Greenhouse Gas Management Plan

Kwinana Renewable Fuels Project

bp Kwinana energy hub

bp Refinery Kwinana Pty Ltd

Applicability:	P&O – projects
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Contents

Symbols and abbreviations

For this document the following symbols and abbreviations apply:

ACCU	Australian Carbon Credit Unit
BDU	Bio Digestion Unit
DCCEEW	Department of Climate change, Energy, the Environment and Water
EPA	Environmental Protection Authority
GHGMP	Greenhouse Gas Management Plan
HGU	Hydrogen Generation Unit
HVO	Hydrotreated vegetable oil
HYD2	Hydrofiner No. 2
HYD3	Hydrofiner No. 3
KIA	Kwinana Industrial Area
klpd	kilolitres per day
KRF	Kwinana Renewable Fuels Project
LPG	Liquid Petroleum Gas
NGER	National Greenhouse and Energy Reporting
PFU	Product Fractionation Unit
POX	Partial Oxidation process
PTU	Pre-Treatment Unit
SAF	Sustainable Aviation Fuel
SMR	Steam Methane Reforming
SPK	Synthetic Paraffinic Kerosene
t CO_2 e/annum	tonnes CO_2 equivalent per annum

Executive Summary

bp has developed this Greenhouse Gas Management Plan (GHGMP) for the purpose of supporting the assessment, approval, and implementation of its proposed Kwinana Renewable Fuels (KRF or biorefinery) project in Kwinana, Western Australia under Part IV of the *Environmental Protection Act 1986* (WA) and all other relevant legislation.

It is expected that the predicted Scope 1 and Scope 2 emissions from the project are likely to exceed 100,000 tonnes carbon dioxide equivalent (CO_2e) per annum and the EPA will have to regard those emissions when considering the referral of the proposal under Part IV of the Environmental Protection Act 1986 (WA).

bp has operated in Kwinana since 1955, when crude oil refinery operations commenced. Oil refining operations ceased in 2021 and the site became a fuel import terminal, with further plans to develop renewable fuels and green hydrogen projects. The KRF project plans to utilise some former refining units and leverage the site's existing storage, pipeline, jetty and utilities infrastructure to produce renewable diesel, sustainable aviation fuel and bio naphtha from bio feedstocks.

bp has ambitions to be net zero across its operations and products by 2050 or sooner and provide the energy products to support its customers and communities to achieve net zero. This plan details bp's intent to manage and reduce greenhouse gas emissions from the proposed KRF project.

The project's fundamental objective is to reduce carbon emissions relating to transport. Transport biofuels have a carbon lifecycle reduction of up to 80%, compared to traditional diesel and jet fuel produced by fossil fuels. The products the biorefinery produces, HVO and SPK are biogenic and hence the lifecycle emissions associated with these products is much lower than traditional diesel or jet fuel. Having a low carbon fuel available in the transportation sector will be essential to support GHG reductions globally.

This GHGMP has been developed in accordance with the template Greenhouse Gas Management Plan provided by the EPA and the EPA's *Environmental Factor Guideline: Greenhouse Gas Emissions* (April 2023).

Proposal Name	bp Kwinana Renewable Fuels Project
Proponent Name	bp Refinery (Kwinana) Pty Ltd
Proposal description and Scope	The Proposal is for the construction and operation of a Renewable fuels processing facility that produces renewable diesel and sustainable aviation fuel (SAF) from vegetable oils, animal fats and other biowaste products. The biorefinery will reuse the existing processing infrastructure formerly used for hydrocarbon refining (such as hydrofiner units, storage tanks, pipelines and utilities including the flare system and wastewater treatment plant) combined with some additional new infrastructure comprised of a Hydrogen Generation Unit (HGU), Pre-Treatment Unit (PTU), Product Fractionation Unit (PFU), Anaerobic Bio Digestion Unit (BDU) and utilities such as cooling water system.

	The Proposal is located at the former bp oil refinery site in the Kwinana Industrial Area and will use existing disturbed footprint to implement this project. No clearing will occur as part of the Proposal. The Proposal Project Development Envelope covers the whole bp boundary which is an already disturbed area. The Proposal is considered to be achieving sustainable outcomes via creation of new job opportunities, production of sustainable fuels from waste feedstocks and by underpinning bp's Kwinana Energy Hub development which will help industry, the State and bp customers to achieve their decarbonisation strategies and reduce greenhouse gas emissions
Purpose of GHG EMP	To support the assessment and approval of the proposal under Part IV of the EP Act To provide management actions and assurance of bp's commitment to reach net zero by 2050 as aligned to bp's strategy and regulatory requirements
Emission estimates	Scope 1 120,750 t CO_2 e/annum 2,898,000 t CO_2 e over life of project Scope 2 47,021 t CO_2 e/annum 1,128,504 t CO_2 e over life of project Scope 3 2,020,981 t CO_2 e/annum 48,503,544 t CO_2 e over life of project
Trajectory of emissions reductions	Safeguard mechanism is expected to apply for this proposal as Scope 1 emissions are greater than 100, 000 t CO_2 e/ annum. EPA WA guidelines minimal expectation is a linear trajectory to net zero by 2050, which bp have also considered. The most stringent yearly reduction will apply and currently it is expected that Safeguard reduction will apply until 2030 and EPA WA linear reduction from 2030 to net zero in 2050. The baseline has been proposed as 120,750 t CO_2 e /annum. It is acknowledged that the Safeguard baseline is unknown, as bp work with the Department of Climate Change, Energy, the Environment and Water (DCCEEW) to define appropriate production variables and best practice for this emerging industry. Unmitigated Scope 2 emissions are expected to be 47,021 t CO_2 e/annum, however it is expected that a green power purchase agreement for KRF will reduce the Scope 2 emissions to zero from commencement of operations. Hence is expected to meet the EPA WA guidelines minimal expectation of a linear trajectory to net zero by 2050.

	Application of the EPA mitigation hierarchy has been applied to the proposal to avoid, reduce, and offset Scope 1, Scope 2 and Scope 3 emissions.
Other statutory decision-making processes which require reduction in GHG emission	The biorefinery will meet the threshold for the Federal Government's Safeguard Mechanism and will be required to reduce emissions each year from the baseline. The biorefinery is anticipated to be a new entrant under Safeguard and considered first of kind for industry so it is expected that the baseline will be developed using appropriate production variables and global best practice. bp is in discussion with DCCEEW on defining the baseline and it is expected to be determined in 2024. The current bp Kwinana Energy Hub GHG emissions are below the facility threshold of 25,000 tonnes CO2 e/ annum. There is still a requirement to report the bp Kwinana emissions based on the overriding group thresholds for BP Australia Investments Pty Ltd Controlling Corporation NGER submission.
Key components in the GHG MP	bp has adopted best design and technology for the biorefinery. bp has carried out a technology evaluation process on the selected technology to ensure that global best practice was considered in regards to carbon footprint and energy efficiency. Steam Methane Reforming was the selected technology as the carbon footprint was lower than most options and offgases could be utilized in the unit rather than flared. bp designed the biorefinery on the basis that renewable offgases generated in the process could be used as a substitute for natural gas, avoiding approximately 158,000 t CO_2 e/ annum of Scope 1 emissions. The SMR technology allowed this reuse and hence one of the reasons why it was selected. The SMR technology allows for steam to be generated from the hot waste gases, which in turn reduces the amount of natural gas that would be required and hence reducing Scope 1 emissions in the design. Adopting green hydrogen as both a feed and a fuel to the biorefinery, can potentially future reduce the Scope 1 emissions by approximately 47,000 t CO_2 e/ annum. bp is exploring this concept with the H2Kwinana project where the first stage will see green hydrogen used as feed and subsequent stages substituting green hydrogen into the fuel gas system. Scope 2 emissions over the life of the project are expected to be zero, as the expectation is that a green power purchase

	agreement will be in place to provide renewable power for the biorefinery. Scope 3 estimate estimates are high level at this stage of the project and will be further refined once supply chains and project design have progressed. It will be evident where the largest scope 3 emissions are and where to target emission reductions. The GHG MP will be updated to include this detail as part of its review cycle. The fundamental objective of the biorefinery is to provide a low carbon fuel that will reduce the Scope 1 emissions of our customers. bp is exploring options to reduce emissions to meet the interim goals by investigating technologies to substitute natural gas from the Proposal, such as green H2 and reusing biogas as a fuel or feed if possible. The proponent will take measures to ensure that the Net Scope 1 GHG Emissions do not exceed: 1. 531,000 t CO_2e from proposal commencement until 30 June 2030 2. 410,550 t CO_2e for the period between 1 July 2030 and 30 June 2035 3. 289,800 t CO_2e for the period between 1 July 2035 and 30 June 2040 4. 169,050 t CO_2e for the period between 1 July 2040 and 30 June 2045 5. 48,300 t CO_2e for the period between 1 July 2045 and 30 June 2050 6. Zero (0) t CO_2e / annum for every five (5) year period from 1 July 2050 onwards
GHG EMP reviews and reporting	bp commits to, at a minimum reviewing and updating the GHG MP in 5 yearly intervals. Activities to take place as part of the review process are; • Verifying the performance of the biorefinery in relation to the targets and objectives outlined in this plan • Consider latest environmental guidance and legalisation in relation to the plan • Verify that the technology is best practice and benchmark against any new facilities • Review the future reduction methods, their progression and if any additional ones should be considered • Effectiveness of internal processes and procedures to reduce and manage GHG emissions (including GHG MP) Actions will be raised in bp's compliance action tracking system to explore any opportunities or inconsistencies identified in the review.

	Annual reporting will occur to National Greenhouse and Energy Reporting (NGER) scheme and emissions will be calculated annually using NGER methodology. Annually the KRF GHG MP performance targets will be reviewed at the completion of the NGER scheme reporting process, when GHG emission estimates have been calculated for the previous financial year. This activity will review the actual emissions against the GHG MP baseline to understand compliance to the 5 yearly targets and trigger any improvement actions if necessary. Under the Safeguard Mechanism Reforms, if the Scope 1 emissions are greater than 100,000 tonnes CO_2 e/ annum, then these estimates will be fed into the Safeguard mechanism reporting process to understand compliance to Safeguard mechanism baseline. The current bp KRF GHG MP will be made available on the bp website.
Proposed Construction Date	Q1, 2024
Proposed Operation	2026
EMP required pre - construction	Yes ☐ No ☑
Proposed project end of life/ decommissioning date	2046

1 Context, Scope and Purpose

bp Refinery (Kwinana) Pty Ltd (bp) is transitioning its former oil refinery site in Kwinana to an energy hub and proposing to establish a Kwinana Renewable Fuels (KRF) biorefinery (this Proposal). The bp Kwinana Energy Hub is within the Kwinana Industrial Area (KIA), Western Australia (WA). The biorefinery would be capable of processing up to 10,000 barrels per day (b/d) of renewable feedstocks such as vegetable oils, animal fats and other waste products to produce hydrotreated vegetable oil (HVO), synthetic paraffinic kerosene (SPK) and bio-naphtha. These products can be blended with mineral oil to produce renewable diesel and sustainable aviation fuel (SAF). In doing so, the biorefinery would provide a reduced carbon fuel source for hard-to-abate sectors, including heavy industry, aviation, mining, and transport.

1.1 Proponent, Proposal description and scope

1.1.1 Proponent

bp Refinery (Kwinana) Pty Ltd

ACN 008 689 763

Registered address

BP Refinery (Kwinana) Pty Ltd

Lot 18 Mason Road

Kwinana WA 6167

1.1.2 Proposal description and scope

KRF is proposed to produce SAF and renewable diesel on the existing bp Kwinana site using renewable feedstocks (vegetable or seed oils) or waste products such as used cooking oil and tallow. The biorefinery has been developed with a design life of 20 years and is intended to process 10,000 barrels of renewable feedstock per day to produce biofuels. The process will produce up to 1,550 klpd hydrotreated vegetable oil (HVO), 1,300 klpd Synthetic Paraffinic (SPK) and 300 klpd bio-naphtha. The SPK and HVO is then blended with mineral oil to produce the sustainable aviation fuel and renewable diesel.

