Hunter Power Project

Net Zero Power Generation Plan

| Approved Version 1

26 June 2025

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1	4 April 2025	Issued for Consultation with EPA and the Department	G Innes	S Clayton	S Clayton
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3	26 June 2025	Issued with responses to Department RFI	G Innes	S Clayton	S Clayton

The initial revisions of this management plan were prepared by HRL Technology Group and Snowy Hydro and approved by the Department for the Hunter Power Project. Details of the review process are detailed in the document history table above. Subsequent versions of the approved Net Zero Power Generation plan will be updated by Snowy Hydro. The reasons for, and key changes to the management plan are detailed in the table below.

Approved management plan version history

Approved version	Date	Description of changes	Author
1	26 June 2025	Previously referred to as Revision 3 (dated 26 June 2025) and approved by the Department	G Innes

Executive Summary

Snowy Hydro is developing a 660 MW capacity power station at Kurri Kurri in the Hunter Region in New South Wales. The Hunter Power Project (HPP) will comprise two heavy-duty, open cycle gas turbines. Operations are expected to commence in 2025, with a total power station life of about 30 years.

The new plant will supplement Snowy Hydro's generation portfolio with dispatchable capacity when energy demand is at its highest. The Hunter Power Project will improve energy reliability and security in the NEM by supporting the firming of more wind and solar renewable energy, with the potential to add 660 MW of power when needed. By providing firmed energy, Snowy Hydro has currently contracted 1.7 GW of renewables that are progressively being commissioned, with plans to increase this further in the coming years. These renewables are displacing approximately 5.8 million tonnes of CO_2 emissions per year out of the electricity system[1].

A Net Zero Power Generation Plan (NZPGP) is a requirement of the Infrastructure Approval (Conditions C2 to C4) and has been prepared in consultation with the EPA and the Department's Climate and Atmospheric Science Group. The NZPGP must be approved by the Secretary prior to commencing operations.

Due to the requirement that NZPGP must be developed and implemented prior to operation of the HPP, greenhouse gas (GHG) assessments completed during the planning phase and HPP design information was used to inform its development. Future review of the NZPGP will be undertaken as subsequent information is gathered during the operation of the HPP.

When considering carbon emissions reductions, it is important to note that whilst best endeavours to reduce emissions are important for peaking plants, the greatest value of peaking plants, with respect to reducing carbon emissions, is the enablement of the broader decarbonisation of the National Energy Market (NEM), supporting net zero policy objectives of state and federal governments. The Department of Planning, Industry and Environment noted in their 2021 Assessment Report[2]:

> *Based on the NSW Government's latest emissions modelling information, the Department considers that the project would not significantly increase greenhouse gas emissions in NSW or constrain the ability to achieve the target of a 50% reduction in emissions by 2030. Further, the hydrogen capabilities of the project present the opportunity to further reduce the emissions of the project, where clean hydrogen is used in the fuel mix*.

For preparation of the NZPGP an independent engineering assessment of various opportunities to displace or offset emissions to achieve Net Zero was undertaken. This assessment process has shown that several options have potential merit however more information is required to complete a detailed assessment of prospective options. This information includes but is not limited to:

- How the plant will be run in practice (e.g. load profile, operational hours);
- What the actual emissions are (from operational data as opposed to modelling);
- Market factors impacting not only the generation profile of the plant but also the availability and cost of carbon offsets (e.g. ACCUs);
- Commercial availability and viability of options such as alternate fuels; and
- Technical feasibility of options (including alternate fuels) when practical constraints, such as available space and operational load profile, are considered.

Key measures that Snowy Hydro will have regard to for reducing emissions include:

[1] The renewable production HPP supports is variable and therefore the direct emissions from HPP will be variable. Total emissions from HPP generation are estimated to be around 0.14 million tonnes of CO_2 per annum (assuming about a 3% capacity factor), equating to a significant net benefit to Australia's transition to renewables.

[2] NSW Department of Planning, Industry and Environment, Hunter Power Project (Kurri Kurri Power Station). Critical State Significant Infrastructure Assessment (SSI 12590060), November 2021

- Maintenance practices, in accordance with Original Equipment Manufacturer (OEM) recommendations, to ensure the equipment is kept in best practicable operating condition and efficiency;
- Operational practices to minimise emission intensity (within NEM demand restraints), such as minimising run-up/run-down times and start-up, optimising output to a high efficiency set-point, and operating with inlet air cooling; and
- Procuring carbon offsets.

Snowy Hydro commit implementing the approved Net Zero Power Generation Plan through performing detailed investigations of options having regard to the appropriate staging/targets provided with a view to offsetting/abating emissions should a technically and financially viable option be identified. Additional options for future consideration may include:

- Fossil fuel displacement opportunities, including:
    - Hydrogen (or other renewable fuel, such as biomethane) blending into the feed gas,
    - Biodiesel and/or renewable diesel to offset fossil diesel.
- Carbon capture and storage and/or utilisation.

Contents

List of figures

List of tables

Glossary of terms

Term	Definition
Commissioning	Program of testing and certification of all Project components, systems, and processes to demonstrate the Project can operate to the required standards before commencing operation. This includes a cold commissioning stage comprised of standard construction type activities, and hot commissioning stage comprised of burning fuel to set up the operational plant and test it according to various performance scenarios.
Department	Same meaning as Department under the EP&A Act.
Mitigation	Action to reduce the severity of an impact.
Operation	The operation of the development, but does not include commissioning, trials of equipment or the use of temporary facilities.
Project	The Hunter Power Project; formerly referred to as the Kurri Kurri Power Station Project.
Project Site	The area of land that is directly impacted on by the development, including access roads, and areas used to store construction materials, as described in the EIS and Infrastructure Approval, including the areas covered by Modification 1 and Modification 2.
Proponent	Snowy Hydro Limited, or any person carrying out the development to which this approval applies.
Secretary	Planning Secretary (of the NSW Department of Planning and Environment) under the EP&A Act, or nominee.
Secretary's Approval	A written approval from the Secretary and/or delegate.
Study Area	The Project Site and any other areas surveyed and assessed for the protection of Aboriginal cultural heritage.

Abbreviations

Abbreviation	Definition
CO_2-e	Carbon dioxide equivalent
DECC	Department of Environment and Climate Change
DPHI	Department of Planning, Housing and Infrastructure (formerly DPIE)
DPIE	Department of Planning, Industry and Environment
EIS	Environmental Impact Statement
EP&A Act	*Environmental Planning and Assessment Act 1979* (NSW)
EP&A Regulation	*Environment Planning and Assessment Regulation* 2021 (NSW)
EPA	Environment Protection Authority (NSW)
EPBC Act	*Environmental Protection and Biodiversity Conservation Act 1999* (Federal)
EPL	Environment Protection Licence under the POEO Act
GHG	Greenhouse Gase
GWP	Global Warming Potential
HPP	Hunter Power Project
kt	Thousand tonnes (kilotonne)
Mt	Million tonnes
NEM	National Electricity Market
NGA	National Greenhouse Accounts
NGER	National Greenhouse and Energy Reporting Scheme
NSW DCCEEW	NSW Department of Climate Change, Energy, the Environment and Water
POEO Act	Protection of the Environment Operations Act 1997
Scope 1	Scope 1 GHG emissions are those released to the atmosphere as a direct result of an activity, or a series of activities, which are part of the proposal.
Scope 2	Scope 2 GHG emissions are those from the indirect consumption of an energy product by the proposal.
Scope 3	Scope 3 emissions are indirect GHG emissions other than Scope 2 emissions that are generated in the wider community. Scope 3 emissions (both upstream and downstream) occur because of the activities of a proposal, but from sources not owned or controlled by the proponent as part of the proposal.
SF_6	Sulphur hexafluoride

1. Introduction

1.1 Project Overview

Snowy Hydro Limited (SHL) is developing a gas fired power station near Kurri Kurri, NSW. Snowy Hydro has obtained approval from the NSW Minister for Planning and Public Spaces under the NSW Environmental Planning and Assessment Act 1979 (EP&A Act). This approval was modified on 1 March 2023 (Modification 1) to expand the Project Site to include Precinct 3B, shown on Figure 1-1, and allow specific activities to occur in this area as well as an increase in light vehicle traffic associated with the Project during its construction phase. The approval was further modified on 16 November 2023 (Modification 2) to allow the construction of a 200 bed Temporary Worker Accommodation Facility which will operate for the duration of the Project's construction phase.

The Project involves the construction, commissioning and operation of the Hunter Power Project (HPP) and electrical switchyard, together with other associated infrastructure (Figure 1-2). The 660 MW, two-unit open cycle gas turbines (OCGT) facility is nearing completion and is expected to deliver first power to the grid in 2025. The gas turbines will primarily be fired on natural gas with the use of diesel fuel as a backup.

The major supporting infrastructure required for the Project is a 132 kV electrical switchyard located within the Project Site. Also required is a new gas lateral pipeline and gas receiving station (which is being developed by a third party and is the subject of a separate planning approval). Multiple existing 132 kV transmission lines will exit the electrical switchyard and eventually connect into the Kurri Zone Substation and the Newcastle Terminal Station.

The new plant will supplement Snowy Hydro's generation portfolio with dispatchable capacity when energy demand is at its highest. By providing firmed energy, the Hunter Power Project will facilitate an estimated 2 GW of renewables, displacing approximately 5.8 million tons of CO_2 emissions per year out of the electricity system.[3] The renewable production HPP supports is variable and therefore the direct emissions from HPP will be variable. The SHL Annual Report for the 23/24 financial year estimated that the total emissions from HPP generation are estimated to be around 0.14 million tonnes of CO_2 per annum (assuming a ~3.5% capacity factor), equating to a significant net benefit to Australia's transition to renewables.

The HPP will operate as a "peak load" generation facility (a peaking plant) supplying electricity at short notice when there is a requirement in the NEM. The power station is licenced to operate a maximum of 1,100 hrs/yr, but as a peaking plant, the actual number of operating hours will be dependent on market conditions and are expected to be significantly lower.

Operations are expected to commence in 2025, with a total power station life of about 30 years.

[3] Snowy Hydro Limited, Annual Report for the financial year ended 30 June 2024.

Figure 1-1 Project Site Location

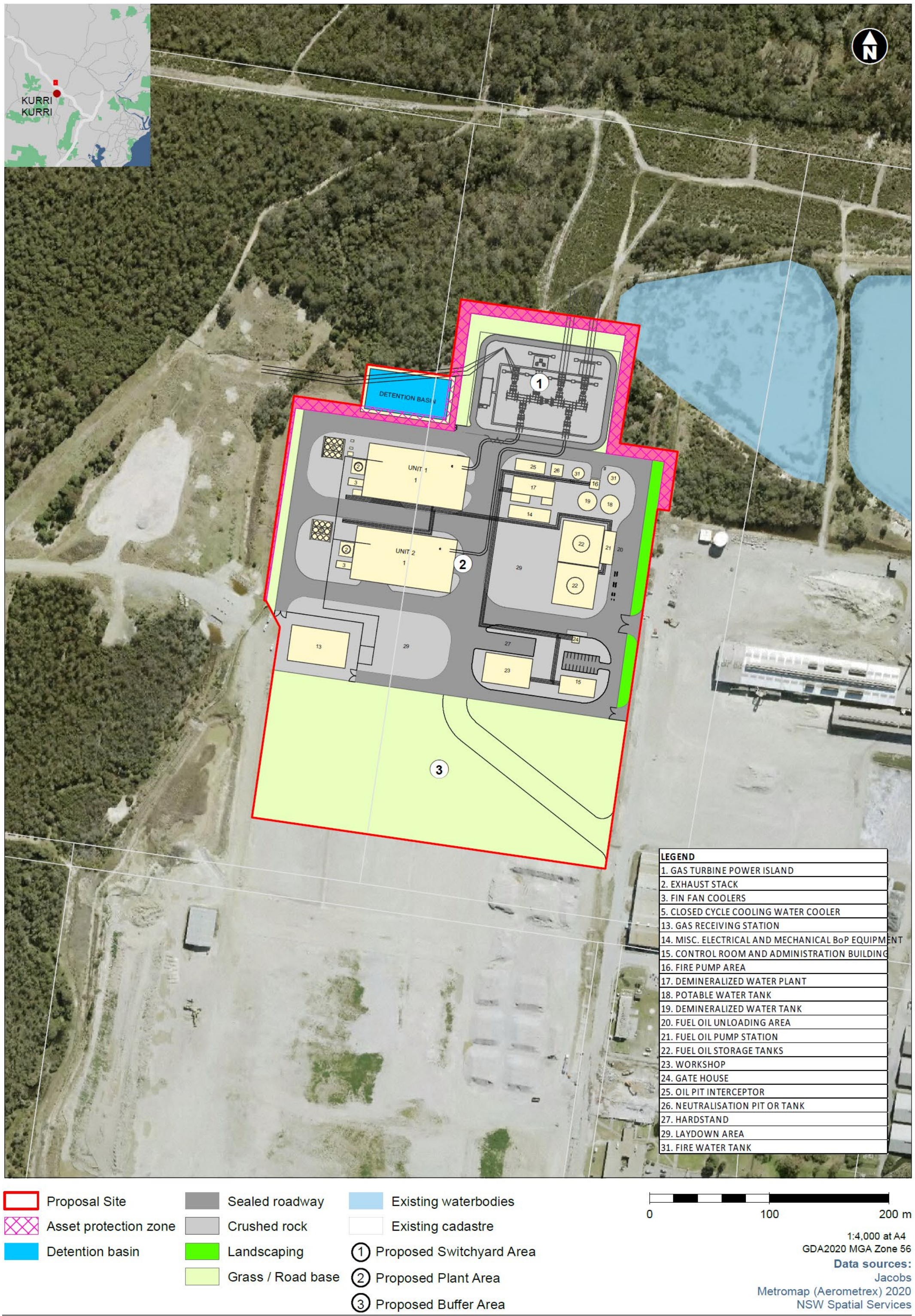


Figure 1-2 Project Site Layout

1.2 Net Zero Power Generation Plan Scope

A Net Zero Power Generation Plan (NZPGP) is a requirement of the Infrastructure Approval (Conditions C2 to C4) and has been prepared in consultation with the EPA and the Department's Climate and Atmospheric Science Group. The NZPGP must be approved by the Secretary prior to commencing operations.

