the refinery. With no interruption of hydrogen supply other than during full refinery turnarounds, then demolition of the SMR to make space for electrolysers will not be an option.

6.8.4.2 RAM and Operations Impact

Steam reformers are operator and maintenance intensive units. Replacing with electrolysers will release O&M personnel for other duties or reduce staff counts.

Operating and maintenance teams will require training to operate new unfamiliar electrolysers, hydrogen and oxygen storage facilities.

Inconsistent energy load can impact the reliability of electrode units thus resulting in variations in hydrogen production. This could be mitigated with spare electrolysers to smooth out hydrogen production levels.

Electrolyser units can be rapidly started-up and shut-down. This enables hydrogen demand changes to be more effectively controlled, resulting in greater turndown flexibility. Alkaline technology is more limited in this regard than the other technologies.

6.8.4.3 HSSE Impact

Oxygen and storage within process areas could increase the risk of fire and explosion.

6.8.5 Example Project Application

6.8.5.1 Process Equipment

The Electrolyser design duty for the high complexity case is 222 MW which will produce approximately 4,000 kg/hr of hydrogen. This capacity is significantly greater than any one electrolyser module can perform. Thus, the high complexity case electrolyser will be made up of a number of different modules.

It is assumed that green energy supply to the facility is reliable and continuous thus hydrogen storage to buffer fluctuations in renewable energy supply has not been considered.

Given the size of the electrolyser required, it is highly likely that existing facilities will not have sufficient capacity within their existing utility systems to provide for the increased utility demand such as cooling water, instrument air, nitrogen etc. Consequently, the supporting utilities required for the electrolyser have been factored into the CAPEX based on in-house information.

6.8.5.2 Electrical Infrastructure

The electrolyser equipment is expected to require electrical feed at 11 kV based on vendor proposal experience at large scales. Multiple electrolyser units (>10) are anticipated to be required to supply the full 222 MW duty. To supply the boilers with cable which affords an ease of installation whilst remaining relatively economic, a cable size of 300 mm^2 had been selected, a total of 65 cables from the substation to the consumers is estimated to be required.

A new, large substation and transformers are required, with 28 off HV tiers feeding 4 off HV/11kV transformers, to maintain a maximum 11kV switchgear current of 5000 A. This results in a new substation building of ca. 313 m^2 and a new transformer area of ca. 218 m^2.

Power supply to the substation and transformer area is assumed to be at 33 kV. 18 off 300 mm^2 cables are required to provide this capacity.

Additions to the site receiving substation and transformers are also expected to be required for the electrolysers due to the additional power required. Area required for these additions is estimated to be 228 m^2 for the substation and 218 m^2 for the transformers.

6.8.5.3 Capital Cost

The CAPEX for an electrolyser has been developed based on vendor quotations and inhouse information and is presented in Table 29. In addition to the electrolyser, costs for support utilities such as water treatment, cooling water, instrument air and nitrogen have been factored in as it is assumed utility systems at existing facilities will be insufficient to support an electrolyser of this size.

Table 29: CAPEX Summary - Electrolyser

Item	CAPEX (MM$)
Process Equipment (1)	295.0
Electrical Infrastructure	26.1
Total Installed Cost (TIC)	321.1

(1) Figure includes the transformers, rectifiers and support utilities are included within this cost.

At present the PEM technology is more CAPEX intensive than the AEC option. However, it is expected that over the coming years as the PEM technology develops the CAPEX will be comparable. Figures presented in Table 29 for process equipment are based on today's estimates. It is expected that over subsequent years electrolyser CAPEX will reduce significantly; by 2030 it is predicted that there will be a 35-40% fall in the equipment cost for PEM electrolysers from today's pricing.

6.8.5.4 Space Requirement

A summary of the plot area requirements for an electrolyser system is provided in Table 30. The PEM technology considered generally takes less plot space than alkaline, particularly if generating at pressure.

The required plot areas for electrical infrastructure are large but are expected to be feasible considering the electrolysers will be built on an adjacent plot.

Table 30: Plot Area Summary – Electrolyser

	Plot Area (m^2)
Process Equipment	29,000 (1)
Electrical Infrastructure	531 (2)
Total	29,531

(1) Includes rectifiers and switchgear, support utilities (cooling water supply etc. and buildings (control room, workshop etc)

(2) Unit substation and transformer area only. Excludes site receiving infrastructure additions.

6.8.5.5 Operating Costs

Based on the total CAPEX estimated and using the factors described in Section 5.3, the non-energy operating cost related to the project is 6.7 MM$, in respect of maintenance cost and property insurance.

If the existing hydrogen production unit is decommissioned, the above operating cost impact could be reduced to some extent.

6.8.5.6 Project Schedule

The project will install multiple electrolyser modules on an unoccupied brownfield plot with extensive cabling, substation and transformer infrastructure. The complexity of this project is relatively low, though the number of modules and plot area required are significant.

Access to the site for any ground preparation, construction of the electrolysers and electrical infrastructure is assumed to be available alongside operating plant as this will be performed on an adjacent plot.

Tie ins to hydrogen main and site supply electrical infrastructure will be required during a major complex turnaround.

To optimise the schedule, requests for quotation, evaluation and orders for engineering have been brought ahead of FID for long lead items (LLIs). The longest lead items are anticipated to be the electrolyser vendor supplied units at ca. 24 months delivery. The critical path optimisation shows LLIs remain on the critical path ahead of piping/bulks arrival and foundation execution.

The project duration from start of FEED to Ready for Start-up is estimated to be three years and five months.

6.9 Electric Heat Tracing

6.9.1 Description and Application

Electric heat tracing (EHT) functions to maintain the temperature of pipework and other equipment susceptible to freezing. Examples include winterisation protection on pipework, ensuring no condensation in the vapour line and maintaining the quality of the product for temperature-sensitive chemicals. Considering the total length of piping in a refinery complex that will require heating, generally by low-pressure steam tracing in the base scenario, the potential for electric heat tracing to reduce energy wastage and combustion of hydrocarbon is significant, though not a major energy consumer on a site scale.

EHT can apply to piping or equipment depending on requirements. By varying supplied voltage and technology, the heat output can be adapted for low- to high-temperature maintenance applications. This can include compensating heat loss to the environment for very long piping of 25km through skin effect heating, or for temperature maintenance up to 500 ˚C using mineral insulation. EHT is recommended for non-metal or lined piping and equipment due to their ability to deliver very low heat output, which may be tricky from using steam or fluid mediums (Ref. 2 & 3).

Additionally, EHT is leak-proof and is therefore simpler to install and maintain. However, if overlapping were to occur, EHT is prone to overheat. Manufacturers have rectified this issue by introducing self-regulating capability for cables with operating temperatures up to 200 ˚C.

An alternative technology for specific application is impedance heating, using the pipe itself as the heating source to uniformly transfer heat to a process stream. No piping modifications are required.

Impedance heaters can heat pipe lengths up to several kilometers to temperatures of 980 ˚C. Higher watt densities can be used up to 29.5 W/cm², due to increased velocities and lower pressure drops. (Ref. 21)

6.9.2 Technology Readiness Level

TRL of 9 is expected. The technology is mature and commercially available for various applications. Electric heat tracing is common for refineries in cold locations.

6.9.3 CO_2 Emissions Savings

The table below provides the CO_2 emission savings when converting steam tracing to electric heat tracing.

Table 31: CO_2 Emission Savings for Electric Heat Tracing

Unit	Equipment	Utility Type	CO2 Saved (tonnes/hr)
Tracing	ISBL and Offsites Steam Tracing	LP Steam	1.82

(1) Figures in the table are based on the high complexity refinery configuration

Due to imperfect condensate collection systems on many older sites, the condensate from steam tracing has been assumed to be 50% recovered to condensate collection.

6.9.4 Operations, Reliability and Safety Impact

6.9.4.1 Ease of Implementation

Electric heat tracing of pipelines and vessels is now commonly installed at refineries, be it new build or retrofitting ageing steam tracing that has become unreliable due to corrosion and leakage.

Wholesale replacement of steam tracing with electrical tracing will be a long-term undertaking as on-line replacement is highly labour intensive. For lines requiring constant heating in warmer seasons, conversion to electric tracing will be scheduled into plant turnarounds.

6.9.4.2 RAM and Operations Impact

In the event of power outage, quick recovery of heat tracing to heavy viscous products such as vacuum residue and liquid sulphur is vital to prevent line plugging and the associated lengthy process of line clearing prior to restarting. Rapid restarting will be easier and quicker on electric tracing.

Maintenance requirements for electric tracing are lower than steam tracing due to elimination of condensate systems. Electric tracing eliminates the widespread use of steam traps which are notorious for passing and wasting steam.

Integrity of insulation is also improved with electric tracing, there is less intervention arising from damp damaged lagging removal and to fix steam tracing leaks.

Overlapping of electric tracing can however cause overheating. Careful design and monitoring systems that automatically identify and control heat should be considered. With electric tracing, more flexible control of heat output through voltage supplied can be achieved, resulting in the ability to precisely control and optimise tracing temperatures.

6.9.4.3 HSSE Impact

Installing electric tracing eliminates the risk of under insulation external pipe corrosion caused by leaking steam tracing. This is often undetected until a process leak occurs or a routine lagging removal and external pipe inspection reveals the pipe section has pitting or has reached minimum thickness levels. However, selection of heating element type is important if steam out or pre-heat is required, as polymer-based elements have an upper temperature limitation before material breakdown. Installation in ATEX areas can also increase cost of equipment and inspections.

6.9.5 Example Project Application

6.9.5.1 Electrical Equipment

The equipment to be installed is limited to the electrical heat tracing with associated control system and cabling.

6.9.5.2 Electrical Infrastructure

Supporting electrical infrastructure has not been specifically scoped for this technology. It is assumed that the local substations and electrical supply can be drawn on for the distributed load across the site. Local cabling and installation are included within the installation factors used in the capital cost calculation below.

6.9.5.3 Capital Cost

The CAPEX for the EHT electrification option has been developed based on typical unit steam tracing line lengths from in-house information. Margin has been included for interconnecting piping, rundown lines and equipment. The estimated CAPEX requirement for replacing steam tracing with EHT for the high complexity refinery case is presented in Table 32.

The CAPEX required to replace all steam tracing is significant. There can be tens of thousands of meters of steam traced lines that would be required to be replaced. This involves a relatively labour intensive activity of gaining access, often at height, removing the existing steam tracing and lagging, then installing the EHT and lagging.

Table 32: CAPEX Summary - EHT

Item	CAPEX (MM$)
Total Installed Cost (TIC)	19.0

6.9.5.4 Space Requirement

There are no plot space impacts from installing EHT as it replaces the steam tracing along piping and around existing equipment. It is also assumed that there is capacity in existing facility electricity supply to cover for the increased power demand as this will be minor compared to the site wide power demand, hence additional electrical infrastructure requiring plot space is not needed.

6.9.5.5 Operating Costs

No change in non-energy operating cost is anticipated by replacing steam tracing with electrical tracing.

6.9.5.6 Project Schedule

Implementation of this project is not anticipated to be impacted by design, delivery or execution lead times. Retrofitting electric tracing to an existing site would be a long term project whereby a team moves from one system to the next. Therefore, execution is expected to take three or more years for full replacement.

6.10 Excluded Electrification Technologies

A number of technologies have been excluded due to there being no attractive applications within the scope of the study. These are listed below.

Plasma Arc: This is applicable to extremely hot applications which do not occur in refinery processes.

Electrosynthesis: E-fuels and e-chemicals would replace the process units of a refinery with fuel production via synthesis gas. The study is focused on brownfield electrification of current refinery emissions sources, hence electrosynthesis of fuels is considered out of scope.

Allam-Fetvedt Cycle: The process involves the conversion of natural gas or other fuels into thermal energy with the capture of carbon dioxide and water. This technology would compete with the other power generation with carbon capture but is not considered within refinery electrification.

Thermionic Generator: The process involves heat conversion to electricity through thermionic emission. The technology has been applied at small scale, remote environments but is not applicable for waste heat utilisation or other identified opportunity power generation.

7. Ranking of Opportunities

7.1 Methodology and Criteria

The technologies have been assessed using high-level quantitative and qualitative criteria to provide a practical view of feasibility and attractiveness of implementation. The parameters used in the ranking are described below.

Capital costs have been estimated from whole-project scaled costs for the purposes of the Phase 2 ranking. Source information for this has been drawn from in-house data, vendor interaction and published data, with appropriate high level adjustments for consistency. Accuracy level is sufficient only to obtain a view of order of magnitude across the site and will be further investigated in Phase 3. The costs aim to give a total installed cost for the technology but do not include electrical or other supporting balance of plant infrastructure, though this additional cost is expected to be required for any large new power user.

Table 33: Ranking Parameters

Category	Explanation
Site Wide CO2 Saved (t/h)	Technology applied to each potential major fuel or steam consumer. Production and transportation emissions are also included for natural gas imports avoided. Electricity import emissions are based on lifecycle emissions of equal parts solar, wind and nuclear.
Site Wide Capital Cost ($MM)	High level indication for screening from in-house, vendor and public domain information. Will be refined with secondary impacts (electrical) scoped and costed.
Cost Efficiency (t/h CO_2 avoided per $MM CAPEX)	Effectiveness of capital investment on CO_2 reduction. Higher is better.
Electrification Efficiency (t/h CO_2 avoided per MWe)	Efficiency of utilisation of additional low carbon power import. Fired duty replaced divided by increased electricity use.
Technology Readiness Level	Per TRL definition. Higher is better.
Ease of Implementation	Ability to install alongside operation and within 8-week TA window, plot space requirements. Groupings: High/Some/No (1-5) likelihood of major implementation issues
Reliability, Availability, Maintainability and Operations Impact	Risk to operations due to single mode of failure (power), inherent reliability, operational difficulty above current technology. Groupings: High/Some/No (1-5) likelihood of operational impact
HSSE Impact	Safety, security, health or environmental impact above current technology. Groupings: High/Some/No (1-5) likelihood of HSSE impact

7.2 Ranking Results

Results of the ranking process and workshop are presented in the following comparisons:

1. The numerical results of the various parameters are presented as a heat map to show where high benefits and concerns lie for each technology.
2. A weighted score is calculated using weighting for each parameter.
3. Electrification efficiency is shown as a measure of the most effective use of renewable power in reducing CO_2 emissions.
4. Heat replacement efficiency is shown as the efficiency of fired heat duty replaced by electricity.
5. A bubble chart is used to show Cost Efficiency versus ease of implementation and operation.

Table 34: Ranking Results

Weighting				1	1	0.4	0.3	0.2	0.1		
						Ease of Implementation and Operation					
Technology	**Applied Equipment**	**Site Wide CO_2 Saved (t/h)**	**Site Wide Capital Cost ($MM)**	**Cost Efficiency (t/h CO_2 per $MM)**	**Electrification Efficiency (t/h CO_2 Reduced per MW Electricity Use)**	**Technology Readiness Level**	**Ease of Implementation**	**RAM and Operations Impact**	**HSSE Impact**	**Comments**	**Weighted Score**
Electric Process Heater (Single Phase)	FCC Gasoline Hydrotreater Diolefin Reactor Heater Isomerisation Reactor Heater Naphtha Reformer Heaters Alkylation Unit Air Preheaters MTBE Feed Preheater	8.1	39.6	0.21	0.24	5	2	5	5	Plot space adjacent to existing heater, multiple units to achieve duty, complex pipe manifolds Simops - access via live plant / major kit movements Less O&M versus current. Reduction in HSSE risk. OPEX for maintenance could be reduced versus current.	5.4
Electric Process Heater (Two Phase)	All reboilers and feed heaters not included in Single Phase or Large Residue	141.0	582.4	0.24	0.24	4	2	2	5	Plot space adjacent to existing heater, multiple units to achieve duty, complex pipe manifolds Heat distribution within radiant section, vapourisation profiles Potential maintenance OPEX benefit	4.6
Electric Heater (Large Residue)	CDU, VDU and Coker Charge Heaters	57.3	224.5	0.26	0.24	2	1	2	5	Plot space adjacent to existing heater, multiple units to achieve duty, complex pipe manifolds High fouling & coking, heat distribution within radiant section impacts on coking management Ease of decoking coker heater tubes. Potential maintenance OPEX benefit Tie in issue and location issues with large outlet piping	3.5
Electric Process Heater (Tank Heating)	All tanks currently heated by steam coils, sulphur storage heating	5.2	25.8	0.20	0.24	5	2	5	5	Need to decommission, clean out tank & make safe for entry, time & availability of tank Could be possible to replace with closed loop hot oil systems.	5.4
Electric Heater (Microwave)	All Heaters within Single Phase, Two Phase and Large Residue categories	197.8	2152.6	0.09	0.11	1	2	3	5	Plot space adjacent to existing heater, multiple units to achieve duty, complex pipe manifolds Unlikely for high temperature service (no lab validation)	2.7
Electric Heater (Mech Vap Recompression)	LPG splitter reboilers	23.2	85.1	0.27	0.91	4	3	3	5	Multiple industrial heat pumps around the site Reliability concern vs. steam/fuel reboiler Compressor equipment could give increase risk of loss of containment of HC vapour New technology for operations Stabiliser application requires further investigation	7.2
Elec. Drive (Pumps & Backpressure Turbines)	All identified steam turbine drivers of shaft work (Pumps & backpressure turbines)	4.8	12.2	0.39	0.25	5	2	5	3	Electric motor & variable drive bigger than steam turbine, plot implication Power failure scenario required. Common mode failure. Reliability should be good Well proven at this capacity	5.8

Technology	Applied Equipment	Site Wide CO2 Saved (t/h)	Site Wide Capital Cost ($MM)	Cost Efficiency (t/h CO2 per $MM)	Electrification Efficiency (t/h CO2 Reduced per MW Electricity Use)	Technology Readiness Level	Ease of Implementation	RAM and Operations Impact	HSSE Impact	Comments	Weighted Score
Elec. Drive (Condensing Turbines)	All identified steam turbine drivers of shaft work (Condensing turbines)	27.3	16.2	1.68	0.98	5	2	5	3	Electric motor & variable drive bigger than steam turbine, plot implication Power failure scenario required. Common mode failure. Reliability should be good Well proven at this capacity	11.8
Electric Boiler (Electrode)	All steam production via boilers	131.6	141.6	0.93	0.24	5	3	4	3	Installed at scale. Build alongside existing steam system and tie in. Plot space required but some flexibility on location. Potential common mode failure of steam supply at same time as power supply to units. Potential maintenance OPEX benefit	7.4
Electric Boiler (Dynamic Combustion Chamber)	All steam production via boilers	121.9	1641.0	0.07	0.13	3	2	3	3	Need H2 & O2 storage, compression & liquid storage tanks Plot space, relatively large multiple units H2 and O2 storage safety risk New operation and material to store	3.3
Electric Furnace (High Temperature)	Steam Methane Reformer	12.7	614.1	0.02	0.16	1	2	3	5	Plot space adjacent to existing heater, multiple units to achieve duty, complex pipe manifolds Not yet proven, 1st pilot plant 2025!	2.6
Electric Heat Tracing	Site wide steam tracing	1.9	19.0	0.10	0.24	5	3	5	5	Installed at scale. Long term implementation required with issues for replacement of high temperature requirements (steam jacketing) No RAM, operations or HSSE impacts identified Power outage (local, site wide), VR, liquid S plugging. Restart easier and quicker on electric tracing.	5.4
Electrolyser	Hydrogen Production Unit replacement	30.3	321.1	0.09	0.15	5	3	2	5	High volume H2 demands will require multiple modular electrolyser units & plot space Significant effort to demolish a SMR & make good plot for electrolysers, unless remote plot space exists Inconsistent energy load can impact reliability New technology for operations	4.5

Figure 10 summarises the resulting weighted scores from Table 34.

Electric process heaters are shown to be a higher priority for immediate projects for simpler and lower duty services, with additional complexities and lower TRL reduces their score for high temperature and large residue heaters. Electrification of the large residue heaters is an important component of the site emissions reduction, hence exploration of retrofit within existing fire boxes and increased focus on early phase technology selection and assistance is recommended.

Microwave heating scores poorly due to low TRL and relatively low efficiency of power utilisation.

Electrolysers score well for replacement of current hydrogen generation technology and are preferred to high temperature electric heater implementation.

Electric heat tracing is a strong opportunity initiative, though unlikely to produce significant short term benefits.

Electric boilers and electric drives applied to condensing turbines appear as the highest priority technologies for implementation due to a blend of efficiency improvement, high TRL and relatively few implementation issues.

MVR is also a very strong technology where it can be applied efficiently, strengthened by its high power utilisation efficiency.