Production Area	Description of Process
Tankfarm	bp will be repurposing existing tanks in the tankfarm to store renewable feedstocks and products
Pre-Treatment Unit (PTU)	The PTU removes impurities from the renewable feedstock to prevent catalyst poisoning in the downstream units. It is a new build unit and has been designed for a large range of feedstocks with a feed capacity of 10,000 barrels per day
Hydrofiners (HYD2/HYD3)	The existing refinery hydrofiners are being repurposed to convert the renewable feedstock to HVO and SPK
Product Fractionation Unit (PFU)	Hydrocarbon products are separated through distillation and then stored in the tankfarm
Hydrogen Generation Unit (HGU)	Hydrogen is generated by converting the LPG and offgas produced from the hydrotreating process in the steam methane reformer. Natural gas is required for stability.
Bio Digestion Unit (BDU)	Waste streams generated in the PTU are treated here by anaerobic digestion to create biogas and renewable power. A low-pressure flare will be built to flare any biogas in abnormal or process upset scenarios to avoiding venting the biogas
Utilities	The existing utilities will still be used to support the project, including as the Wastewater treatment plant, flare, jetty facilities and the steam generation equipment. A new closed cooling water system will be constructed.

Table 1-1 Biorefinery process units

1.2 Purpose of GHG MP

The purpose of the GHG MP is to detail how bp Kwinana plans to deliver WA's net zero reduction requirements (Government of Western Australia, 2019) for its planned Kwinana Renewable Fuels project. In doing so, this plan will also detail how the project plans to meet the Federal Government's Safeguard Mechanism. bp's Scope 1 and 2 emission reduction targets in line with the proposal to reach net zero by 2050 or sooner.

The bp Kwinana Energy Hub has existing emissions from current site operations. These emissions are excluded from this GHG MP as this plan focuses on the Kwinana Renewable Fuels project.

1.3 bp's net zero strategy

In 2020, bp set out its net zero ambition and its strategy to become an integrated energy company. bp is aiming by 2050 or sooner to get to net zero across its operations for both Scope 1 and Scope 2 emissions. Sustainability has been embedded across the strategy with the development of sustainability targets and aims to focus on reaching net zero, caring for the planet, and its people. bp believes that its ambition and aims, taken together, are consistent with the goals of the Paris Agreement including pursuing efforts to limit temperature rise to 1.5C above pre-industrial levels.

bp's strategy to become an integrated energy company involves:

- decarbonising the energy industry, including reducing emissions from operating sites through technologies or improving efficiencies and scaling up low carbon businesses such as bioenergy
- Investing in low carbon energy to rapidly scale up renewable power, as well as laying foundations for renewable hydrogen production
- Investing in convenience and mobility, growing our electric vehicle networks, and increasing our number of convenience sites

2 GHG EMP Components

2.1 Emission Estimates

The expected GHG emissions for the project are presented in Table 2-1 for Scope 1, Scope 2 and Scope 3 emissions over the phases of the project, construction, commissioning and operation.

Scope	Annual emissions t CO_2 e/year	Total Emissions over Projects life (until net zero at 2050) t CO_2 e	Source
Construction			
Scope 1	10,000	15,000	Diesel fueled vehicles and equipment
Scope 2	0	0	Expect power to be used but majority from diesel fired generators, but it would displace Scope 1 emissions
Scope 3	-	10,036	Emissions associated with steel and concrete manufacture only
Total		**25,036**	
Commissioning			
Scope 1		28,232	Emissions associated with natural gas consumption over estimated energized 5 month commissioning period. Flaring would be expected, but not currently quantifiable. Scope 2 are expected but not quantifiable and would be considered minimal compared to the commissioning Scope 1 emissions.
Total		**28,232**	
Operation			
Scope 1	120,750	2,898,000	Combustion of natural gas in the biorefinery fired furnaces and reboilers and fugitive emissions Maximum Scope 1 emissions are from maximum HVO production
Scope 2	47,021	1,128,504	Power demand is expected to be covered by a green power purchase agreement for the life of biorefinery, hence would result in zero Scope 2 emissions
Scope 3	2,020,981	48,503,544	Refer to section 2.1.2 for breakdown of Scope 3 emissions
Total	**2,188,752**	**52,530,048**	

Biogenic CO_2 emissions	158,000	3,792,000	These are not Scope 1 emissions, but still reportable under NGER scheme Combustion of process offgas and LPG in the HGU and biorefinery fired furnaces Maximum biogenic emissions are from maximum SPK production.

Table 2-1 KRF GHG Emissions

2.1.1 Construction Emissions

The construction of the project is expected to take 18 months and generate mainly Scope 1 GHG emissions related to the combustion of diesel by stationary and mobile equipment. The number of diesel-powered vehicles, cranes, generators, concrete trucks and concrete pumps required for construction was conservatively estimated and then diesel usage data from vehicle manufacturers was used to calculate the volume of diesel used. Calculation methodology was based on emission factors from NGER Measurement Determination ((National Greenhouse and Energy Reporting (Measurement) Determination 2008, 2022) Schedule 1 Part 2 and Part 4 Fuel combustion. Assumptions applied to the calculation include 5 day a week operation for 10 hours a day and at 50% machinery capacity. A total estimate of 15,000 tonnes of CO_2 is expected to be generated as a result of Scope 1 emissions over the 18-month construction period. This accounts for 0.5% of the total Scope 1 emissions expected over the life of this project.

Scope 2 emissions for the construction period are expected to be small as the majority of power is expected to be generated from diesel fueled generators. It is possible that Scope 2 emissions may displace the scope 1 emissions calculated and hence the cumulative emission estimate would not change.

Scope 3 emissions for the construction period are estimated at 10,036 t CO_2e and the significant sources have been identified as the manufacture of the steel and concrete for the structures. An estimate of steel required for the project was based on the volume of steel used in the existing crude oil refining equipment and the emission intensity of 1.83 t CO_2e per tonne steel manufactured was applied (Pandit J, 2020). Concrete volumes were estimated from the existing refining operation foundations and an emission intensity of 272 kg CO_2 e / m^3 concrete manufactured ((Fanttill A.P, 2019).
Emissions associated with transportation of materials to site has been identified as a source of Scope 3 emissions, however difficult to calculate at this point of the project as supplier chains are unknown and there is a high level of uncertainty.

2.1.2 Commissioning Emissions

The energized commissioning of the project is planned to occur over a 5-month period and generate mainly Scope 1 GHG emissions. These are related to natural gas consumption for the following:

- Generation of steam for PTU startup with temporary steam generators
- Reaction products and combustion emissions at the HGU Reformer
- Combustion emissions at the HYD2, HYD3 and PFU Fired Heaters

The natural gas consumptions are derived from the duration of commissioning activities, and required unit capacity at the individual process unit level during these activities from design heat and mass balances. The calculation methodology was based on emission factors for natural gas consumption as per Table 2-4 from NGER Measurement Determination (National Greenhouse and Energy Reporting (Measurement) Determination 2008, 2022).

Unit	Duration (days)	CO_2 tonnes e/ commissioning period
PTU	92	3492.0
HGU	78	22594.1
HYD2	49	15649.2
HYD3	20	1409.2
PFU	19	333.6
		28231.9

Table 2-2 Commissioning Scope 1 estimate

A total estimate of 28,232 tonnes of CO_2 is expected to be generated as a result of Scope 1 emissions over the 5-month energized commissioning period where natural gas will be consumed. This accounts for less than 1 % of the total Scope 1 emissions expected over the life of this project.

This estimate has a high degree of uncertainty as commissioning plans are still being developed. It is also expected that there will be flaring as part of commissioning, however these emissions are not quantifiable at this stage of the project.

There will be power used during this period, but it is difficult to determine the usage at the current stage of the project and would be considered minimal compared to the commissioning Scope 1 emissions.

2.1.3 Operational Emissions

Scope 1 emissions

Scope 1 emissions are generated from the combustion of natural gas, biogas, process gases, fugitive methane emissions and diesel combusted in mobile and stationary vehicles onsite. The breakdown of Scope 1 emissions for the biorefinery are shown in Table 2-3 KRF Scope 1 emissions

bp engaged a third party to carry out a comprehensive review of KRF's GHG Scope 1 and Scope 2 emissions including source data analysis, review of calculation methodology and its adherence to the National Greenhouse and Energy Reporting (NGER) methods and areas of uncertainty.

Emission Source	Estimated Quantity t CO_2 e /annum	Data Source	Measurement Method	Comments/Assumptions
Direct combustion – of natural gas in process	116,795	Natural Gas consumption from design mass and energy balances	Calculation / Schedule 1 Part 2 - Fuel combustion - gaseous fuels of NGER (Measurement) Determination 2008	Natural gas usage is dependent on operating mode and feedstocks. Maximum Scope 1 emissions are from maximum HVO production. Assumes 94% availability
Direct Combustion – Stationary (biogas combusted for electricity generation)	3,712	Biogas generated volume from design mass and energy balances	Calculation / NGER factor applied Schedule 1 Part 2 - Fuel combustion - gaseous fuels of NGER (Measurement) Determination 2008	Includes the methane and nitrous oxide from biogas incomplete combustion. CO_2 emissions from this source are biogenic and not included
Direct combustion – Stationary (offgas and mixed LPG stream combusted in HGU)	93	Offgas and mixed LPG volumes from design mass and energy balances	Calculation / NGER factor applied Schedule 1 Part 2 - Fuel combustion - gaseous fuels of NGER (Measurement) Determination 2008	Includes the methane and nitrous oxide from offgas incomplete combustion. CO_2 emissions from this source are biogenic and not included
Direct combustion – Mobile/Transport Emissions	Not considered for KRF biorefinery (considered under bp Kwinana Energy Hub) bp Kwinana Energy Hub uses approximately 1,500 t CO_2 e /annum of diesel onsite. This number is expected to be unchanged for KRF and hence not included as part of this project			
Feedstock emissions – emissions associated with the use of natural gas as a feedstock	These emissions are considered to be embedded within the product or used for process heat rather than being reported separately. Process heat emissions are included in direct combustion emissions above.			

Fugitive Emissions – includes natural gas, biogas and offgas/mixed LPG stream	151	Estimated from historical bp Kwinana measurements for the crude oil refinery	Estimated from historical bp Kwinana measurements for the crude oil refinery	Fugitive emissions from pipework and fittings containing natural gas, offgas and mixed LPG stream
TOTAL Scope 1 emissions	120,750			

Table 2-3 KRF Scope 1 emissions

The majority of Scope 1 GHG emissions from the biorefinery are generated through the combustion of natural gas. The Scope 1 emissions over the operating life of the project have been estimated at a maximum of 120,750 t CO_2 e /annum without any GHG mitigation. This estimate will form the baseline for the proposal and was based on NGER methodology.

The main sources of GHG direct point source emissions are the combustion heaters and reboilers in the processing units. These sources are:

- Two revamped furnaces HYD2 & HYD3
- Two new furnaces PFU and HGU
- Two new incinerators for electrical generation from biogas
- Reuse existing refinery flare and an additional flare for biogas

The operating emissions presented in Table 2-3 are the maximum emissions bp expects in the future based on maximum HVO production. Different feedstocks have a different hydrogen demand, which then alters the operation of the HGU and the offgas generation. The hydrofiners can run in two operating modes, one to produce maximum HVO (which has the largest natural gas demand and hence represented as the maximum case), and the other maximum SPK. These modes have differing H_2 demands and different GHG emissions. This means that product demand affects the GHG emissions from the biorefinery.

Natural gas for the Proposal will be imported by pipeline through the existing line. When processing the renewable feedstocks, offgas containing light hydrocarbons is generated. The design has been optimised to reuse this offgas as feed for hydrogen production and also as a fuel source for heating. There are two types of CO_2 generated from point sources: black CO_2 (from the combustion of natural gas) and biogenic CO_2 (from the combustion of the offgases from the process). According to the NGER guidelines, biogenic emissions from the combustion of biogas are treated differently from fossil fuel emissions. Combustion of fossil fuels derived from organic matter such as oil and natural gas contributes to greenhouse gas emissions. Biogenic fuels are derived from recently living organic matter, such as plants or agricultural waste and their combustion is considered to be carbon neutral under the NGER scheme. This is because the carbon dioxide released during the combustion is considered to be part of the natural carbon cycle.