Table 1-1 Infrastructure Approval conditions – Net Zero Power Generation Plan requirements

Condition	Requirement(s)	Where addressed
C2	Prior to the commencement of operations, the Proponent must prepare a Net Zero Power Generation Plan for the development, to the satisfaction of the Secretary.	
	a) The plan must be prepared by a suitably qualified, experienced and independent person approved by the Secretary	Appendix A – Appointment of experts to prepare NZPGP
	b) The plan must be prepared in consultation with the EPA and the Department's Climate and Atmospheric Science Group;	Section 1.3
	c) The plan must investigate opportunities to achieve Net Zero greenhouse gas emissions from the development including consideration of:	Section 5
	(i) contemporary best practice and continuous improvement measures;	
	(ii) applicable Commonwealth and State greenhouse gas emissions targets and policies including a commitment to Net Zero by 2050, and 50% reduction compared to 2005 levels by 2030;	
	(iii) latest technology for displacing natural gas or diesel as the fuel supply, such as use of green hydrogen.	
	d) The plan must describe measures to displace or offset greenhouse gas emissions having regard to:	
	(i) the investigations undertaken under condition C2(c); and	Section 5
	(ii) the following Net Zero targets by calendar year: • from the commencement of operations until 2029: 10% of total Scope 1 greenhouse gas emissions; • from 2030 until 2039: all Scope 1 greenhouse gas emissions resulting from generating electrical power at the premises for more than 175 cumulative hours per calendar year (or 2% of the year); and • from 2040 onwards: all Scope 1 greenhouse gas emissions.	Section 5

Condition	Requirement(s)	Where addressed
C3	Every three years following the approval of the plan, or other timeframe agreed by the Secretary, a report shall be submitted to the Secretary to update the outcomes of the investigations and measures described in condition C2.	Section 9
C4	The Proponent must implement the approved Net Zero Power Generation Plan.	

Note: This NZPGP focuses on Scope 1 emissions for the operation of the HPP as per the requirements listed above in *Table 1-1*.

1.3 Consultation

Infrastructure Approval requires that the NZPGP is prepared in consultation with the EPA and the Department's Climate and Atmospheric Science Group and to the satisfaction of the Secretary. The following table outlines the consultation steps that were undertaken during the plan's development and the outcomes of that consultation.

Table 1-2 Consultation undertaken during the development of this NZPGP

Version	Agency	Feedback	Response & section reference
0	EPA and DPHI (23 Sep 2024)	Guidance provided was to prepare a plan following the methodology outlined in the NSW EPA Guide for Large Emitters.	Noted.
1	EPA (23 Apr 2025)	The emissions estimates in Section 2.1.1 should use the most recently available emission factors, particularly for Scope 2 and Scope 3 emissions.	Infrastructure Approval (Conditions C2 to C4) applies to Scope 1 emissions from the operation of the HPP. Only Scope 1 emission estimates for the operation of the HPP have been updated for the NZPGP.
1	EPA (23 Apr 2025)	The Net Zero Plan should include sufficient supporting information to allow the calculation of emissions to be replicated, with information disaggregated for each operation. Section 2.1.2. should include more information about the hourly fuel consumption rates of the Class F gas turbines and calculations behind the fuel quantity estimates. This can include references to the manufacturers data sheets or other technical information sources. This information is useful in setting measurable, auditable objectives and performance indicators to evaluate emissions performance. It can also be	Scope 1 emissions have been updated based on OEM design information. OEM Natural Gas Case 2: • Design Output = 372 MW per GTG • Maximum allowable station output = 660 MW • Heat Rate for maximum design output = 8.707 GJ/MWh (LHV) x 1.11 ~ 9.665 GJ/MWh (HHV) OEM Diesel Case 2: • Output = 288.7 MW per GTG Heat Rate = 9.428 GJ/MWh (LHV) x 1.05 ~ 9.899 GJ/MWh (HHV)

Version	Agency	Feedback	Response & section reference
		used to set site-specific criteria to verify and determine whether additional measures should be implemented to meet Net Zero targets under Condition C2	
1	EPA (23 Apr 2025)	The emissions estimates should include all stages of the development, including construction and decommissioning phases of the project.	Infrastructure Approval (Conditions C2 to C4) applies to Scope 1 emissions from the operation of the HPP. Construction and decommissioning emissions, as well as Scope 2 and 3 emissions during operations do not apply to Infrastructure Approval (Conditions C2 to C4) and have been removed from the NZPGP. The EIS should be referred to for these emission estimates.
1	EPA (23 Apr 2025)	The Net Zero Plan should include additional information in Section 2.2 to specify how the energy production figure of 778,405 MWh per annum was derived.	The energy produced value of 778,405 MWh was taken from the EIS and had been used for consistency. The energy produced quantity has been revised in Section 2.2 based on the OEM design data and the maximum annual diesel operations (175 hours) and Natural Gas (925 hours) for the maximum total station operations of 1,100 hours.
1	EPA (23 Apr 2025)	The comparison with NSW and Australian emissions in Section 2.3 should be updated to include the most recently available NSW inventory data (currently for 2022).	Section 2.3 updated to include 2022 data sourced from Emissions by state and territory from Australia's National Greenhouse Accounts (ANGA).
1	EPA (23 Apr 2025)	Section 6.1.1 in the Net Zero Plan specifies that the maximum capacity factor proposed for the Hunter Power Project (HPP) is 1,100 hours per year or 12.6%, but on pages 6 and 15 it is 12%. These discrepancies should be rectified, and the correct assumed capacity factor should be nominated.	The NZPGP is updated to be consistent for 1,100 hour operations (12.6%): • 175 hr diesel (maximum allowable operations for diesel firing); and 925 hr natural gas.
1	EPA (23 Apr 2025)	Section 6.3.1 in the Net Zero Plan states hydrogen is a low greenhouse gas (GHG) fuel. However, it may be beneficial if the Net Zero Plan provides some context, as its global warming potential (GWP) is approximately 11 ± 5 (100-year GWP) due to its leakage and subsequent chemical reactions changing the abundances of the greenhouse gases methane, ozone, and stratospheric water vapour, as well as aerosols. Hydrogen leaks would need to	Overarching comments regarding alternative fuels are added to Section 6. Specifically, regarding the comments raised it is noted: • Hydrogen leaks and/or un-combusted hydrogen emissions would produce Scope 1 emissions. However, it is noted that: ○ The GWP for Methane (primary component of Natural Gas) used

Version	Agency	Feedback	Response & section reference
		be minimised across the entire value chain to realise the benefits of switching to a hydrogen economy.	for NGER reporting is 28, which is higher than for hydrogen. ○ Hydrogen is not a GHG type reported under the NGER system. • Hydrogen can produce NOx when combusted and therefore could impact HPP non-greenhouse gas emissions. This would also be applicable to utilisation of other potential fuels and would require further analysis if fuel switching options are progressed in the future. • Safety hazards relating to the use of any alternative fuel would require detailed evaluation if a fuel switching options was progressed in the future.
1	EPA (23 Apr 2025)	Hydrogen can also produce NOx when combusted as a fuel, and for transparency this should be clarified.	
1	EPA (23 Apr 2025)	Consideration of using ammonia as a fuel should recognise the significant hazards associated with its handling and storage (i.e., the toxicity and corrosiveness being key safety issues).	
1	EPA (23 Apr 2025)	Further justification should be provided as to why is there insufficient room for heat recovery steam generators (HRSGs) to allow conversion to combined cycle gas turbine (CCGT). For transparency, the Net Zero Plan should discuss and nominate the design constraints identified during the review.	Further details regarding the CCGT evaluation have been added to Section 6.4.2.
1	EPA (23 Apr 2025)	The Net Zero Plan referred to an independent engineering assessment that was undertaken to evaluate the potential measures to reduce or offset GHG emissions. The Net Zero Plan should provide details of the independent assessment, by including the range of options considered, their feasibility assessment and justification for any options that were not recommended for implementation. Findings and conclusions of independent expert review are important to understand the expected environmental performance. Therefore, more details on the independent engineering assessment should be included in the Net Zero Plan.	Additional details regarding the assessment are presented in Section 6.
1	EPA (23 Apr 2025)	The Net Zero Plan should include reduction goals based on Net Zero targets under Condition C2 of the Instrument of Approval. Setting reductions goals upfront is key to demonstrate that emission reductions goals for the project are consistent with the condition. The EPA	Section 7 is updated to provide further details regarding the Infrastructure Approval conditions targets.

Version	Agency	Feedback	Response & section reference
		recognises that emissions reduction trajectories may be 'lumpy' and may depend on the implementation of different technologies or processes at different stages of a project. Therefore, consistent with the Large Emitters Guide, the Net Zero Plan should include a description of uncertainties in the timing and feasibility of emerging technologies to support progress towards emissions reduction goals.	
1	EPA (23 Apr 2025)	Noting that the project will likely rely on acquiring offsets to achieve Net Zero targets under Condition C2, particularly for 2029, the Net Zero Plan should provide an estimate of the number of offsets planned to be used for the HPP. It should also discuss whether suitable offsets are likely to be available at the time of the proposed acquisition and give the reasons for reaching this view.	Section 6.5 is updated to provide further detail regarding carbon offsets.
1	EPA (23 Apr 2025)	Section 9 of the Net Zero Plan needs to include more details on the methodology that will be used to evaluate the adequacy or effect of implementing the proposed mitigation measures. To be consistent with the Guide, the Net Zero Plan could be improved by including: • Site specific, measurable, auditable objectives and performance indicators to evaluate emissions reduction measures. These should be used to inform and evaluate targeted actions and implement all reasonable and feasible measures to reduce greenhouse emissions. • Criteria to verify and determine whether additional measures should be implemented to meet projected emissions and inform actions for improvement. • Discussion on how the projected emissions will be used to benchmark annual emissions during the project's life. Inclusion of the above in the Net Zero Plan will help evaluate ongoing emissions as part of future reviews of the Net Zero Plan and inform whether further actions are needed to achieve emission reduction goals.	Section 9 is updated to provide detail on a potential approach to evaluate the impact of mitigation measures.

1.4 NSW Legislative Context

NSW's legislative context for this Net Zero Power Generation Plan includes the following:

- the Climate Change (Net Zero Future) Act 2023 legislates NSW whole-of-government climate change actions to deliver a net zero future by 2050. It includes guiding principles that consider the impacts and opportunities with the aim of a sustainable future and resilient NSW. It sets NSW reduction targets, based on 2005 levels, of a 50% reduction 2030 and a 70% reduction by 2035.
- the Net Zero Plan Stage 1:2020 – 2030 sets out the NSW Government plan for the next 10 years, committing to a strong economy, an improved quality of life and continued environmental protection. The plan is focused on the local opportunities and priorities for NSW within global climate change actions as well as tracking the progress and evaluating future projections.
- the Protection of the Environment Administration Act 1991 establishes the statutory body of NSW EPA and its Board establishing its objective to protect, restore and enhance the quality of the environment in NSW, while maintaining ecologically sustainable development. The Act also requires that EPA report, every three years, on the state of the NSW environment.
- the Protection of the Environment Operations Act 1997 was established to consolidate previous environmental legislation and thereby strengthen the environmental protection regulatory framework in NSW. It clarifies roles and responsibilities between EPA, local councils and other authorities in NSW and establishes EPA's regulatory responsibilities, including the issuing of approvals and licences for scheduled activities.
- the NSW Environment Protection Authority (EPA) Climate Change Policy establishes EPA's statutory responsibilities in the delivery of the broader NSW Government climate change objectives, including the reduction of greenhouse gas emissions.
- the Climate Change Action Plan 2023 – 26 outlines EPA's regulatory actions over the next three years, including the further development of regulatory actions, to support achieving net zero emissions by 2050.
- the NSW EPA Guide for Large Emitters, Guidance on the greenhouse gas assessment and mitigation plan to be prepared for large emitting projects within environment impact assessments DRAFT FOR CONSULTATION, 2024 and NSW Guide for Large Emitters, Guidance on how to prepare a greenhouse gas assessment as part of NSW environmental planning processes, January 2025 provide guidance for large emitting new facilities and existing facility modifications, including guidance on the preparation of GHG Assessments and GHG Mitigation Plans, to address EPA approval and licencing conditions.

2. GHG emissions estimate

2.1 GHG emissions

The development of this NZPGP is required prior to the commencement of operations as per Infrastructure Approval condition C2. Since operational GHG emission data is not available, the GHG Assessments completed during the planning phase have been used to inform the NZPGP development.

This facility will be providing peaking power at times of high demand and low supply from other sources. Although it has a proposed maximum operating capacity of 1,100 hours per year (~12.6% of the year), which was used as the basis for the following GHG emissions estimates, the HPP is expected to operate an average of 2% of the year (175 hours/year) with possible variances to 4-8% of the year (~350-700 hours of operation/year, respectively). This will result in much lower absolute emissions than those presented.

Construction and decommissioning emissions do not apply to Infrastructure Approval (Conditions C2 to C4) and have been removed from the NZPGP. The EIS should be referred to for these emission estimates. Additionally, Scope 2 and 3 emissions during operations do not apply to Infrastructure Approval (Conditions C2 to C4). It should be noted that the Scope 2 and Scope 3 emissions are expected to be a relatively small component of the overall emissions:

- Based on the EIS the estimated grid annual grid electricity consumption is 578,000 kWh. Based on the FY25 NGER Scope 2 factor for NSW (0.66 kg CO_2-e/kWh) the Scope 2 emissions would be 381 tCO_2-e per year.
- Scope 3 emissions are predominantly associated with the fuel supplies. The annual estimate for the EIS for haulage was 48,925 tCO_2-e (Year 1) and 93,572 tCO_2-e per year (Years 2-30).

The Scope 1 emissions estimates presented below represent two timeframes:

- First year of operation, which includes commissioning; and
- Operational years 2-30.

2.1.1 EIS GHG assessment methodology

The GHG assessment conducted for the EIS was completed in accordance with National Greenhouse Accounts guidance and associated factors. The methodology for assessment of GHG impacts is summarised as follows:

- Create an inventory of likely GHG emissions to determine the scale of the emissions and a baseline from which to develop and deliver GHG reduction options.
- Aggregate emissions into the equivalent emissions of carbon dioxide. The prominent GHGs, and their most common sources include:
  - Carbon dioxide (CO_2) – by far the most abundant, primarily released during fuel combustion;
  - Methane (CH_4) – as fugitive emissions from gas production and transportation;
  - Nitrous oxide (N_2O) – from industrial activity, fertiliser use and production;
  - Hydrofluorocarbons (HFCs) – commonly used as refrigerant gases in cooling systems;

  - Perfluorocarbons (PFCs) – used in a range of applications including solvents, medical treatments and insulators; and
  - Sulphur hexafluoride (SF_6) – used as a cover gas in metal smelting, and as an insulator in high-voltage electrical switch gear.
- Determine an assessment boundary that defines the scope of GHG emissions and the activities to be included in the assessment.
- Use emissions factors to determine emissions of GHGs from processes or activities, where it is impractical to directly measure (or model) emissions.