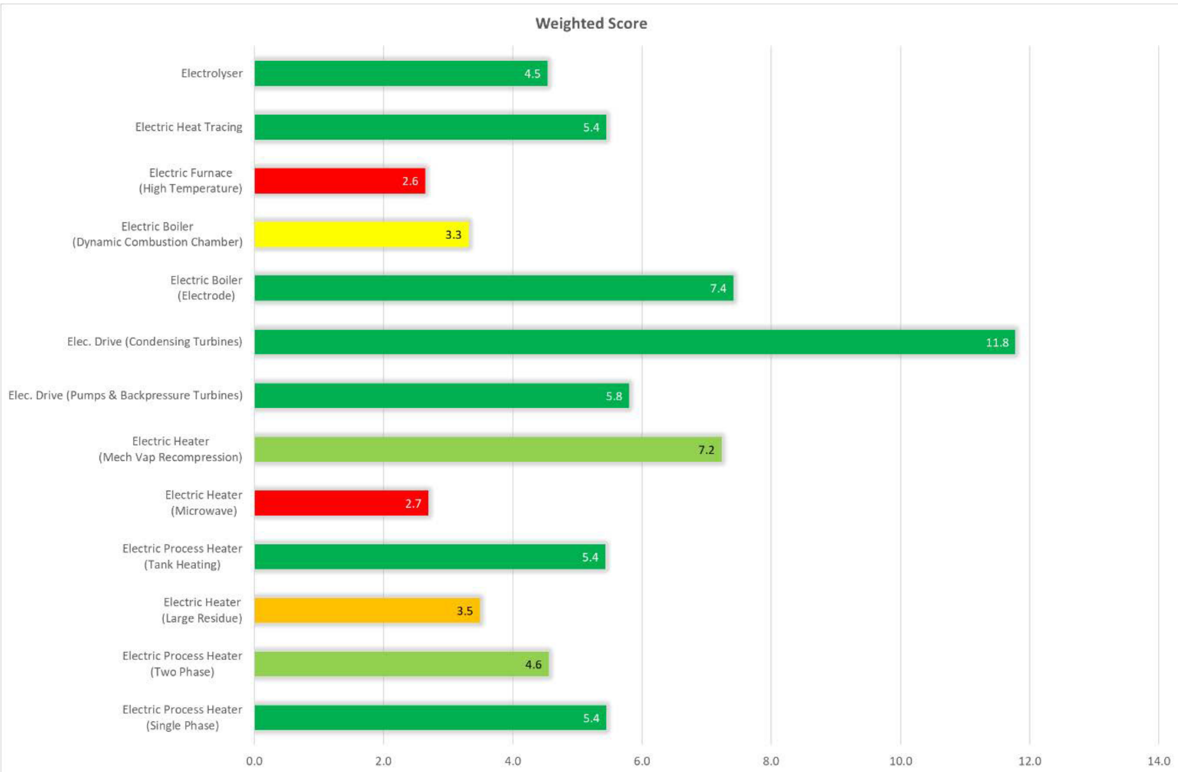

Figure 10: Technology Weighted Score. Colour denotes TRL.

Utilisation of available renewable electrical power to extract the greatest CO2 reduction benefit is illustrated in Figure 11. Efficiencies around 0.24 (t/h)/MW represent the savings due to direct replacement of fired heat with electrical heat, with associated fired heater and steam distribution efficiency.

Electric furnace (high temperature process heater) application to SMRs shows a low emissions reduction efficiency as the CO2 produced from the process is not reduced.

The dynamic combustion chamber and electrolyser technologies also show relatively low electrification efficiencies due to the low efficiencies assumed for current electrolyser conversion. Microwave overall efficiency is also poor compared with the other technologies.

Electric drives have very high efficiencies of electrical utilisation for condensing turbine replacement with motors whereby a large benefit is attained by replacement of the condensing heat rejection in large machines. Backpressure turbines, where a desuperheated letdown provides the replacement exhaust-level steam, do not show measurably greater efficiency than replacement of the fired steam boiler with an electrode boiler.

MVR is inherently very efficient as power input is multiplied by additional heat extraction from the overheads when compared with existing reboiler and overhead cooler arrangements.

Electric heat tracing further benefits from reducing condensate losses from a highly distributed system.

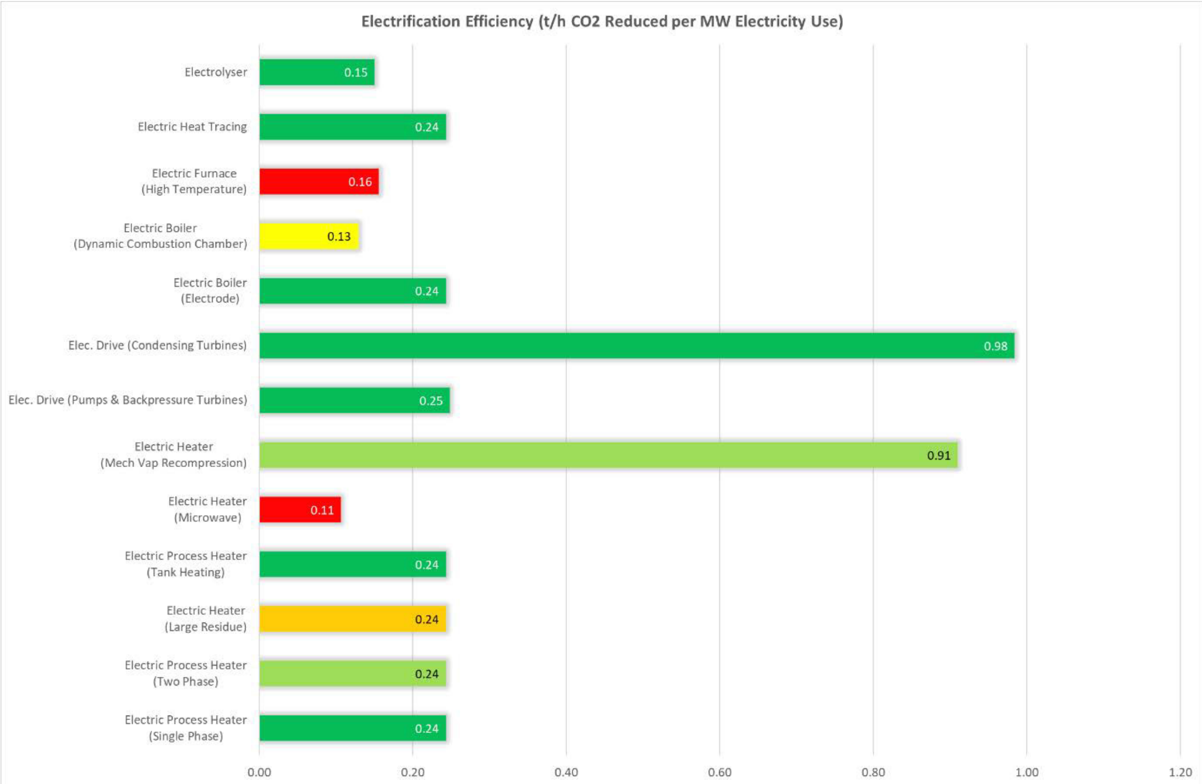

Figure 11: Technology Electrification Efficiency. Colour denotes TRL.

Figure 12 shows the efficiency of fired duty replacement by electric power. This provides a similar picture to Figure 11 above. Electrolysis as a replacement for steam methane reforming is credited with avoidance of reaction CO_2 in Figure 11, hence the heat replacement efficiency shows a worse relative result for this technology.

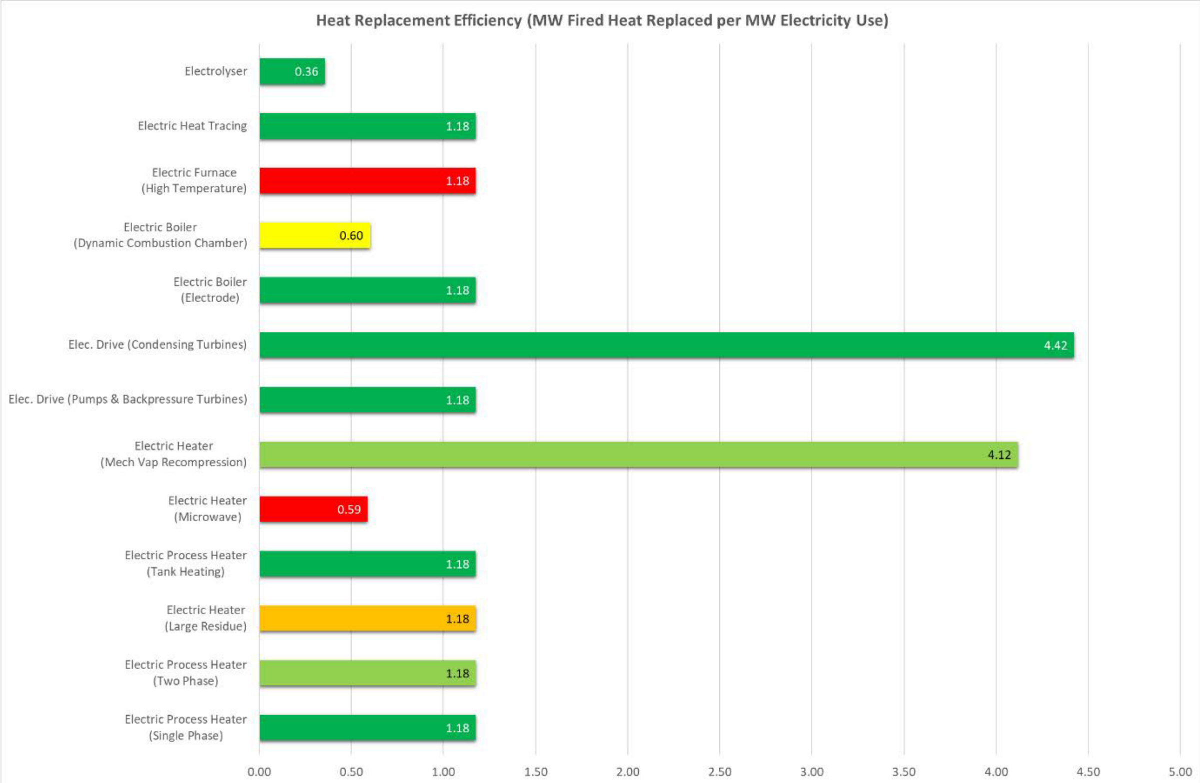

Figure 12: Heat Replacement Efficiency. Colour denotes TRL.

Figure 13 combines various elements of the ranking table.

Cost efficiency in CO_2 reduction is shown on the vertical axis against a weighted average of TRL, Ease of implementation, RAM and operations impact, and HSSE impact. Colour represents TRL and size of bubble represents the scale at which it can be applied.

Electric boilers are shown to be cost efficient, ready and easy to implement with a large potential application size. It should also be noted that unlike some other technologies applied directly to equipment, electrification of steam production can be implemented without widely distributed projects across the site.

Electrolysers and the less complex electric heaters have moderate cost efficiencies and strong immediate implementation potential.

Electric motor drives are shown to be very strong for cost efficiency and ease of implementation for condensing turbine replacement, but backpressure turbines show much poorer cost efficiency due to a much reduced emissions benefit.

MVR has a lower cost efficiency, though product yield and quality benefits may be found for this technology.

DCC and large residue heaters are shown to have implementation and TRL challenges to overcome, though are important for consideration of electrical storage and site decarbonisation scale respectively.

Again, high temperature electric process heaters applied to SMR replacement and microwave heating are shown to be poorly ranked against other options.

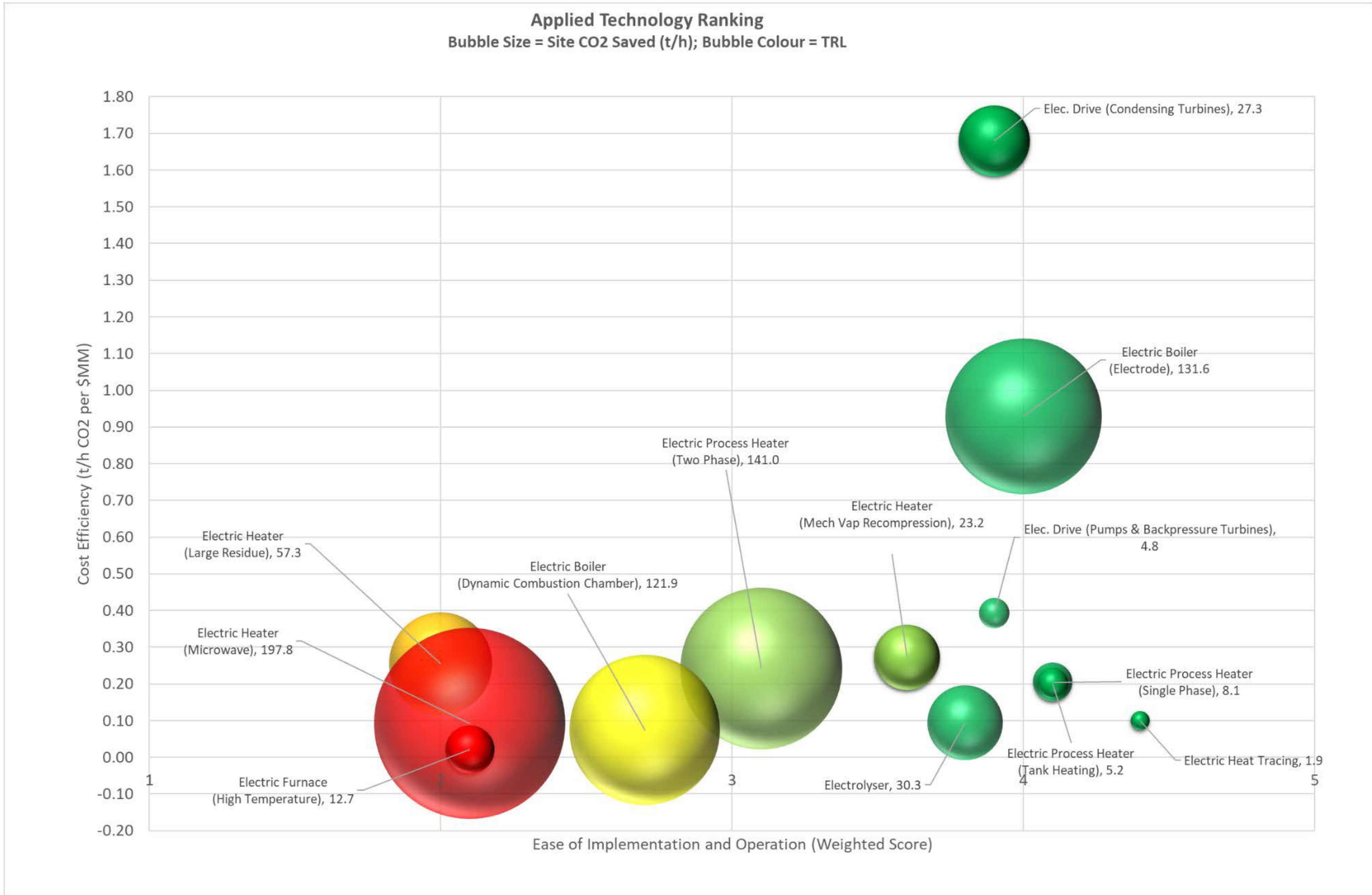

Figure 13: Technology Ranking Comparison, Cost Efficiency, Ease of Implementation, CO_2 Savings and TRL

8. Key Results Summary

Table 35 provides a summary of the CAPEX figures for the example electrification project options investigated in this report, allowing high-level application to other assets by scaling.

Table 35: Key Results Summary for Example Project Applications

Technology Type	Equipment Item Electrified	Equipment TIC (MM$)	Electrical TIC (MM$)	Project TIC (MM$)	Fired Duty Replaced (MW)	Electrical Demand Increase (MW)	CO2 Saved (tonnes/hr)
Electric Heater	CDU Crude Heater	64.4	29.2	**93.6**	118.6	100.8	24.4
Electric Heater	Debutaniser Reboiler	9.0	6.1	**15.1**	16.3	13.9	3.4
Electric Tank Heating (Direct)	Facility Tank Heating Requirements	8.9	6.1	**15.0**	24.5	20.9	5.0
MVR	Propylene Splitter	80.0	5.4	**85.4**	105.0	25.5	23.1
Electric Boiler	Steam Boiler	94.0	47.6	**141.6**	637.5	542.0	131.1
Electrolyser	Hydrogen Production	295.0	26.1	**321.1**	96.5	183.0	30.6
DCC	Steam Production	1,530.0	111.0	**1,641.0**	637.5	949.0	121.0
Electric Drive (backpressure replacement)	CDU Bottoms Pump	0.2	0.1	**0.3**	0.3	0.3	0.1
Electric Drive (condensing replacement)	FCC Main Air Blower	4.6	4.2	**8.8**	65.0	15.1	14.4
Electric Heat Tracing	Facility Heat Tracing	N/A	19.0	**19.0**	9.2	7.8	1.9

9. Other Considerations

Other topics relevant to Phase 4 refinery-wide scenarios and phasing of electrification are discussed in the following sections.

9.1 Fuel Gas Reduction Measures

Fuel gas is expected to be in excess once significant electrification is implemented at a site level. The fuel gas stream at a fuels refinery is typically composed of light gases including hydrogen, methane, ethane and liquid petroleum gases (LPGs) such as propane and butane.

In a complex refinery with significant hydrotreating, hydrogen produced by the processing units is usually in deficit and requires dedicated production via a hydrogen production unit. Therefore, hydrogen remaining in the fuel gas is relatively low. In a simple, low complexity refinery with a naphtha reformer, the reformer often produces more hydrogen than is required by the process units, hence the fuel gas can contain a significant amount of this component.

Methane and ethane are usually considered low-value and have no other use than as fuel in the fuel gas system. The exception to this is where the ethane can be separated and routed to a co-located ethane cracker for petrochemicals. Other non-combustion uses of these gases are currently uncommon and are explored in Section 9.2.

LPG recovery from fuel gas is usually maximised as the value of LPG is greater than the marginal fuel. This is expected to be aligned with the base case through de-ethaniser and absorber operations.

Various technology and investment levels are required to separate the individual components of fuel gas, such as membranes or pressure swing adsorbers for hydrogen and very low temperature distillation for methane.

The following units are highlighted as the main fuel gas producers, summarising potential fuel gas reduction measures without significantly compromising on performance.

9.1.1 Delayed Coking Unit

Though a large amount of fuel gas is burned in the heater, cokers are generally net exporters of fuel gas. As this is a thermal conversion process and liquid yield is normally maximised, there are no known changes to the process or operation that would reduce fuel gas components production.

Gas plant separation upgrades can be applied to remove LPG from fuel gas, though the impact is expected to be limited as LPG will be removed to economic extent in the base case.

9.1.2 Naphtha Reforming Unit

In general, naphtha reformers are operated at the minimum severity to balance the octane requirements of the gasoline pool. This is due to the loss of reformate yield at increased severity, hence fuel gas production is minimised in the normal operating case.

Chloride level optimisation is recommended, as well as catalyst selectivity improvement via catalyst replacement to reduce cracking to fuel gas. Both measures are part of the base case of a well operated site.

Separation of the hydrogen-rich product stream from the naphtha and LPG liquid products via recontacting or cold box technologies removed LPG from the fuel gas, though this could also be recovered in an absorber or de-ethaniser downstream of the unit. A high LPG recovery is expected in the base case.

9.1.3 Fluid Catalytic Cracking Unit

The FCC Unit is also a major fuel gas producer due to the cracking reactions present. Design changes with marginal reductions in fuel gas yield such as cyclone design improvement, riser and feed nozzle modifications are possible, though these are expected to have taken place during the latest FCCU revamp as an opportunity.

Operational optimisation is a more feasible option than for other units to reduce fuel gas production as multiple handles exist for manipulating the unit yields. For example, reducing riser top temperature will reduce fuel gas production as well as decreasing the yield of higher value products; high value LPG yield can then be compensated by altering the catalyst composition (e.g. increasing ZSM-5). However, it should be noted that limiting fuel gas production is likely to result in an economic impact with respect to overall yield. Experience of optimising catalyst formulation against riser top temperature shows around 5% reduction in FCCU fuel gas production by reducing severity and maximising other variables to the unit constraints.

LPG recovery is generally considered good from an FCC gas plant due to the high value of propylene product that must be separated from fuel gas. Lean oil absorption is typical with supplementary chilling if required.

9.1.4 Fuel Gas Reduction Opportunity

From the above discussion, the opportunity from the base case(s) for fuel gas reduction within the process is limited to the FCC where approximately 5% reduction could be possible without significant economic penalty.

LPG recovery potential from the fuel gas has also been quantified at a high level. Using typical refinery data, LPG content in the refinery fuel gas pool is approximately 20% greater than the content in the FCC gas plant fuel gas. As the FCC gas plant can be considered to have a high LPG recovery, this leads to an opportunity to decrease the fuel gas pool quantity by a similar amount, though this is highly specific to the site.

9.2 Non-Combustion Fuel Gas Use

Any remaining excess fuel gas from the electrification scenarios should ideally be routed to uses avoiding combustion to avoid the fuel gas emissions migrating from Scope 1 (direct) to Scope 3 (inherent in product use). However, even exporting fuel gas as fuel would reduce global fuel emissions.

The following describes potential non-combustion fuel gas processing routes for methane and ethane, as these components are unlikely to find utilisation within a fuels refinery.