Therefore when reporting under NGER scheme, the emissions from the combustion of biogas are significantly less than the combustion of natural gas. A small emission is still counted due to the fact that 100% combustion cannot be assumed. This is done to differentiate them from the emissions associated with fossil fuel combustion, which release carbon that has been sequestered for millions of years and contribute to the increase in atmospheric greenhouse gas concentrations.

Carbon dioxide absorbed by plants during the growth of biomass is roughly equivalent to the amount of carbon dioxide produced when the fuel is burned in a combustion engine, which is simply returned to the atmosphere. When these elements are accounted for, the use of sustainable aviation fuel has been shown to provide significant reductions in overall CO_2 lifecycle emissions compared to fossil fuels, up to 80% in some cases. Furthermore, SAF contains fewer impurities (such as sulphur), which enables an even greater reduction in sulphur dioxide and particulate matter emissions than present technology has achieved. In the case of SAF produced from municipal waste, the environmental gains are derived both from avoiding petroleum use and from the fact that the waste would be otherwise left to decompose in landfill sites, producing no further benefits, rather than being used to power a commercial flight, which would otherwise be powered by fossil-based fuel.

Figure 2-1 shows in detail the process flow of the biorefinery, the combustion sources and the different combustion streams used.

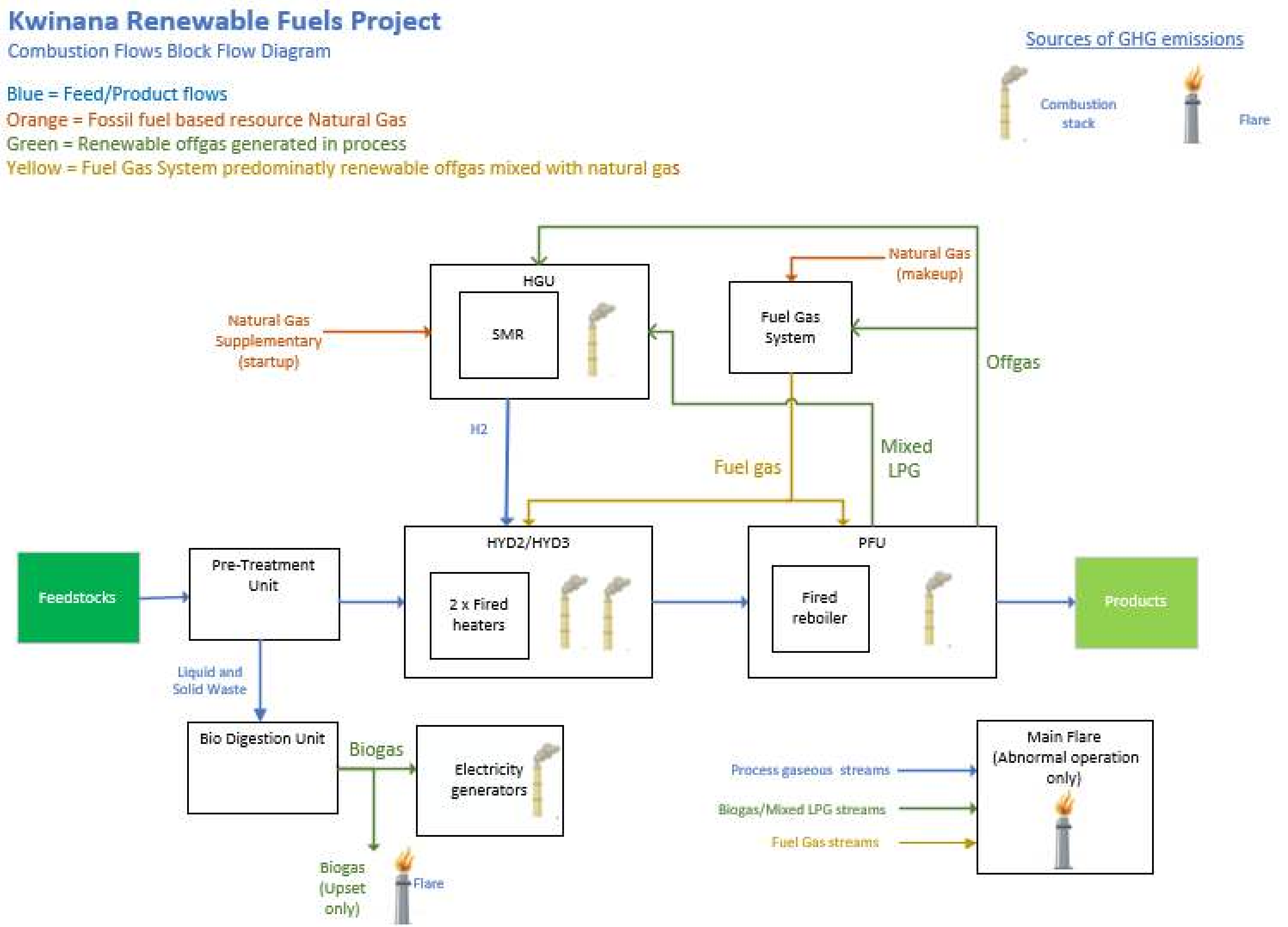

Figure 2-1 KRF Combustion Flows

It is planned that the biogenic CO_2 emissions will be reported under the NGER scheme and separate to Scope 1 emissions (aligned with the reporting requirements of the IPCC reporting guidelines for national inventories and practice). The Scope 1 estimate was calculated using NGER factors from the natural gas and biogas combusted and includes the uncombusted methane and biomethane due to assumed inefficiencies of the combustion sources as per National Greenhouse and Energy Reporting (Measurement) Determination 2008. Refer to Table 2-4. It is estimated that 158,000 t CO_2e/annum will be biogenic emissions.

It is only the CO_2 emission from the combustion of the biogenic gas that is exempt from the Scope 1 calculation. Due to combustion inefficiencies, methane and nitrous dioxide will be emitted and these are included under Scope 1 emissions. The emission factors used for these emissions are from National Greenhouse and Energy Reporting (Measurement) Determination 2008 and represented in Table 2-4.

Fuel combusted	Scope 1 emission factors		
	CO_2	CH_4	N_2O
Natural gas transmitted or distributed in a pipeline	51.4	0.1	0.03
Sludge biogas that is captured for combustion	0.0	6.4	0.03
Biomethane	0.0	0.1	0.03

Table 2-4 Excerpt of Schedule 1 Part 2 - Fuel combustion - gaseous fuels of NGER (Measurement) Determination 2008

Emergency and shutdown scenarios have not been considered as part of the Scope 1 estimate. The flaring system is still being designed and hence reliable data is not known for the calculations. It is expected that in an emergency scenario or shutdown, there would be a short period of very high greenhouse gas emissions followed by a period of very low emissions while the biorefinery is shutdown. It is not expected that these events would raise the emissions over the calculated baseline of 120,750 t CO_2e/annum. It is also noted that most of the emissions in these scenarios are likely to be biogenic and hence not incorporated into scope 1 emissions.

A planned shutdown for maintenance activities will be carried out in a controlled manner which would reduce the amount of flaring required. The current maintenance strategy is to have HYD2 and HYD3 catalyst changes on a two year frequency and larger turnaround events very 6 years. Decommissioning emissions in terms of flaring emissions, would be very similar to a planned shutdown.

Operating the biorefinery at reduced rates or turndown condition is not expected to cause an increase in Scope 1 GHG emissions compared to forecast. These operations may result in lower operational efficiency, in terms of GHG emission per unit of production. Less natural gas would be consumed at turndown condition, resulting in lower Scope 1 emissions.

Scope 1 emissions from the combustion of diesel in stationary and mobile vehicles is expected to be unchanged from the current use onsite and hence not included in this estimate (it is already covered under bp Kwinana energy hub reporting requirements.)

Scope 1 emissions also result from methane fugitive emissions from the natural gas, offgas and biogas pipelines and fittings. The existing crude oil refinery had measured these fugitive emissions as part of the previous Part V licence and had also used the results for previous crude oil refinery NGER reporting and these estimates were applied to this project. It has been estimated that approximately 5.6 tonnes per annum (157 t CO_2 e / annum) of fugitive methane emissions will result from the biorefinery. This estimate is considered conservative as the biorefinery is on a smaller scale than the crude oil refinery. Once operational, direct monitoring methods such as gas detection monitoring may be used to provide an accurate estimate of methane leakage to report under NGER scheme. The estimates and how they were applied to the biorefinery are represented in Table 2-5.

Source	Direct measurement Methane tonnes/year	t CO_2e per annum (CH_4 global warming factor of 28)
Crude Oil Refining		
Natural Gas pipework	2.1	58.8
Refinery Fuel Gas Pipework	1.4	39.2
Biorefinery estimates		
Natural gas pipework	2.1	58.8
Mixed Fuel System	1.4	39.2
Biogas system	2.1	58.8
		156.8 TOTAL

Table 2-5 Fugitive emissions methodology

A third party GHG consultant completed an exercise on how to estimate fugitive emissions when pipe details were still unknown and could only find general assumptions on percentage of fugitives from total volume of gas processed in a typical gas plant. This operation is considerably different to the biorefinery operation and bp assumed that actual plant data would be more representative of biorefinery fugitive emissions.

Scope 2 emissions

Scope 2 operational emissions are estimated to be 47,021 t CO_2 e /annum for the biorefinery and 1,128,504t CO_2 e /annum for the life of the project until net zero at 2050 without any GHG mitigation. Power demand was estimated conservatively at the design maximum of 14 MW per day, biorefinery availability of 94% and daily power demand of 80%. The maximum power demand assuming 100% availability and 100% daily demand is 62,546 t CO_2 e /annum. The emission factor of 0.51 kg CO_2 e/annum for the South West Interconnected System (SWIS) from NGER Measurement Determination 2022-2023 emission factor was applied.

The anaerobic digestor in the BDU will generate biogas which will be burnt in gas engines generating approximately 2.3 MW of power for the site and offsetting approximately 10,200 t CO_2 e / annum (Table 2-6).

	Power generated (kwh/year)	CO_2 offset t CO_2 e /annum
BDU gas engines	20,000,000	10,200

Table 2-6 CO_2 Offset from onsite power generation

The resulting power demand of 72,198,400 kwh/year (36,821 t CO_2 e/annum) will be required from Western Australia's main electricity network, the South West Interconnected System (SWIS) grid. bp Kwinana plans to source a green power purchase agreement for the biorefinery to ensure that this external electricity demand is from a renewable power source. Hence it is expected that the Scope 2 emissions associated with this project will be zero over the life of the biorefinery.

Scope 3 emissions

The biorefinery will produce a low carbon fuel for transportation that is essential to support Scope 3 reductions globally. The products from the biorefinery will have a lower carbon intensity than traditional fossil refined products, with the potential to reduce the lifecycle emissions by up to 80% relative to fossil fuels. This will enable our customers to further reduce their Scope 1 emissions. Scope 3 emissions are expected both domestically and internationally through imported feedstocks and ability to supply biofuels to both the Australian and international markets.

bp has conducted an analysis of potential operational Scope 3 emissions against the fifteen Scope 3 categories from the *GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard.* These categories were considered in terms of significance, size and how reasonably they can be quantified. bp acknowledges that as several supply chains are in the process of being defined, the Scope 3 emissions are estimates only and will be refined as the project progresses. It is expected that an independent consultant will verify Scope 3 estimates and calculation methodology once more data is known. Summary of the significant Scope 3 emissions for the biorefinery based on expected feedstocks for the first year of operation is in Table 2-7.