The GHG inventory for the assessment was calculated in accordance with the principles of the Greenhouse Gas Protocol (GHG Protocol). The GHG emissions that form the inventory are split into three categories known as 'Scopes'. Scopes 1, 2 and 3 are defined by the GHG Protocol and are summarised as follows:

- Scope 1 – Direct emissions from sources that are owned or operated by a reporting organisation (examples – combustion of diesel in company owned vehicles or used in on-site generators);
- Scope 2 – Indirect emissions associated with the import of energy from another source (examples – importation of electricity or heat); and
- Scope 3 – Other indirect emissions (other than Scope 2 emissions) which are a direct result of the operations of the facility but from sources not owned or controlled by that facility's business (examples include business travel (e.g. by air or rail) and usage of the facility's product by other businesses).

2.1.2 Scope 1 emission estimates during operation

The Scope 1 gas turbine combustion emissions are based on expected turbine performance data provided by the OEM (Table 2-1 for Natural Gas and Table 2-2 for Diesel firing). The following design cases have been used to calculate the estimated Scope 1 emissions for the NZPGP.

- OEM Natural Gas Case 2:
  - Output = 372 MW per GTG
  - Heat Rate = 8.707 GJ/MWh (LHV) x 1.11 ~ 9.665 GJ/MWh (HHV)
- OEM Diesel Case 2:
  - Output = 288.7 MW per GTG
  - Heat Rate = 9.428 GJ/MWh (LHV) x 1.05 ~ 9.899 GJ/MWh (HHV)

Due to the maximum allowable station output constraint being 660 MW, it is assumed that for Natural Gas firing with 2 GTs operating concurrently that the maximum output will be 330 MW per GT. Thermoflow modelling was conducted to determine the heat rate for operation of the GTs at 330 MW on Natural Gas (relative to the Case 2 design condition) as there is an efficiency reduction expected due to operating at the GTs at lower than maximum design output (e.g. 330 MW is about 89% of maximum design output). The relationship as a function of turbine output is shown in *Figure 2-1*.

For the Scope 1 emission estimates the following is assumed for Natural Gas operations:

  - Output = 330 MW per GTG
  - Heat Rate = 9.904 GJ/MWh (HHV)

- For the 330 MW output operations it is therefore estimated that the natural gas consumption is about 0.239 GJ/MWh higher (~2.5% higher) than the OEM Natural Gas Case 2 for maximum design output.

Table 2-1: Gas Turbine Expected Performance Data Sheet for Gas Firing

Gas Turbine Expected Performance Data Sheet for Gas Firing

Sheet No. 1 Rev. for Contract DATE: 3-Aug-21

COMMERCIAL DATA														
Customer		Snowy Hydro												
Project Name		Kurri Kurri												
Manufacture Name		MITSUBISHI POWER , LTD.												
INPUT INFORMATION														
G/T Model		M701F												
NOx Control		DLN												
Fuel Type		Natural Gas												
Fuel LHV	kJ/kg	46384												
CONDITIONS		1	2	3	4	5	6	7		8	9	10	11	
Ambient Temperature	deg.C	-5	20	20	35	35	46	46		-5	20	35	46	
Relative Humidity	%	100	70	70	30	30	10	10		100	70	30	10	
Barometric Pressure	mbar	1007	1007	1007	1007	1007	1007	1007		1007	1007	1007	1007	
Frequency	Hz	50	50	50	50	50	50	50		50	50	50	50	
Eva.cooler	ON / OFF	OFF	OFF	ON	OFF	ON	OFF	ON		OFF	OFF	OFF	ON	
Wet Compression	ON / OFF	N/A	N/A	N/A	N/A	N/A	N/A	N/A		N/A	N/A	N/A	N/A	
GT Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0		100.0	100.0	100.0	100.0	
Net Output	kW	375,000	372,000	375,000	339,800	366,610	306,880	363,880		330,000	330,000	330,000	330,000	
Net Heat Rate	kJ/kWh	8,677	8,707	8,687	8,879	8,748	9,097	8,754		8,858	8,898	8,920	8,912	
Fuel Flow	kg/h	70,150	69,830	70,230	65,040	69,140	60,180	68,670		63,020	63,300	63,460	63,400	
Wet Compression Flow rate	t/h	0	0	0	0	0	0	0		0	0	0	0	
Exhaust Flow	Ton/h	2,606.7	2,680.0	2,678.8	2,539.6	2,645.1	2,387.1	2,634.0		2,454.3	2,422.0	2,475.2	2,431.9	
Exhaust Temperature	deg.C	638.8	638.0	638.2	648.2	641.4	659.9	642.2		622.2	650.0	651.1	650.0	
Exhaust Gas Composition														
O2	wt.%	12.54	12.70	12.62	12.86	12.55	13.09	12.57		13.01	12.66	12.85	12.57	
CO2	wt.%	7.10	6.87	6.92	6.76	6.90	6.67	6.88		6.78	6.90	6.77	6.89	
H2O	wt.%	5.78	6.35	6.49	6.29	6.88	5.81	6.84		5.53	6.37	6.29	6.84	
SOx	wt.%	0.00	0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	
N2	wt.%	73.27	72.78	72.67	72.79	72.37	73.12	72.41		73.37	72.77	72.79	72.40	
Ar	wt.%	1.31	1.30	1.30	1.30	1.30	1.31	1.30		1.31	1.30	1.30	1.30	
SOx	ppmvd	1.68	1.64	1.65	1.61	1.65	1.58	1.65		1.60	1.65	1.61	1.65	

Table 2-2: Gas Turbine Performance Data Sheet for Oil Firing

Gas Turbine Expected Performance Data Sheet for Oil Firing

Sheet No. 2 Rev. for Contract DATE: 3-Aug-21

COMMERCIAL DATA								
Customer		Snowy Hydro						
Project Name		Kurri Kurri						
Manufacture Name		MITSUBISHI POWER , LTD.						
INPUT INFORMATION								
G/T Model		M701F						
NOx Control		DLN						
Fuel Type		Distillate oil						
Fuel LHV	kJ/kg	42000						
CONDITIONS		1	2	3	4	5	6	7
Ambient Temperature	deg.C	-5	20	20	35	35	46	46
Relative Humidity	%	100	70	70	30	30	10	10
Barometric Pressure	mbar	1007	1007	1007	1007	1007	1007	1007
Frequency	Hz	50	50	50	50	50	50	50
Eva.cooler	ON / OFF	OFF	OFF	ON	OFF	ON	OFF	ON
Wet Compression	ON / OFF	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GT Load	%	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Net Output	kW	298,700	288,700	294,400	259,100	283,900	230,700	281,400
Net Heat Rate	kJ/kWh	9,343	9,428	9,381	9,739	9,486	10,097	9,509
Fuel Flow	kg/h	66,440	64,800	65,750	60,080	64,120	55,460	63,710
Water Injection Flow Rate for de Nox	t/h	54.0	53.0	53.0	49.0	52.0	45.0	52.0
Wet Compression Flow rate	t/h	-	-	-	-	-	-	-
Exhaust Flow	Ton/h	2,687.7	2,721.5	2,746.8	2,577.8	2,686.1	2,422.3	2,674.7
Exhaust Temperature	deg.C	525.0	525.3	523.6	537.0	528.6	550.3	529.5
Exhaust Gas Composition								
O2	wt.%	13.58	13.76	13.69	13.94	13.62	14.18	13.65
CO2	wt.%	7.85	7.57	7.61	7.41	7.58	7.30	7.57
H2O	wt.%	5.20	5.75	5.89	5.69	6.27	5.21	6.23
SOx	wt.%	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N2	wt.%	72.08	71.64	71.53	71.68	71.25	72.02	71.27
Ar	wt.%	1.29	1.28	1.28	1.28	1.28	1.29	1.28
SOx	ppmvd	0.24	0.24	0.24	0.23	0.24	0.23	0.24

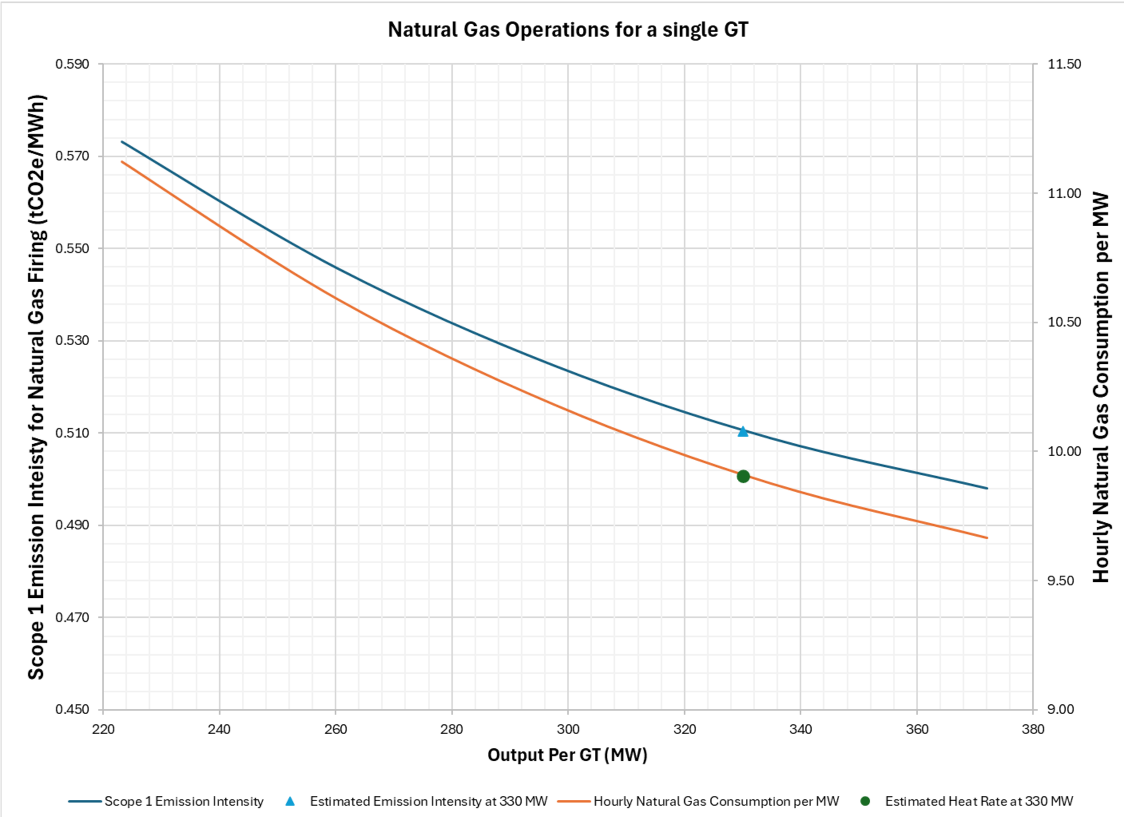


Figure 2-1 Thermoflow modelled GT Scope 1 emission intensity and heat rate as a function of output based on OEM Case 2 Specifications

The assumptions applied for the Scope 1 emission estimates for power station operations are:

- National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Compilation No. 18, Compilation date: 31/08/2024) Schedule 1 energy content factors and emission factors have been applied
- Year 1:
  - Assumes six months during commissioning, where operation is on diesel fuel only, at a capacity factor equalling 100 hours of operation. Maximum diesel firing output (288.7 MW per GT) is assumed for a conservative estimate of total emissions.
  - A further six months of operation on gas and diesel at the licenced capacity factors, but for the six month period:
    - Diesel operations for 175 hours per year / 2 = 87.5 hours. Maximum diesel firing output (288.7 MW per GT) is assumed for a conservative estimate of total emissions.
    - Natural gas operations for 925 hours per year /2 = 462.5 hours. Maximum Natural Gas firing output (330 MW per GT) is assumed for a conservative estimate of total emissions.
  - Back-up diesel generator annual fuel consumption of 10 kL (386 GJ).
- Years 2-30:
  - Assumes operation on gas and diesel at the licenced capacity factors:

   - Diesel operations for 175 hours per year. Maximum diesel firing output (288.7 MW per GT) is assumed for a conservative estimate of total emissions.
   - Natural gas operations for 925 hours per year. Maximum Natural Gas firing output (330 MW per GT) is assumed for a conservative estimate of total emissions.
- Back-up diesel generator annual fuel consumption of 10 kL (386 GJ).

Table 2-3 Year 1 Operating Scope 1 Emissions Estimates

Fuel	**Emission Source**	**Hours**	**Output per GT**	**Total Output**	**Heat Rate**	**Energy Consumed**	**NGER Emission Factor**	**Scope 1**	**Scope 1 Intensity**
			MW	**MWh**	**GJ/MWh**	**GJ**	**kgCO2e/GJ**	**tCO2e**	**tCO2e/MWh**
Diesel	Gas Turbine Commissioning and prior to construction completion	100	288.7	57,740	9.899	571,591	70.20	40,126	0.695
Natural Gas	Combustion in Gas Turbines	463	330	305,250	9.904	3,023,267	51.53	155,789	0.510
Diesel	Combustion in Gas Turbines	87.5	288.7	50,523	9.899	500,142	70.20	35,110	0.695
Diesel	Combustion in back up Generator					386	70.20	27	
Total		**650**		**413,513**	**30**	**4,095,387**		**231,052**	**0.559**

Table 2-4 Years 2-30 Annual Emissions Estimates

Fuel	**Emission Source**	**Hours**	**Output per GT**	**Total Output**	**Heat Rate**	**Energy Consumed**	**NGER Emission Factor**	**Scope 1**	**Scope 1 Intensity**
			MW	**MWh**	**GJ/MWh**	**GJ**	**kgCO2e/GJ**	**tCO2e**	**tCO2e/MWh**
Natural Gas	Combustion in Gas Turbines	925	330	610,500	9.904	6,046,535	51.53	311,578	0.510
Diesel	Combustion in Gas Turbines	175	288.7	101,045	9.899	1,000,285	70.20	70,220	0.695
Diesel	Combustion in back up Generator					386	70.20	27	
Total		**1,100**		**711,545**		**7,047,206**		**381,825**	**0.537**

As noted previously, Scope 2 and Scope 3 emissions do not apply to Infrastructure Approval (Conditions C2 to C4) and therefore, are not updated from the EIS for the NZPGP. However, to provided context the Scope 2 and Scope 3 emission estimates from the EIS are summarised in *Table 2-5*, which illustrates that Scope 1 emissions are the predominant emission type (~80% of the total shown in *Table 2-5*).