9.2.1 Methane

9.2.1.1 Steam Methane Reforming (SMR)

This process produces hydrogen; at least 50% of the world's hydrogen supply is via the SMR process. Methane is reacted with steam at high temperature in the presence of nickel catalyst. The process is fully commercialised and well applied in this industry. Methane is an ideal feed to the SMR process, though capture of the process emissions and decarbonising the reformer heater fuel would be required to eliminate most of the emissions.

9.2.1.2 Methanol Synthesis

The process produces methanol which is the second major synthesis gas product and the building block for many chemicals. It is also one of feed chemicals to the MTBE unit, which could integrate with an MTBE unit on a refinery. The process is fully commercialised and well applied in industry. Decarbonisation of the process would also be required similar to SMRs.

9.2.1.3 Oxidative Coupling

The process produces ethylene and longer chained hydrocarbons. Oxidative coupling of methane (OCM) is a technique developed to convert methane to valuable chemicals and can be far more carbon efficient than the established production methods. The OCM process is currently in the process of commercialisation where patented technologies and a pilot plant unit have been developed to date.

9.2.1.4 Methane Pyrolysis

The process produces hydrogen via methane decomposition at 1065°C to hydrogen and solid carbon. The industrial-grade carbon is then sold or disposed of in landfills. The methane to hydrogen conversion is halved compared to the SMR process, but there are no CO_2 emissions. The technology is in the process of scale up from 14 tonnes/day to 164 tonnes/day of hydrogen production.

9.2.1.5 Andrussaw Process

Hydrogen cyanide is produced through a high-temperature (1100°C) reaction with ammonia, methane and air over a catalyst. The process is fully commercialised and well applied in this industry.

9.2.2 Ethane

9.2.2.1 Ethane Steam Cracking

The process produces ethylene amongst other useful components. Ethane is diluted with steam and heated to high temperatures (>1000 °C) to produce ethylene at >50% single pass conversion. The process is fully commercialised and well applied in this industry. The high furnace heat input a high temperature is also a focus of decarbonisation and electrification.

9.2.2.2 Ethane Dehydrogenation

The process produces ethylene via catalytic ethane dehydrogenation and it has a lower temperature constraint compared to pyrolysis. The technology is currently in development as an alternative to steam cracking and fluid catalytic cracking processes. To achieve commercial implementation, improved catalytic selectively is required.

9.2.2.3 Ethane Dehydroaromatisation

The process produces the valuable aromatics Benzene, Toluene, Ethylbenzene and Xylene. A temperature of 600 °C is required for high equilibrium conversion. Commercialisation using ethane is not yet developed, but it is an established process for longer chain hydrocarbons (C3/C4).

9.2.2.4 Ethane Oxidation

Ethane undergoes partial oxidation in the presence of MoVNb catalyst to form Ethylene and Acetic acid. The process is commercialised and has been applied industrially in Saudi Arabia.

9.2.2.5 Oxidative Chlorination

The production of vinyl chloride via this method could have a higher economic potential than ethylene chlorination. However, the corrosive nature of this reaction, high temperature (>500 °C) and poor selectivity have limited the commercialisation of this process. A pilot plant at 1,000 tonnes/annum capacity is under investigation in Germany.

9.3 Utility Systems Turndown & Decommissioning

The following section describes the potential impacts of electrification to key utility systems in terms of reduction in capacity. Electrification has a significant impact on a facilities utility balance and it is important to understand the suitability of the existing infrastructure as a result. Discussion is focused on the high complexity case utility configuration where cogeneration is employed with the balance of steam produced by fuel fired boilers as this represents the most complex system. A schematic of the high complexity steam and power system is presented in Figure 14.

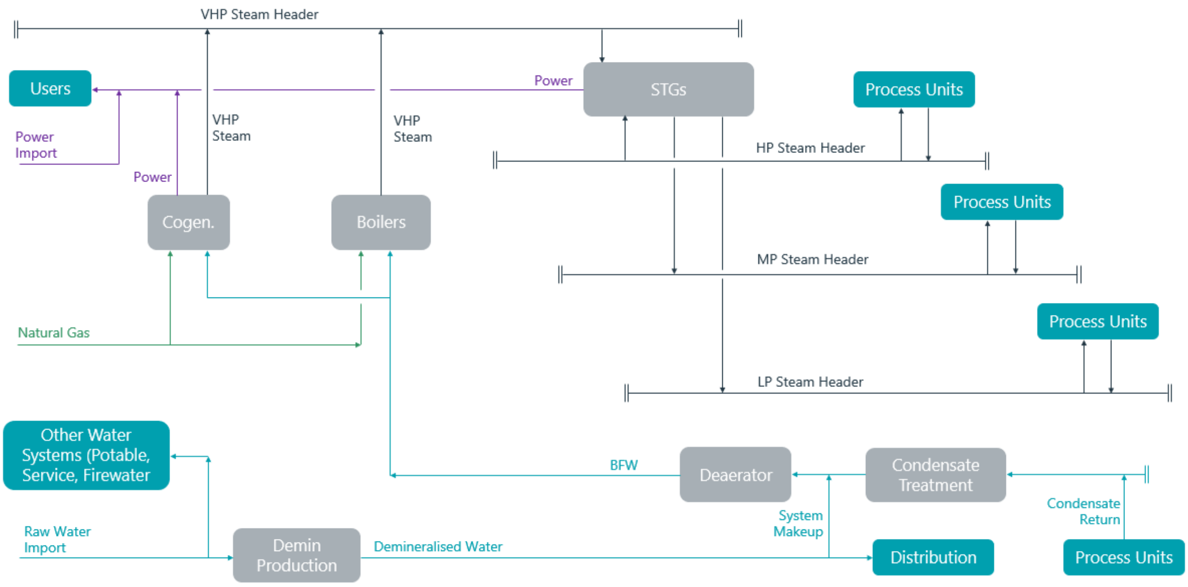

Figure 14: High Complexity Case Utility Configuration

9.3.1 Turndown

9.3.1.1 Steam Boilers

With the electrification of steam consumers there will be a fall in steam demand. Consequently, it is important to understand the extent to which steam boilers can turn down to deal with this reduced demand.

Steam boilers are capable of operating at 20% of their design capacity and so offer a relatively high amount of flexibility for a particular facility as steam users are removed through electrification and demand reduces. Operating boilers at turndown only has a minor impact on the overall efficiency, typically resulting in a 1-2% drop.

The preference in terms of boiler operation at reduced steam demand would be to keep the boilers operating at turndown so that should a boiler be lost the other(s) can quickly ramp up to cover demand. However, electrification may result in the need to leave boilers on cold standby based on the site wide demand. It would typically take 24 hours to bring the boilers back online if required with potential site production impacts.

It is possible to turn off burners within a boiler with vendor input so that turndown below 20% can be achieved. This can lead to issues with control and steam temperature.

An alternative approach would be to electrify the steam boiler thus avoiding the need to electrify individual process users and any turndown issues. This approach would also minimise disruption to the facility as individual steam users would continue to be operated as normal.

9.3.1.2 Steam Distribution

Superheated steam is distributed across a refinery to ensure that condensation is avoided. At normal turndown, heat loss will likely lead to a drop in the level of superheat at the consumers but condensation within the distribution system is not expected. At very low steam rates where site steam demand has reduced to a small fraction of the design capacity, this may lead to excessive heat loss and condensation in the steam headers.

9.3.1.3 Cogeneration

The base case high complexity refinery configuration employs cogeneration to produce both steam and electricity from fuel gas firing at high thermal efficiency. With electrification and the reduction in steam demand, cogeneration would likely require turndown or shut down to avoid production of excess steam. Although a facility would still require power, operating a cogeneration unit when the steam demand is no longer present would be an energy inefficient and carbon intensive way of producing electricity.

A cogeneration system can typically be turned down to 30% of capacity. However, the overall system efficiency also falls with turndown falling to ~50% (LHV basis) at maximum turndown compared to 75-80% efficiency when operating normally. In addition, operating gas turbines at turndown for extended periods will lead to more frequent cleaning and turnaround requirements.

Maintaining existing steam users by electrifying the boilers would also allow the Cogeneration unit to continue to operate at full steam production thus maximising this energy efficient process.

9.3.2 Decommissioning

As electrification proceeds there may become a point where a utility system, such as fuel gas fired boilers or cogeneration systems, is no longer required as the facility steam requirements can be satisfied by steam produced from process users or the system has been replaced by an electrification option.

Redundant equipment can either be mothballed for use in future if necessary but given the intent to electrify and reduce carbon emissions, the decommissioning and dismantling of the equipment would present the most beneficial course in achieving electrification and carbon dioxide reductions. Plot space would then be released for further electrification options that are expected to require a significant footprint.

9.4 Energy Storage Options

Low-carbon power supply from a source external to the site is central to realising electrification advantages. Future power grid agreements for decarbonised power may include adjustments to the price according to power supply fluctuation.

Refinery sites have the potential to use existing or future infrastructure and processes to buffer grid renewable power generation swings. Examples are given below.

9.4.1 Battery Storage

Considered the economic baseline for easily charged and discharged power storage, but current storage density would have limited practical application versus the full refinery power demand.

Siting battery storage at a high-power consumer such as a refinery with various voltage levels may be advantageous above other grid locations, but there are no obvious synergies with refinery technology.

9.4.2 Electrolysis and Hydrogen Storage

Increased green hydrogen generation capacity via electrolysers, storage of hydrogen and use as a reliable fuel is costly, but also enables decarbonisation of difficult large fired heaters.

Advantages of building this capability at a refining site rather than elsewhere in the energy network include leveraging the existing hydrogen distribution system, potential uses for the oxygen byproduct and experience with high-hazard processing and storage at refining sites.

9.4.3 Reverse Osmosis and Water Treatment

Depending on site location, refineries often use large amounts of energy to treat seawater via reverse osmosis and to treat waste water. Treated and untreated water is cheap and easy to store, hence buffering these operations with tank storage to match the availability of cheap, low-carbon power is a promising opportunity.

This opportunity would require investment in greater processing capacity and storage to enable greater throughput than the long-term average.

9.4.4 Process Unit Capacity Swings

Overall reduction in refinery throughput would require turndown or a low-energy circulating operation during periods of low renewables availability and maximum throughput when low-carbon power is readily available, utilizing existing hydrocarbon storage as a buffer.

This opportunity would require extensive engineering and operations study but could align well with potential refinery overcapacity in a future scenario.

9.4.5 Molten Salt or Hot Silicon Thermal Storage

High-temperature salts, often heated by thermal solar facilities, are stored in insulated storage tanks for later use. Alternatively, hot silicon can be used with a potentially higher volumetric energy density than molten salt. Silicon is also more widely available than the salts required for thermal storage.

This technology does not show any clear synergy with a refinery site, other than proximity to a major point consumer.

9.5 Breakeven Carbon Intensity of Imported Power

The equivalent lifecycle CO_2 emissions of electricity generation sources such as wind, nuclear and solar have been combined into a low-carbon power import assumption of 24 $gCO_{2(eq)}$/kWh in the Phase 2 benefit calculations. This is far lower than the vast majority of countries' current average carbon intensity for power generation. A low carbon electricity source is expected to be a pre-condition of large-scale electrification of a refinery with the aim of decarbonising the site.

Therefore, an assessment has been made of the breakeven carbon intensity of imported power whereby each technology would no longer have an emissions benefit. This shows where particularly power-efficient technologies could be applied earlier in a phased investment approach when imported power has not yet been highly decarbonised.

The following power import carbon intensities can be compared with the breakeven results:

- Combined Cycle Gas (CCG) Power Plant (Ref. 46): 490 $gCO_{2(eq)}$/kWh
- Coal Power Plant (Ref. 46): 820 $gCO_{2(eq)}$/kWh
- CCG Power Plant with Carbon Capture (Ref. 46): 170 $gCO_{2(eq)}$/kWh
- World average 2021 (Ref. 47): 425 $gCO_{2(eq)}$/kWh

Table 36: Breakeven Carbon Intensity of Imported Power

Technology Type	Power Import Lifecycle CO_2 Emissions at Zero Project Emissions Benefit ($gCO_{2(eq)}/kWh$)	Comment
Direct Electric Heaters	219	Benefit unlikely without significant low-carbon power
MVR/Heat Pumps	885	**Benefit significant for current power generation**
Electric Drives (Replacing Condensing Turbines)	959	**Benefit significant for current power generation**
DCC	89	Benefit unlikely without significant low-carbon power
Electrolyser	126	Benefit unlikely without significant low-carbon power

Many countries achieve power emissions lower than 200 $gCO_{2(eq)}/kWh$. However, without significant investment in large scale low carbon power generation, benefits are unlikely for direct power-to-heat unless the efficiency of a heat pump or replacement of condensing turbines can be leveraged.

As an example of the power generation technology required, zero project emissions benefit (breakeven) occurs for simple electric heating at 60% low carbon and 40% combined cycle gas power production, assuming low carbon generation equivalent to that used in the Phase 2 calculations.

10. Conclusions

The relative merits of the studied electrification technologies have been assessed at a high level and summarised in Section 7.2. Most of the technologies reviewed have been found to be feasible for implementation in the short-medium term and are competitive versus other electrification options.

It is proposed that microwave heating is not considered further due to a lower maturity and lower electrical utilisation efficiency than competing technologies for process heating.

It is also proposed that high temperature electrical process heaters to replace SMR furnaces are not considered further in this analysis due to lower maturity and remaining process emissions when compared with electrolysis.

Electrolysis capital cost efficiency and efficiency of power utilisation are currently lower than other electrification technologies. However, both cost and efficiency are expected to continue to improve, hence future case sensitivities will be important.

Plot space is a key concern for the electrification revamps occurring within the process units such as MVR, electric drives and large electric heaters. Large substation and transformer requirements are also anticipated to be a feasibility issue for some sites where adjacent space is not available.

The potential for disruption of refinery operations are greater for the electrification technologies being applied within the process areas such as mechanical vapour recompression and large heater replacements. Technologies applied to the steam or hydrogen system are able to be constructed in new plots and tied into refinery mains during shutdowns.

Scheduling of significant investments with standard contracting strategies and decision gates gives implementation schedules from FEED to Ready for Start-up of around 3 years for most process unit revamps. Large compressor driver replacements are expected to take 2.5 years including electrical infrastructure, whilst the large electrolyser-based technologies are expected to take 3-4 years. Electrolyser and electrode boiler equipment are identified as some of the longest lead items at 18-24 months delivery.

Fuel gas reduction measures have been assessed and potentially significant reductions in both FCC fuel gas production and separation of LPG from fuel gas have been estimated. The combined reduction in fuel gas is estimated to be 25%.

Turndown of the utilities system has generally been found to be possible without significant penalty, though very low steam production within an existing system should be considered further at a site level.

Phased investment will need to be sensitive to the differences in electrical efficiency of the different technologies, where heat pump/MVR and replacement of condensing turbines can be applied beneficially prior to extensive decarbonisation of power supply. Phase 4 facility-wide scenarios and Road Maps will be developed based on the output from Phase 2 and 3.

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7	DECARBONISATION OPTIONS
8	Catalytic conversion of ethane to valuable products through non-oxidative dehydrogenation and dehydroaromatization
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12	Electrification in the Dutch process Industry
13	Emerging technologies: cross-country experience
14	SHELL AND DOW START UP E-CRACKING FURNACE EXPERIMENTAL UNIT
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16	Renewable Energy for Industry
17	Plugging in: What electrification can do for industry - McKinsey
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19	Electrochemical Routes for Industrial Synthesis
20	HELIMAX™ Ultra-Efficient Electric Heat Exchanger | Watlow
21	Chromalox Capabilities Brochure

Reference Number	Source
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24	SST Group - Corporate Brochures
25	Determining Sensor Placement In A Thermal System
26	PARAT electrode boiler
27	Chromalox catalogue
28	60MW hydrogen plant set to boost Brazil's clean energy future
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33	HT_Report_DynamicCombustionChamber
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35	Decarbonisation options for large volume organic chemical production, shell pernis
36	Organic Rankine Cycle (ORC) worldmap
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41	DISTILLATION OPTIMIZATION BY VAPOR RECOMPRESSION
42	H2 View Exclusive – Calculating the Cost of Green Hydrogen
43	Capillary-fed electrolysis cell
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Reference Number	Source
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A ROADMAP TO DECARBONIZE REFINING

Phase 4 Report: Representative site roadmap

Credit: Unsplash/Adigun Ampa

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1. Background

The Oil and Gas Climate Initiative ("OGCI"), launched in 2014, is a voluntary, CEO-led initiative which aims to drive the industry response to climate change. OGCI explicitly supports the Paris Agreement and its aims, collaborating on actions to reduce greenhouse gas (GHG) emissions, and acting with integrity to accelerate and participate in the energy transition. OGCI brings together twelve Oil and Gas companies, which together account for over 30% of global operated oil and gas production. Member companies are Aramco, bp, Chevron, CNPC, Eni, Equinor, ExxonMobil, Occidental, Petrobras, Repsol, Shell and TotalEnergies.

OGCI members leverage their collective strength to lower the carbon footprint of the energy, industry, and transportation value chains via engagements, policies, investments and deployment. This includes actions and knowledge-sharing across several key areas of impact on GHG. The OGCI is currently composed of six workstreams (WS), working on the following topics: CCUS, Role of Gas (and methane leakage), Energy Efficiency in the Industry, Transport, Natural Climate Solutions and Low Emission Opportunities.

The Energy Efficiency in Industry Workstream (EEI WS) has formed a working group with the purpose of developing a long-term roadmap to electrification based on technology, economics, and carbon reduction potential. This work aims to inform OGCI members of the potential for electrification to contribute carbon intensity reductions. The first stage for the development of this roadmap consists of the identification of opportunities and barriers for electrification of the O&G assets.

Electrification encompasses a range of complex opportunities for oil and gas operations, requiring a roadmap that describes and assesses the choices available in specific locations, ranging from electricity-driven rotating equipment, electric heaters, electric boilers, heat pumps and battery storage solutions through to fully electric facilities supplied from electrical grid systems, as well as optimal sequencing and timing in the overall asset life cycle. Electrification offers a powerful lever for efficiency gains, associated carbon reduction through low-carbon electricity and offers the potential for zero Scope 1 emissions from oil and gas facilities, meaning the topic is key to OGCI objectives.

In this context, the OGCI EEI WS has appointed Wood as independent consultant to assess the potential of electrification, a GHG emissions reduction lever, for the Refining Industry.

The study will focus on application of electrification to existing, generalised sites as opposed to greenfield development opportunities, capturing the difficulties and opportunities inherent in existing facilities.

2. Objectives

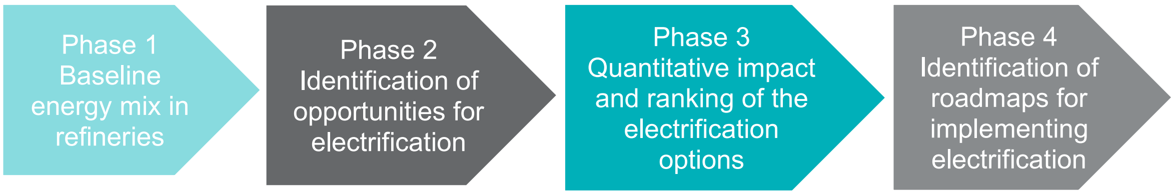


Figure 1: Refining Industry Electrification Study Phases

Figure 1 provides an overview of the steps taken in each project phase. The primary objective of Phase 4 is to apply the electrification technologies investigated in Phases 2 and 3 to the three refinery-wide complexity cases defined in Phase 1. Roadmaps are developed which show scenarios for application of electrification over time.

Utilising the representative projects analysed in Phases 2 and 3, ranking criteria and technology efficiencies are used to formulate and justify the roadmaps, identifying the overall cost, power consumption and CO_2 reduction for each stage.

For each refinery complexity a suggested phased implementation plan is developed based on the following analyses.

- Priority of each option
- Technology readiness level of each opportunity
- Interactions and synergistic effects between opportunities
- Low carbon power availability
- Major impacts on produced fuel routing (gas, process unit steam generation)
- Long lead items and project implementation timescales

To overcome specific barriers, alternative roadmaps will explored.

3. Abbreviations

Abbreviation	Description
BFW	Boiler Feed Water
CAPEX	Capital Expenditure
CCUS	Carbon Capture, Utilisation and Storage
CDU	Crude Distillation Unit
CO_2	Carbon Dioxide
EPC	Engineering, Procurement and Construction
FCC	Fluidised Catalytic Cracker
FEED	Front End Engineering Design
FG	Fuel Gas
HC	High Complexity
HP	High Pressure
IEA	International Energy Agency
MC	Medium Complexity
MP	Medium Pressure
MVR	Mechanical Vapour Recompression
LC	Low Complexity
LP	Low Pressure
O&U	Offsites and Utilities
OPEX	Operating Expenditure
ORC	Organic Rankine Cycle
PEM	Polymer Electrolyte Membrane (electrolysis)
SMR	Steam Methane Reformer
TRL	Technology Readiness Level
VDU	Vacuum Distillation Unit

4. Roadmap Basis & Methodology

The following section describes the basis, methodology and assumptions made in developing the electrification roadmaps for the three refinery complexities.