Scope 3 source	Total t CO_2 e/annum	Emission factor / methodology used
Feedstock Production and Conditioning	74,993	JEC methodology
Upstream biofeeds processing	41,906	JEC methodology
Upstream biofeed shipping	40,000	JEC methodology
Upstream Natural Gas processing and distribution	9,720	2022 NGA Factors workbook
Downstream product shipping	110,000	IMO GHG Study
Distribution and Dispensing at Retail sites	24,899	JEC methodology
Combustion of Final Product	1,719,463	Industry standard emission factors
TOTAL	2,020,981	

Table 2-7 Breakdown of Scope 3 emissions

Summary of the GHG Protocol Scope 3 categories considered in this estimate are below;

1. Purchased goods and services - These are the emissions associated with the extraction, production and transportation of goods and services purchased or acquired by bp Kwinana in the reporting year. It would represent all the emissions for cultivation, processing and transportation of the bio feedstocks and production and transportation of chemicals used in the biorefinery. Scope 3 emissions vary for the feedstocks, depending on what upstream processing is required. For example, seed oils will produce emissions from cultivating the crop, harvesting and drying to processing into a vegetable oil. The JEC consortium (Prussi, 2020) provides evaluation of well to wheels energy use and GHG emissions for a range of fuel options. This methodology was used to calculate the 'well to tank' Scope 3 emissions and ranges from zero for UCO to approximately 60,000 t CO_2 e/annum for canola oil. Table 2-7 shows the emissions for the typical feedstock blend expected in the first year of operation. Natural gas is supplied by the existing Dampier Bunbury pipeline and it is currently in operation for the terminal operations. Natural gas exploration, processing and distribution emissions have been estimated using emission factors from Australian National Greenhouse Account Factors. This category will also include chemical manufacture when supplier chains are known.
2. Capital Goods - These are the emissions associated with the extraction, production and transportation of capital goods purchased or acquired by bp Kwinana in the reporting year. Once in production, the purchase of capital goods is expected to be small and hence this category of Scope 3 emissions is deemed insignificant for operations at this stage of the project.

3. Fuel and Energy related activities (not included in Scope 1 or Scope 2) – These are emissions associated with the extraction, production and transportation of fuels and energy.
    a. Upstream emissions of the extraction, production and transportation of energy and fuel for the biorefinery include natural gas and diesel. Natural gas emissions have been calculated under Purchased goods and services above. Diesel is used in mobile equipment and vehicles onsite. The combustion of these fuels is already captured as a Scope 1 emission. The diesel is supplied by the import terminal and will have associated emissions from the shipping process. However, the diesel usage is unexpected to change as a result of this project and considered to be insignificant at this stage of the project.
    b. Upstream emissions associated with purchased electricity – there will be Scope 3 emissions associated with generation of the electricity offsite. All cooling and heating is produced onsite, so emissions associated with these are already accounted for under Scope 1 and 2 emissions. These emissions are deemed insignificant at this stage of the project.
    c. Transmission and distribution losses – accounts for the emissions associated with the generation of electricity that are lost in the transmission and distribution system. These emissions are deemed insignificant at this stage of the project compared to the other categories.
4. Upstream transportation and distribution – emissions associated with transportation and distribution of the feedstocks and chemicals for the biorefinery. Initially it is expected that the bio feedstocks will be both sourced locally and imported from South East Asia, however the biorefinery has been designed for a vast range of feedstocks which maybe sourced from all over the world Shipping estimates were calculated using emission factors from International Marine Organisation (IMO) GHG study.
5. Waste generated in operations – emissions associated with disposal of waste generated in the biorefinery. The most significant waste stream generated in the biorefinery is the sludge waste from the BDU. Due to the high level of uncertainty this value is not included in the Scope 3 estimate and these emissions will be included when there is sufficient definition on the values.
6. Business Travel – emissions resulting from transportation of employees for business purposes is not quantifiable at this stage of the project, but deemed to be minimal.
7. Employee commuting – emissions resulting from transportation of employees from their place of residence to bp Kwinana is not quantifiable at this stage of the project but deemed to be minimal.
8. Upstream Leased Assets – bp doesn't expect to lease any upstream assets, hence emissions associated with leased assets would be zero.
9. Transportation and distribution of sold products – these are GHG emissions associated with transportation and distribution of the biorefinery products. There are three products associated with the biorefinery, HVO, SPK and bionaphtha. Some product will be pumped via the existing pipeline to the Kewdale Terminal. Electric pumps transfer the biofuel, hence this energy is captured under Scope 2 emissions. It is expected that the remaining product will be shipped domestically and internationally. Shipping estimates were calculated using emission factors from International Marine Organisation (IMO) GHG study.
10. Processing of sold products – of the products manufactured at the biorefinery, only the bionaphtha is expected to undergo further processing as part of the plastic

industry. Once the plastic manufacturing details are known for the bio naphtha, then these emissions can be estimated.

11. Use of sold products – The biofuels will be exported domestically and internationally for combustion in the aviation industry and road transport industry. The biofuel can be blended with mineral oil to meet the blended ratio specified by the customer. Once blended, the biofuel will combust into biogenic CO_2 (from the SPK or HVO component) and black CO_2 (from the mineral oil component). GHG emissions associated with the combustion of the blended biofuels has been estimated using industry standard emission factors of diesel and aviation fuel.
12. End of Life treatment of sold products – The combustion of the biofuels is the end of life for those products and emissions associated with this are captured under Category 11 Use of sold products. The final disposal of the plastic produced from the bionaptha is unknown at this stage of the project.
13. Downstream leased assets – bp doesn't expect to lease any downstream assets, hence emissions associated with leased assets would be zero.
14. Franchises – bp doesn't predict there will be any relevant franchise arrangements as part of this proposal.
15. Investments – bp doesn't expect that the proposal will result in any downstream investments.

Breakdown of material Emissions by proposal source

Kwinana Renewable Fuels Facility (ABN: 54008689763) does not intend to use the Organisation Standard methodology by Climate Active to claim carbon neutrality or to seek a carbon neutral certification. However, the methodology will be used as best practice guidance to validate and report emissions that occur because of the operation of Kwinana Renewable Fuels Facility.

For the purpose of the Kwinana Renewable Fuels Facility (ABN: 54008689763) an emission boundary is established using the Cradle-to-Grave lifecycle assessment principle. This implies that the emission boundary will extend from the moment biogenic feedstocks are cultivated and gathered till the biogenic fuel source is ultimately combusted by the consumer. Waste processing of by-products is also considered under this definition. The Cradle-to-Grave lifecycle principle was selected as it describes the complete environmental footprint of products produced, this enables efficient and effective decarbonization of key lifecycle steps.

The control approach was utilized to determine which emissions were considered to under direct control of Kwinana Renewable Fuels Facility. The Operational Control definition was selected for this definition as it is the most utilized and recommended method. Under this definition Kwinana Renewable Fuels will report 100% of the operations which it has "the full authority to introduce and implement its own operating policies".

As Kwinana Renewable Fuels Facility is expected to commence operation in Q2 2026, the operational period between Q2 2026 to Q2 2027 is set as the base year. As the base year selected for Kwinana Renewable Fuels is in the future, all estimated data used is representative of projected emissions.

Scope 1 Emission Description	Annual Emission Quantity tCO_2e	% Total Scope 1 Emissions	Materiality	Direct ownership	Quantified
Stationary Combustion (Natural Gas)	116,795	96.72%	Yes	Yes	Yes
Stationary Combustion (Bio Methane)	3,804	3.15%	Yes	Yes	Yes
Fugitive Emissions	151	0.13%	No	Yes	Yes
Total Scope 1 Emissions	120,750	100%	-	-	Yes
Emissions not occurring in Base Year					
Construction Related Emissions	10,000	-	Yes	No	Yes
Commissioning Related Emissions	28,232		Yes	Yes	Yes
Scope 2 Emission Description	**Annual Emission Quantity tCO_2e**	**% Total Scope 2 Emissions**	**Materiality**	**Direct ownership**	**Quantified**
Renewable Power Purchase Agreement	47,021	100%	Yes	Yes	Yes
Total Scope 2 Emissions	47,021	100%	-	-	Yes
Scope 3 Emission Description	**Annual Emission Quantity tCO_2e**	**% Total Scope 3 Emissions**	**Materiality**	**Direct ownership**	**Quantified**
Feedstock Production & Conditioning	74,993	3.71%	Yes	No	Yes
Feedstock Processing & Extraction	41,906	2.07%	Yes	No	Yes
Feedstock Transport	40,000	1.98%	Yes	No	Yes
Upstream Natural gas processing and distribution	9,720	0.48%	No	No	Yes
Production Conditioning & Distribution	24,899	1.23%	Yes	Yes	Yes
Downstream product shipping	110,000	5.44%	Yes	No	Yes
Combustion of Final Product	1,719,463	85.08%	Yes	No	Yes
Total Scope 3 Emissions	2,020,981	100%	-	-	Yes
Emissions not occurring in Base Year					
Construction Materials	10,036	-	No	No	Yes

Table 2-8 Materiality of Emissions by source

Table 2-9 outlines emission sources that have not been quantified for the Kwinana Renewable Fuels Facility in the base year and the justification behind this decision.

Emission Description	Scope of Emission	Materiality	Direct Ownership	Justification for unquantified Status
Employee Travel and Commuting	3	No	Yes	Lack of Accurate Information
Waste-water Treatment	3	No	No	3rd Party Operational Control
Solid Waste Treatment	3	No	Yes/no	Solution Dependent
Diesel Combustion for onsite Transport Energy	1	No	Yes	1,500 tCO2e considered under Kwinana Energy Hub
Office Equipment	3	No	No	Immaterial Emission level
Feedstock Land Management Change	3	Yes	No	3rd Party Operational Control
Blending of Sold Products	3	Yes	Yes/no	Solution Dependent
Power for Facility Construction	2	Yes	No	3rd Party Operational Control
Non-Combusted Final Product Use	3	Yes	No	Bio-Naphtha is not combusted

Table 2-9 Unquantifiable Known emissions

Emissions from Existing Operations

The bp Kwinana Energy Hub currently emits CO_2 through its operation of a fuel import terminal and through work onsite in support of its transition. Previously, bp Kwinana operated as a crude oil refinery and reported GHG emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER Act). The safeguarding baseline was 739,256 t CO_2e/annum. In 2021, the crude oil refinery was shut down and steam boilers were installed to provide steam supply to the import terminal. Annual GHG emissions have still been reported through NGERs.

The two main sources of Scope 1 emissions associated with current operation result from natural gas combustion in the steam boilers and diesel use in stationary and mobile equipment onsite. In the 2022 calendar reporting year, bp Kwinana Energy Hub's Scope 1 emissions were 23,505 t CO_2e and Scope 2 emissions were 17,065 t CO_2e and were considered higher than normal due to decommissioning activities, Table 2-10. Expected emissions going forward are 7,000 t CO_2 e/annum from natural gas combustion and 1,500 t CO_2 e/annum from diesel combustion in stationary and mobile equipment. These emissions are ongoing and this project's emissions will be in addition to those for bp Kwinana Energy Hub.

	Source	t CO_2 e / annum
Scope 1 emissions	Steam generation and diesel use	23,505
Scope 2 emissions	Power	17,065
	TOTAL	40,569

Table 2-10 2022 Existing bp Kwinana Energy Hub GHG emissions

2.2 Trajectory of Emission reduction

bp is committed to its strategy and requirements from the EPA greenhouse gas guidelines to reach net zero for the Proposal by 2050. bp has defined the Scope 1 baseline at 120,750 t CO_2e/annum as defined in Section 2.1.3.

In line with the State GHG emissions policy for Major Projects, long term and interim reduction goals have been developed for the project.

bp shall take measures to ensure that Cumulative Scope 1 GHG Emissions do not exceed:

(a) A cumulative scope 1 emissions of 531,300 tCO_{2}-e for the period until 30th June 2030;

(b) A cumulative scope 1 emissions of 410,550 tCO_{2}-e for the period between 1st July 2030 and 30th June 2035;

(c) A cumulative scope 1 emissions of 289,800 tCO_{2}-e for the period between 1st July 2035 and 30th June 2040;

(d) A cumulative scope 1 emissions of 169,050 tCO_{2}-e for the period between 1st July 2040 and 30th June 2045;

(e) A cumulative scope 1 emissions of 48,300 tCO_{2}-e for the period between 1st July 2045 and 30th June 2050;

These targets are represented in Table 2-11 including the mitigation measures that bp are expecting to undertake to meet the proposed targets. These are further discussed in Section 2.4.