Table 2-5 Annual and Lifetime Emissions Estimates Summary by Scope during operations

Scope	**Annual Emissions – Year 1 (t CO_2-e)**	**Annual Emissions – Years 2-30 (t CO_2-e)**	**Lifetime Emissions – 30 Years (t CO_2-e)**
Scope 1	231,052	381,825	11,303,978
Scope 2 (as per EIS adjusted for FY25 NSW grid factor)	381	381	11,430
Scope 3 (as per EIS)	48,925	93,572	2,762,513
Total Emissions (all Scopes)	**280,358**	**475,778**	**14,077,921**

2.2 Emissions intensity

As described in Australia's Long-Term Emissions Reduction Plan (Australian Government, 2021), the Australian Government's pathway for achieving net zero emissions by 2050 is set out by deployment of low emissions technology at scale in all sectors, including electricity generation. The Department considers that this project operating as a peaking plant, with an emission intensity significantly lower than coal-fired power generation, while also providing dispatchable power, has an important role to play in overall system reliability and security.

Based on the GHG assessment presented in Section 2.1.2 during the Year 2 through 30 operation the HPP emission intensity is estimated as 0.54 tCO_2-e/MWh (Scope 1 + 2). This is based on the annual Scope 1 emissions and output estimates summarised previously in *Table 2-4*. Emission intensity in Year 1 is estimated to be slightly higher (0.56 tCO_2-e/MWh) due to commissioning activities, where operation is on diesel fuel only.

The HPP emission intensity is estimated to be better than other F-Class OCGT power stations connected to the NEM as shown in Table 2-6.

Table 2-6 Comparison of HPP emission intensity to other NEM connect OCGT Power Stations

Plant Name	**Year of Commission**	**Turbine Class**	**Nominal Capacity**	**Total Scope 1 + 2 Emissions**	**Energy Produced**	**Emission Intensity**
			MW	**tCO_2-e**	**MWh**	**tCO_2-e/MWh**
Oakey Power Station, QLD	1999	E-Class	332	55,368	78,323	0.71
Laverton North Power Station, VIC	2006	E-Class	320	74,824	116,734	0.64
Colongra Power Station, NSW	2009	E-Class	668	68,817	105,241	0.65
Mortlake Power Station, VIC	2012	F-Class	566	257,274	449,318	0.57
Bairnsdale Power Station, VIC	2001	Aero-derivative	92	34,130	62,804	0.54
Hunter Power Project, NSW	**2023**	**F-Class**	**660**	**382,206**	**711,545**	**0.54**

Notes:

1. Total Emissions, Energy Production, and Emissions Intensities for other plants have been derived from the 2023-24 NGER Electricity Sector Emissions and Generation Data.

2. Parameters for the Hunter Power Project are based on the EIS greenhouse gas assessment estimates as presented in the NZPGP, which assumes 1,100 hr operations per year at maximum output. Emissions intensities of the existing plants presented would have been impacted at any operations at part-load and by performance degradation since those plants were commissioned.

Based on 2023-24 electricity sector NGER data[4], the Hunter Power Project has a forecast emission intensity that is comparable to the lowest emission intensities of all OCGT power stations connected to the NEM in Australia as shown in Figure 3.

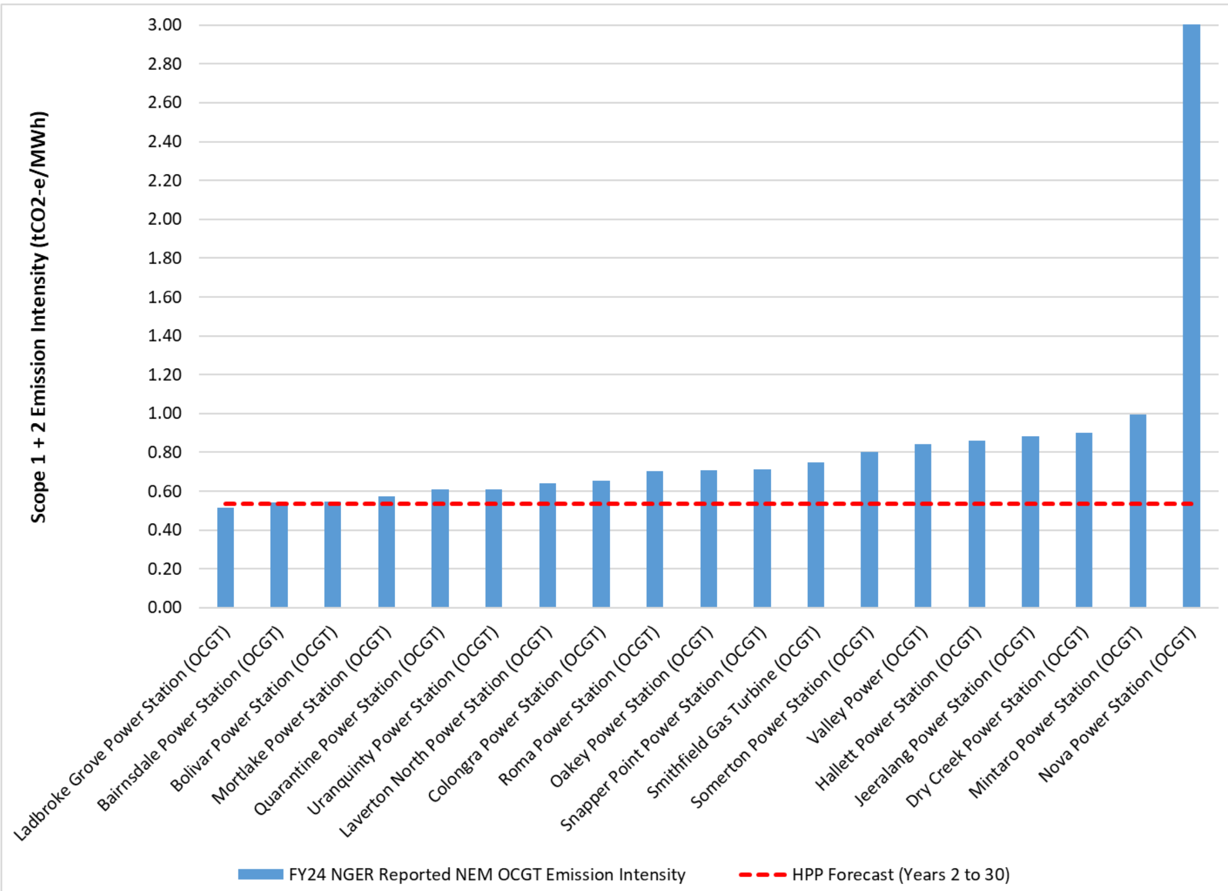


Figure 2-2 FY24 Scope 1 + 2 Emission Intensity of NEM Connected Open Cycle Gas Fired Power Stations

In comparison to other grid connected renewable and fossil fuelled power stations in Australia, the average emissions intensity is projected to be lower than the average for all other grid connected fossil fuel powered power stations, including the average for other natural gas power stations (which includes combined cycle plants).

[4] https://cer.gov.au/markets/reports-and-data/nger-reporting-data-and-registers/electricity-sector-emissions-and-generation-data-2023-24#designated-generation-facility-data-2023%E2%80%9324

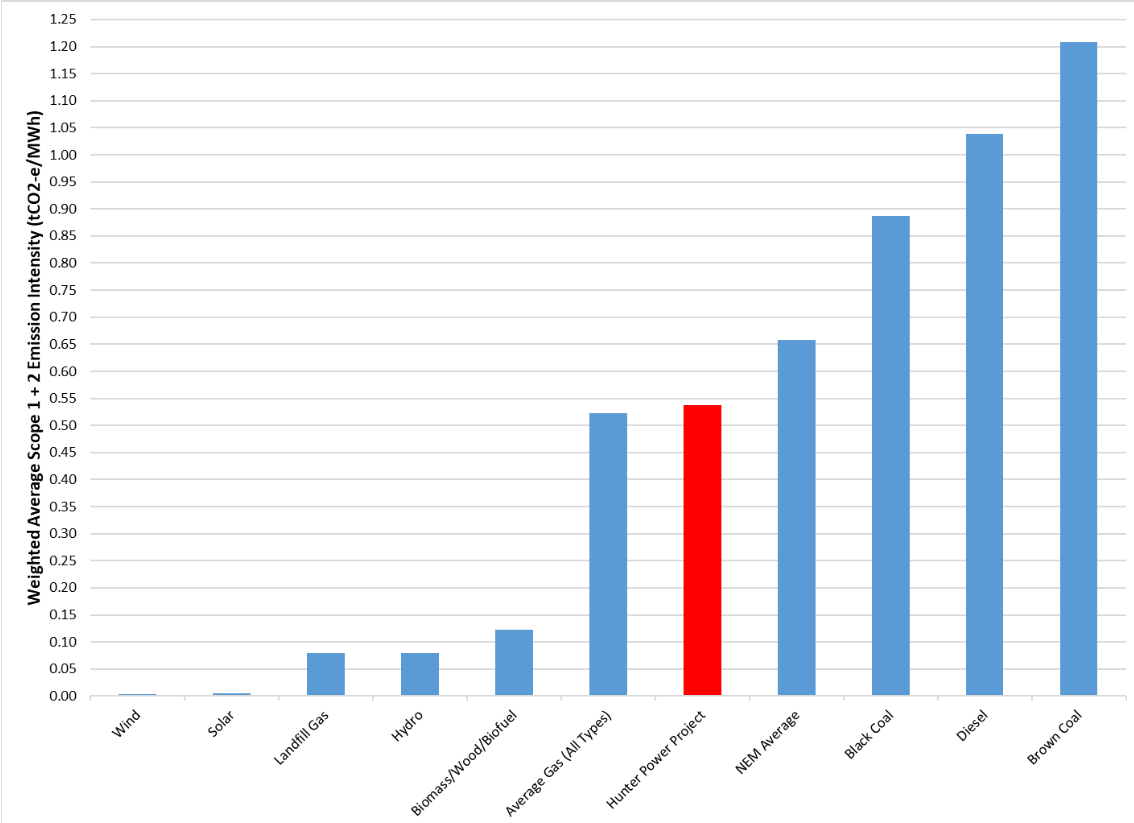


Figure 2-3 Comparison of the weighted average emission intensity of the Proposal to other NEM connected power sources

2.3 Comparison with NSW emissions

In 2022, NSW recorded net greenhouse gas emissions of 110.997 million t (Mt) CO_2-e.[5] By 2030 NSW GHG emissions are targeted to fall to 78.9–87.6 MtCO_2-e per year, a 47–52% reduction from 2005 levels.

Based on the annual Scope 1 emission estimates for the HPP (381,825 tCO_2-e for 1,100hr operations) the power station emissions would account for a maximum about 0.34% of 2022 NSW emissions and about 0.44%-0.48% of the target 2030 NSW emissions.

Relative to Australian total greenhouse gas emissions the HPP emissions would account for a maximum about 0.09% of 2022 Australian emissions based on a total of 432.6209 MtCO_2-e emitted in Australia during 2022.[6]

[5] https://www.greenhouseaccounts.climatechange.gov.au/
[6] https://www.greenhouseaccounts.climatechange.gov.au/

The GHG Assessments were previously reviewed and assessed by the Department[7] and the following was noted in the 2021 Assessment Report[8]:

- *The Department acknowledges that the NSW Government has recently announced through the Net Zero Plan Stage 1: 2020-2030 Implementation Update (2021), a target of reducing NSW's emissions by between 47-52% compared to 2005 levels by 2030 – with an emissions target of between 78.9 to 87.6 MtCO_2-e per year that would be achieved through current policy settings.*

- *Based on the NSW Government's latest emissions modelling information, the Department considers that the project would not significantly increase greenhouse gas emissions in NSW or constrain the ability to achieve the target of a 50% reduction in emissions by 2030. Further, the hydrogen capabilities of the project present the opportunity to further reduce the emissions of the project, where clean hydrogen is used in the fuel mix.*

To further ensure that GHG emissions estimates are not exceeded, the Department has included the following conditions in the Infrastructure Approval, which limits total operating hours and the portion of the operational time when diesel may be used.

> *A8. Fuel burning equipment must not be operated for the purpose of generating electrical power at the premises for more than 1,100 cumulative hours per calendar year.*
>
> *A9. Fuel burning equipment must not be fired on diesel for the purpose of generating electrical power at the premises for more than 175 cumulative hours per calendar year.*

[7] NSW Department of Planning, Industry and Environment, Hunter Power Project (Kurri Kurri Power Station). Critical State Significant Infrastructure Assessment (SSI 12590060), November 2021

[8] NSW Department of Planning, Industry and Environment, Hunter Power Project (Kurri Kurri Power Station). Critical State Significant Infrastructure Assessment (SSI 12590060), November 2021

3. Safeguard Mechanism obligations

The Safeguard Mechanism is the Australian Government's policy for reducing emissions at Australia's largest industrial facilities. It sets legislated limits, known as baselines, on the greenhouse gas emissions of these facilities. These emissions limits will decline, predictably and gradually. These limits will help achieve Australia's emission reduction targets of 43% below 2005 levels by 2030 and net zero by 2050.

The Safeguard Mechanism commenced in 2016. It was reformed in 2023 to ensure that covered facilities contribute to meeting these targets.

The Safeguard Mechanism is applicable to facilities that emit more than 100,000 tCO_2-e a year. For these facilities baselines are set. The Safeguard Mechanism applies to the electricity sector as a single 'sectoral' baseline across all electricity generators connected to one of Australia's main electricity grids. Individual grid-connected electricity generators are not covered if total emissions from grid-connected electricity generators do not exceed the sectoral baseline. Therefore, by being covered by the sectoral baseline, the HPP will not have a facility specific Safeguard Mechanism baseline (if total emissions from grid-connected electricity generators do not exceed the sectoral baseline).

The sectoral baseline is 198 million tCO_2-e per year. Scope 1 emissions for grid connected electricity generators in 2023-24 totalled 137 million tCO_2-e (31% below the sectoral baseline).

The HPP will contribute to achieve the sectoral baseline by supporting the sector's transition away from high emitting power generators. Snowy Hydro estimate that the HPP will facilitate an estimated 2 GW of renewables, displacing approximately 5.8 million tons of CO_2 emissions per year out of the electricity system. The SHL Annual Report for the 23/24 financial year estimated that the total emissions from HPP generation are estimated to be around 0.14 million tonnes of CO_2 per annum (assuming a ~3.5% capacity factor), equating to a significant net benefit to Australia's transition to renewables and contribution to the electricity sector achieving the sectoral baseline.