4.1 Primary Roadmap Basis

There are several ways that the electrification options can be prioritised. For example, technologies with a lower cost may be targeted first or those with the greatest energy efficiency. For the purposes of this study, cost efficiency of CO_2 emissions abatement was taken as the primary driver for selection of technology for the primary roadmap. Those with the highest abatement efficiencies were placed earlier in the roadmap subject to technology readiness and an available low-carbon grid.

The availability of a low-carbon grid is crucial to the development of the electrification roadmap. At limited availability of low-carbon power many electrification technologies would not save CO_2 globally due to the power required to operate the technologies being sourced from a grid with a high carbon intensity, as discussed in Phases 2 and 3. The approach taken by this work is to consider a specific recognised date when large-scale low-carbon power is available.

4.2 Roadmap Timings

The following timing basis has been considered:

- The earliest project start date considered is the beginning of 2024 to allow for company strategy to be in place.
- Large scale, low-carbon power is assumed to be available from 2030 (IEA target). This target is more realistic for countries with advanced economies and strong decarbonisation progress. For countries where decarbonisation is lagging, 2040-2050 is targeted. Roadmaps have been based on a 2030 target with sensitivity performed for 2050.
- The electric heater technology for replacement of fired residue heaters is currently not mature and significant difficulties must be overcome. It is assumed that this technology will be developed sufficiently such that a full-scale project can start in the year 2032 (10 years from 2022) with proven commercialisation of the technology at this point.
- Large projects run sequentially where possible to reduce disruption to the running plant. This also allows reasonable time for further low-carbon power generation capacity to be added. Where possible some overlap of projects to optimise schedule is considered; for example pre-FEED/ FEED is assumed to progress on a new project whilst the previous project's EPC is completed.
- Large scale projects follow the schedules assessed in Phases 2 and 3. The project duration includes the following project stages: feasibility/pre-FEED, FEED and EPC. In general, the schedules show that for a 4.5 year project, pre-FEED and FEED stages take 1.5 years followed by 3.0 years for EPC and start-up preparation.

4.3 Utility Balances

Electrification of a refinery facility results in significant changes to the steam and fuel gas balances. This can result in the facility being steam or fuel gas long, meaning there is an excess of these utilities. In the case of steam long, it indicates a point beyond which energy efficiency within the facility will fall as the excess steam would need to be vented/recovered as condensate and energy lost. To proceed past the point of fuel gas long, the excess fuel gas requires an alternative destination, or to be reduced/ removed via fuel gas reduction measures such as adjustments to unit operating parameters and LPG recovery. This is discussed in more detail in Section 9.1 and 9.2 of the combined Phase 2 and 3 report.

For the purpose of Roadmap identification, the following approaches are taken when an electrification step leads to a steam or fuel gas long situation.

- Where a facility's roadmap reaches a steam long scenario, mitigation measures are employed to bring the steam system back to balance. Depending on the steam pressure level in excess this may be electrifying backpressure steam turbine drives to reduce LP steam excess or selecting a steam exchanger to be in operation rather than being directly electrified.
- Where a facility reaches a fuel gas long scenario, electrification is not limited in the primary roadmap in order to demonstrate the ultimate fuel gas length. An assessment is made as to whether mitigation measures are sufficient to remove the fuel gas excess or whether another approach is required to prevent combustion of the excess fuel case such as via routing to an alternative "non-combustion" technology.

4.4 Fuel Gas Composition

Imported natural gas and refinery produced fuel gas have different carbon intensities due to differing compositions. In addition, imported natural gas has an added CO_2 footprint due to the natural gas supply chain resulting in natural gas having a slightly higher carbon intensity than indigenous refinery fuel gas.

When a facility is short of fuel gas and electrification reduces the fuel gas demand, the CO_2 saving though this action is observed against a natural gas import saving. Conversely, when a facility is fuel gas long, natural gas imported has ceased and electrification results in CO_2 savings from the refinery produced fuel gas, provided fuel gas is routed to a non-combustion outlet or displaces equivalent combustion elsewhere.

For purposes of this work, and in order to normalise this effect and allow a fair comparison between technology electrification steps, an average carbon intensity is considered across the full Roadmap, whether the facility is fuel gas long or not. That way CO_2 savings from early electrification steps can be compared directly to later electrification steps. In reality, the early electrification steps will achieve a greater CO_2 saving as natural gas imports are reduced whereas in later electrification steps when fuel gas is long CO_2 savings are proportionately lower as it is now fuel gas combustion being reduced. Whether utilising the average carbon intensity or actual figures depending on fuel gas long/short situation, the same total CO_2 savings are achieved at the end of the electrification road map.

4.5 Waste Heat Recovery

Low grade heat recovery and upgrading methods have been considered as part of the combined Phase 2 and Phase 3 report and include Organic Rankine Cycle (ORC) for electricity generation and Heat Pumps for steam generation.

The CO_2 abatement CAPEX efficiencies for these technologies are low, achieving ~0.06 tCO_2/MM$ when referencing CO_2 savings against a hydrocarbon power grid. There are other technologies that offer better results in terms of CO_2 abatement efficiency. The primary roadmap prioritises technologies with the greatest abatement efficiency; this positions the waste heat recovery methods at the end of the roadmap when the power imports are expected to be from a low-carbon grid, further reducing the CO_2 abatement efficiency as less CO_2 will be saved by generating utilities at this point.

As a result, the roadmaps developed have not considered waste heat upgrading due to the low CO_2 savings relative to the CAPEX investment required. However, this does not mean that the technologies should be excluded from an energy efficiency perspective. Both offer a route to significantly reduced OPEX costs through reduced energy imports which depending on pricing may prove to be economically attractive. This is equally true for other waste energy power generation technologies such as turbo expanders that would align with energy efficiency improvement rather than electrification.

As discussed in previous Phases, it is recommended that energy efficiency opportunities are developed and screened alongside electrification options to ensure an optimised overall investment roadmap for decarbonization.

4.6 Other Key Assumptions

The following are other key assumptions made in developing the refinery electrification roadmaps.

- CO_2 saved considers both direct and indirect CO_2 savings as a result of technology electrification. For example, electrification of condensing turbines reduces the facility HP steam demand and fuel gas firing requirements. This also impacts other utility systems such as reduced BFW, LP steam in the deaerator and cooling water via condensate recovery, which contribute to additional CO_2 savings as a result of the electrification step.
- Electrification is performed at well operated and maintained refinery facilities. Unnecessary energy losses though operations and poor equipment condition are minimal, though the physical design is aligned with a typical existing site.
- A simplified linear CAPEX investment across each project timeframe is considered.
- CAPEX figures reported are based on 2023 prices, hence no forward escalation is included.
- Reported power import demands include an allowance to account for losses in electrical imports. This inefficiency is also included within the reported CO_2 savings.
- CO_2 savings presented in this report are referenced against a low-carbon grid, aligned with Phase 2 and 3 analyses. The implication of this is that for pre-2030 the reported CO_2 savings for technologies implemented are higher than achieved at this point and are only realised beyond 2030 when the low-carbon grid is available. Referencing all technologies against the low-carbon grid is performed to ensure technologies are directly comparable before and after low carbon grid availability.
- A modular approach is taken to electrical infrastructure investment requirements as each major step of electrification proceeds. For substation and transformer expansions and cabling within the site this is expected to be realistic, provided sufficient plot area is available.
- Further project and impact assessment assumptions are provided in the Phase 2 and 3 report.

5. Primary Roadmap Definition

As detailed in Section 4.1, the primary roadmap is focused on prioritising the technologies offering the greatest CO_2 abatement efficiencies relative to CAPEX investment. This approach assumes there is sufficient low-carbon power available to support the electrification initiatives past 2030.

The steps taken within the roadmap are presented in Roadmap Steps

Table 1 and Figure 2 along with the CO_2 abatement efficiency and project implementation time for each step. Those technologies with the greatest CO_2 abatement efficiency are generally implemented earlier in the roadmap to maximise implementation of the most cost-efficient technologies and to allow some higher-cost technologies to reduce in cost over time.

The primary roadmap electrifies the large residue heaters based on the assumption that the technology will be commercialised when implementation is required. However, this is a potential roadblock to the primary road map and opens additional routes should the technology not be ready. Alternative approaches to achieve electrification of the large residue heaters are also shown in Figure 2. These routes are investigated further in Section 6.2.

5.1 Roadmap Steps

Table 1: Primary Electrification Roadmap Steps

Step	Description	CO_2 Abatement Efficiency (tCO_2 per hr/ MM$)	Implementation Time (Years)	Remarks
1	Electrification of Condensing Turbines	1.6	2.5	Technology offering greatest CO_2 abatement efficiency. Condensing turbines are inefficient due to condensation of steam without energy recovery, hence the high abatement efficiency
2	MVR installed for propylene splitter to recover heat from overheads for use in reboiler	0.27	3.5	Lower abatement efficiency compared to other technologies that come later in the Roadmap. However, TRL and high electrical efficiency enables installation before large scale low-carbon power available. Technology is able to save CO_2 even utilising a high carbon intensity grid
3	Fuel gas fired steam boilers replaced with electric boilers + cogeneration switched off Undertaken once grid achieves large-scale low-carbon power	0.9 (boiler)	4.5	The technology performs well in terms of CO_2 abatement efficiency due to CAPEX requirements being comparatively low. Inclusion of an electric steam boiler avoids the need to replace multiple steam users with electric alternatives such as steam heaters, tank heating, tracing and steam turbine drives minimising disruption. Cogeneration is also turned off as part of this step based on the assumption that consumption of power from low-carbon grid would not detract from another more beneficial use in terms of CO_2 reduction external to the facility. A sensitivity where cogeneration is maintained is also performed in Section 6.2.1
4	Electric heaters replace non-residue fired heaters	0.1-0.3	4.0	The CO_2 abatement efficiency for electric heaters is a range based on the heater duty and complexity. Larger heaters are more cost effective.
5-1	Electric heaters replace large residue/ feed heaters (Primary Roadmap)	0.25	4.5	Although offering a reasonable expected CO_2 abatement efficiency, electric heaters to replace large fuel fired residue heaters are not currently viable. Hence these are positioned in the roadmap at point where viability and commercialisation are expected to be proven.

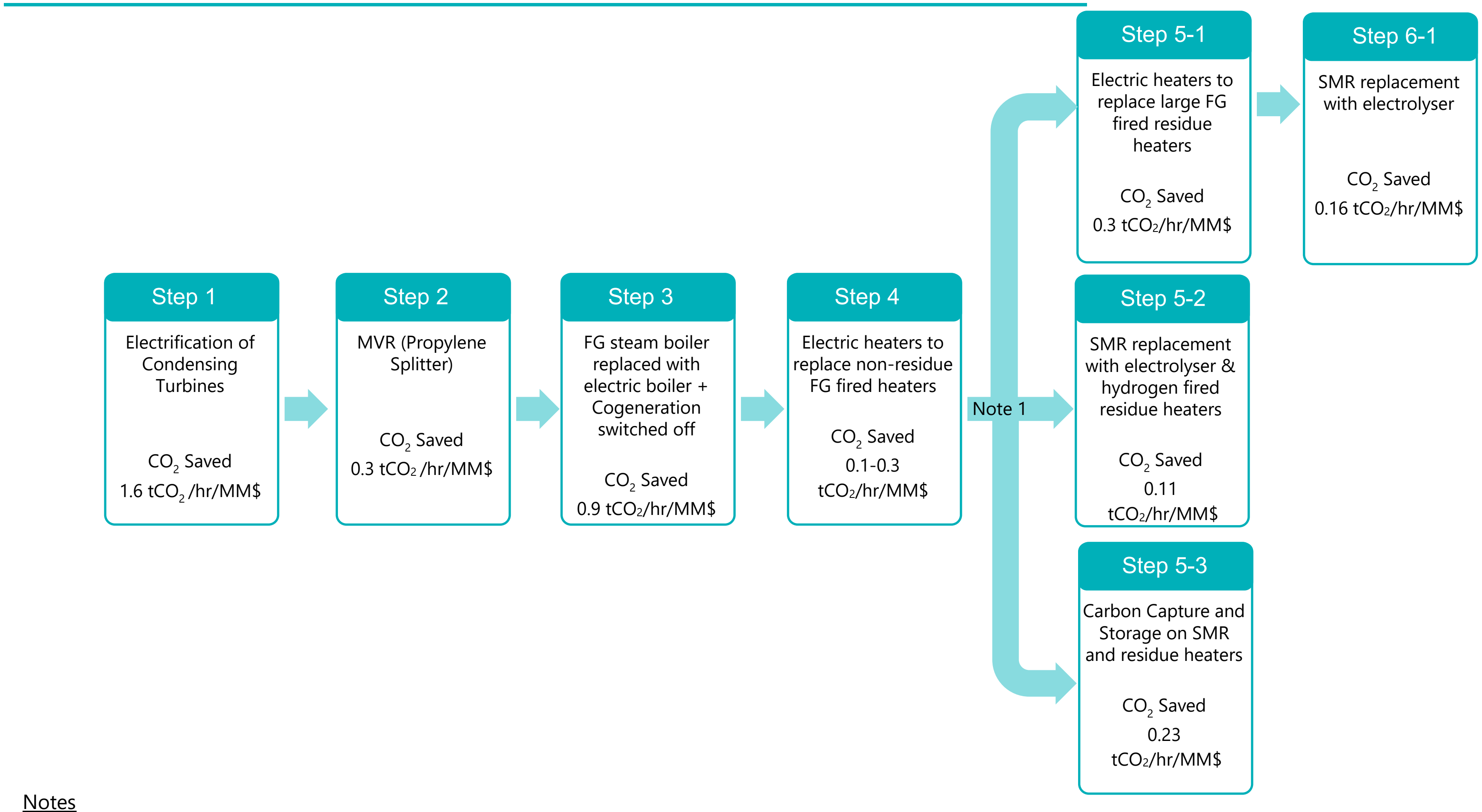
Step	Description	CO_2 Abatement Efficiency (tCO_2 per hr/ MM$)	Implementation Time (Years)	Remarks
6-1	SMR replaced with electrolysers (Primary Roadmap)	0.10 [(3)] 0.16 [(4)]	4.5	Electrolysis is positioned at the end of the Roadmap due to the low CO_2 abatement efficiency. Even with improved efficiency and reduced CAPEX expected by 2035, relative to other technologies the abatement efficiency remains low.
5-2	SMR replaced with Electrolysers & Residue Heater converted to H2 Firing (Alternative Roadmap)	0.11 [(4)]	4.5	This technology approach offers an alternative to replacing large fuel fired residue heaters with electric heaters should the technology development take longer than expected or be infeasible. Rather than replace with electric heaters the fired heaters are maintained but instead fired with hydrogen with the necessary modifications to the burner systems. The hydrogen is produced by electrolysis. This is a costly option due to the large hydrogen demand and subsequent electrolyser capacity required.
5-3	Fuel Fired Large Residue Heater Maintained. CO_2 removed via CCS (Alternative Roadmap)	0.23	4.5	Although not an electrification option, another potential approach to remove the CO_2 emissions from large residue heaters is to utilise carbon capture technology. Applicability of this technology is highly dependent on site location and available space but is another route that could be taken if electric heaters for this application are not yet ready or electrification options are proven to be too costly.

(1) Figures presented are applicable to the high complexity refinery case

(2) CO_2 abatement efficiencies are referenced against a low-carbon grid

(3) Electrolyser 2022 basis

(4) Combined Electrolyser and fired heater revamp CO_2 abatement efficiency, electrolyser 2035 basis



Notes

1. The Primary Roadmap following implementation of Step 4 (electric heaters to replace non-residue fuel gas heaters) electrifies the large residue heaters. Should this technology not be ready then alternative routes to electrify/ decarbonise are presented, represented by steps 5-2 and 5-3
2. Reported CO_2 abatement efficiencies are all referenced against a low-carbon grid and are for the high complexity refinery case.

Figure 2: Primary Electrification Roadmap

5.2 Roadblocks and Alternatives

Several potential roadblocks have been identified that prevent the primary Roadmap from being achieved or significantly reduce its benefits. These are described in Table 2 and the alternative routes to decarbonisation are investigated further as part of Section 6.2.

Table 2: Electrification Roadblocks

Identifier	Roadblock	Description
B1	Limited availability of low-carbon power	The primary roadmap assumption has been that there is sufficient availability of low-carbon power post-2030 that use by the refinery would not detract from a more effective external application. If low-carbon power is limited, cogeneration operation can be maintained throughout the electrification roadmap as it offers a relatively efficient way of producing power and steam and helps to reduce low-carbon power import demands.
B2	Delay in commercialisation of large residue electric heaters	In the event that electric heaters are not ready for large residue heater applications, the heaters could instead be fired on hydrogen. This would require a revamp of the burner system as well as installation of an electrolysers to provide the hydrogen. This step is shown in Figure 2 by step 5-2 The impact of potential future developments in electrolyser technology are also investigated to determine if a step change in performance can bring about improved CO_2 abatement efficiency and result in a change in the roadmap approach
B3	Delay in commercialisation of large residue electric heaters	In the event that electric heaters are not ready for large residue heater applications fuel gas firing can be maintained as CO_2 removed from emissions via Carbon Capture and Storage (CCS) technology. This step is shown in Figure 2 by step 5-3. This alternative is also relevant where a fuel gas long position cannot be sufficiently mitigated by reducing fuel production or routing to other uses.
B4	Low-carbon power availability (2050)	It has been assumed that low carbon power will be widely available by 2030 for refinery electrification. However, as explained previously this is the target for countries with more advanced decarbonisation strategies. For others, a more realistic target is 2040-2050. A roadmap is developed to demonstrate the impact to the primary roadmap from a delay in availability of low-carbon power

Identifier	Roadblock	Description
B5	Current inefficient condition of steam and condensate system	For the primary roadmap it is assumed that electrification is performed at a well operated and maintained facility. However, some sites have relatively inefficient utilities systems particularly around the steam and condensate transport system where steam leaks, poor insulation and poor trap maintenance are common. Electrifying these systems per the primary roadmap (electric steam boiler) would not remove the inefficiencies and contribute to an unnecessarily higher low-carbon power import demand. A roadmap is developed whereby these inefficiencies are targeted as part the electrification process by replacing steam heating and tracing with electric heaters and the impact the roadmap in terms of CO2 savings, CAPEX and power import demand quantified. Figure 3 provides a schematic of the Roadmap and shows how it differs from the primary roadmap. The early electrification steps for the condensing turbine and MVR system for the propylene splitter are still applicable. However, following that, the route diverges as electric boilers are not implemented. Although offering lower CO2 abatement efficiency, the replacement of the SMR with an electrolyser to produce hydrogen is brought forwards in the roadmap. This is because the SMR is a major steam producer at the facility and following electrification of steam users, this steam will no longer be required and electrification of the SMR via a electrolysers helps prevent the facility becoming steam long.