Period	End of Period Annual Emission Target (tCO_{2}-e)	Cumulative Scope 1 Emissions (tCO_{2}-e)	Reduction from Baseline (%)	Mitigation Measures
1st July 2026 – 1st July 2030	99,600	531,300	-	Starting Baseline of 120,750 t CO_2e/annum
1st July 2030 – 1st July 2035	72,450	410,550	20	Green Hydrogen as Feed
1st July 2035 – 1st July 2040	48,300	289,800	40	Green Hydrogen as Fuel, Biogas substitution for natural gas
1st July 2040 – 1st July 2045	24,150	169,050	60	Green Hydrogen, Electrification,
1st July 2045 – 1st July 2050	0	48,300	80	Green Hydrogen, Electrification, CCS
2050 onwards	0	0	100	Green Hydrogen, Electrification, CCS

Table 2-11 Emission Reduction Targets and Possible Mitigation measures

Figure 2-2 and Figure 2-3 displays the annual emissions and cumulative emissions over the project life including the emission reduction by 2050, if the proposed reduction targets are met. This is based on the EPA WA GHG guidance minimal expectations of a linear trajectory to net zero by 2050 or sooner. Section 2.3 outlines the emission reduction strategy and technologies that will be explored by bp to meet the GHG reduction targets.

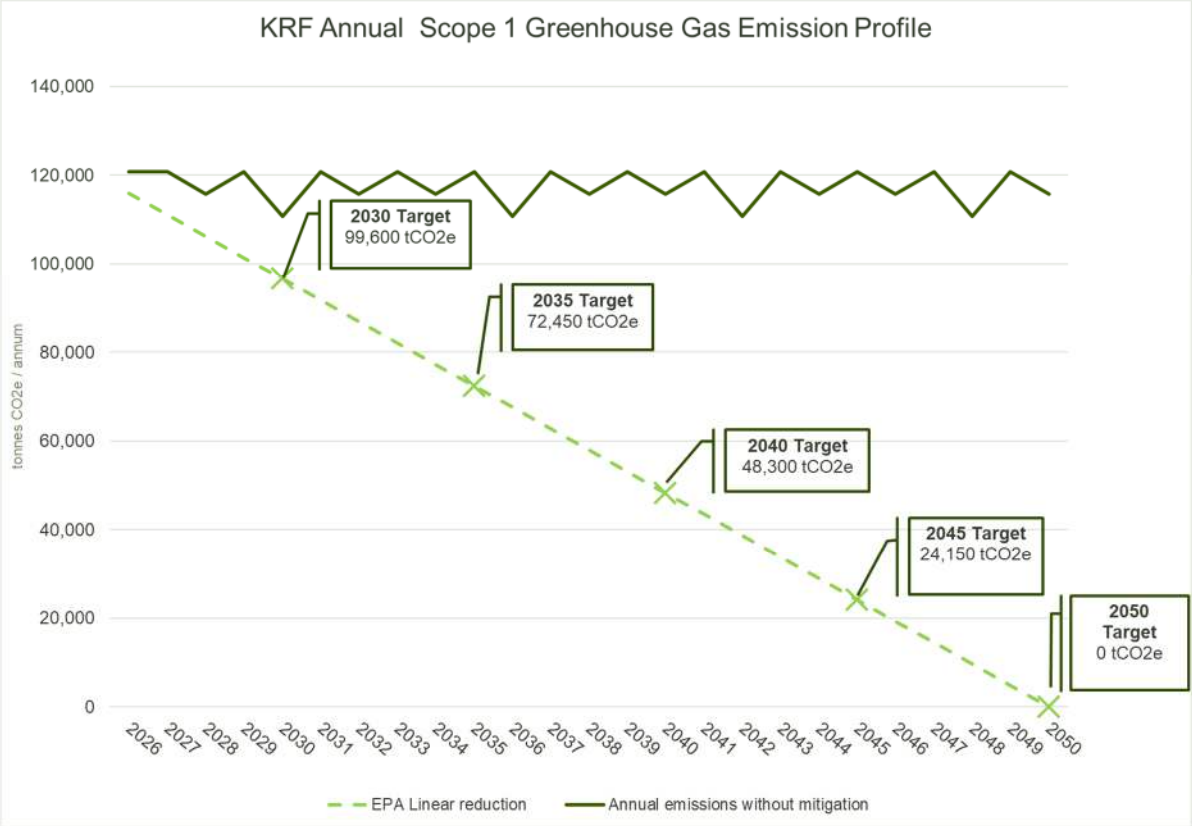

Figure 2-2 Scope 1 emissions forecast

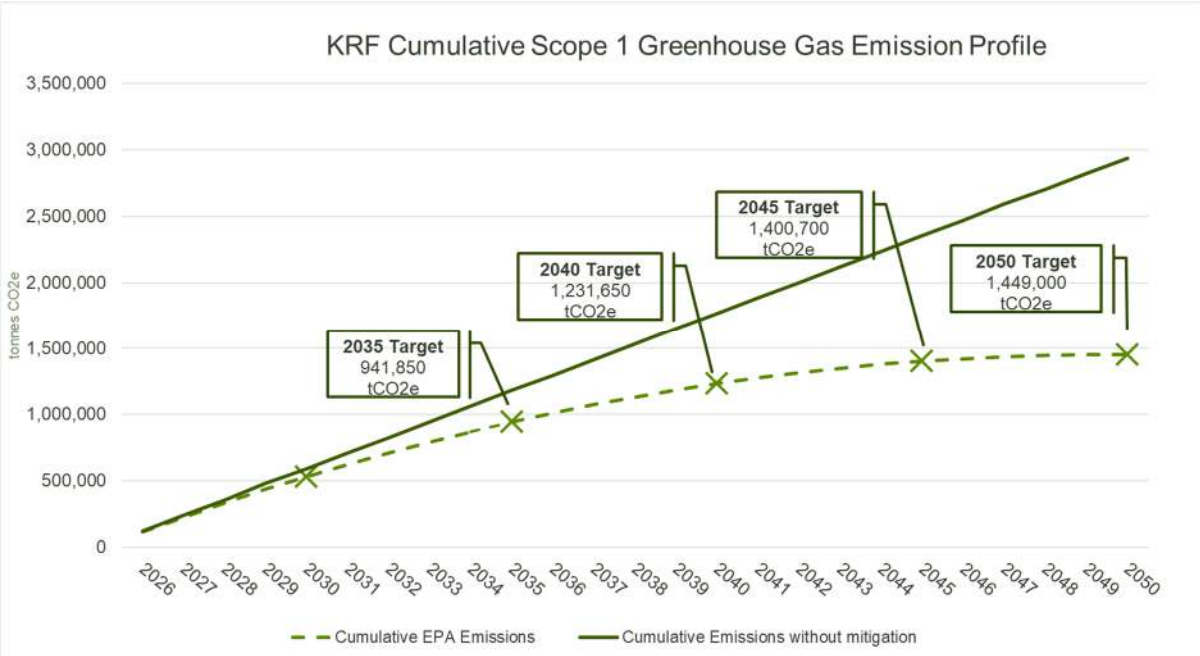

Figure 2-3 Cumulative Scope 1 emission forecast

bp acknowledges that the forecast trajectory of emissions is likely to change under the Safeguard Mechanism Reforms. It is expected that the trajectory to 2030 will follow the safeguard reduction as it is more stringent than the linear trajectory. bp will align the trajectory to the legislation that is the most stringent, keeping up with latest Safeguard advice to ensure compliance to both EPA guidance and Safeguard.

Figure 2-4 shows the Scope 2 annual emission forecast for the project. No reduction targets are required for the Scope 2 emissions, as the strategy is to secure a green power purchase agreement from commencement of operations, to ensure all power used at the biorefinery is from a renewable source. No other Scope 2 emissions have been identified. Hence the cumulative mitigated emissions (with the power purchase agreement for the biorefinery in place) show that the Scope 2 emissions over the life of the project will be zero.

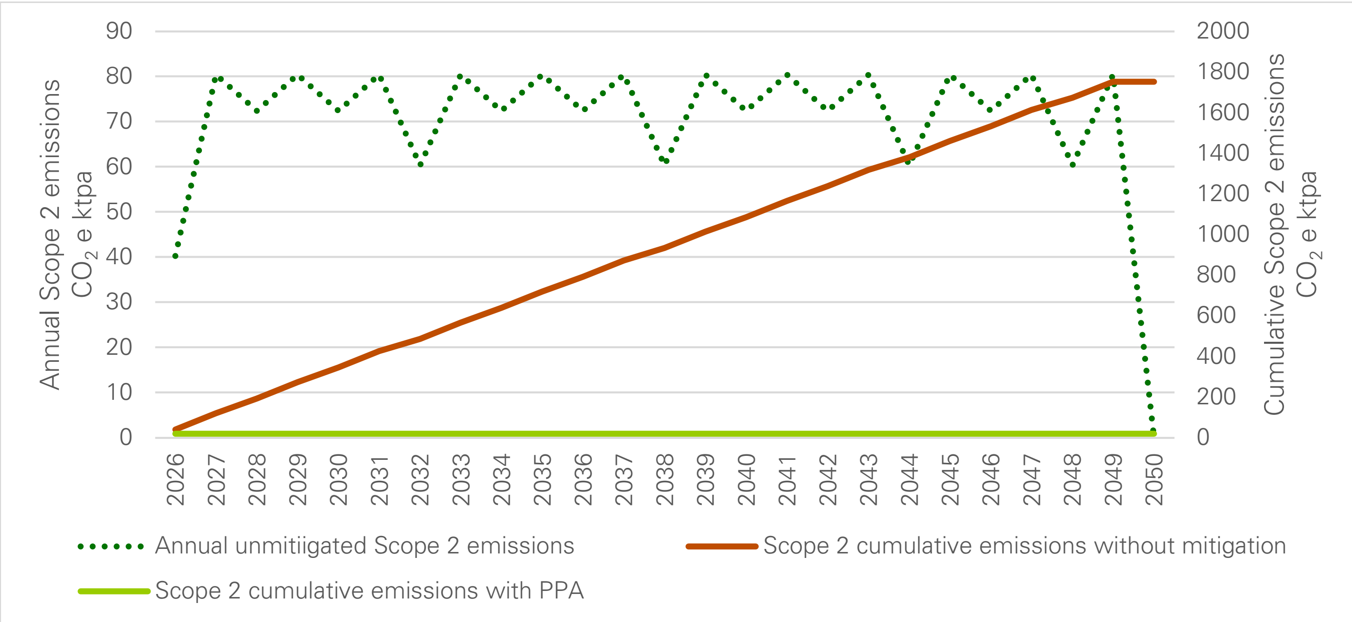

Figure 2-4 Scope 2 emission forecast

2.3 Mitigation measures adopted to avoid, reduce or offset Scope 1, 2 and 3 emissions

bp has identified a range of emission reduction opportunities as part of the design of the project that is aligned to the EPA's mitigation hierarchy – avoid, reduce or mitigate and seeks to demonstrate that all reasonable and economically viable measures have been explored and applied.

The EPA mitigation strategy will be adopted in the development of the Management Plan in the following order:

- Avoidance – Biorefinery operations designed to avoid emissions where possible
- Reduction – Progressive reduction in emissions over life of operations such that a net carbon zero emission is achieved by 2050

- Offset – Should avoidance and reduction not be possible, bp will propose an offset strategy to offset the residual emissions.

bp has designed the biorefinery with greenhouse gas emissions as low as possible through engineering measures, reuse of existing industrial plot and redundant equipment where possible. Table 2-12 indicates the details and approximate emission reductions from the carbon reduction initiatives and technologies implemented by bp.