The HPP will comply with any possible future amendments or reductions to sectoral baseline and/or potential future legislative reforms to the Safeguard Mechanism.

4. Electricity Firming Infrastructure obligations

Snowy Hydro Limited has no Long-Term Energy Service Agreements (LTESA) for the HPP; therefore, the Electricity Firming Infrastructure obligations do not apply.

5. GHG emission goals

The Infrastructure Approval requires the NZPGP to describe measures to displace or offset greenhouse gas emissions having regard to the targets listed in the following condition:

C2. (d) describe measures to displace or offset greenhouse gas emissions having regard to:

(ii) the following Net Zero targets by calendar year:

- *from the commencement of operations until 2029: 10% of total Scope 1 greenhouse gas emissions;*
- *from 2030 until 2039: all Scope 1 greenhouse gas emissions resulting from generating electrical power at the premises for more than 175 cumulative hours per calendar year (or 2% of the year); and*
- *from 2040 onwards: all Scope 1 greenhouse gas emissions.*

An independent engineering assessment of multiple opportunities to displace or offset emissions to achieve the Infrastructure Approval Condition C2(d)(ii) targets was undertaken and is discussed in Section 6. The strategies to displace or offset emissions are discussed in Section 7.

The HPP, as the new Snowy Hydro fast-start, on-demand gas station, will enable the integration of more wind and solar energy into the grid. Supporting renewables in the NEM is an integral component of Australia's decarbonisation efforts and achieving Snowy Hydro and national emissions targets.

The HPP is being developed as a strategic asset to contribute to the overall Snowy Hydro GHG reduction strategy and the broader decarbonisation of the NEM. The Snowy Hydro Statement of Expectations primary objective is to provide and enable reliable, secure, affordable, renewable and firming energy in Australia, including the facilitation of decarbonisation of the National Electricity Market (NEM).[9] By providing firmed energy, Snowy Hydro has currently contracted 1.7 GW of renewables that are progressively being commissioned, with plans to increase this further in the coming years. These renewables are displacing approximately 5.8 million tonnes of CO_2 emissions per year out of the electricity system[10].

[9] Snowy Hydro Limited, Statement of Expectations, 20 December 2024

[10] The renewable production HPP supports is variable and therefore the direct emissions from HPP will be variable. Total emissions from HPP generation are estimated to be around 0.14 million tonnes of CO_2 per annum (assuming about a 3% capacity factor), equating to a significant net benefit to Australia's transition to renewables.

6. Measures to displace or offset GHG emissions

This facility will be providing peaking power at times of high demand and low supply from intermittent renewable generation and changing electricity market demands. Although the power station is licenced to operate a maximum of 1,100 hrs/yr (12.6% capacity factor), it is expected to operate an average of 2% (175 hours/year) of the year with possible variances to 4-8% of the year (~350-700 hours of operation/year, respectively). This will result in much lower emissions than those presented in Section 2. Given the timing of this NZPGP (i.e. prior to the commencement of operation) the following measures to avoid and reduce GHG emissions are options that may be considered into the future as the actual operating averages year on year are currently not established.

Approach to assessment of GHG emissions reduction options

When considering carbon emissions reductions, it is important to note that whilst best endeavours to reduce emissions are important for peaking plants, the greatest value of peaking plants, with respect to reducing carbon emissions, is the enablement of the broader decarbonisation of the National Energy Market (NEM), supporting net zero policy objectives of state and federal governments.

The Department has noted the following in their 2021 Assessment Report[11]:

> *Based on the NSW Government's latest emissions modelling information, the Department considers that the project would not significantly increase greenhouse gas emissions in NSW or constrain the ability to achieve the target of a 50% reduction in emissions by 2030. Further, the hydrogen capabilities of the project present the opportunity to further reduce the emissions of the project, where clean hydrogen is used in the fuel mix.*

To support the development of this NZPGP, a high-level technical engineering study was conducted to investigate opportunities to achieve Net Zero GHG emissions from the HPP. Key focus areas included:

- Assess the HPP technology against best available technology gas turbine peaking plants;
- Review operational and maintenance practices to reduce emissions;
- Review the potential of using hydrogen or other biofuels to displace fossil fuels;
- Review potential technology options to reduce Scope 1 emissions; and
- Evaluate potential options to off-set Scope 1 emissions.

A model of the HPP turbines was developed using Thermoflex software to assist in assessment of given options to reduce carbon emissions. The options to reduce emissions were considered based on key aspects including:

- Technical Feasibility / Readiness;
- Cost Implications; and
- Assessing the GHG emission reduction estimates against targets listed in Infrastructure Approval condition C2(d)(ii).

Using these criteria, several opportunities were assessed and considered in the context of the different emissions reduction targets (as specified in Infrastructure Approval condition C2(d)) as a means of evaluation and comparison of the different emissions reduction options. Outputs from the technical

[11] NSW Department of Planning, Industry and Environment, Hunter Power Project (Kurri Kurri Power Station). Critical State Significant Infrastructure Assessment (SSI 12590060), November 2021

assessment of different options were presented on a per MW or MWh basis (e.g. t CO_2 /MWh) where possible to facilitate direct comparison of emissions reductions options.

Importantly, a range of plant information and assumptions were required to undertake the technical review of options to reduce carbon emissions. It must be highlighted that there are uncertainties in a range of these parameters given that the HPP is not yet operational and the uncertainty of use into the future. Key project information and assumptions are listed below in *Table 6-1*.

Table 6-1 Key Project Information and Assumptions

Item	Value
Project location	Hunter Valley, NSW
Ambient temperature	20°C
Relative humidity	70%
Technology type	Open cycle gas turbines
No of turbines	2
GT model	Mitsubishi Power M701F
NOx Control	Dry Low NOx (DLN)
Fuel types	Natural gas and diesel
Operating hours - maximum	1,100 hours/yr
Maximum number of hours of operation (diesel)	175/year
Maximum allowable plant output	660 MW
Natural gas energy value	46,384 kJ/kg LHV
Design case modelled	100 % load natural gas firing
Natural gas composition	Composition specified to match design case fuel energy value
Design maximum power output	372 MW per gas turbine for natural gas firing at 100%
Load when operating	100%
Start-up time for turbines	30 minutes

Key design performance data for natural gas and diesel fired operation is presented in *Table 6-3*.

Table 6-2 Key Performance Data for Natural Gas and Diesel Firing

Item	Units	Natural Gas (Design Case 2)	Diesel (Design Case 2)
Ambient temperature	°C	20	20
Relative humidity	%	70	70
Evaporator cooler	-	Off	Off
GT load	%	100	100
Net output	kW	372,000	288,700
Net heat rate	kJ/kWh	8,707	9,428
Fuel flow	kg/h	69,830	64,800
Exhaust flow	kg/h	2,680	2,721.5
Exhaust temperature	°C	638.0	525.3
Exhaust oxygen concentration	wt %	12.70	13.76
Exhaust CO_2 concentration	wt %	6.87	7.57

Consolidated Assessment of Options to Reduce GHG Emissions

The range of options considered in the engineering assessment are detailed in the following sections:

GHG Emissions Reduction Option	NZPGP Section
Operational and maintenance practices to reduce emissions	Section 6.2
Fossil fuel displacement to reduce Scope 1 emissions	Section 6.3
Technology options to reduce Scope 1 emissions	Section 6.4
Carbon offsets	Section 6.5

A consolidated assessment of the range of options to reduce GHG emissions is presented in the current section of the NZPGP. The individual sections of the plan outlined above should be referred to for more detail on the specific options considered and the reasoning for their feasibility assessment and justification for why the options were not recommended for implementation.

As noted previously turbine fuel combustion emissions will be the predominant emission source and are expected to account for essentially all the GHG emissions (Scope 3 emissions are predominantly associated with the fuel supplies and are therefore dependent on fuel use). Therefore, mitigation measured that were assessed focused on reducing fuel combustion.

A summary of the assessment findings is presented in *Table 6-3* to *Table 6-5*.

Low carbon fuels are a potential means of reducing net emissions with the cost implication dependent on the fuel type and potential turbine modifications required for firing the alternative fuel. The availability of alternative fuels and technical feasibility of utilising alternative fuels in the HPP gas turbines will be reviewed over the life of the HPP.

Opportunities to reduce emissions in the short to medium term are limited since the HPP is a new built power station that is considered Best Available Technology (BAT) for open cycle gas turbines. Additionally, due to peaking plant operations there is limited potential to reduce GHG emissions through operational practices, such as minimising start-ups and load optimisation, since these factors will predominantly be a function of NEM requirements.

Furthermore, opportunities to achieve Net Zero GHG emissions were undertaken as an engineering screening study to identify potentially prospective options. Further detailed engineering studies would be required to progress opportunities and/or validate economic and technical feasibility. As noted by the EPA during the consultation process:

- Hydrogen can produce NOx when combusted and therefore utilisation of hydrogen as a fuel could impact HPP non-greenhouse gas emissions. This would also be applicable to utilisation of other potential fuels and would require further analysis if fuel switching options are progressed in the future.

- Hydrogen is estimated to have a global warming potential (GWP) of approximately 11 ± 5 (100-year GWP) and therefore hydrogen leaks and/or un-combusted hydrogen emissions would produce Scope 1 emissions. However, it is noted that:

    - The GWP for Methane (primary component of Natural Gas) that is used for NGER reporting is 28, which is higher than for hydrogen.

    - Currently hydrogen is not a greenhouse gas that is reported under the NGER system.

- Ammonia used as a fuel presents hazards associated with its handling and storage. Safety hazards relating to the use of any alternative fuel would require detailed evaluation if a fuel switching options was progressed in the future.

Key measures that Snowy Hydro will have regard to for reducing emissions include:

- Maintenance practices, in accordance to OEM recommendations, to ensure the equipment is kept in best practicable operating condition, which will contribute to maximising efficiency.
- Operational practices (within NEM demand restraints):
  - Minimise run-up and run-down times;
  - Minimise number of start-ups;
  - Optimise load (MW output) to high efficiency set point.
- Carbon offsets.

Additional options for future consideration when and if economic and technical feasibility changes include:

- Fossil fuel displacement opportunities, including:
  - Hydrogen (or other renewable fuel, such as biomethane) blending into the feed gas;
  - Biodiesel and/or renewable diesel to offset fossil diesel.
- Carbon capture and storage and/or utilisation.

A summary of mitigation options for reducing carbon emissions for the HPP is presented in Table 6-3.

Table 6-3 Summary of Operational and Maintenance Practices to Reduce Scope 1 Emissions for the HPP

Mitigation Option	Description	Scale of Scope 1 Mitigation	Technical Suitability	Prospective Option for 10% Scope 1 Reduction	Prospective Option for 100% Scope 1 Reduction	Justification for Feasibility / Comment
Inlet combustion air cooling	Cooling combustion air to increase mass flow and turbine output and efficiency	NA		No	No	Air cooling is already included in plant design.
Increase fuel quality	Utilise higher quality fuel which results in lower CO_2 emission	Small		No	No	Gas is received by pipeline with the specification out of the HPP control.
Upgrades to increase turbine efficiency	Upgrade turbine to increase efficiency and reduce emissions	Small		No	No	Plant is new and utilises best available technology so opportunities to increase efficiency are limited.
Reduce start-up times	Minimising start-up time minimises unnecessary fuel consumption and emissions.	Small		No	No	The plant has a short start up time of 30 minutes which is set by the turbine OEM.
Load optimisation	Carbon emissions from a gas turbine are strongly influenced by load.	Small		No	No	Load optimisation will not lead to emissions reduction but would be a means of minimising emissions.
Implement different NOx emissions control technology	The choice of NOx emission technology can impact gas turbine efficiency and output.	Small		No	No	The HPP turbines include dry low NOx which is the NOx emissions control technology which is considered the optimum NOx reduction technology from a heat rate / net unit efficiency perspective.
Modify / improve maintenance practices	Maintenance practices will have an impact on plant efficiency.	Small		No	No	Maintenance practices will be established to ensure the equipment is kept in best practicable operating condition, which will contribute to maximising efficiency and minimising emissions.

Table 6-4 Summary of Fossil Fuel Displacement Options to Reduce Scope 1 Emissions for the HPP

Option	Description	Scale of Scope 1 Mitigation	Fuel Suitability	Fuel Availability (2025)	Prospective for <u>10%</u> Scope 1 Reduction	Prospective for <u>100%</u> Scope 1 Reduction^	Justification for Feasibility / Comment
Biodiesel	Displacing fossil fuels with renewable fuels or lower carbon fuels will reduce net plant carbon emissions.	Dependant on maximum feasible biodiesel input.	Selected parameters don't match turbine specification		Yes	Potentially, but reduces output by >12% (e.g. 289 MW vs 330 MW gas firing)	Need to confirm suitability for MHI turbine given that selected biodiesel parameters do not match turbine specification. A key constraint would be reduced maximum plant output and thus reduced revenue. Additionally, diesel operations are licenced for a maximum for 175 hours which may also apply to biodiesel.
Renewable diesel (biomass based)		Dependant on maximum feasible Renewable Diesel input.	Expected to meet diesel specification	Not currently commercially available. Availability would be reviewed over time.	Potentially suitable. Further evaluation required.		Not currently commercially available. The technical suitability for use in MHI gas turbines would need to be confirmed. A key constraint would be reduced maximum plant output and thus reduced revenue. Additionally, diesel operations are licenced for a maximum for 175 hours which may also apply to Renewable Diesel.
Hydrogen		~10% at 30% fuel addition	Limited to ~30% without significant modifications		Yes	No	Limit on maximum hydrogen fraction. Suitability of hydrogen dependant on cost and availability which is currently limited.
Biomethane		100%	Provided meets pipeline / turbine specification	Not currently commercially available. Availability would be reviewed over time.	Yes	Yes	Technically suitable option provided biomethane specifications match pipeline quality specification / turbine specification. Prospective future option if biomethane available at suitable price.
Synthetic natural gas (biomass based)		100%	Provided meets pipeline / turbine specification		Potentially suitable although further evaluation would be required.	Potentially suitable although further evaluation would be required.	Alternative fuels not currently commercially available but they represent possible future options. The technical suitability of fuels for use in MHI gas turbines would need to be confirmed. The availability of alternative fuels and technical feasibility of utilising alternative fuels in the HPP gas turbines will be reviewed over the life of the HPP.
Bio-ethanol		Further work required to evaluate potential reduction	Further work required to assess suitability / modifications for MHI turbine				
Bio-methanol							
Sustainable liquid fuels							
Ammonia							
Straight vegetable oil (SVO)							

^ ***Note:*** *No fuel displacement option could result in 100% Scope 1 reduction. Options were considered at near 100% reduction (i.e. reduction of 100% CO_2 emissions from Turbine fuel combustion)*

Table 6-5 Summary of Technology Options to Reduce Scope 1 GHG Emissions for the HPP

Mitigation Option	Description	Scale of Potential Mitigation	Technical Feasibility / Readiness	Cost	Prospective for <u>10%</u> Scope 1 GHG Emissions Reduction	Prospective for <u>100%</u> Scope 1 GHG Emissions Reduction	Justification for Feasibility / Comment
Carbon capture and sequestration / utilisation	Post combustion removal of the carbon dioxide from the gas turbine exhaust combined with either sequestration or utilisation.	>90%	Carbon capture is feasible although a storage or utilisation option would be required.	High	10% reduction would be achievable but capital intensive option and not well suited to peaking plant.	High reduction (>90%) would be achievable but capital intensive option and not well suited to peaking plant.	Carbon capture is technically proven although there are currently limited utilisation and sequestration options which limits the applicability to the Hunter Power Project. Carbon capture represents a high capital cost mitigation option which is not ideally suited to peaking plants which operate a small proportion of the year.
Implementation of combined cycle	The hot gases produced from combustion in the gas turbine are passed through a heat recovery steam generator (HRSG) to raise steam which is supplied to a steam turbine to produce electricity.	Up to 30% reduction in carbon intensity. Does not reduce Scope 1 emissions although reduces carbon intensity.	Combined cycle technology is commercially proven although not well suited to peaking plants.	High	Option capable of 10% reduction but capital intensive option and not well suited to peaking plant.	Reduction limited to about 30%	Combined cycle technology is widely utilised although typically for baseload or intermediate capacity factor applications. Implementation of combined cycle would represent a high capital cost mitigation option. Additionally, it is not a well suited technology for peaking plants which operate a small proportion of the year.