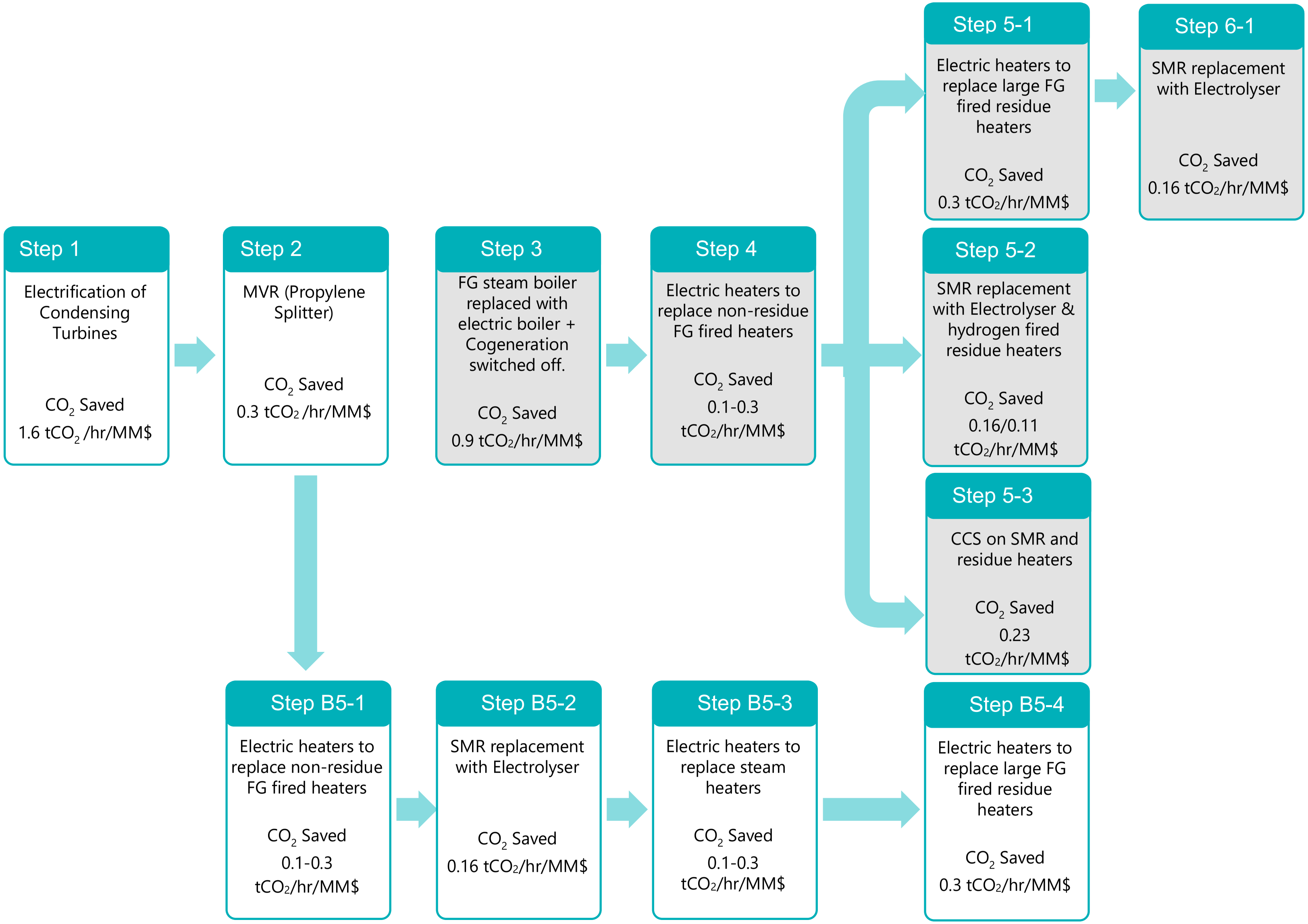


Figure 3: Electrification Roadmap – Direct Electrification of Steam Users

6. Results

6.1 Primary Electrification Roadmap

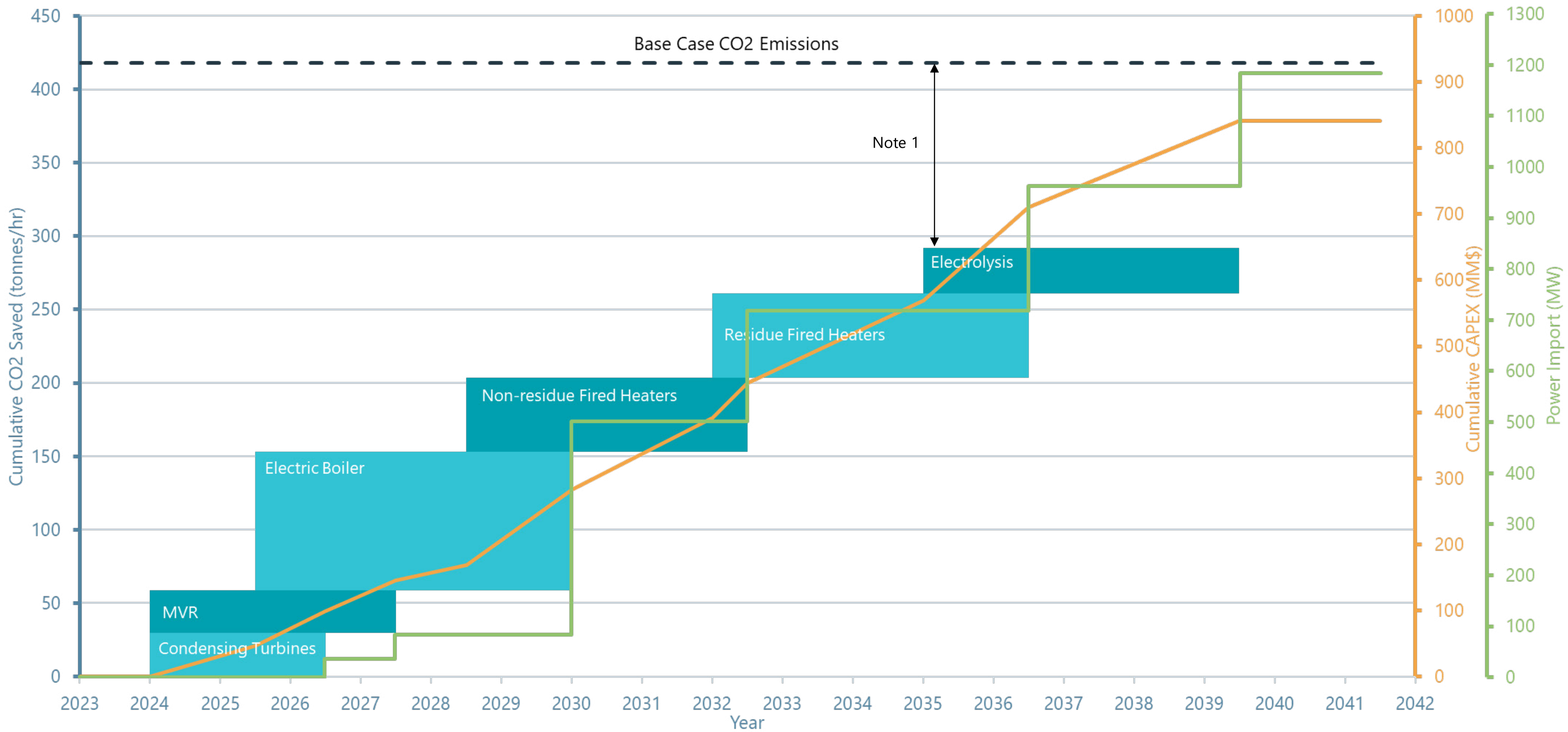
This section presents results for the primary electrification roadmap. Table 3 provides a high-level comparison between the refinery complexities. Figure 4, Figure 5 and Figure 6 provide the primary roadmaps for the high, medium and low complexity refinery configurations respectively. As to be expected with a higher complexity facility, greater CO_2 savings are achieved following electrification. However, a larger CAPEX investment and power import is required. The low complexity case has significantly lower CO_2 savings, CAPEX requirements and power import demands in part because the case has a lower refinery throughput compared to the high and medium complexity cases. There is also no residue processing in this case hence the level of electrification required is lower.

Table 3: Primary Roadmap – Total CO_2 Savings, CAPEX and Power Import

	Units	Low Complexity	Medium Complexity	High Complexity
Total CO_2 Savings	t/hr	49	211	292
Total CAPEX	MM$	119	615	832
Total Power Import	MW	213	958	1184

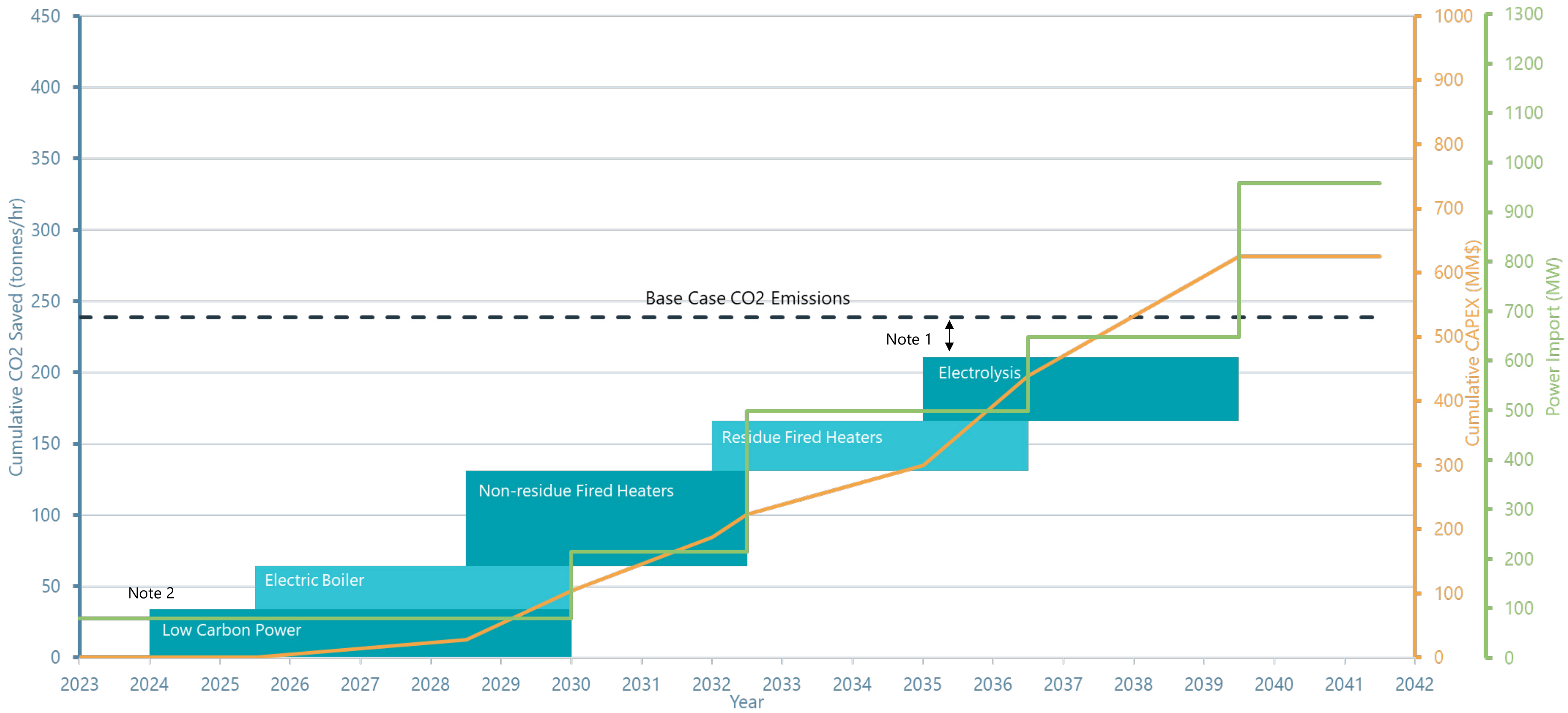
For the high complexity facility, the largest step change in terms of CO_2 savings is found when the electric boiler is implemented and cogeneration system switched off. A key assumption within this roadmap is that a low-carbon grid is available to support this technology at startup in the year 2030. Without the low-carbon grid, implementation of electric boiler technology would be delayed as it would not offer CO_2 savings.

There is also a relatively large delta between the quantity of CO_2 saved and the remaining CO_2 to reach the base case CO_2 emissions. A similar delta is also observed for the medium and low complexity configuration but not to the same extent. This is because for the high complexity case an FCC is included within the configuration. The FCC process involves burning produced coke that releases further CO_2, which cannot be eliminated via electrification methods. The medium and low complexity cases do not have an FCC as part of their configurations. Other methods could be considered to mitigate this CO_2 release from the FCC such as CCS.



(1) Delta between base case CO_2 emissions and cumulative CO_2 emission savings is due to FCC coke emissions, residual refinery fired emissions and electrical import CO_2 emissions (Scope 2).

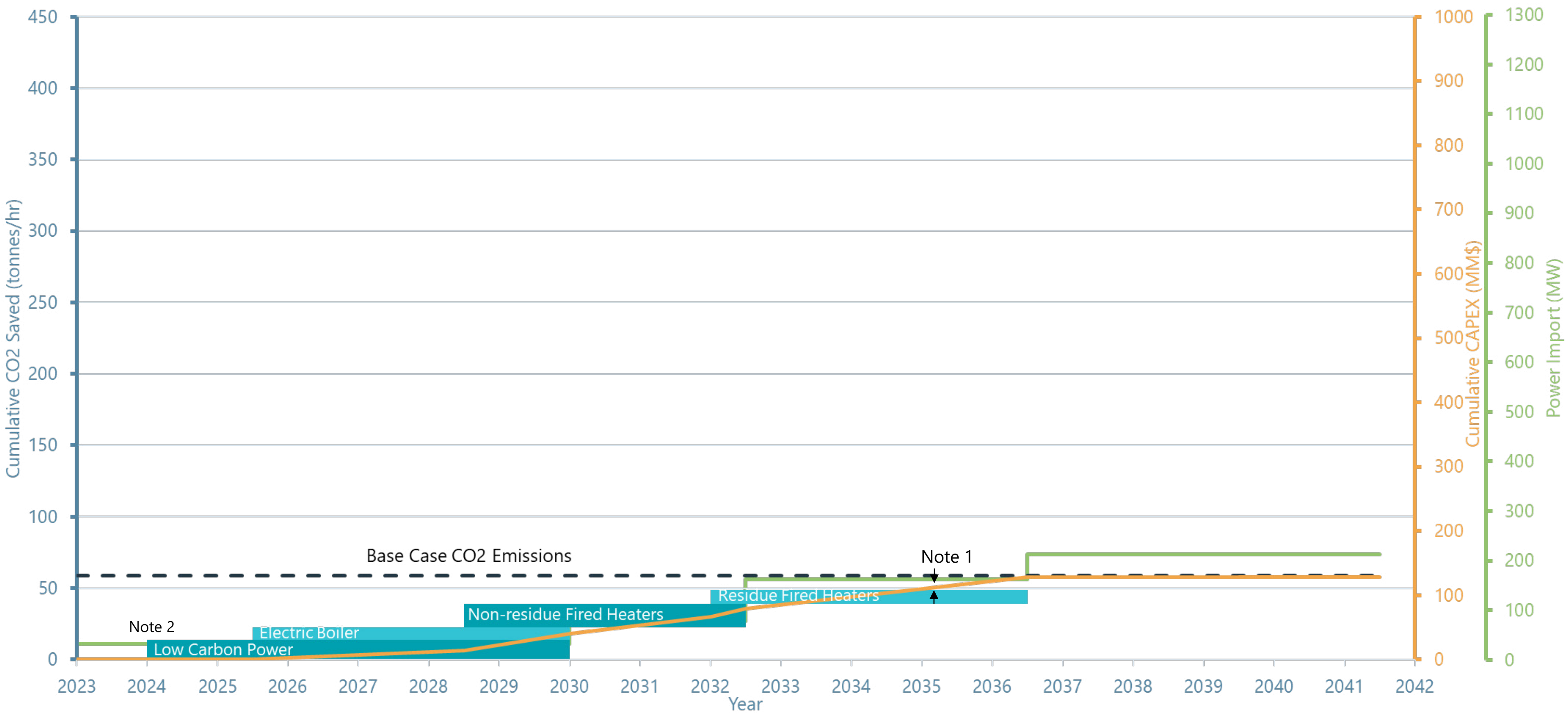
Figure 4: Primary Roadmap – High Complexity Refinery Roadmap



(1) Delta between base case CO_2 emissions and cumulative CO_2 emission savings due to residual refinery CO_2 emissions and electrical import CO_2 emissions (Scope 2).

(2) Low Carbon Power – A quantity of CO_2 savings is attributed to low-carbon power. This is imported power in the base case that initially is imported from a grid with high carbon intensity but as the grid is made low-carbon, CO_2 savings are achieved. The same does not occur in the high complexity case as there is no power import in the base case; all power required is generated on site via cogeneration.

Figure 5: Primary Roadmap – Medium Complexity Refinery Roadmap



(1) Delta between base case CO_2 emissions and cumulative CO_2 emission savings due to residual refinery CO_2 emissions and electrical import CO_2 emissions (Scope 2).

(2) Low Carbon Power – A quantity of CO_2 savings is attributed to low-carbon power. This is imported power in the base case that initially is imported from a grid with high carbon intensity but as the grid is made low-carbon, CO_2 savings are achieved. The same does not occur in the high complexity case as there is no power import in the base case; all power required is generated on site via cogeneration.

Figure 6: Primary Roadmap – Low Complexity Refinery Roadmap

As previously discussed, the facility fuel gas balance is important during electrification. Electrification of fuel gas users can lead to a situation where the facility is fuel gas long. Figure 7 provides the fuel gas balance for the Primary Roadmap. As electrification steps are taken the overall facility fuel gas demand decreases. As a result of this decrease, the quantity of natural gas import also decreases. Eventually the quantity of fuel gas produced by the facility is greater than that consumed. For this specific scenario this occurs during the electrification of non-residue fired heaters.

Further electrification steps only increase the extent to which fuel gas is long. As the quantity of excess fuel gas is greater than that expected to be reduced by operational changes and LPG recovery, this excess fuel gas requires an alternative destination for the electrification steps taken to be effective.

Analysis described in Phases 2 and 3 estimated operational changes and LPG recovery projects could reduce fuel gas production by approximately 25%. It is additionally noted that future technology development in catalyst and process technology could enable further reductions in fuel gas production driven by more facilities facing fuel gas long concerns.

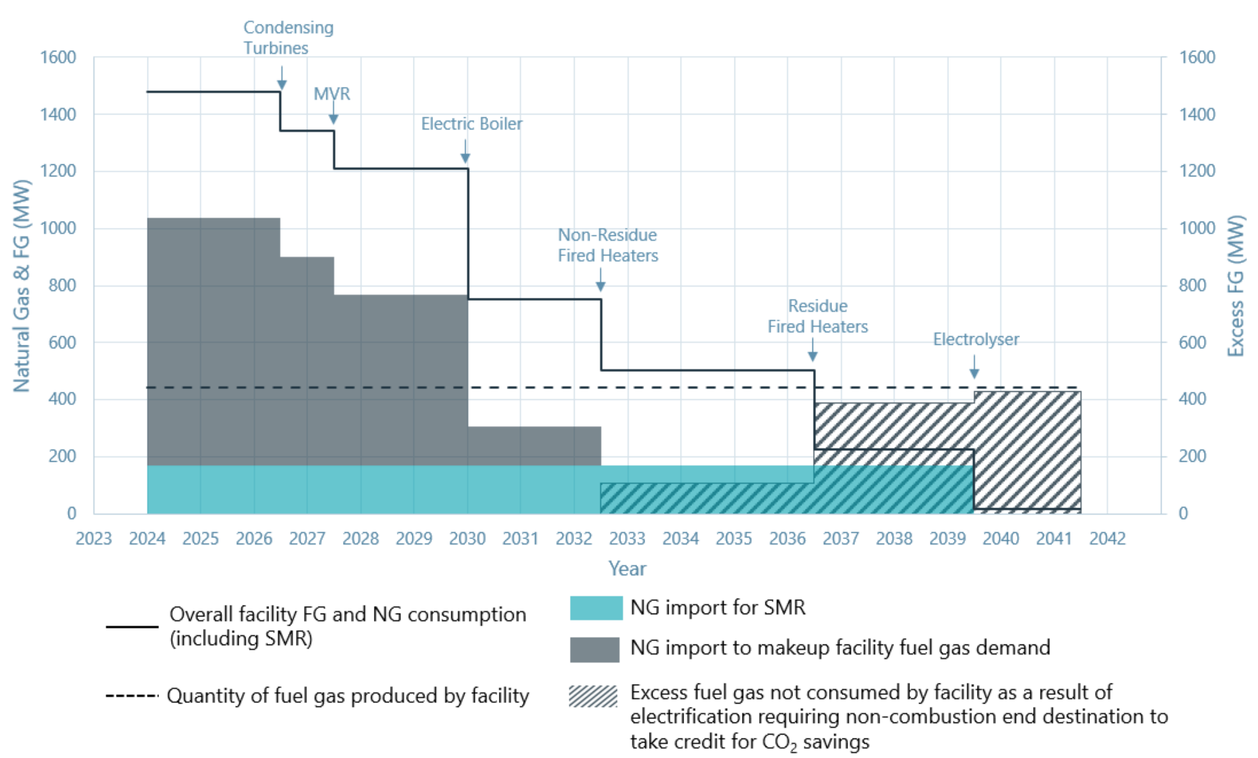


Figure 7: Primary Roadmap – Fuel Gas Balance High Complexity Refinery Case

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6.2 Roadblock Scenario Analysis

The following section provides the results from the analysis of the various potential roadblocks and alternatives described in Section 5.2.

6.2.1 Limited Availability Low-Carbon Power (Cogeneration Maintained) (Case B1)

The primary electrification roadmap considered that the cogeneration facility will be switched off as the electric boilers are implemented. Provided there is a well-supplied low-carbon grid this would be an effective way of reducing the carbon footprint of the facility with relatively low CAPEX investment required other than the electrical infrastructure required to support an increased import demand. However, the cogeneration system is an energy efficient way of producing power and steam and if the power from the low-carbon grid could be better utilised elsewhere by a more carbon intensive process. Operating the cogeneration facility also allows some flexibility where grid power price and carbon intensity fluctuates. Figure 8 provides the roadmap for the scenario where the Cogeneration facility is maintained.

Table 4 provides a comparison between the primary roadmap and Case B1 where cogeneration is maintained. As expected, there are lower CO_2 savings due to the continued combustion of fuel gas in the cogeneration gas turbines. However, the overall CAPEX and power import requirements are reduced. This means that the power produced does not need to be imported and if the low-carbon grid is restricted in available power then this may be viewed as regionally advantageous.