Design consideration	Discussion	Estimated indicative CO_2 e mitigated per annum
Location of Project	This project was designed for the existing bp Kwinana site acknowledging the lower environmental impact (including GHG emissions) related to • Existing site in industrial area. No clearing required for the project site • Elimination of export transport emissions as Kwinana site has a direct pipeline to Perth Airport • Reuse of existing refinery equipment and utilities such as supply pipework for natural gas and water	• Lower GHG emissions from transportation using existing pipeline compared to shipping or road exports *(Scope 3 avoidance ≈ 1675 t CO_2 e/annum)* • No clearing required of 9.4 hectares avoiding Scope 1 emissions from diesel operated equipment and Scope 2 emissions from waste transport offsite • Reuse of existing refinery equipment reducing the Scope 1, 2 and 3 emissions that would arise from manufacturing, transportation and installation costs associated with new infrastructure *(Scope 3 avoidance ≈ 1830 t CO_2 e/annum) for steel manufacture)* • Lower indirect transport emissions as the project can utilize various synergies and existing pipelines in the Kwinana Industry area (reducing Scope 3 emissions)
Design Elements	Hydrogen Generation Unit (HGU) will be the largest carbon dioxide emitter in the facility and has been designed taking into account GHG reduction technologies. The offgas generated as	• HYD2 fired heater only required on startup as preheats the feed utilising the exothermic heat of reaction *(Scope 1 avoidance ≈ 14,366 t CO_2 e/annum)*

	part of the process has been incorporated into the design as a feedstock for hydrogen generation. The project is designed to recover waste heat where possible to reduce natural gas requirements and generate steam for use in the biorefinery	• PFU hot recycle to HYD3 minimises heating requirements for cracking reactor and eliminates the requirement for a combustion heater (*Scope 1 avoidance ≈ 11,800 t CO_2 e/annum*) • HGU High Temperature Shift reactor selected over a Medium temperature shift reactor as it generated lower CO2 emissions, *(Scope 1 avoidance ≈ 200 t CO_2 e/annum)* • Counter current heat exchanger network for energy recovery and to minimise reboiler requirements (*Scope 1 avoidance ≈ 17500 t CO_2 e/annum*) • Designed for no flaring during normal operation.
Choice of best available technology and equipment	The project has chosen the best available technology and equipment to ensure emissions are as low as possible and maintained to ensure efficiency	• Burner control systems bp's mandated furnace requirements lowers excess O2 in burners *(Scope 1 avoidance ≈ 60 t CO_2 e/annum)* • Air preheaters on PFU and HYD3 *(Scope 1 avoidance ≈ 2400 t CO_2 e/annum)* • Insulation and Refractory, heat tracing to eliminate heat loss *(Scope 1 avoidance ≈ 8000 t CO_2 e/annum)*

Table 2-12 KRF GHG emission design avoidance strategy

2.4 Mitigation measures adopted to avoid, reduce or offset Scope 1 emissions

The project is fundamentally about decarbonizing greenhouse gas emissions related to transport, however bp have also considered how to further avoid or reduce Scope 1 emissions through the design of the biorefinery.

The hydrogen generation is the largest single contributor to greenhouse gas emissions in renewable fuels production. Figure 2-5 displays visually the different hydrogen generation options considered by bp for this project.

Assessment of the relative carbon footprints was a key consideration in selection of the hydrogen production pathway for delivering business and project objectives. Comparative life cycle assessment of these pathways led to the following high-level conclusions regarding carbon emissions:

- Direct CO_2 emissions (reaction emissions and emissions related to combustion of natural gas) is the largest contributing factor towards carbon footprint.
- Green hydrogen (from electrolysis) has the greatest potential for reducing direct CO_2 emissions, although in the case of KRF was determined to not be commercially viable for 100% of facility demand.
- Hydrogen production pathways that utilise the heavier renewable hydrocarbon feedstock produced in the KRF facility, such as a naphtha reformer, will generally have higher direct CO_2 emissions, as the feedstock has a higher C:H ratio compared to the lighter products.
- Lower direct CO_2 emissions may be expected with the application of pure oxygen in the Partial Oxidation (POX) process to limit CO_2 generation for a given feed slate. However, the requirement for an Air Separation Unit (ASU) or other oxygen production system, and associated electricity usage for plant operation and compression, is a significant contributor to the carbon footprint of this pathway.
- The carbon footprint associated with hydrogen production via Steam Methane Reforming (SMR) was hence determined to be comparable with POX process (Aliyu, 2022).
- Opportunity for (over-the-fence) hydrogen import from a third party was not available to KRF.

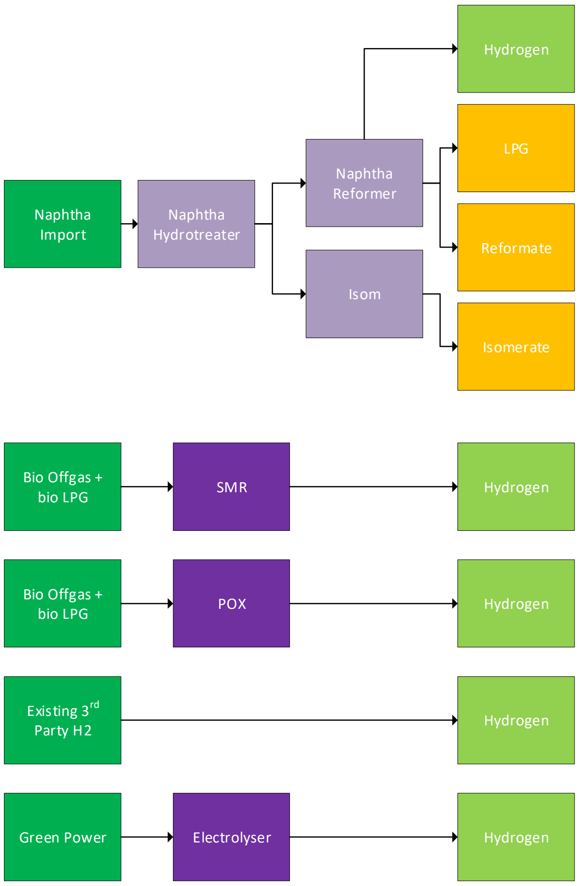

Figure 2-5 Hydrogen Generation Technology Selection Options

Technology evaluation on these options focused on technology readiness, health safety and environmental aspects, commercial feasibility, and ability to manage waste off gases minimizing flaring. The project team selected steam methane reforming (SMR) as the hydrogen generation technology because;

- Carbon footprint was lower than several options and comparable to POX process that could have additional power requirements
- It could take the offgas streams and combust them, reducing the requirement for routine flaring in line with bp strategy and also world no flaring policies. The flare will only be required for process or safety upsets and not for normal operation
- It was proven technology and able to meet project schedule, proven safety record and commercially feasible.
- The SMR has functionality to produce steam as a byproduct, reducing the natural gas requirement for the biorefinery and producing steam with a much lower carbon intensity compared to fossil fuel steam.

Following selection of steam methane reforming technology, this provision was competitively bid across multiple licensors in accordance with the technology acquisition strategy. Hydrogen production via SMR is a well-established and commercially available technology, with all licensors in the bid evaluation process having supplied more than 20 licensed units operating at similar capacities to KRF since 2000.

Energy efficiency was a key metric for evaluation of offers at the proposal stage. It may be noted that steam methane reforming is a mature and well understood process flowscheme, and licensors offer flow schemes that are already heavily optimised to maximise energy efficiency and minimise the use of feed and fuel. The differential in GHG impact between licensor flow schemes was observed to be limited and all offers were closely matched for this metric. The selected licensor were differentiated in their intellectual property (IP) for reformer burners and reformed gas waste heat boiler design, improving assurance that the unit will have the full capacity to utilize the renewable offgases., whilst meeting best practice in NOx emissions.

The HGU design incorporates the use of the offgas and LPG generated from the PFU as a feed and a fuel to the biorefinery. This offgas consists of hydrogen, lighter hydrocarbons and carbon dioxide but can vary in composition depending on which product the biorefinery is producing (SAF or HVO). By using the offgas as a substitute to natural gas, the biorefinery's natural gas demand is reduced significantly, by approximately 158,000 CO_2 e tonnes / annum (the biogenic GHG emissions).

Green hydrogen was identified as the option with the smallest carbon footprint and considered as part of the technology evaluation but was not deemed feasible as;

- Not commercially viable for 100% of supply
- Does not integrate with waste off gases or steam supply.
- Technology readiness lower than the desired scale.
- Meet the desired project schedule

Green H2 is a clear opportunity to further reduce Scope 1 emissions and so the HGU has been designed to be able to take green hydrogen and for lower production rates. bp is currently progressing a green hydrogen project for the Kwinana site (H2Kwinana) which will allow green hydrogen to be used directly at the hydrofiners for the biorefinery.

The existing infrastructure associated with the Hydrofiners was designed to be reused as part of the project basis. Compared to a new build hydroprocessing unit, this reduces both capital cost as well as lifecycle carbon emissions associated with manufacture, transportation, installation and construction of a new facility.

All technology provision was competitively bid across multiple licensors in accordance with the technology acquisition strategy. This includes assessing several criteria including energy efficiency to ensure the project is assessing best and leading practice relating to GHG management across the licensors. For the Hydrofiners, this meant that the licensor had a focus on a high yield with a lower loss of light hydrocarbons. Catalyst selection has been an important factor to minimize competing reactions that cause an increase in carbon monoxide and carbon dioxide through the biorefinery.

Heat is required for the process and fired heaters and reboilers will be required that will burn either offgas or natural gas. The design of these has taken into account several opportunities to further reduce emissions (refer to Table 2-12 such as:

- Utilising exothermic heat of reaction or waste heat to preheat streams
- Extensive counter current heat exchanger network for energy recovery
- PFU hot recycle stream to HYD3 minimizes heating requirement for cracking reactor and eliminates need for a combustion heater
- Burner systems and layouts to include air preheaters and bp mandated furnace requirements to lower natural gas requirements

Pumps and compressors have been designed to run on electricity rather than fuel powered, to reduce scope 1 emissions. Insulation and refractory prevent heat loss to the atmosphere and reduce the amount of heating required.

bp will explore different options and technologies to further lower the operating GHG emissions over the life of the biorefinery. Installing and implementing these options will be subject to understanding the feasibility, practicality, and commercial viability of the mitigations. Table 2-13 demonstrates the options that bp is exploring to further lower emissions. The largest source of Scope 1 GHG emissions is the combustion of natural gas as a fuel for heating and also for hydrogen production, so options to substitute out the natural gas are being considered.

bp is currently progressing a green hydrogen project for the Kwinana site (H2Kwinana) which will allow green hydrogen to be used directly at the hydrofiners for the biorefinery. The use of green hydrogen as it becomes available would reduce the CO_2 emissions from the facility in two Stages.

- Stage 1: Enable a reduction in the required hydrogen production via the Steam Methane Reforming pathway to meet biorefinery demand, and therefore lower emissions from the SMR.
- Stage 2: Further decarbonise fuel gas (combustion heat) by substituting natural gas for hydrogen as combustion heat source.

This project will be phased, potentially providing GHG reductions up to 47,000 t CO_2 e/ annum through HGU turn down by substituting out natural gas. The HGU will be operated at lower throughput with green H2 but will remain online as it is required for managing the biogenic offgases and also steam production for the biorefinery. Once green hydrogen is available to the site, than it can be explored to further decarbonize fuel gas by substituting natural gas for hydrogen in the combustion sources.

It will also be explored the possibility and feasibility of using the biogas as a substitute for natural gas in the fuel gas system, rather than use it for electricity. Approximately 1,200 kg/h of biogenic biogas could backout natural gas, reducing the Scope 1 emissions generated.

bp has explored the feasibility of a Carbon Capture Unit (CCU) for the project, but with no sales outlet or sequestration facility, it is not currently economical to pursue further. The HGU has been designed with the capacity to tie in a CCU when it may be feasible to do so. Another option that may be feasible in the future is using the waste CO_2 streams to manufacture eFuels, as an additional strategy to further decarbonize products for customers in hard-to-abate sectors.