Table 6-6 Summary of Options to Offset Scope 1 GHG Emissions for the HPP

Mitigation Option	Description	Scale of Mitigation	Cost Implication	Prospective Option for <u>10%</u> Scope 1 GHG Emissions Reduction	Prospective Option for <u>100%</u> Scope 1 GHG Emissions Reduction	Justification for Feasibility / Comment
Acquisition of ACCUs	Acquiring carbon credits to offset emissions.	Up to 100%	Dependent on ACCU cost and extent of reduction	Prospective option although viability dependent on ACCU availability and cost.		Snowy Hydro will give preference to reducing direct emissions through implementing commercially viable mitigation measures. Therefore, carbon offsets will likely be a secondary measure.

6.1 Operational and Maintenance Practices to Reduce Emissions

Operational and maintenance practices utilising the existing plant, with the aim of improving heat rates and reducing fuel usage and thus carbon emissions, could be considered as a means of reducing carbon emissions. Such approaches typically do not require significant capital expenditure or changes in fuel type.

The applicability of such options at the HPP, and the extent of carbon emissions reduction achievable, depends on the specifications and procedures for the gas turbines. Importantly, as the HPP is a peaking plant, the applicability of operational and maintenance practices that may be suitable for a base load plant, may not be suitable for the HPP.

6.1.1 Comparison against Best Practice for Open Cycle Gas Turbine Peaking Plants

A review of industry best practice operational and maintenance practices used to minimise greenhouse gas emission intensity for Open Cycle Gas Turbine (OCGT) plants operated as peaking power stations was completed to assess whether the HPP equipment and practices represent best practice. This also allowed for the identification and assessment of practices and improvement options.

When compared, OCGT plants are more flexible than combined cycle plants with faster starts, lower part load and faster load ramping. OCGT plants are more capable as peaking plants to support intermittent renewable generation and changing electricity market demands, where the plant will have limited number of operating hours each year.

The additional steam cycle included in combined cycle plants adds additional capital cost but does make the plant more efficient at converting energy to electricity, resulting in reduced GHG emissions per MWh. Combined cycle plants are widely used for baseload power generation with a high-capacity factor and high number of hours per year. Importantly, traditional combined cycle plants are less flexible given the inclusion of the steam cycle, which inherently has limitations on ramp rates and start-up times.

More flexible combined cycle units have been developed recently, given the penetration of more intermittent electricity sources (i.e. renewables) into the electricity generation market. Fast start combined cycle plants can incorporate a range of techniques to reduce start-up times and increase ramp rates.

The fast start combined cycle plants have improved flexibility and are well suited to intermediate capacity factors. The capacity factor proposed for the HPP, which is designed as a peaking plant, will be low (maximum 1,100 hours per year or 12.6% and expected capacity factor of 2%). It is thus considered that open cycle technology is the most appropriate technology selection for the HPP. Additionally, conversion to CCGT is not considered a viable option for the HPP units as there is not sufficient space to install a Heat Recovery Steam Generator at the exhaust of each unit required for CCGT conversion.

The efficiency of a gas turbine impacts the fuel use and thus the carbon emissions. The achievable efficiency for a given gas turbine is impacted by a range of factors including turbine type, capacity, pollution control inclusions, operating and maintenance practices, plant location, ambient conditions and operating load.

Energy efficiency associated with Best Available Technology (BAT) for new gas turbines[12] is 36 to 40% (HHV) or about 39.6 to 44.0% (LHV). The gas turbines selected for the HPP have been estimated to have a gross efficiency of 40.6 % (LHV) suggesting the units can be considered as best available technology.

The use of the latest technology F-Class gas turbine design includes improved turbine blading designs and allows the turbines to operate with higher compression pressure ratios and increased firing temperature, amongst other design features. These factors contribute somewhat to a decreased gas turbine heat rate and subsequently an increased turbine efficiency and improved emissions intensity.

[12] Ireland EPA, BAT Guidance Note on Best Available Techniques for the Energy Sector (Large Combustion Plant Sector)

6.2 Operational and maintenance practices to minimize fuel consumption

Given that the gas turbines selected for the HPP are considered high efficiency OCGTs, there are limited opportunities (particularly due to operation as a peaking plant) to implement operational and maintenance practices which will lead to a significant reduction in emissions. Effective operational and maintenance practices will however be adopted to maintain plant efficiency and minimise carbon emissions over the life of the plant. Some practices are noted below to further demonstrate best technology and practice.

6.2.1 Inlet Combustion Air Cooling

Increased plant outputs can be achieved by precooling the combustion air to the turbine, which increases mass flow to the turbine. However, doing so, will not necessarily increase efficiency or result in a reduction in carbon emissions. The typical categories for cooling are evaporative cooling and chilling systems. Evaporative cooling involves adding liquid water into the combustion air whilst chilling systems use mechanical or adsorption chillers and can have a significant auxiliary power load. The HPP has evaporative cooling; therefore, additional inlet combustion air cooling is not considered a prospective technology for further improving efficiency and reducing carbon emissions.

The evaporative cooling is estimated to reduce heat rate by about 0.23% at maximum output conditions for lower ambient temperature (20°C). Comparing high ambient temperatures (46°C), there will be a more significant improvement in heat rate of ~3.8% with the evaporative cooler in operation and additionally the achievable net sent out power will be significantly higher (57 MW).

These results suggest that operating the HPP with the evaporative cooler on will be an operational practice which limits carbon emissions and allows operation at higher outputs.

6.2.2 Increase Fuel Quality

The natural gas quality can also impact resultant carbon emissions. Higher methane content results in lower CO_2 emissions per unit of energy produced given that methane has a higher hydrogen-to-carbon ratio compared to other hydrocarbons. Impurities such as the presence of higher hydrocarbons (e.g., ethane, propane) and non-combustible impurities like CO_2 and nitrogen should also be minimised. The HPP will receive pipeline natural gas which meets specifications for pipeline gas in Australia.

Snowy Hydro will not be able to influence the quality of natural gas delivered to the HPP and thus increasing fuel quality is not considered a prospective option to reduce carbon emissions.

6.2.3 Upgrade Turbine to Achieve Higher Efficiency

The HPP includes high efficiency turbines considered to be BAT. Thus turbine upgrades to achieve higher efficiency to reduce fuel consumption and GHG emissions is unlikely to be a practical option to reduce carbon emissions.

6.2.4 Improved Combustion Conditions

Combustion efficiency is influenced by factors including compression ratio and firing temperature. The discharge pressure of the compressor relative to ambient pressure is termed the compression ratio. For a given firing temperature, a higher compression ratio will yield better efficiency. Turbine firing temperature is proportional to specific output power. There is an optimum adiabatic temperature ratio between the compressor and turbine that maximizes power output and efficiency.

The turbine operating conditions are specified by the manufacturer and should be optimised for the turbine design.

6.2.5 Reduce Start-up and Run-down Times

Minimising start-up time needed to reach full operational capacity minimises unnecessary fuel consumption and emissions. The start-up time for the gas turbines is a manufacturer specification and is considered relatively short, at about 30 minutes.

The impact of emissions during start-up will be dependent on the length of time the plant operates for each start. If the plant were operated for longer periods following each start and for less days per year, then the emissions associated with start-up would reduce.

The above point is presented to highlight the impact of start-up on emissions, although in practice, other factors will control how often and for how long this plant is operated. Reducing the start-up time would however reduce Scope 1 emissions.

Run-down times will also have a similar impact on emissions as start-ups.

Operation of the HPP will have regard to reducing emissions, within NEM demand restraints, by making effort to:

- Minimise run-up and run-down times; and
- Minimise number of start-ups.

As a peaking plant, HPP will be required to start up when needed and run as long as needed. Reducing the number of start-ups and increasing the time the plant is operated will primarily be dependent on NEM requirements.

6.2.6 Load Optimisation

Carbon emissions from gas turbines are strongly influenced by load. At 60% load, which is the minimum load based on emissions compliance requirements, the carbon emissions intensity would increase by about 14% when compared to 100% load. Through load optimisation it could be possible to minimise carbon emissions. For example, the carbon emissions for operating two units at 60% load would be about 14% higher than for operating one unit at 100% load.

Operation of the HPP will have regard to reducing emissions, within NEM demand restraints, by making effort to optimise load to a high efficiency set point. However, as a peaking plant, HPP will be required to operate in a manner to meet NEM requirements, which may require operating at lower than optimal loads for efficiency.

6.2.7 NOx Emissions Control Technology

The choice of NOx emission technology can impact gas turbine efficiency and output. The two primary types of control are wet low NOx (WLN) which involves the addition of water or steam and dry low NOx (DLN) which involves staged air combustion. Both approaches reduce the peak flame temperature which reduced NOx formation. The WLN technology increases mass flow to the turbine which increased power output. However, the efficiency of the turbine reduces (by about 3%) given the energy consumption for evaporating the injected water.

DLN is the more optimal control type from a heat rate / net unit efficiency perspective. The HPP turbines include DLN, therefore, this can be considered best available technology.

6.2.8 Regular Maintenance

Regular maintenance on the gas turbines will assist in maintaining peak plant efficiency, and by doing so, will minimise GHG emissions. Examples of regular maintenance are compressor and turbine blade cleaning, combustion air filter cleaning/replacement and fuel leak detection/repair.

Maintenance practices will be aligned with OEM recommendations that will ensure the equipment is kept in best practicable operating condition, which will contribute to maximising efficiency.

6.3 Fossil fuel displacement to reduce Scope 1 emissions

Displacing fossil fuels with alternative fuels is a potential pathway to significantly reducing carbon emissions. There are a wide range of fuels that have been fired in gas turbines, as illustrated below.

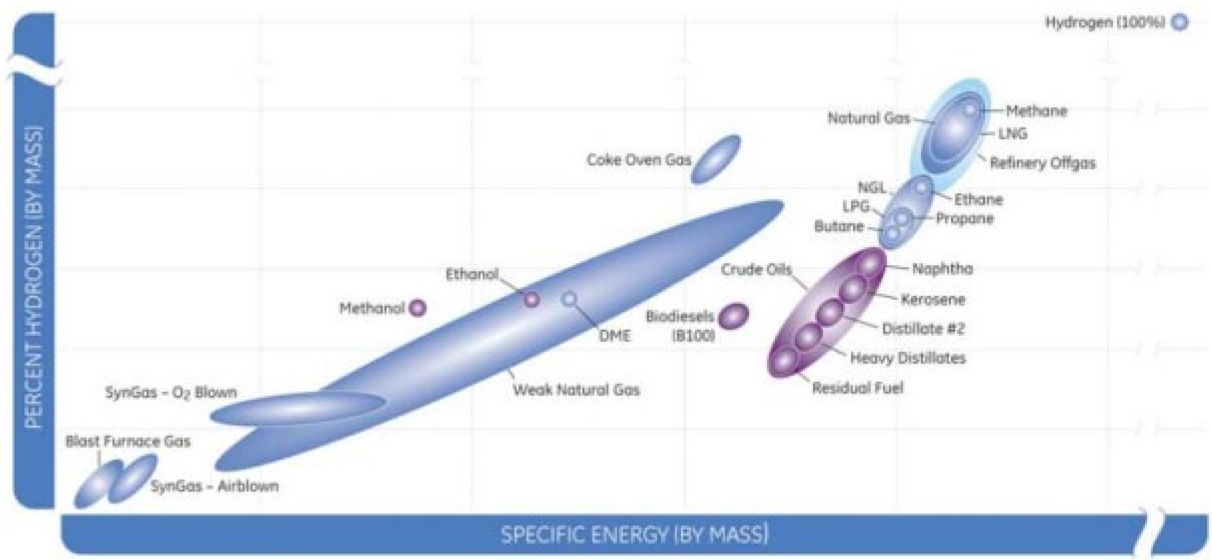


Figure 6-1 Fuel Options for Gas Turbines (GE Energy, 2011)

It should be noted that not all these fuels are currently available commercially at large scale in Australia. There is currently significant interest in alternatives to fossil fuels given the need for decarbonisation and thus there are projects in the development phase, but which have not yet moved to commercial operation. Therefore, the viability of alternative fuels may change over the life of the HPP.

Potential alternative fuels are reviewed briefly in the sections below. Focus areas are the stage of development or technology readiness and potential technical risks for utilisation in the HPP gas turbines.

6.3.1 Hydrogen

Hydrogen[13] is a low GHG emitting fuel, which could be used to displace natural gas consumption. The Australian Government has developed a National Hydrogen Strategy which highlights the interest in hydrogen in an Australian context[14].

The main product of combusting 100% hydrogen is water and there is no production of CO_2 during combustion. Utilisation of green hydrogen produced through electrolysis is thus a potential pathway to reducing emissions.