Table 4: Comparison of Primary Roadmap (Cogen. Switched off) and B1 (Cogen. Maintained) – High Complexity Refinery Configuration

	Units	Primary Roadmap	Case B1 (Cogeneration Maintained)	Delta
Total CO_2 Savings	t/hr	292	254	-38
Total CAPEX	MM$	832	801	-31
Total Power Import	MW	1,184	1,008	-176

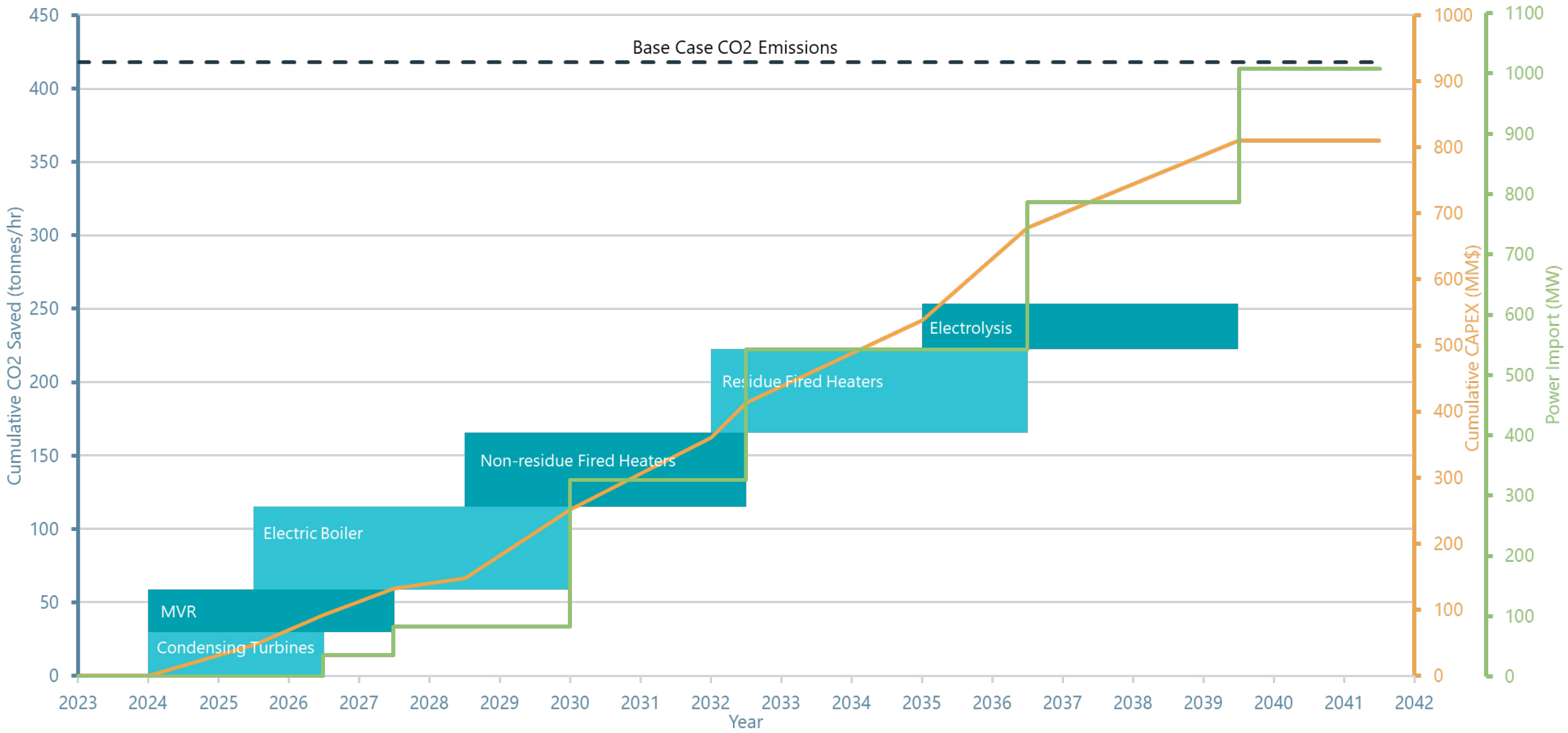

Figure 8: Case B1 – High Complexity Refinery Roadmap

Figure 9 provides the fuel gas balance for Case B1 where the cogeneration system is maintained across the electrification Roadmap. Compared to Figure 7 (primary roadmap where cogeneration is switched off), the point at which the facility becomes fuel gas long is delayed until electrification of the large residue heaters and the overall extent to which the facility is fuel gas long at the end of electrification is reduced.

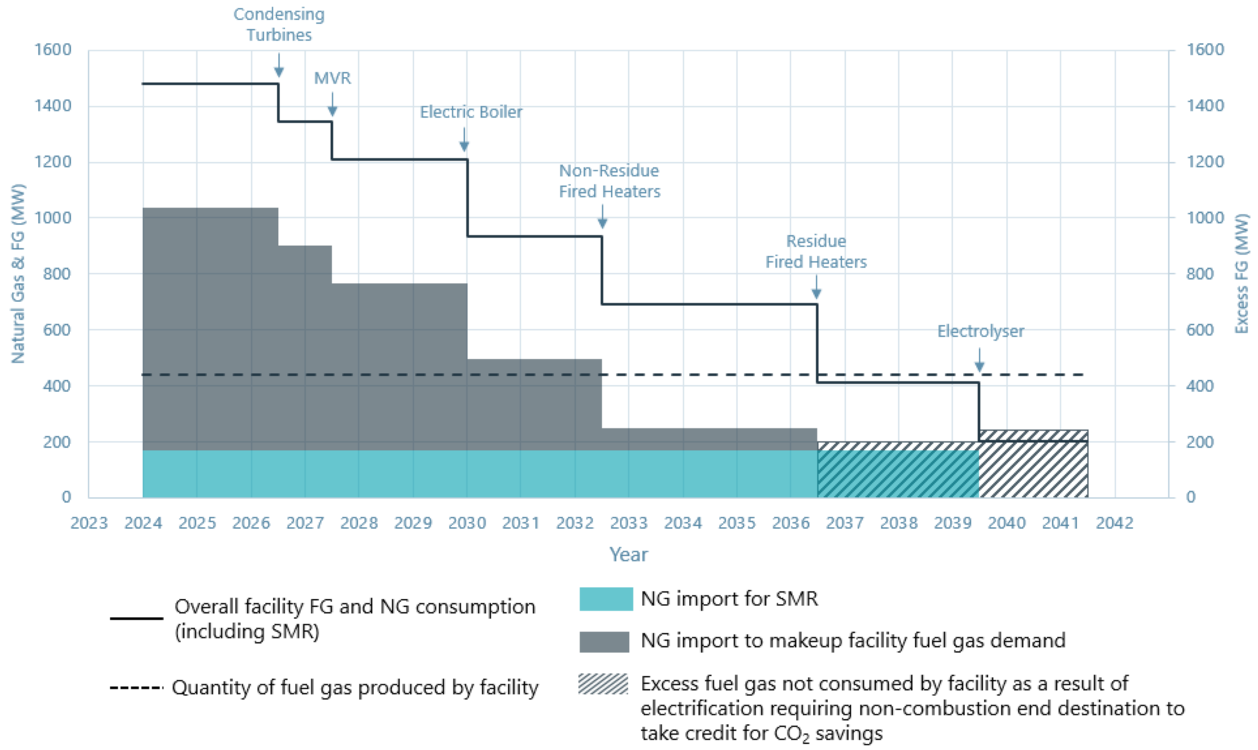

Figure 9: Case B1, Cogeneration System Maintained – Fuel Gas Balance High Complexity Refinery Case

6.2.2 Delay of Large Residue Electric Heaters (Hydrogen Firing) (Case B2)

If appropriate electric heater technology, whether by revamp of the existing firebox or by new construction, is not ready when the large residue heaters are due for electrification, the heaters could be converted to be fired on hydrogen. For this to occur, the heaters will require revamp and electrolysers installed to provide the hydrogen. Figure 10 provides the electrification Roadmap for this scenario based on the high complexity refinery configuration and Table 5 provides a comparison with the primary roadmap. Case B2 achieves similar overall CO_2 savings but they are marginally lower due to inefficiencies of the hydrogen fired heaters and hydrogen production compared to electric heaters. To achieve these savings there is a significant increase in CAPEX and power import requirements.

The advantage of this route is that the electrification end point occurs earlier compared with the primary roadmap as the SMR replacement step occurs at the same time as the residue heaters are being converted to hydrogen as both require electrolysers. In addition, utilising hydrogen as an energy medium allows the potential for storage and buffering of intermittent low-carbon power, though at additional CAPEX.

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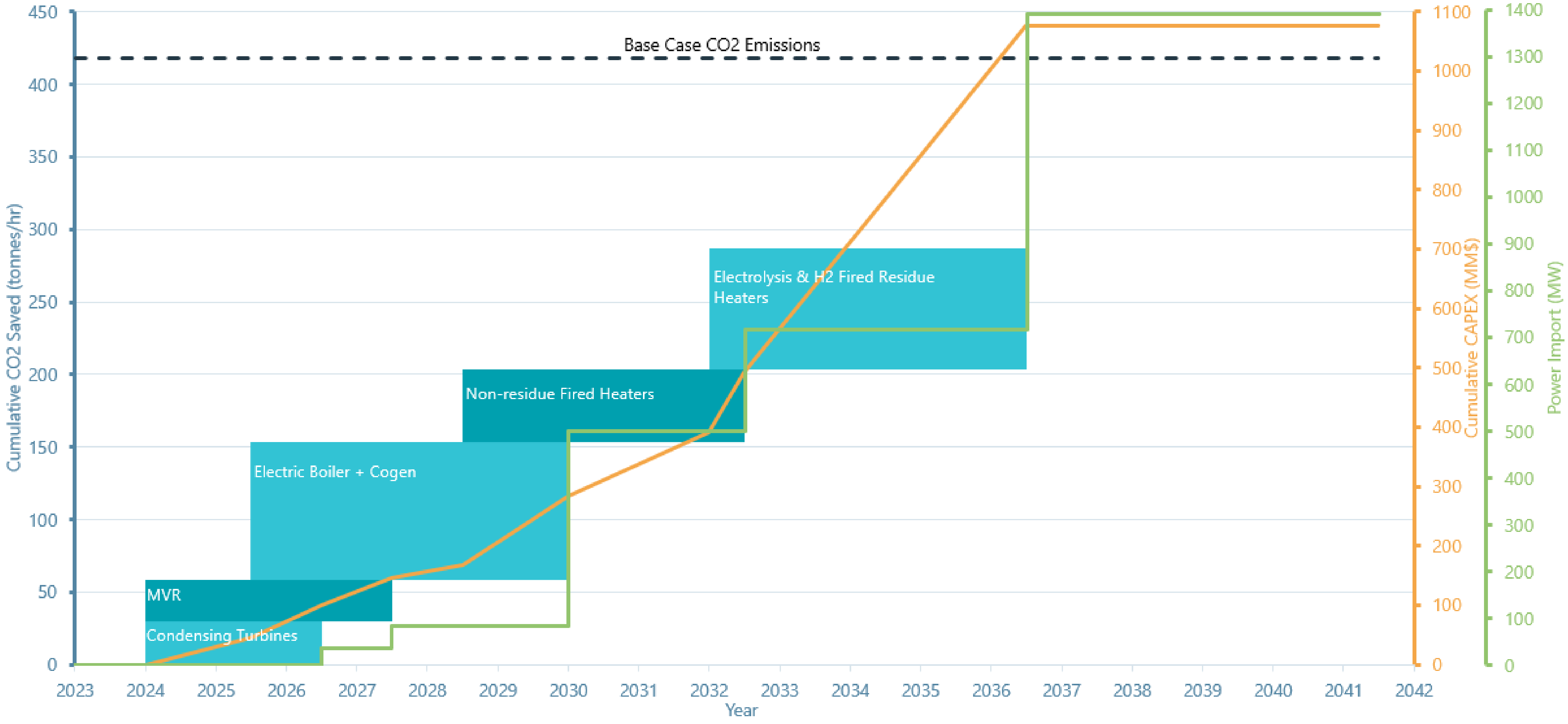

Figure 10: Case B2 – Hydrogen Fired Residue Heaters - High Complexity Refinery Roadmap

Table 5: Primary Roadmap vs. Case B2 – High Complexity Refinery Configuration

	Units	Primary Roadmap	Case B2 (Hydrogen Fired Residue Heaters)	Delta
Total CO_2 Savings	t/hr	292	287	-5
Total CAPEX	MM$	832	1,066	234
Total Power Import	MW	1,184	1,390	206
Electrification End Point	Year/s	2039	2036	-3

6.2.2.1. Electrolyser Efficiency

This section explores the potential impact that future electrolyser technology may have on the electrification roadmap by looking at the example of the primary roadmap and the electrolyser implementation step where the SMR is replaced.

The electrolyser technology for replacing the SMR has a relatively low CO_2 abatement efficiency hence its position towards the end of the electrification roadmap. However, electrolyser technology is developing rapidly and there are new electrolyser technologies in addition to the traditional PEM and alkaline-based electrolysers that may offer improved efficiencies in the future and be commercially ready for implementation when required in the roadmap. Consequently, a sensitivity is performed to assess the potential benefits of these new technologies.

Current PEM electrolyser efficiencies are 55 kWh/kg H_2. This is expected to improve to 50 kWh/kg H_2 by 2035. Alternative technology (e.g. Hysata) currently in development is expected to achieve 41.5 kWh/kg H_2 but the TRL level at present is around 3-4. For the purposes of this analysis, it is assumed that the technology is ready for implementation around the year 2035.

Table 6 presents the comparison between the two technologies. The greater efficiency of the alternate technology results in a lower power import demand and lower CAPEX as fewer electrolyser modules are required. The CO_2 saved is limited because at the point of implementation a low-carbon grid is available and so improvements in energy efficiency have a reduced impact.

Table 6: Comparison of electrolyser technology based on the Primary Roadmap High Complexity Refinery Configuration

	Units	Primary Roadmap – PEM	Primary Roadmap – Alternative High Efficiency	Delta
Electrolyser Efficiency	kWh/kg H2	50.0	41.5	-8.5
CO_2 Saved	t/hr	291.7	292.5	0.8
CAPEX (1)	MM$	832	806	-26
CO_2 Abatement Efficiency	tCO_2 per hr/MM$	0.35	0.36	0.01
Power Import	MW	1,184	1,150	34

(1) CAPEX figures are based on 2035 estimates. A CAPEX figure for the alternative technology is unavailable; CAPEX has been based on the closest comparable technology (PEM).

6.2.3 Delay of Large Residue Electric Heaters (Carbon Capture) (Case B3)

As discussed in the Phase 2 and 3 combined report the extent to which a facility is fuel gas long can be reduced though operating parameters, LPG recovery, or the impact eliminated by routing the excess fuel gas to an alternative destination. If these measures are not sufficient or are economically or technically unattractive then the option to maintain fuel gas consuming equipment and ensure the CO_2 released through its combustion is captured may be preferred. Case B3 provides this roadmap scenario.

Figure 11 provides the electrification roadmap for the carbon capture and storage (CCS) option whilst

Table 7 provides a comparison of this option with the primary roadmap where the electrification is allowed to proceed without restriction when the facility goes fuel gas long. Overall, there is a marginal increase in the quantity of CO_2 saved with the CCS option as the quantity of power import is lower and so the overall carbon footprint is reduced. The CAPEX investment required between the two options are similar for the basis considered as part of this work. However, in the case of the CCS option, CAPEX is highly dependent on location as a large portion of the cost is associated with the pipeline or other transport facilities that route the CO_2 to storage. For the example case given, pipeline investment is included to reach a storage location 150 km offshore. In some instances, the distance between facility and suitable storage location may be too far for the option to be economical. In other cases, transport and injection costs may be drastically reduced by a hub or consortium approach.

The CCS option considers the capture of CO_2 from the large residue heaters (CDU, VDU, Coker) as well as the SMR. Consequently, the roadmap finishes earlier than the primary roadmap as there is no requirement for an electrolyser given the CCS is capturing the CO2 released from the SMR.

For the primary roadmap, the electric residue heaters and electrolyser contribute to a significant power import requirement. As the CCS option does not include these electrification technologies and instead maintains fuel gas consumption, there is a significant reduction in the power import demand for the facility.

Table 7: Primary Road Map vs. Case B3 (CCS) – High Complexity Refinery Configuration

	Units	Primary Roadmap	Case B3 (CCS)	Delta
Total CO_2 Savings	t/hr	292	298	6
Total CAPEX	MM$	832	817	-15
Total Power Import	MW	1,184	871	-313
Roadmap End Point	Year/s	2039	2036	-3

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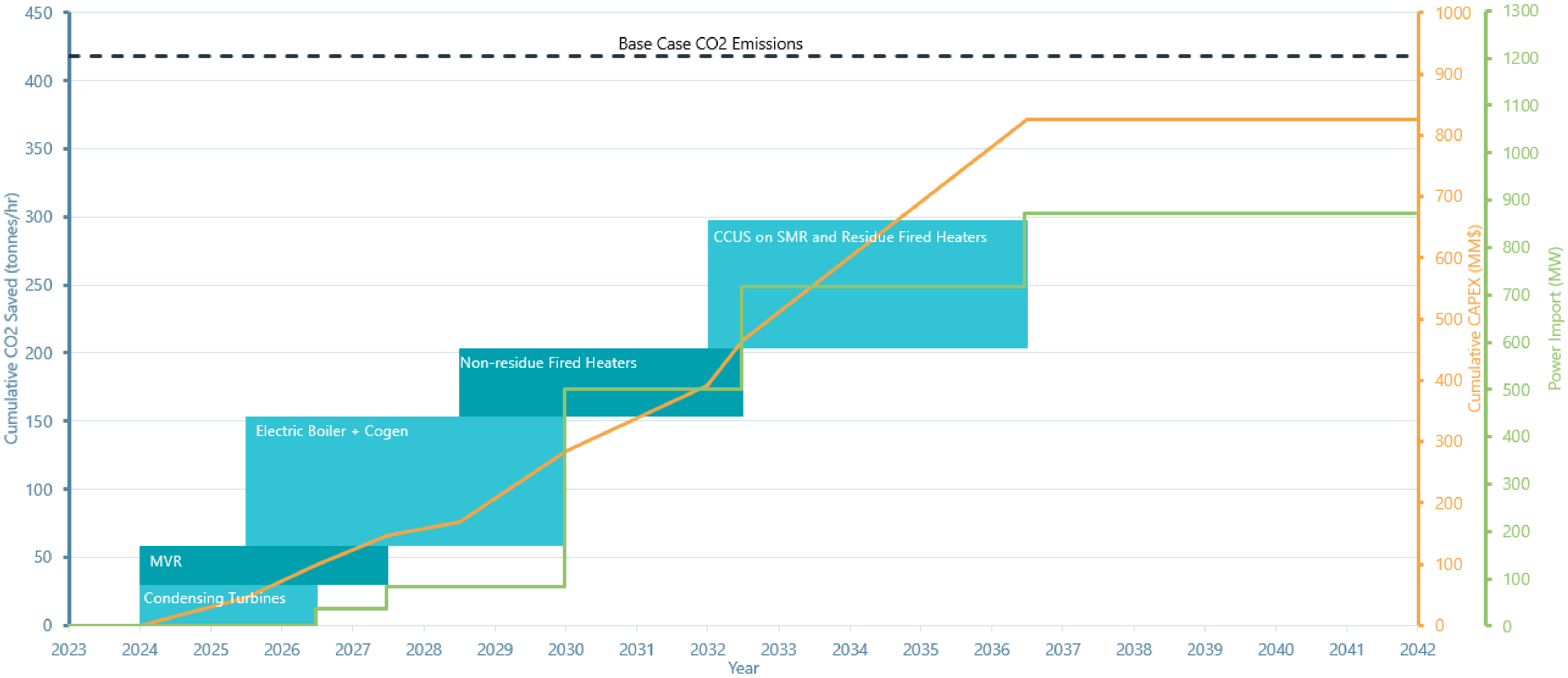

Figure 11: Case B3 - CCS - High Complexity Refinery Roadmap

Figure 12 provides the revised fuel gas balance for Case B3 and the implementation of the CCS option. The CCS is dedicated to the large residue heaters and SMR and so the option still experiences a slight fuel gas long scenario following the electrification of the non-residue fuel fired heaters. However, unlike the primary roadmap, the extent to which fuel gas is long does not increase past this point. The extent to which the facility is fuel gas long is relatively low and can be removed in its entirety if the cogeneration facility is also maintained or fuel gas production is curtailed. CCS has not been considered for the individual smaller scale fired heaters due to the difficulty and complexity in capturing all these streams.

The facility still emits a relatively large proportion of CO_2 that has not been removed through electrification or captured via CCS. This is primarily due to emission from the FCC. Applying CCS to the FCC emissions would increase the CO_2 savings and remove the majority of remaining emissions.