Design consideration	Description	Estimated indicative CO_2 e mitigated per annum
Energy Efficiencies	Energy efficiency monitoring over the operation to ensure performance and consideration of measures to reduce emissions intensity over time	≈ 3,000
Green H_2 to reduce fossil based feed (Natural Gas) to HGU for H_2 production	bp is investigating producing green H2 at the bp Kwinana Energy Hub. This green H_2 could be fed directly to the HYD2 and HYD3 units, reducing the hydrogen production requirement at the HGU. The HGU has been designed for turndown to import green H_2.	≈ 47,000
Biogas	Utilising the biogas from the BDU as a substitute for natural gas	≈ 36,000

	Assuming 100% GHG saving per biogas molecule.	
Green H_2 as fuel gas	The natural gas used for fuel in the fuel gas system could be substituted for green H_2 produced by renewable energy to further lower our GHG emissions. Amount of Green H2 substitution related to the amount of biogas produced / procured. On an energy equivalent basis with natural gas.	≈ 11,000
Electric Heating on tanks and pipework	Substituting steam pipe tracing and heating systems to electric, powered by renewable source. Based reduction in steam production and associated Scope 1 or 2 emissions.	≈ 20,000
Carbon Capture Unit	The KRF design includes future installation of a CO_2 removal system on the HGU. Due to lack of sales outlet or CO_2 sequestration facility, it is currently not economical to pursue further, but bp will continue to explore this possibility	TBD

Table 2-13 KRF Biorefinery Scope 1 GHG emission reduction strategy

2.5 Mitigation measures adopted to avoid, reduce or offset Scope 2 emissions

Scope 2 emissions for the biorefinery result from power generation. Approximately 2.3 MW of electricity will be generated onsite by biogas driven generators, however the remaining 12MW will be required from the South West Interconnected System. To reduce our Scope 2 emissions, a green power purchase agreement will be in place from project commencement. The biorefinery scope 2 emissions will be net zero from start of operations, aligning to meeting net zero by 2050 for both bp strategy and EPA guidelines.

2.6 Mitigation measures adopted to avoid, reduce or offset Scope 3 emissions

The project's fundamental objective is to reduce carbon emissions relating to transport. Transport biofuels have a carbon lifecycle reduction of up to 80%, compared to traditional diesel and jet fuel produced by fossil fuels. The products the biorefinery produces, HVO and SPK are biogenic and hence the Scope 3 emissions associated with these much lower than diesel. Initial Scope 3 analysis for the project indicate that product combustion accounts for the majority of Scope 3 emissions, so providing a product with a lower carbon intensity reduces Scope 3 emissions further.

The siting of the project at the existing bp Kwinana site provides several further benefits to avoid and reduce Scope 3 emissions. The existing site has been an industrial site since 1955. This ensures that no vegetation clearing is required for the biorefinery and that redundant infrastructure can be reused, eliminating scope 3 GHG emissions associated with clearing.

Redundant equipment has been incorporated into the design and reducing emissions associated with manufacture and transport of the steel and concrete for the biorefinery. Several utilities are still operational at the bp Kwinana site which will support the biorefinery such as the jetties, utilities and wastewater treatment plant. The site already has connected to utilities such as natural gas, nitrogen and potable water. The symbiosis between industry in the Kwinana Industrial Area can be utilised to further reduce indirect transport emissions.

A large siting benefit is the existing pipeline to the Kewdale terminal can be utilised for product supply to customers, reducing the requirement for road tankers, eliminating transport Scope 3 emissions or the requirement for a new pipeline if the biorefinery was located elsewhere.

As further supply chains are established, bp will collaborate and work with our key suppliers to develop sustainable supply chains and embed sustainable practices focused on avoiding and reducing greenhouse gas emissions and increasing circularity for waste reduction or elimination. bp has included sustainability processes as part of their procurement practices including utilising sustainability criteria (including Scope 3 emissions) into the tender and vendor selection process, to ensure that supply chains Scope 3 emissions are minimised where possible.

Long term measures to reduce Scope 3 emissions for the biorefinery will be identified once the Scope 3 emission estimate is refined. This will include consideration of where bp can have the biggest impact to mitigate Scope 3 emissions both domestically and internationally.

2.7 Benchmarking

An emission intensity (also referred to as carbon intensity) is the emission rate of a given pollutant relative to the intensity of a specific activity, or an industrial production process. For example, grams of carbon dioxide released per megajoule of energy produced (gCO_2-e/MJ) is commonly used measurement for renewable fuels.

The implementation of this proposal will provide a reduced carbon fuel source for hard to abate sectors and been shown to provide significant reductions in overall CO_2 lifecycle emissions (up to 80%, dependent on feedstock) compared to fossil fuels. The biofuel or renewable energy industry is relatively new and this will be the first Sustainable Aviation Fuel facility for bp globally. bp engaged a consultant to complete a benchmarking activity in regards to developing Safeguard Mechanism production variables. Their conclusion was that in order to set the best practice emissions intensity value for the production variable, facility specific data that meets the Department of Climate change, Energy, the Environment and Water (DCCEEW)'s guideline is required. Their research found inconsistent data due to differences in system boundaries, technologies, feedstock types and energy sources and it was assumed that DCCEEW would have similar findings.

bp refineries utilise the services of Solomon Associates for performance improvement insights, and it is planned that the Kwinana Renewable Fuels facility will leverage this for continuous improvement. Solomon Associates recognize the shift in refining to renewable fuels production facilities,and are moving to collect data to benchmark the effectiveness of these new facilities, however there is limited operational data available at this time. Benchmarking against traditional refinery units does not provide an effective comparison for renewable fuels facilities due to the very different feed slates, reaction pathways and operating conditions.

There are no similar Australian or global facilities to benchmark the biorefinery against, however there are several directives and guidelines in the European Union for renewable fuel production ensuring that any new facilities produce transport biofuels that provide at least a 65% reduction in overall greenhouse gas emissions compared to traditional fossil fuels.

The Renewable Energy Directive (RED) is a directive in EU law that aims to promote the use of renewable energy by requiring 32% of the energy consumed within the EU to be renewable by 2030. The latest update (RED II) includes objectives to achieve an increase in the use of energy from renewable sources by 2030, to foster better energy system integration and to contribute to climate and environmental objectives. This directive is linked to the sustainability certification processes required to export renewable diesel within the EU. bp will be expected to meet these requirements(including meeting the emission intensities in the guideline) to supply renewable fuel to the EU.

Comparing RED II emission intensities from HVO produced by various feedstocks for their entire lifecycle, clearly shows the reduction in greenhouse gas emissions that can be achieved from manufacturing diesel from biofuels compared to traditional fossil fuels (Table 2-14)

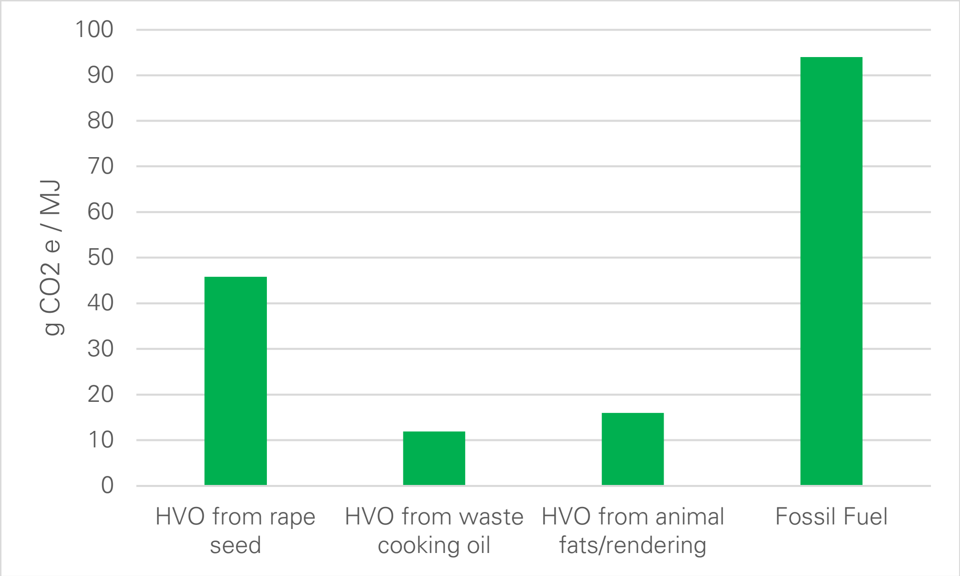

Table 2-14 RED II Carbon Lifecycle Intensity for various feedstocks

bp have used the RED II methodology to benchmark the biorefinery against the typical processing emission intensities expected for the biorefinery. RED II methodology offers two emission benchmarking metrics, the more conservative default GHG value and the more representative typical GHG value, bp has opted to benchmark using the latter. Table 2-15 outlines the processing emission intensities for HVO production based on different feedstocks. These example benchmarks for processing emission intensities are from RED II, and range between 10.2 and 14.5 g CO_2 e / MJ depending on feedstock. An example breakdown of potential feedstocks for a full year of operation was used to get a weighted average emission intensity. The worst case reportable GHG emissions is when the refinery is producing maximum HVO, hence HVO production has been considered in the benchmarking activity.
Table 2-16 demonstrates that the KRF emission intensity is expected to be approximately 6 g CO_2 e / MJ, which is well under the reference benchmark for typical emission intensity from industry as assumed in RED II It is expected that SPK production will yield a similar emission intensity.

Feedstock	%	Typical RED II GHG Values g CO_2 e / MJ
Feedstock Canola Oil	17	10.7
Feedstock Tallow	23	14.5
Feedstock UCO	60	10.2
Weighted average of blend		11.3

Table 2-15 Example of feedstock emission intensity

Total Scope 1 emissions (t CO_2 e/annum)	120,750
Total Scope 2 emissions (t CO_2 e/annum)	0
Total Scope 1 and Scope 2 (t CO_2 e/annum)	120,750
Max HVO throughput (kl/year)	565,752

Max HVO Energy throughput (MJ/annum)	19575019200
Emission Intensity (g CO_2 e / MJ)	6.17

Table 2-16 Biorefinery HVO Benchmarking to RED II emission intensities

2.8 Other statutory decision-making processes which require reduction in GHG emissions

bp has considered the relevant legislation, policy and guidance in the development of this GHG MP. Legislation and policy that applies to the biorefinery are outlined below:

- National Greenhouse and Energy Reporting Act 2007
- Carbon Credits (Carbon Farming Initiative) Act 2001
- National Greenhouse and Energy Reporting (Measurement Determination) 2008
- National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015
- Safeguard Mechanism (Crediting) Amendment Bill 2023

bp continues to report the bp Kwinana Energy Hub greenhouse gas emissions under annual NGER reporting scheme. The current bp Kwinana Energy Hub GHG emissions are below the facility threshold of 25,000 tonnes CO_2 e/ annum. There is still a requirement to report the bp Kwinana emissions based on the overriding group thresholds for BP Australia Investments Pty Ltd Controlling Corporation NGER submission.

The biorefinery is expected to have emissions greater than 100,000 tonnes CO_2 e / annum safeguard threshold. bp commits to meeting the requirements of the Safeguard Mechanism, and the biorefinery will be required to reduce its total emissions over time, reducing its baseline by 4.9% until 2030 and subsequent decrease yearly from 2030 onwards.

It is expected that bp Kwinana Energy Hub will be a new entrant as part of the safeguarding mechanism and a baseline will be developed using appropriate production variables and global best practice. DCCEEW are in the process of developing new production variables and subsequently determining best practice emission intensity for production variables. To date, no variable has been determined for the renewable fuel industry. bp have been engaged in consultation with DCCEEW and it is expected that the production variables will be known in 2024.

2.9 Consistency with other GHG reduction tools

In February 2020, bp announced its ambition to become a net zero company by 2050 or sooner, and to help the world get to net zero. Five of these aims set guidelines for the decarbonisation of bp's operations and products (and are applicable to the biorefinery):

- Aim 1 is to be net zero across our operations (Scope 1 and 2 emissions) on an absolute basis by 2050 or sooner.

  bp are targeting a 20% reduction in Scope 1 and Scope 2 operational emissions by 2025 and aim for 50% reduction by 2030 against the bp group 2019 baseline.

  Aim 2 is to be net zero on an absolute basis across the carbon in our upstream oil and gas production by 2050 or sooner. This is our Scope 3 aim and is based on bp's net share of production. bp are targeting a 10-15% reduction by 2025 and will aim for 20-30% by 2030 against our 2019 baseline.

- Aim 3 is to reduce to net zero the carbon intensity of the energy products we sell by 2050 or sooner.

  This aim applies to the average carbon intensity of the energy products we sell. It is estimated on a lifecycle (full value chain) basis from the use, production, and distribution of energy products per unit of energy (MJ) delivered.