Existing gas turbine plant (not specific to the HPP) are currently only able to burn blends of hydrogen and natural gas up to 5 to 10% by volume hydrogen, with up to 20 to 30% by volume being utilised in some limited cases (USEPA, 2022). The specific amount of hydrogen is dependent on the turbine model and combustion system. Research is ongoing to develop gas turbines which can be operated on 100% hydrogen.

While the Hunter Power Project units are technically capable of up to 15vol% hydrogen co-firing with some modifications, there is additional plant and equipment required to be installed to enable hydrogen co-firing. Mitsubishi Heavy Industries has confirmed to Snowy Hydro, as part of an early works study, that 30% H_2 Co-Firing (hydrogen at 30% with gas and retaining backup diesel firing capability, alongside gas and diesel) is technically feasible with a change to the gas turbine burners, some other ancillary equipment and balance of

[13] Green Hydrogen – hydrogen produced by the electrolysis of water, using renewable electricity.
[14] National Hydrogen Strategy Summary2024, https://www.dcceew.gov.au/sites/default/files/documents/national-hydrogen-strategy-2024-summary.pdf

plant modifications. Production, shipping and storage of hydrogen has not been considered by Snowy Hydro, noting the supply of hydrogen in sufficient quantities for 15vol% or 30vol% is not currently available.

6.3.2 Biodiesel and renewable diesel

Biodiesel is a generic term for mono-alkyl esters that are produced from alcohols (typically methanol) and triglycerides (e.g. fats and oils) that can be used neat or in blends as a fossil diesel alternative. The extent of modifications to combustion equipment that would be required to operate on these fuels is yet to be determined.

There are however some differences in properties between biodiesel and fossil diesel that, given that gas turbines have stringent fuel specifications, could have implications for the suitability of direct firing of biodiesel or firing of biodiesel / fossil diesel blends in the HPP gas turbines.

Renewable diesel and other (non-fuel ethanol) biofuels can be produced biomass feedstock, including those used for biodiesel production, through a variety of processes, such as:

- Hydrotreating;
- Gasification;
- Pyrolysis; and
- Other biochemical and thermochemical technologies.

Renewable diesel is similar to biodiesel but a significant difference is that it is a hydrocarbon that is essentially chemically equivalent to petroleum diesel. Therefore, it is expected to be more prospective as a direct fossil fuel diesel replacement.

The Australian Government is currently working on an amendment to the Fuel Quality Standards Act (2000) to make provision for the inclusion of renewable diesel. It must be further noted that utilisation of biodiesel or renewable diesel will not eliminate direct carbon emissions.

Future consideration of the use of biodiesel and/or renewable diesel for future NZPGP revisions will be assessed when and if economic and technical feasibility changes.

6.3.3 Other fuel displacement options

There are a range of other fuel displacement options which are considered less prospective than the fuels reviewed in the previous section, largely given the status of technology development and the related commercial availability of the fuels in the short to medium term. A summary of these alternative fuels is provided in the table below.

As there is significant interest in alternative fuels, given the need to decarbonise and move towards net zero, the availability and viability of alternative fuels may increase in the future. These will continue to be considered as the NZPGP is reviewed in the future.

Table 6-7 Other Fuel Displacement Options

Fuel Displacement Option	Description	Challenges
Biogas and Biomethane	Biogas can be used directly for electricity generation or can be refined/upgraded to remove CO_2 and other components to produce biomethane, which is also defined as renewable natural gas.	Challenges surrounding scaling up production, cost, emissions from sourcing and transporting biogas, and feedstock availability.

Fuel Displacement Option	Description	Challenges
	Biogas is a much lower grade fuel than natural gas with lower energy values and high contaminant levels. Biomethane has similar properties to natural gas and has the potential to be injected into the natural gas distribution network.	The technology is in place for biogas production in Australia. However, the biogas is typically combusted on-site for power generation and not broadly available to the market. Conversion of biogas to biomethane is in the development phase and would require significant upgrade to have comparable properties to natural gas.
Renewable Synthetic Natural Gas (SNG) via Gasification	Synthetic natural gas is a fuel gas consisting primarily of methane that can be produced from a range of fossil fuels and bio-based fuels or from hydrogen. Use of a renewable feedstock would be required to produce SNG that effectively reduced CO_2 emissions in a gas turbine.	Gasification is well proven globally, although the bulk of projects are in China and has not been widely adopted in other countries, largely due to high costs compared to competing technologies. There are currently no commercial plants producing renewable SNG in Australia.
Renewable Synthetic Natural Gas (SNG) via Methanation	An alternative approach to production of renewable SNG is the methanation of CO_2 and renewable H_2.	Currently, CO_2 methanation has only been demonstrated at small scale, with the largest at 6 MW scale (as of 2018). There are no commercial plants producing renewable SNG in Australia.
Bioethanol	Bioethanol can be produced from fermentation of lignocellulosic biomass, starch containing feedstocks or sugar containing raw materials. It has been reported that use of bioethanol in a gas turbine reduces NOx emissions compared to diesel and natural gas without reducing the power but would require greater quantities to achieve the same output as that of conventional fuels.	A key concern is that, to support feedstock requirements for bioethanol production, large land use is needed, which can result in habitat and vegetation loss. This is a potential concern for any process requiring large quantities of a biomass feedstock. The technology for bioethanol production has been demonstrated internationally with current commercial applications of bioethanol use in gas turbines. Bioethanol is not currently commercially available in Australia.
Bio methanol	Bio methanol can be produced from gasification, reformer-based processes and the pulping cycle in pulp mills. Reformer based processing involves pre-treating of biogas extracted from biomass before introducing steam to	Since mid-2000s bio methanol use as a fuel has increased. Demonstrations for methanol use in gas turbines have been conducted successfully but have yet to be commercialised within the energy industry. The calorific value is about half

Fuel Displacement Option	Description	Challenges
	generate syngas for methanol synthesis.	that of diesel, thus twice the amount is required. Bio methanol is not currently commercially available in Australia.
Sustainable Liquid Fuels	Sustainable liquid fuels can be produced via either gasification, or via pyrolysis with selected gas components converted to liquid fuels with similar properties to diesel. The product can be further upgraded to produce a diesel product that could be directly utilised in gas turbines.	Gasification has been extensively proven by Sasol in South Africa and in China, although the approach has not proven economically viable in Australia and most countries internationally. Sustainable liquid fuels are not commercially available in Australia.
Ammonia	Green ammonia can be produced where the hydrogen is produced from a renewable source whilst ammonia can also be produced using hydrogen produced from fossil fuels. There are companies that have looked to adopt ammonia fired gas turbines, but development is still within the testing phase. There is also interest in utilising ammonia as a hydrogen source, with ammonia received on site converted to hydrogen for subsequent feed to the gas turbine.	The HPP gas turbines are not designed for direct firing of ammonia and thus ammonia is not considered as a prospective alternative fuel for the HPP project.
Straight Vegetable Oil (SVO)	SVO is derived from waste oils and is attractive for its low production cost, simple production process and efficient energy consumption.	The major challenge for the use of SVO is its high viscosity and due to variable raw material sourcing, the quality of the oil is unpredictable for each batch. SVO is not currently a prospective alternative fuel.

6.4 Technology options to reduce Scope 1 emissions

The following technology options have been considered:

- Carbon capture; and
- Conversion to Combined Cycle Turbines.

It should be noted that carbon capture by itself is not a viable option to reduce carbon emissions. There is a need to either sequester/store the carbon or beneficially utilise the carbon.

6.4.1 Carbon Capture Technologies

Carbon or CO_2 capture refers to the process where CO_2 is separated from a gas stream and converted into a purified CO_2 stream. Carbon capture is possible in any process where a carbon-based fuel is combusted to produce a gas containing CO_2.

The key processing steps include carbon capture, dehydration and compression. There are several different carbon capture technologies with selection influenced by the feed stream properties and components, and consideration of energy, cost and utility availability. The primary carbon capture technologies include:

- Absorption;
- Adsorption;
- Membrane;
- Cryogenics;
- Solid looping; and
- Inherent capture.

A range of options within these technologies are commercially ready. Storage of captured carbon dioxide requires a suitable storage location, ideally local to the plant location, or a suitable utilisation option. Carbon dioxide can also be transported by trucks or pipelines for subsequent storage or utilisation. The storage location should a secure underground geological formation to prevent emissions returning to the atmosphere.

Carbon storage has been demonstrated globally, with in the order of 50 large scale integrated CCS projects under development or in operation. The bulk of projects, related to enhanced oil recovery, are in North America and Europe, although there are a range of projects around the world.

Carbon capture from natural gas fired emission sources has been commercially implemented internationally, primarily for utilisation rather than storage. There have also been a range of international studies and project developments that have assessed the feasibility and costs of carbon capture for natural gas fired emissions.

There are currently no commercial carbon capture locations in NSW, therefore, the option of CCS is not currently viable.

Future consideration of CCS for future NZPGP revisions will be assessed when and if economic and technical feasibility changes. Based on preliminary consideration, space is anticipated to be a constraint which limits the technical feasibility of CCS for the HPP project.

6.4.2 Converting to combined cycle gas turbines

Combined cycle involves the hot gases produced from combustion in the gas turbine being passed through a heat recovery steam generator (HRSG) to raise steam, which is supplied to a steam turbine to produce electricity. Combined cycle plants are commercially proven and widely used globally, although more commonly for baseload operation or high-capacity factor operation.

Combined cycle plants are less flexible than open cycle designs and thus less suited to acting as peaking plants to support intermittent renewable generation and changing electricity market demands.

More flexible combined cycle units have been developed due to the penetration of more intermittent electricity sources (i.e. renewables) entering the electricity generation market. Fast start combined cycle plants can incorporate a range of techniques to reduce start-up times and increase ramp rates including a HRSG bypass stack to allow open cycle start-up with the HRSG slowly brought to temperature. The fast start combined cycle plants are well suited to intermediate capacity factors although less suited to a peaking plant such as in HPP.

In summary, the installation of HRSGs to allow for conversion to a combined cycle gas turbine (CCGT) is a proven technology option that improves the efficiency (and output) of gas turbines systems. However, CCGTs are most commonly used for baseload or high-medium capacity factor operations. CCGTs are less flexible than open cycle designs due to the operational constraints of the steam cycle for the HRSG plant. Therefore, CCGTs are less suited to acting as peaking plants to support intermittent renewable generation and changing electricity market demands.

Since the HPP is being installed as a peaking plant, which is expected to have a low capacity factor (i.e. maximum 1,100 hours per year operation, but likely significantly lower), the installation of HRSGs is not expected to be a viable option under this expected operating regime. Additionally, Snowy Hydro anticipate that there are spatial constraints that would impede the ability to install HRSGs.

Furthermore, retrofitting HRSGs to the HPP may not be an effective option for reducing absolute emissions. This is due to the conversion to CCGT would result in a significant increase in the HPP output (MW), which would be produced at a higher efficiency. Therefore, the emission intensity may improve, but not the absolue Scope 1 emissions produced.

Due to the mitigation options assessed for the NZPGP being conducted as an engineering screening study, detailed analysis (such as equipment sizing, equipment layout, etc.) was not considered. Detailed engineering studies would be required to progress opportunities and/or validate economic and technical feasibility.

6.5 Carbon Offsets

Carbon offsets are one of the measures that Snowy Hydro will assess for reducing emissions of the project over time. Snowy Hydro will give preference to reducing direct emissions through implementing commercially viable mitigation measures. Therefore, carbon offsets will likely be a secondary measure.

Based on current analysis conducted by Snowy Hydro, it is expected that the acquisition of carbon offsets at >10% of the HPP Scope 1 emissions will not be economically feasible.

Assuming an ACCU spot price of $35/tCO_2e$ (i.e. similar to recent spot prices) this will equate to about a $1.88/MWh increase in operating costs based on the HPP estimated Scope 1 emission intensity to offset 10% of emissions. If offsets were increased to 100% at the $35/tCO_2e$ ACCU cost, it would increase HPP operating costs by about $18.78/MWh. Additionally, when considering that ACCU costs will likely increase in the future, the cost implications could increase significantly (e.g. 100% offset at $95/tCO_2e$ cost, which is similar to the 2030 High emissions scenario presented in ACCU Market Analysis - Final Report[15] would increase HPP operating costs by about $50.98/MWh).

Such increases in the HPP annual operating cost could impact on the ability to participate in the energy market, particularly since other power stations are not subject to similar NZPGP emission targets. Consequently, the cost implications associated with acquiring carbon offsetss could impact energy affordability for the consumer.

Table 6-8 Example ACCU Costs for offset rates for base 381,825 tCO_2-e and 711,545 MWh Operations

Assumed ACCU Cost	**$/tCO2e**	**35**	**50**	**65**	**80**	**95**
% offset of Total Scope 1 Emissions	**Offset Required**	**ACCU Cost per MWh**				
	tCO_2-e	**$/MWh**	**$/MWh**	**$/MWh**	**$/MWh**	**$/MWh**
10%	**38,183**	1.88	2.68	3.49	4.29	5.10
20%	**76,365**	3.76	5.37	6.98	8.59	10.20
30%	**114,548**	5.63	8.05	10.46	12.88	15.29
40%	**152,730**	7.51	10.73	13.95	17.17	20.39
50%	**190,913**	9.39	13.42	17.44	21.46	25.49

[15] https://www.climatechangeauthority.gov.au/sites/default/files/documents/2023-12/ACCU%20Market%20Analysis%20-%20Final%20Report%20For%20Publication.pdf

60%	**229,095**	11.27	16.10	20.93	25.76	30.59
70%	**267,278**	13.15	18.78	24.42	30.05	35.68
80%	**305,460**	15.03	21.46	27.90	34.34	40.78
90%	**343,643**	16.90	24.15	31.39	38.64	45.88
100%	**381,825**	18.78	26.83	34.88	42.93	50.98

If 10% of the total Scope 1 emissions are offset by acquisition of carbon offsets, the annual quantity of offset required would be about 38,183 tCO_2e (assuming 1,100 hour (12.6% capacity factor) at full output operations).

At the capacity factor range that is expected (4% to 8%), the number of offsets required to account for 10% of Scope 1 emissions is estimated to be around 12 to 24 $ktCO_2e$ per year (for full output operations).