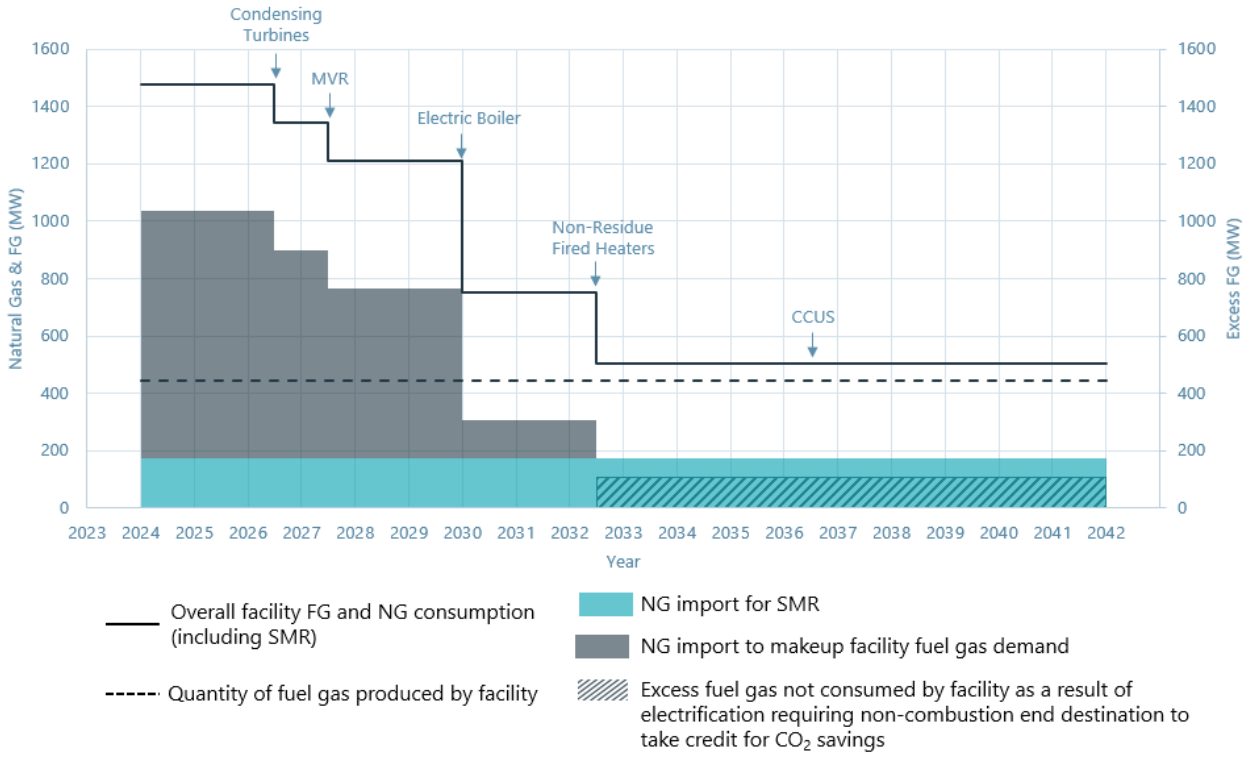

Figure 12: Case B3 – CCS - Fuel Gas Balance High Complexity Refinery Case

6.2.4 Low Carbon Power Availability Delay to 2050 (Case B4)

One of the main assumptions has been that large scale low-carbon power will be available from the year 2030 onwards. As discussed previously this is an IEA target more realistic for countries with advanced decarbonisation. For countries where decarbonisation is lagging 2040-50 is the realistic target. A sensitivity case has been performed to illustrate how the roadmap would look for a high complexity refinery located in a country where decarbonisation is relatively underdeveloped.

Figure 13 displays the primary electrification roadmap adjusted to the low-carbon grid availability being delayed from 2030 to 2050. The MVR and Condensing turbine projects are able to proceed as normal as they are not dependent on the low-carbon grid availability. There then follows a long delay to 2050 before implementation of the remaining electrification steps that can proceed with the availability of the low-carbon power with the final electrification step being completed by 2059.

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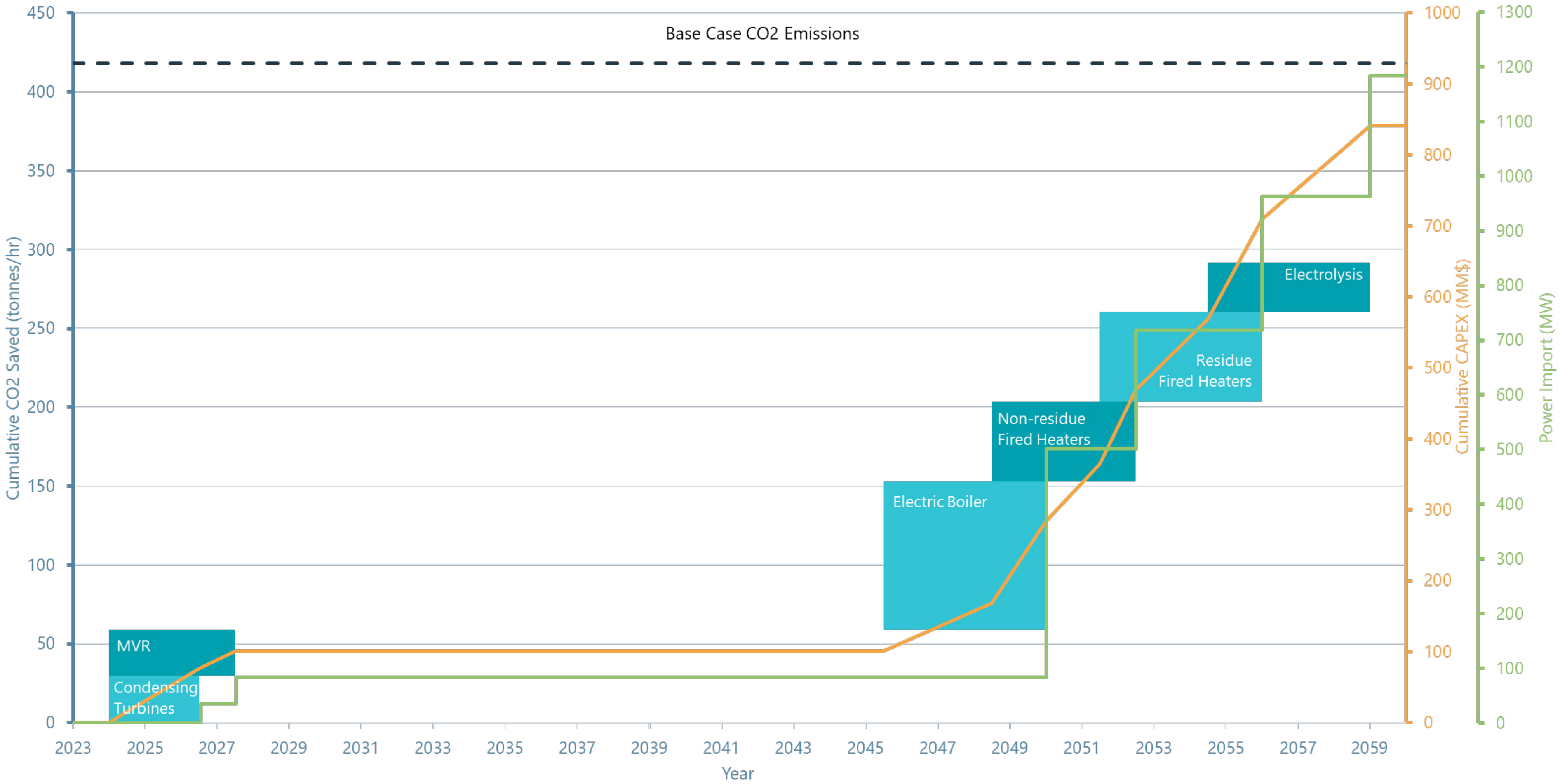


Figure 13: Case B4, Primary Roadmap Delayed Low-Carbon Grid Availability - High Complexity Refinery Case

Figure 14 explores the breakeven carbon intensity for the various technologies in the primary roadmap whereby the available grid carbon intensity can be compared to the breakeven grid carbon intensity of a particular technology to understand if implementation would be capable of reducing CO_2 emissions.

The breakeven grid intensity for the condensing turbines and MVR technology is significantly higher than the world average grid intensity. In general, these technologies will reduce the carbon footprint of a facility even at high grid carbon intensities. For the other technologies the breakeven grid carbon intensity is below the recent world average grid carbon intensity. This means that implementing these technologies before large-scale low-carbon power imports are achieved would result in an increase in a facility's carbon footprint, defeating the purpose of electrification. This analysis is discussed further in Section 9.5 of the Phase 2 & 3 Report.

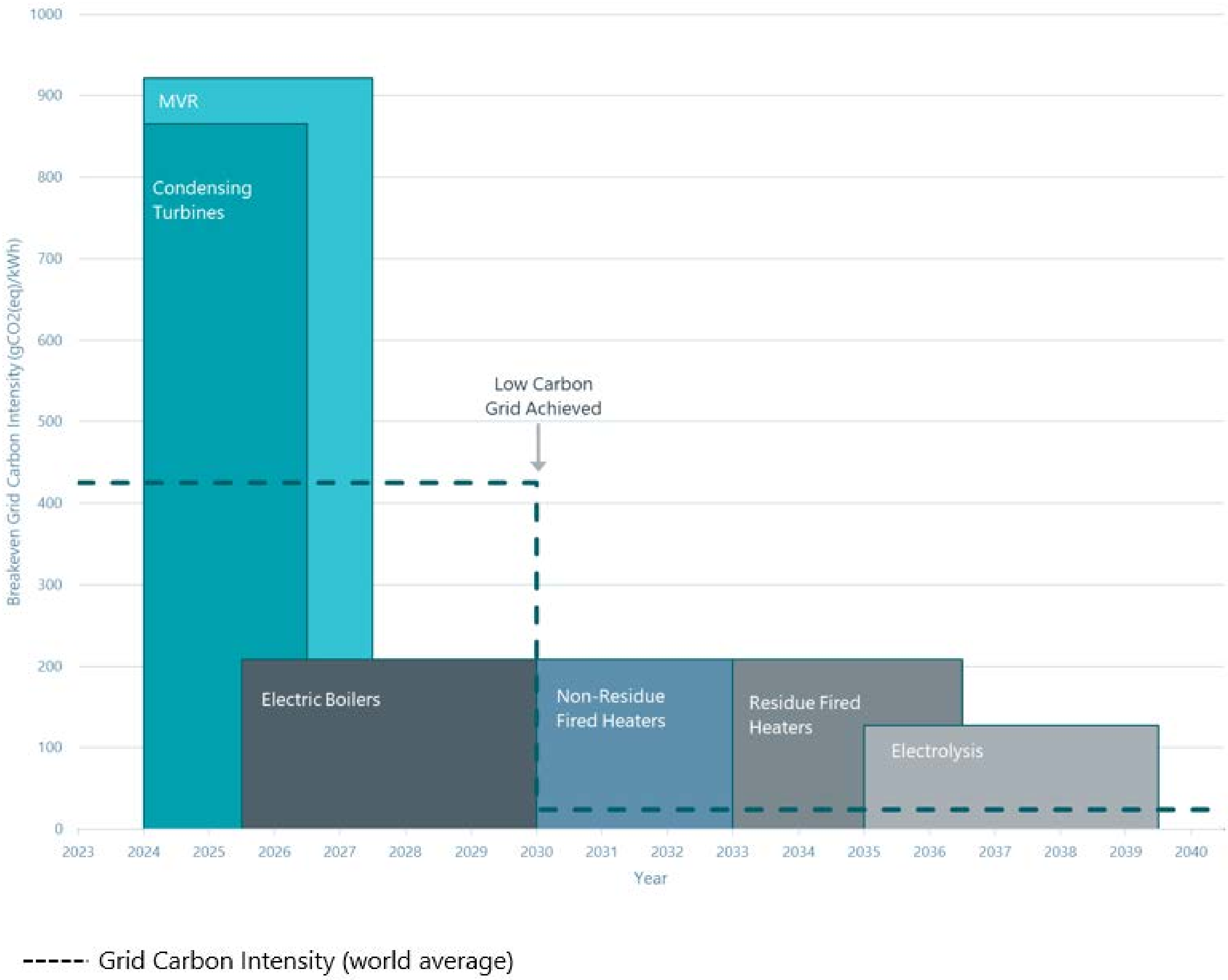


Figure 14: Technology Breakeven Grid Carbon Intensity

6.2.5 Inefficient Steam and Condensate System (Case B5)

The Primary Roadmap focused on the prioritisation of technologies offering the higher CO_2 abatement efficiencies relative to CAPEX. This approach assumes that the facilities being electrified are well operated and maintained. However, some specific facilities suffer from inefficient steam and condensate systems, including leaks, passing traps and poor insulation. Installing an electric boiler without resolving these inefficiencies and losses will result in an increased power import demand from a low-carbon grid. Consequently, a sensitivity case has been run whereby, instead of installing an electric boiler, the individual steam users are electrified, thus removing the steam and condensate energy inefficiencies and ensuring the low-carbon power import is not simply compensating for these losses.

Figure 15 provides the electrification Roadmap for Case B5 where individual steam users are electrified whilst Table 8 provides a comparison of key results with the Primary Roadmap. Comparing the two cases the same or similar CO_2 savings and power import demands are achieved. However, the key difference is that the direct electrification of individual steam heaters is very costly compared to installing electric boilers. Project difficulty is expected to be much greater in reality for direct electrification due to the dispersed steam users, including tracing, throughout the site.

Table 8: Primary Roadmap vs. Case B5 (electrification steam heaters) – High Complexity Refinery Configuration

	Units	Primary Roadmap	Case B5 (Electrification Steam Heaters)	Delta
Total CO_2 Savings	t/hr	292	292	0
Total CAPEX	MM$	832	1,096	264
Total Power Import	MW	1,184	1,170	-14
Electrification End Point	Year/s	2039	2039	0

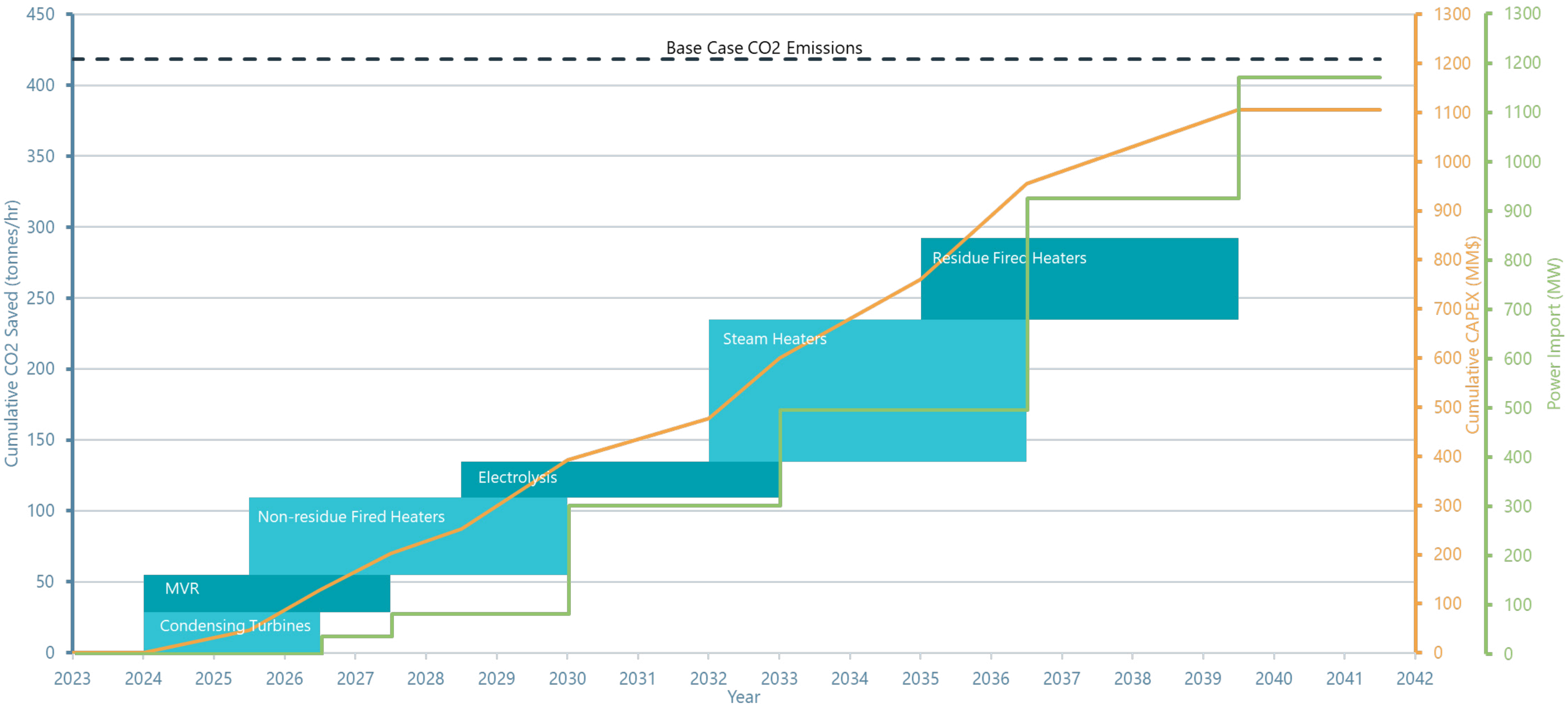


Figure 15: Case B5, Electrification Steam Users – High Complexity Refinery Case

wood.

6.3 Facility Energy Profile

6.3.1 Overall Facility Energy Profile

The facility energy profile as electrification proceeds is illustrated for the primary roadmap in Figure 16, Figure 17 and Figure 18 for the High, Medium and Low complexity cases respectively.

In general, as electrification proceeds there are overall efficiency savings as fuel gas demand reduces and power increases. However, in the final electrification step for the high and medium complexity configurations there is an increase in overall energy demand. This is because replacing the SMR with an electrolyser, although saving $CO_{2,}$ is a more energy inefficient approach to reaching the hydrogen product required.