- Aim 4 is to install methane measurement at all our existing major oil and gas processing sites by 2023, publish the data, and then drive a 50% reduction in methane intensity of our operations.

- Aim 5 is to increase the proportion of investment we make into our non-oil and gas businesses.

This project is the direct outcome of bp implementing its strategy to help decarbonise the fuel industry. Renewable fuels production is part of a suite of clean energy activities that will help bp meet its net zero aims.

2.10 Offsets

Offset units are used to compensate for emissions a business produces, to help compensate their carbon footprint. Offsets have a place in the decarbonization strategy where physical measures do not exist or are not feasible.

bp would use offsetting only after all other practical and feasible means for reducing and mitigating GHG emissions have been implemented. It is expected that bp will use offsetting between major projects to meet the linear reduction trajectory.

When it becomes apparent that offsets will be required, bp will develop an offset purchasing strategy that would involve due diligence. bp's trading and shipping business that is already active in the carbon offset market would secure the appropriate/required offsets. These would then be cancelled in the relevant offset registry for the purposes of achieving the emissions trajectory set out in the carbon management plan. Where these are Australian Carbon Credit Units (ACCUs) or other eligible safeguard compliance units they may also be surrendered for the purposes of meeting the projects obligation under the safeguard mechanism. We anticipate the cancellation or surrender of offsets would occur after the emissions reporting for the period has been completed (i.e in arrears not forward offsetting).

Globally bp manages a large carbon offsets portfolio and is made up of over 100 projects across the world. Each carbon offset project in the portfolio has been verified by third party firms accredited under the applicable offset standards. Verification also maintains that carbon offsets should be real, additional, verifiable and permanent.

Should offsets be required for the project, bp will meet the offset integrity standards expected under Climate Active or equivalent offset standard endorsed by the Australian or West Australian governments applicable at the time. As part of bp's assurance processes, it is required that our offsets have independent third-party verification and certification.

3 Adaptive Management, continuous improvement and review of GHG EMP

As a minimum, the bp KRF GHG MP will be updated in 5 yearly intervals to align with the milestones set out in the Paris Agreement and also the EPA Environmental Factor Guideline Greenhouse Gas Emissions (EPA, Environmental Factor Guideline: Greenhouse Gas Emissions, 2023). As part of the review process, the following activities will take place;

- Verify the performance of the biorefinery in relation to the targets and objectives outlined in this plan
- Consider the latest environmental guidance and legalisation in regards to the GHG MP and consider any changes to targets or reduction technologies that may result
- Verify that the technology utilised in the biorefinery is best practice and review any new technologies and equipment
- Review and update the benchmarking activity against any new facilities
- Review of the proposed future reduction methods, their progression and if any additional ones should be considered
- Report the offsets used for the corresponding reporting years including the record that the offset has been cancelled in the relevant registry
- Effectiveness of internal processes and procedures to reduce and manage GHG emissions (including the GHG MP)
- Discussion of the GHG performance with Kwinana Energy Hub Senior Leadership team

If required, improvement actions will be raised through bp's compliance action tracking system to explore any inconsistencies or opportunities identified in the above activities

The management plan may be reviewed at other times if triggered by the following activities:

- Introduction of a new process or modification or increasing efficiency of an existing activity that has the potential to alter GHG emissions
- Installing or introducing any GHG reduction measures
- Changes to relevant State and Commonwealth legislation and requirements

Any changes to the GHG MP triggered by this process will follow the change process as described in Section 0.

4 Reporting

The biorefinery will be required to report its annual GHG emissions under the NGER scheme. Annually the KRF GHG MP performance targets will be reviewed at the completion of the NGER scheme reporting process, when GHG emission estimates have been calculated for the previous financial year. These estimates will be fed into the Safeguard mechanism reporting process to understand compliance to Safeguard mechanism baseline. This activity will review the actual emissions against the GHG MP baseline to understand compliance to the 5 yearly targets and trigger any improvement actions if necessary.

After the 5 yearly review of the GHG MP, the performance of the biorefinery in regards to its commitments will be reported internally to bp management and also to the EPA if requested.

Under the Safeguard Mechanism Reforms, if the Scope 1 emissions are greater than 100,000 tonnes CO_2 e/annum, than these estimates will be fed into the Safeguard mechanism reporting process to understand compliance to Safeguard mechanism baseline.

The current bp KRFMP will be made available on the bp website.

5 Stakeholder Consultation

Extensive stakeholder engagement has occurred with respect to the KRF project as part of the bp Kwinana Energy Hub stakeholder and communication strategy for the site's transition from oil refinery to fuel import terminal and now integrated energy hub. The extensive summary of stakeholder engagement is provided in the Section 38 bp KRF Referral Supporting document. Table 5-1 includes GHG specific stakeholder consultations that have occurred. Future consultation will occur with relevant stakeholders as required.

Stakeholder	Date	Issues /topics raised	Proponent response / outcome
Kwinana Industry Council	02/09/2021	bp briefing to Director: ■ Proposal in the context of site transition to an integrated energy hub ■ Opportunity to decarbonise industry (biofuels) ■ Site utilisation KIC was supportive of Proposal and requested regular engagement in relation to Proposal development and value-adding to the KIA.	Stakeholder to be kept updated
	15/11/2021	bp briefing to Director: ■ Proposal update and H2Kwinana feasibility	
Media and General community	21/10/2021	Kwinana Industry Council Community Information Forum - Public community information event for industry, community, and local government. bp discussed site transition plans (including Proposal). Questions were raised regarding: ■ Biofuels (use of, process for refining) ■ Jobs ■ Support for the integrated energy hub	All questions addressed at event with no concerns or follow ups. bp contact information provided to community for more information as needed.
	17/02/2023	Deputy Premier announced project into FEED. Premier made comments in media statement.	Attracted broad media interest and coverage – all positive
	11/03/2023	Hosted a stall at the City of Kwinana's Children's Festival (estimated attendance: up to 10,000 local community members). The event is promoted by the City of Kwinana. bp was gold sponsor of event and featured in City lead promotion. Project featured in discussions.	High community attendance. No concerns raised. High interest in jobs and biofuels opportunities to decarbonise hard to abate sectors.
	21/03/2023	Present at KIC Quarterly Roundtable – about 40 attendees from local businesses. Discussion on feedstocks, carbon reduction opportunities from products, discussion on waste management	Committed to keeping KIC members updated and follow up conversations with some interested parties

	28/03/2023	Kwinana Industry Council Community Information Forum - Public community information event where bp Energy Hub Manager presented an update to the community on the bp site and more detail on the Kwinana Renewable Fuels Project. About 30 community, Industry and local government representatives were in attendance. Questions raised were regarding ethical issues on sourcing of feedstocks and how bp was managing these	All questions addressed at event with no concerns or follow ups. bp contact information provided to community for more information as needed
Department of Water and Environmental Regulation (DWER) & Environmental Protection Authority (EPA)	30/11/2021	bp briefing to industry regulator regarding: ■ Update on site activities, including the transition to import terminal. ■ Discussed current licence and prescribed premises and what amendments required to reflect the operation as an import terminal. ■ Introduction to upcoming projects for the Kwinana Energy Hub. DWER requested early engagement for projects.	bp will engage early with the DWER for the energy hub projects and keep DWER updated with the Proposal progression.
	13/12/2022	bp briefing to industry regulation and EPA Services discuss the Proposal and potential environmental impacts in detail. The EPA Services Unit requested: ■ bp to present proposal to EPA Chair ■ Part V feedback was that works approval is achievable by bp's timeframes provided sufficient quality and detail in the submission. It was also possible to have parallel processing of Part IV and V to minimise delays. ■ EPA Services requested information on what was the marine scope of this Proposal. ■ Ongoing engagement up to Works Approval submission (under Part V of the EP Act). ■ EPA Services Unit mentioned that referral will be through the new system Environmental Online and that bp should familiarise itself with the system to avoid additional delays.	bp confirmed in the meeting that there is no marine scope as part of this proposal. The existing jetty and pipeline facilities do not require upgrading. Site visit with EPA Chair, board and EPA officers was completed on 21/02/2023.
	21/02/2023	bp hosted a site visit for the EPA chair and board members and representatives of EPA services. Discussion and visit included: ■ Site visit of existing operations ■ Discussion of Kwinana site transition in terms of skills, technology ■ Overview of this proposal and its environmental impacts ■ Overview of other bp potential projects in Western Australia Outcomes	EPA perspective was that the Proposal is likely to trigger a single factor for assessment which is Greenhouse Gases (GHG) and could anticipate its submission within the coming weeks

<table>
<tr><td></td><td></td><td>EPA agreed that the proposal like to be a single factor assessment
EPA provided bp with information to provide in referral documents</td><td></td></tr>
<tr><td rowspan="2">City of Kwinana</td><td>9/06/2022</td><td>Site tour and Proposal briefing to Council and Management (CEO, Director, Mayor, Elected members, and Executive Manager).
Feedback received:
Interest in local jobs, skills and training
Opportunities for the City's net zero targets for biofuels
Supportive of Proposal
Questions regarding waste management
Keen interest in being updated and involved</td><td>Meeting to be held with the City’s Planning and Environmental Services team</td></tr>
<tr><td>16/08/2022</td><td>Preliminary meeting (online) held with the City confirmed:
Support for Joint Development Assessment Panel (JDAP) Approval Pathway
DA to be presented to Council to provide opportunity for alternative recommendation prior to being forwarded to JDAP
Proposed development likely to be classified as “General Industry” use
City likely to advertise DA concurrently with referral to relevant authorities
Design review not required, only assessment against 10 Design Principles in SPP 7.0 required
Development Application to address:
City’s Planning Framework and relevant State Planning Policies
Bushfire prone impact assessment
City of Kwinana Coastal Adaption Plan
Noise and cumulative risk associated with development including waste and airborne emissions
Impact to adjacent pipelines
Transport and access movements and issues
Conditions of approval likely to include:
Requirement for Public Art
Others as informed by referral agency comments
Development likely to be exempt from requiring building permit under the Building Act however, to confirm with building surveyor.
Beneficial to brief Councillors on the Proposal.</td><td>Continue to liaise with City as design progresses and DA preparation commences to confirm:
Land use designation
Implications of any changes in design since initial engagement
Any updates in policy requirements
Briefing with Council to inform recommendations forwarded to JDAP</td></tr>
</table>

		Continue to liaise with City through DA preparation and consideration stages.	
	3/04/2023	Briefing to the Major and Council	Supportive of project. Interested in decarbonisation opportunities for the City from biofuels.
	15/05/2023	City of Kwinana site visit and KRF pre-approval briefing Large group attended (22 total) across planning, environmental, bushfire, management, community relations and economic development. Supportive of the project and provided guidance on Development Application process.	Questions related to: ■ Waste streams ■ Jobs ■ Land utilisation ■ Traffic impacts All questions addressed at meeting.
DJTSI and Energy Policy WA	14/06/2022	Site tour and briefing for the Executive Directors (multiple), Directors (multiple), and Principal Policy Adviser. Discussion focused on: ■ Site transition, including Proposal and the H2Kwinana project ■ Infrastructure and jobs/ skills to support future site requirements ■ Security of fuel supply	Subsequent conversations and data sharing regarding electrical infrastructure (not pertaining to Proposal) and site transition plans
Department of Transport and Department of Primary Industry and Regional Development	23/05/2023	Low carbon teams from DPIRD and DoT attended site for a tour and project briefing. Discussion around biofuels and ability to support industrial and state decarbonization.	Supportive of project. Discussion regarding feedstock planning and sustainability considerations. General discussion around biofuels and net zero opportunities
Department of Climate Change, Energy, the Environment and Water	28/09/2023	Discussion on Safeguard Mechanism and implications for project as a new facility, and potential draft production variables that may apply.	Ongoing discussion for draft production variables

Table 5-1 Stakeholder Engagement including GHG specific topics

6 Changes to GHG MP

bp acknowledges that any changes to this GHG MP, must follow the change process outlined in Instructions – *How to prepare Environmental Protection Act 1986 Part IV Environmental Management Plans* (EPA, Instructions - How to prepare Environmental Protection Act 1986 Part IV Environmental Management Plans, 2021). bp will provide a summary and justification for all changes.

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