Table 6-9 Offsets for 10% Scope 1 Emissions as a function of capacity factor

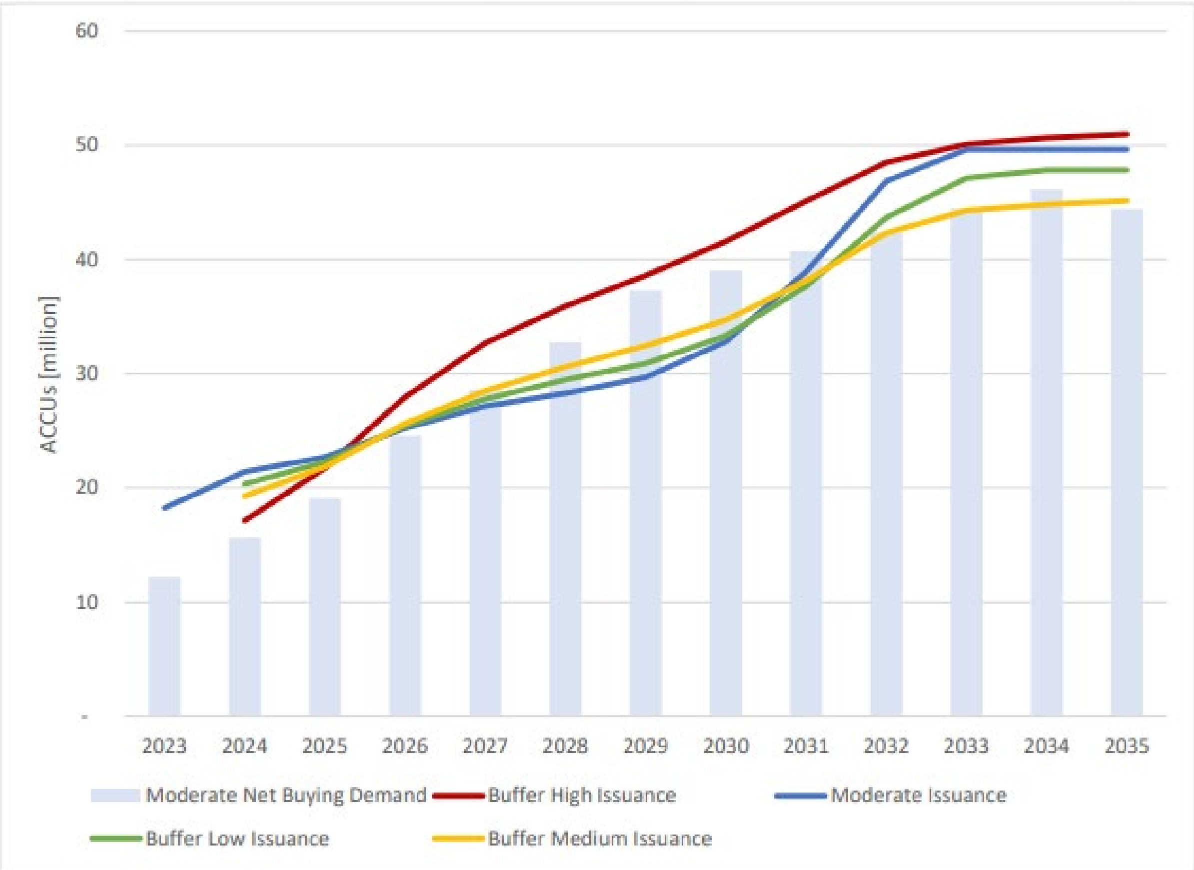
					Turbine Combustion		**Back-Up Generator**	**Total**	**Total**
	Natural Gas	**Diesel**	**Natural Gas**	**Diesel**	**Natural Gas**	**Diesel**	**Diesel**	**Combustion Emissions**	**10% Offset**
Capacity Factor	**hr**	**hr**	**MWh**	**MWh**	**tCO2e**	**tCO2e**	**tCO2e**	**tCO2e**	**tCO2e**
12.6%	925.0	175.0	610,500	101,045	311,578	70,220	27	381,825	38,183
11.0%	807.5	152.8	532,976	88,214	272,012	61,303	27	333,343	33,334
10%	734.1	138.9	484,524	80,194	247,284	55,730	27	303,041	30,304
9%	660.7	125.0	436,071	72,175	222,556	50,157	27	272,740	27,274
8%	587.3	111.1	387,619	64,156	197,827	44,584	27	242,438	24,244
7%	513.9	97.2	339,167	56,136	173,099	39,011	27	212,137	21,214
6%	440.5	83.3	290,714	48,117	148,370	33,438	27	181,836	18,184
5%	367.1	69.4	242,262	40,097	123,642	27,865	27	151,534	15,153
4%	293.7	55.6	193,810	32,078	98,914	22,292	27	121,233	12,123
3%	220.2	41.7	145,357	24,058	74,185	16,719	27	90,931	9,093
2%	146.8	27.8	96,905	16,039	49,457	11,146	27	60,630	6,063

Should Snowy Hydro opt to acquire carbon offsets, they will be purchased from the open Australian carbon market. Based on an ACCU Market Analysis conducted for the Climate Change Authority (ACCU Market Analysis - Final Report[16]). It is expected that forecast annual ACCU issuance will outpace annual buying demand in the short-term, which is underpinned by continuing issuance to existing projects anchored to carbon abatement contracts with the Commonwealth. The forecast shown below indicates that through to 2035 it is expected that the net buying demand for ACCUs will be less than the number issued.[17]

Therefore, Snowy Hydro expect that sufficient ACCUs should be available to meet the demand for the HPP if required.

[16] https://www.climatechangeauthority.gov.au/sites/default/files/documents/2023-12/ACCU%20Market%20Analysis%20-%20Final%20Report%20For%20Publication.pdf

[17] RepuTex Energy, 2023



Source: RepuTex Energy, 2023.

Figure 6-2: RepuTex ACCU issuance forecast by buffer scenario (relative to Moderate Emissions scenario)

7. Strategies to displace or offset emissions

The HPP will supplement Snowy Hydro's generation portfolio with dispatchable capacity when energy demand is at its highest. By providing firmed energy, the HPP will facilitate an estimated 2 GW of renewables, displacing approximately 5.8 million tons of CO_2 emissions per year out of the electricity system.[18] The SHL Annual Report for the 23/24 financial year estimated that the total emissions from HPP generation are estimated to be around 0.14 million tonnes of CO_2 per annum (assuming a ~3.5% capacity factor), equating to a significant net benefit to Australia's transition to renewables. Therefore, the HPP will be a strategic asset to contribute to the overall strategy the broader decarbonisation of the National Energy Market (NEM).

When considering carbon emissions reductions, it is important to note that whilst best endeavours to reduce emissions are important for peaking plants, the greatest value of peaking plants, with respect to reducing carbon emissions, is the enablement of the broader decarbonisation of the National Energy Market (NEM), supporting net zero policy objectives of state and federal governments. The Department of Planning, Industry and Environment noted in their 2021 Assessment Report[19]:

> *Based on the NSW Government's latest emissions modelling information, the Department considers that the project would not significantly increase greenhouse gas emissions in NSW or constrain the ability to achieve the target of a 50% reduction in emissions by 2030. Further, the hydrogen capabilities of the project present the opportunity to further reduce the emissions of the project, where clean hydrogen is used in the fuel mix.*

For preparation of the NZPGP an independent engineering assessment was conducted (see Section 6) to evaluate potential measures to displace or offset GHG emissions. This assessment process has shown that several options have potential merit however more information is required to complete a detailed assessment of prospective options. This information includes but is not limited to:

- How the plant will be run in practice (e.g. load profile, operational hours),
- What the actual emissions are (from operational data as opposed to modelling),
- Market factors impacting not only the generation profile of the plant but also availability and cost of carbon offsets (e.g. ACCUs),
- Commercial availability and viability of options such as alternate fuels, and
- Technical feasibility of options (including alternate fuels) when practical constraints, such as available space and operational load profile, are considered.

The HPP will be delivering peaking power, with operation expected between 4%-8% capacity factors (~350 hours -700 hours of operation/year, respectively). The low capacity factor anticipated for the HPP operating as a peaking power station presents technical and economic challenges that limits the feasibility of implementing measures to displace or offset emissions.

Key measures that Snowy Hydro will have regard to for reducing emissions include:

- Maintenance practices, in accordance with OEM recommendations, to ensure the equipment is kept in best practicable operating condition and efficiency,
- Operational practices to minimise emission intensity (within NEM demand restraints), such as minimising run-up/run-down times and start-up, optimising output to a high efficiency set-point, and operating with inlet air cooling, and
- Procuring carbon offsets.

Snowy Hydro commit to performing detailed investigations of options having regard to the appropriate staging/targets provided with a view to offsetting/abating emissions should a technically and financially viable option be identified. Additional options for future consideration may include:

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[18] Snowy Hydro Limited, Annual Report for the financial year ended 30 June 2024.
[19] NSW Department of Planning, Industry and Environment, Hunter Power Project (Kurri Kurri Power Station). Critical State Significant Infrastructure Assessment (SSI 12590060), November 2021

- Fossil fuel displacement opportunities, including:
    - Hydrogen (or other renewable fuel, such as biomethane) blending into the feed gas;
    - Biodiesel and/or renewable diesel to offset fossil diesel.
- Carbon capture and storage and/or utilisation.

In addition, Snowy Hydro are exploring opportunities to enter into a partnership with academic and research organisations to regularly monitor technical advancements that could be applicable for reducing Scope 1 emissions from the HPP operations. This will also provide an opportunity to explore ongoing innovations and developments which may assist HPP with carbon abatement.

8. Monitoring and reporting

The Infrastructure Approval includes the following NZPGP reporting requirements with respect to this Plan:

> *C3. Every three years following the approval of the plan, or other timeframe agreed by the Secretary, a report shall be submitted to the Secretary to update the outcomes of the investigations and measures described in condition C2.*

In addition to this, an annual update on the progress towards Net Zero Targets will be provided to the Department as a part of the Compliance Reports that are a requirement of Conditions C10-13 of the Infrastructure Approval.

Snowy Hydro Limited has several other GHG monitoring and reporting requirements, including National Greenhouse and Energy Reporting (NGER), for the HPP. Snowy Hydro must also comply with sustainability reporting requirements under the Corporations Act 2001 (Corporations Act), which includes the publication of an annual Sustainability Report, that consists of:

- The climate statements for the year;
- Any notes to the climate statements; and
- The directors' declaration about the statements and notes.

9. Review of the Net Zero Power Generation Plan (NZPGP)

Reviews of the NZPGP will occur on a regular basis, as well as after certain trigger events. In accordance with condition C5 of the Infrastructure Approval, the triggers for further review of this Plan include:

- The submission of an incident report under condition C6;
- The submission of an audit report under conditions C15 to C19;
- The approval of any modification to the conditions of this approval; and
- A direction of the Secretary (Department of Planning Industry and Environment) under condition A2 of Schedule 2.

Within 3 months, unless the Secretary agrees otherwise, of any of the above triggers this document must be reviewed and if necessary, revised to the satisfaction of the Secretary. Where revisions are made, then within 4 weeks of the review, the revised document will be submitted to the Secretary for approval, unless otherwise agreed with the Secretary.

Given that HPP is still to be commissioned, operational data needed to benchmark is not yet available. Therefore, initially, the HPP performance will be assessed against the OEM design specifications (e.g. commissioning testing and acceptance of the HPP will be assessed against design / contractual specifications).

The initial operating years (e.g. years 1-3) will be used to establish the baseline performance for the HPP. It is expected that the key performance indicators for the HPP from a GHG perspective will be:

- Total Scope 1 emissions (which will be directly quantified by the quantity of fuel consumed);
- Electricity generated and sent out to the grid;
- Heat rate (directly related to the fuel consumed and electricity output); and
- Scope 1 emission intensity (directly related to the Scope 1 emissions and electricity sent out).

Therefore, the key variables that will be monitored to assess the performance are:

- Quantity of Natural Gas combusted, which is supplied by pipeline and measured at a high accuracy revenue metering station;
- Quantity of Diesel combusted, which is invoiced by the fuel supplier based on the quantity delivered to the HPP storage tanks; and
- Electricity delivered to the grid, which is measured by high accuracy revenue metering as per NEM requirements.

The above variables will also be the primary variables that will be required for NGER reporting. The GT efficiency will be dependent on the load (% of maximum output) as was discussed in Section 2. As previously shown in *Figure 2-1*, at maximum design output the Scope 1 emission intensity for natural gas firing is expected to be about 0.498 tCO_2e/MWh or an hourly fuel consumption (heat rate) of about 9.66 GJ/MWh. At the maximum allowable station output (660 MW) with both GTs operating at 330 MW concurrently the Scope 1 emission intensity for natural gas firing is about 2.5% higher (0.510 tCO_2e/MWh). At low load conditions (e.g. ~60% load) the Scope 1 emission intensity and heat rates are expected to be much higher (0.573 tCO_2e/MWh and 11.12 GJ/MWh).

Operational data (fuel consumption and electrical output) will be used in the future to monitor the Scope 1 intensity and heat rate against target values such as those illustrated in the figure below.

The effect of implemented mitigation measures will be apparent by quantifying the relative difference in the Scope 1 emissions intensity pre- and post- project implementation multiplied by the sent-out electricity (net Scope 1 emissions difference).

10. Conclusions

Snowy Hydro commit implementing the approved Net Zero Power Generation Plan through performing detailed investigations of options having regard to the appropriate staging/targets provided with a view to offsetting/abating emissions should a technically and financially viable option be identified. Additional options for future consideration may include:

- Fossil fuel displacement opportunities, including:
  - Hydrogen (or other renewable fuel, such as biomethane) blending into the feed gas,
  - Biodiesel and/or renewable diesel to offset fossil diesel.
- Carbon capture and storage and/or utilisation.

11. References

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Appendix A – Appointment of experts to prepare NZPGP

Department of Planning, Housing & Infrastructure

Our ref: SSI-12590060-PA-76

Daryl Young
Project Director – Hunter Power Project
Snowy Hydro Limited
Via Major Projects Portal

29/07/2024

Subject: Appointment of experts to prepare Net Zero Power Generation Plan

Dear Mr Young

I refer to your request for the Planning Secretary's approval of Glenn Innes of HRL as suitably qualified, experienced and independent person to prepare the Net Zero Power Generation Plan under Schedule 2, Condition C2 of the approval for the Hunter Power Project (SSI-12590060).

The Department has reviewed the nomination and information you have provided and is satisfied that Glenn Innes is suitably qualified, experienced and independent. Accordingly, I can advise that the Planning Secretary approves the appointment of Glenn Innes to prepare the Net Zero Power Generation Plan.

If you wish to discuss the matter further, please contact Jack Turner on 9995 5387.

Yours sincerely

Stephen O'Donoghue
Director
Resource Assessments

As nominee of the Planning Secretary

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