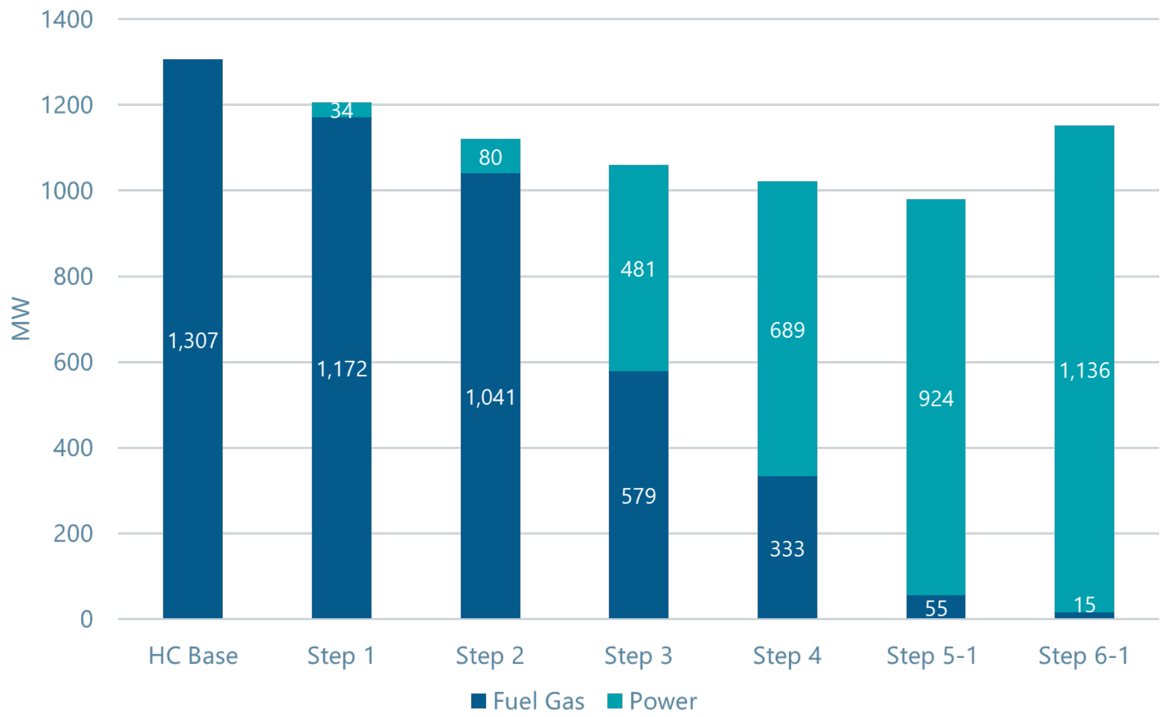
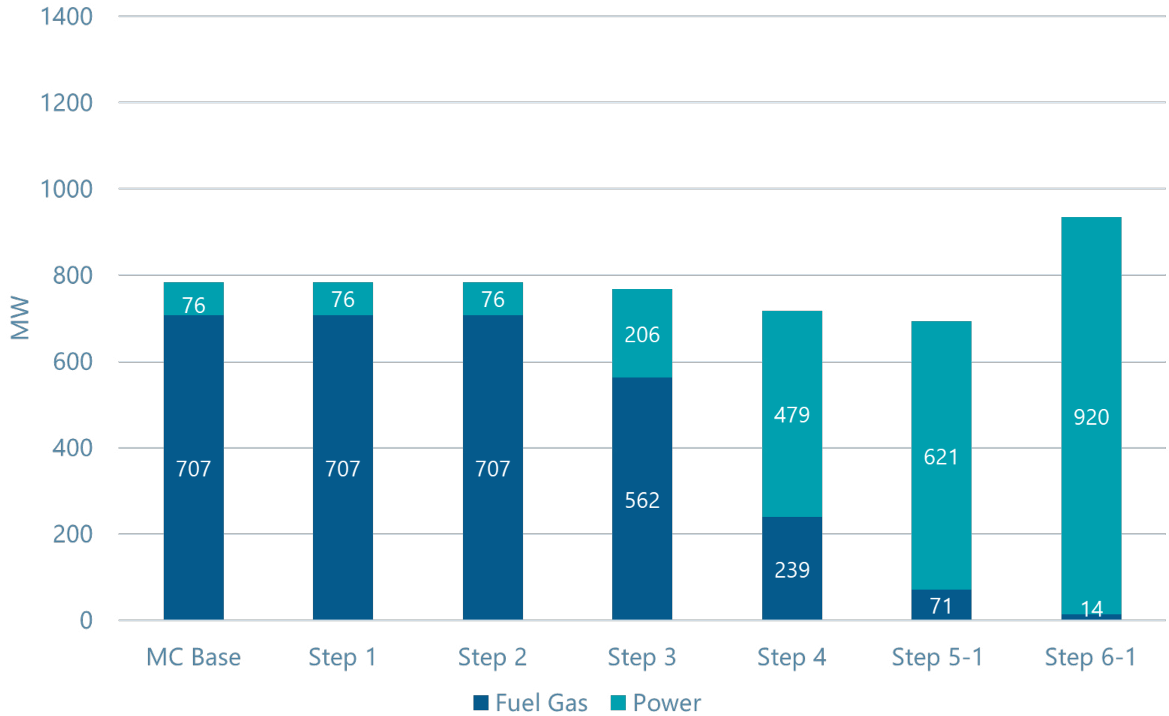
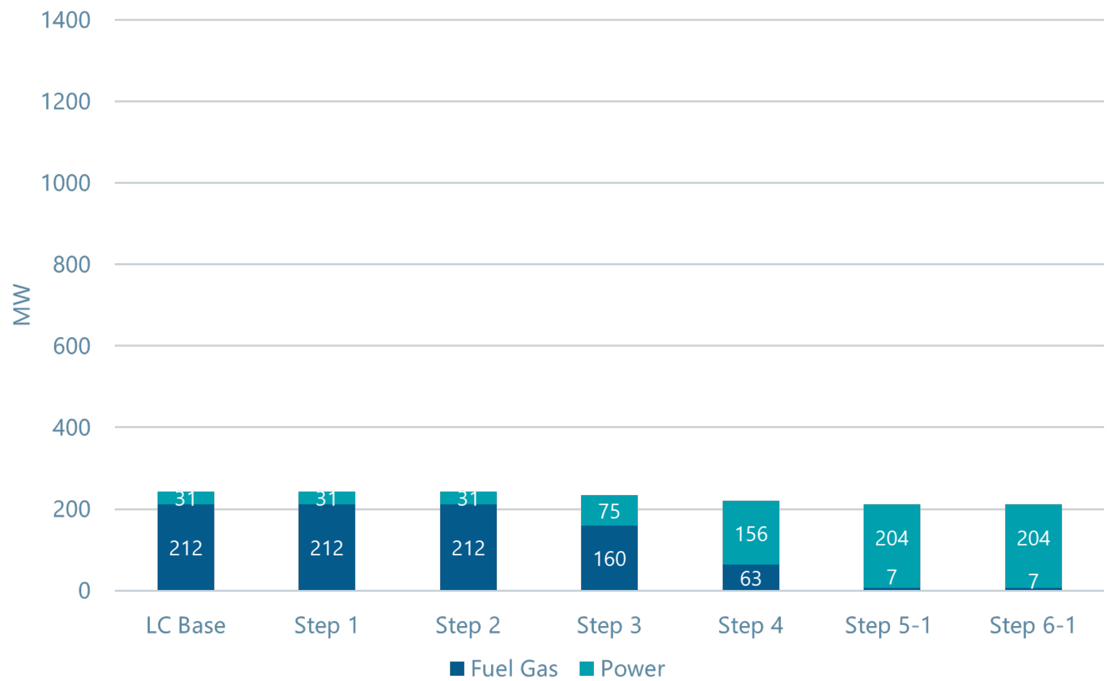


Figure 16: Primary Roadmap Energy Profile – High Complexity Case



(1) No change for Step 1 and 2 as medium complexity case does not have condensing turbines or a propylene splitter (MVR) as part of its configuration

Figure 17: Primary Roadmap Energy Profile – Medium Complexity Case



(1) No change for Steps 1 and 2 as low complexity case does not have condensing turbines or a propylene splitter (MVR) as part of its configuration. Configuration also produces an excess of hydrogen, hence there is no SMR in this configuration for replacement with an electrolyser.

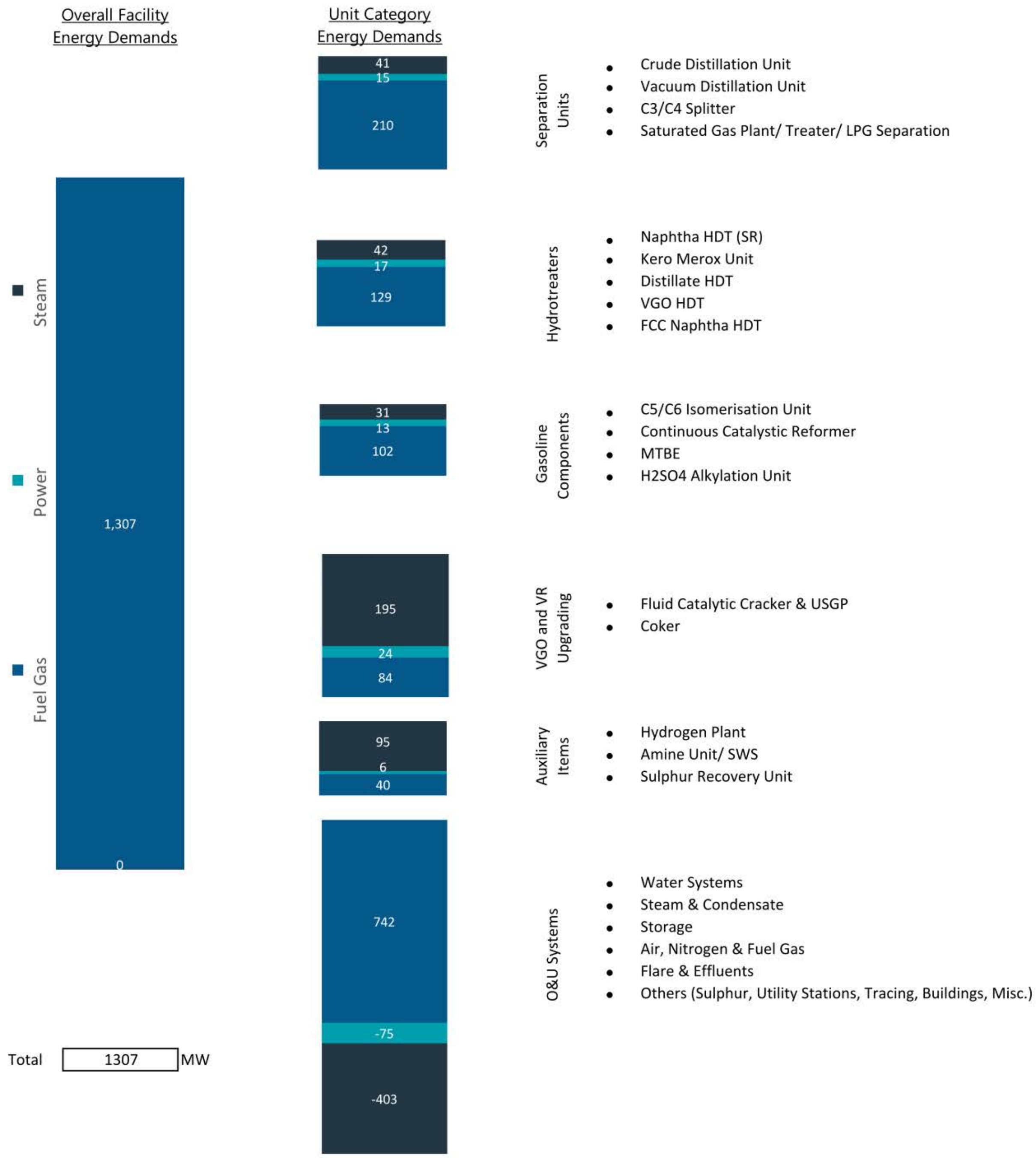
Figure 18: Primary Roadmap Energy Profile – Low Complexity Case

6.3.2 Unit Energy Profiles

Figure 19 and Figure 20 provide a comparison between the energy profiles before and after electrification for the high complexity refinery configuration based on the primary roadmap focussing on CO_2 abatement efficiency relative to CAPEX. The base case does not import power as it is generated by on-site cogeneration and steam turbine generators. Steam is reported as it represents an energy vector on the unit level; it is not imported or exported from the facility but produced and consumed internally.

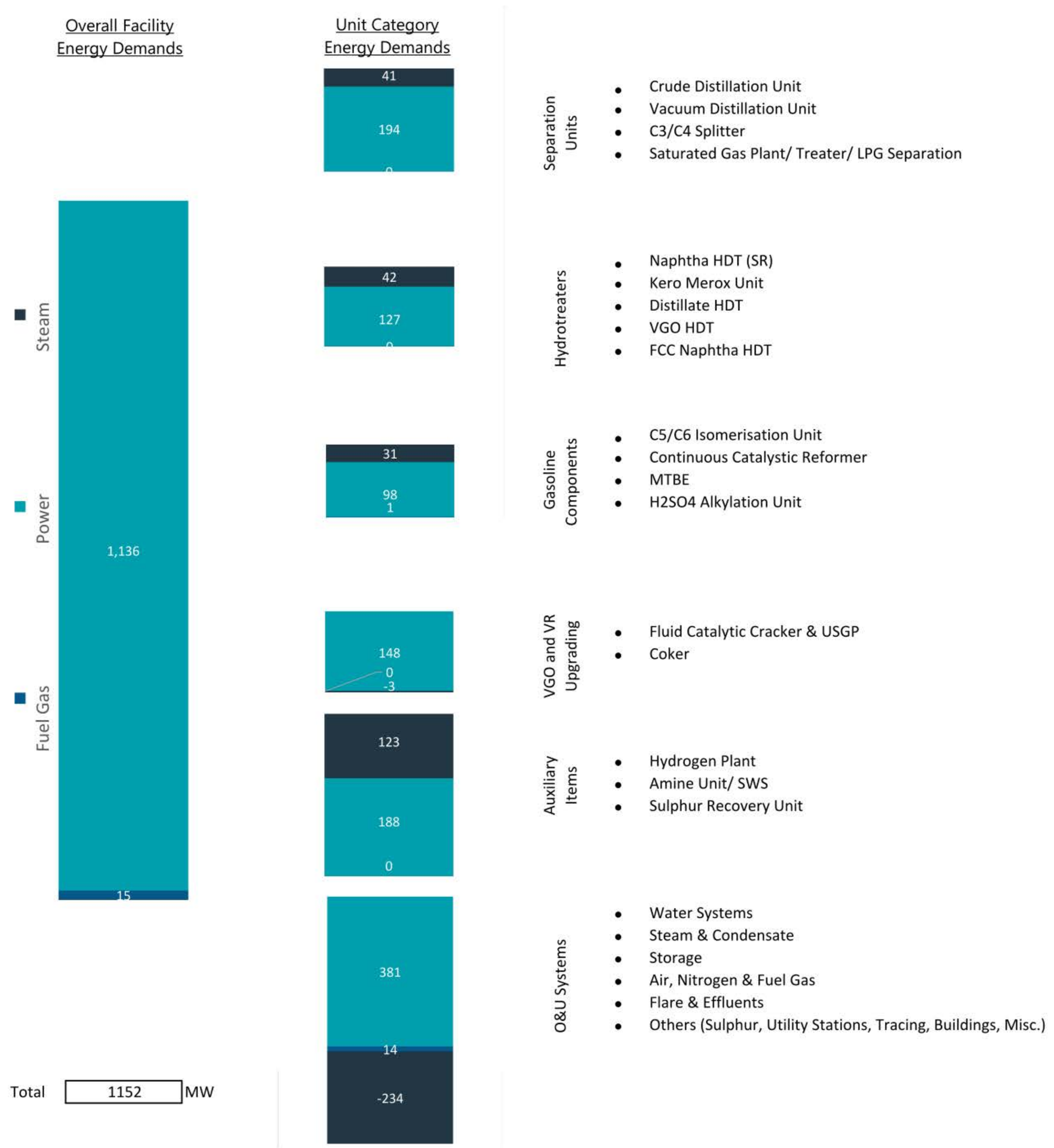
There is a significant change in how energy is consumed following electrification whereby fuel gas consumption has almost been eliminated with only minor residual demands remaining. In addition, there is a significant reduction in the facility overall steam demand, seen by the reduction in steam production from the O&U system. This is primarily due to the electrification of the condensing steam turbines and implementation of the MVR system on the propylene splitter.

Overall energy efficiency of the site is improved due to application of higher efficiency electrification technologies, resulting in a total site energy demand reduction from 1307 MW to 1152 MW. There is however a significant increase in the energy requirements of the auxiliary systems, this is attributed to the SMR being replaced by an electrolyser at lower efficiency, resulting in a high power demand in this area.



(1) Negative figure represents a production, positive a consumption

Figure 19: Base Unit Energy Profile – High Complexity Case



(1) Negative figure represents a production, positive a consumption

Figure 20: Primary Roadmap Unit Energy Profile following Electrification – High Complexity Case

wood.

6.1 Marginal Abatement Cost Curve

Figure 21 shows the marginal abatement cost for the technologies applied to the high complexity primary roadmap.

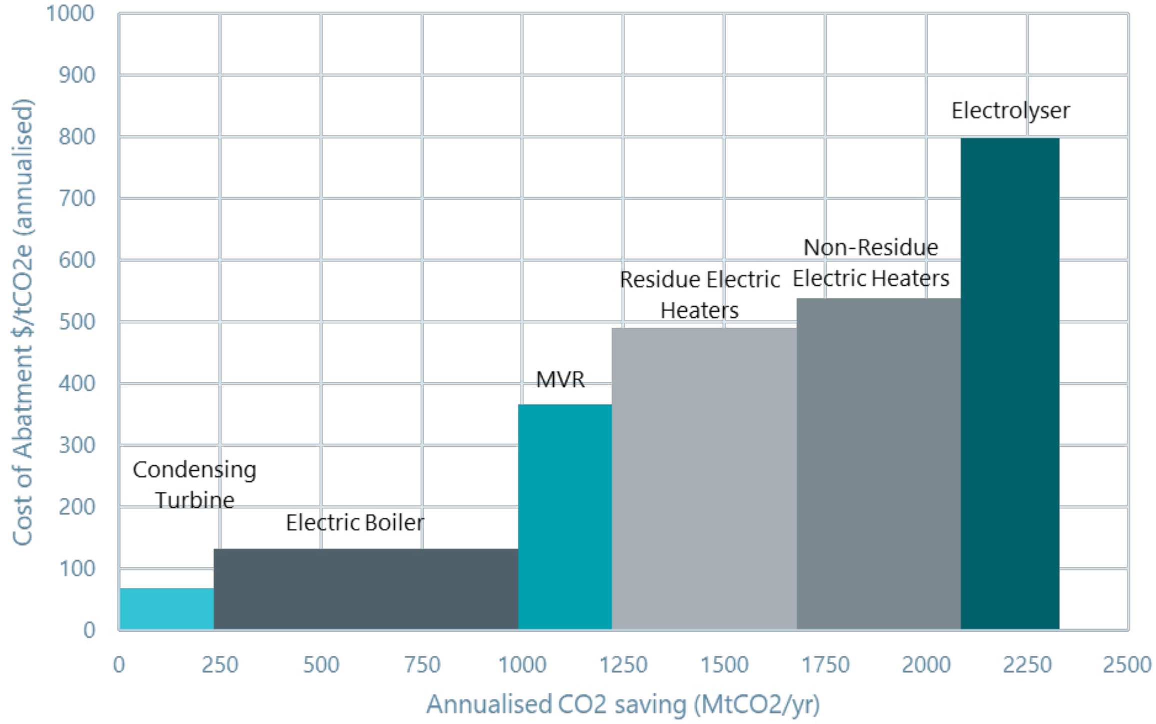


Figure 21: Marginal Abatement Cost Curve – High Complexity Case

7. Conclusions

Electrification roadmaps for the three representative refinery configurations have been analysed. Alternative roadmaps have been presented responding to specific difficulties (roadblocks) that could hinder the primary roadmap implementation.

7.1 Primary Roadmap

The primary roadmap was based on maximising the capital cost efficiency of CO_2 abatement. This resulted in a plan for phased investment that prioritised replacement of the existing fired boilers with electric boilers and maintaining the existing steam consumers. Other technologies required for fired duty replacement were implemented in order of decreasing cost efficiency through the roadmap, with the exception of very high power efficiency projects such as mechanical vapour recompression, which could be implemented beneficially prior to large-scale low-carbon power being available.

Electrification was found to enable decarbonisation of the great majority of the Scope 1 and 2 emissions from the sites. A significant remaining gap of unabated CO_2 emissions was found to be present at the end of the roadmap for the high complexity case, due in large part to the burning of coke in the FCC process. Other methods could be considered to mitigate this CO_2 release from the FCC such as carbon capture and storage.

The quantity of excess fuel gas at the end of the roadmap is greater than that expected to be reduced by operational changes and LPG recovery. This excess fuel gas requires an alternative destination for the final electrification steps taken to be effective, or alternative final steps should be considered as described in the roadblock analysis.

Where large-scale low-carbon power is available by 2030, the roadmap completion is anticipated by 2040, with delays to power availability postponing the end date further.

7.2 Roadblock Analysis

Alternative roadmaps were developed to address potential issues that could be present for a specific site. These alternatives were driven by:

- More limited or later availability of large-scale low-carbon power
- Delay or technological infeasibility of direct electrification of large residue heaters
- Inefficient or poor condition of the existing steam system

Maintaining the cogeneration plant in operation, rather than shutting this facility down as presented in the primary roadmap, enabled a reduction in power import and reduced electric boiler spend, whilst decreasing the overall decarbonisation extent. Flexibility to respond to swings in grid low-carbon power availability was also identified.

Hydrogen firing in the existing large residue heaters was analysed as an alternative to avoid direct electrification of these heaters. This option resulted in a significantly greater cost and power import than the primary roadmap for similar ultimate decarbonisation.

Carbon capture of the large residue heater and SMR emissions was shown to require a similar level of investment as the primary roadmap assuming that pipeline investment is included to reach a storage location 150 km offshore. This cost is highly sensitive to the logistics of the captured CO_2. Power import requirements are significantly reduced for the carbon capture case against the primary roadmap, though the excess fuel gas product is also eliminated.

A scenario whereby the steam consumers such as reboilers, heaters and tracing are replaced by direct electrical heating was also analysed to address a situation whereby the site's steam systems have significant condition and efficiency issues. Without including the potential benefit of eliminating a very inefficient steam system, this analysis resulted in a significantly greater investment cost.

In addition, where alternative routing of unused fuel gas is impractical, carbon capture from fired heaters and maintaining cogeneration were shown to be effective in eliminating fuel gas length.

As discussed in previous Phases, it is recommended that energy efficiency opportunities are developed and screened alongside electrification options to ensure an optimised overall investment roadmap for decarbonisation. This includes power or steam generation from waste heat, as well as power recovery turbines.

7.3 Recommended Further Work

The following are anticipated to be required for site-specific application and to provide detailed decision input to roadmap and roadblock strategies:

- Energy consumption and consumer baselining for specific site(s) to enable site-specific utility balance breakpoints and economics. Emissions, fuel and imported power pricing scenarios would enable overall economics to be produced.
- Broader application of heat pump and mechanical vapour recompression via hybrid solutions would likely yield energy efficiency and electrification benefits to sites via further study.
- Periodic updates will be required to assess the viability of emerging technologies targeting replacement of large, problematic fired heaters.
- The role of refinery and other industry electrification in low-carbon power grid demand buffering is potentially important and the practical feasibility of the operational swings and design requirements would benefit from further investigation.
- Carbon capture, transportation and storage should be explored for specific geographies and multi-site hub scenarios to provide a comparison to electrification that is applicable to a range of sites.

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