ASX ANNOUNCEMENT

GREENHOUSE GAS EMISSIONS REDUCTION PATHWAY

31 January 2023

- **Arafura has chosen a greenhouse gas (GHG) emissions reduction pathway for the Nolans NdPr Project to achieve its 2050 Net Zero Emissions commitment which includes:**
    - **Electricity generation, from solar and wind with battery storage, targeting 50% of Project power by 2030.**
    - **Concentrated solar thermal generation, with thermal energy storage for steam generation, with transition commencing in 2030.**
    - **Transition to renewable fuels for firming power, commencing in 2040.**
- **The reduction pathway covers electrical power and thermal power as steam generation which together account for approximately 85% of the Project's forecast emissions.**
- **Analysis demonstrates that the reduction pathway is likely to reduce total energy costs over the first 14-years of production and only result in a minor increase in costs over the life of mine.**
- **A demonstration scale, proof of concept, concentrated solar thermal system, combined with thermal energy storage, is planned prior to 2030.**

Arafura Rare Earths Limited (**ASX:ARU**) (**"Arafura"** or the **"Company"**) has released its greenhouse gas (**GHG**) emissions reduction pathway for the electrical power and steam requirements for its 100%-owned Nolans Neodymium-Praseodymium (NdPr) Project ("**Nolans**" or the "**Project**") in the Northern Territory. Release of the pathway is intended to provide Arafura's stakeholders with information on how the Company intends to meet its 2050 Net Zero Emissions commitment (*refer to ASX announcement 29 November 2021*).

To select the pathway, five different potential pathways were evaluated for reduction of GHG emissions from stationary power and steam generation. All candidate pathways had emissions profiles which achieved net zero by 2050 for stationary energy generation, through a combination of the deployment of zero emissions generation technologies and the phasing in of renewable fuels.

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The choice of pathway has included consideration of the gas price equivalent costs to ensure robust commercial decision-making. The cost outcomes for the chosen pathway, which are detailed in the following pages, include:

- Prior to 2030 the estimated gas price equivalent cost of the chosen pathway is A$6.10 per GJ, which is less than the Project's base case gas price of $A8.34 per GJ (inclusive of transport) (*refer to the Company's Project Update released to ASX on 11 November 2022)*.
- Prior to 2040 the estimated gas price equivalent cost of the chosen pathway is A$8.20 per GJ, approximately equivalent to the use of gas (inclusive of transport).
- Estimated average cost of the chosen pathway over the life of mine (LOM) is equivalent to generating all energy from gas at a gas price of A$9.70 per GJ.

The equivalent gas prices presented above provide a preliminary comparison of the cost impact of implementing the chosen pathway, relative to the Project's base case gas price assumption of $A8.34 per GJ (inclusive of transport). This preliminary analysis indicates that the chosen GHG emissions reduction pathway is not likely to create a material cost change, or material change to the projected financial outcomes of the Project, as provided in the most recent Project Update (*refer to ASX announcement 11 November 2022*). See Appendix A for a detailed description of the calculation methodology for equivalent gas price.

Note that these figures are preliminary estimates, generated only for the purpose of providing relative comparisons between the candidate pathways and the business as usual pathway.

Arafura Rare Earth's Managing Director, Gavin Lockyer, said: "*The GHG emissions reduction pathway developed for Nolans demonstrates the viability of Arafura Rare Earths to become a net zero producer of NdPr oxide. NdPr is critical to many of the products necessary to achieve a global net zero future, such as electric vehicles and wind turbines. By publicly releasing our GHG emissions reduction pathway for stationary power we are providing our customers, investors and other stakeholders with a better understanding of how we intend to meet our net zero 2050 commitments. As a result, the pathway will help our customers meet their own GHG emissions reduction objectives as well."*

"We recognise we will need to address a range of challenges in decarbonising rare earth processing, which is, by its nature, an energy intensive process. Nonetheless, the Arafura team is committed to implementing a practical, cost-efficient pathway to net zero. We will keep a close watch on changes in the price, technology maturity and availability of relevant technologies, such as long-duration energy storage, and update the GHG emissions reduction pathway in future if it is appropriate to do so."

The costs of the candidate pathways have been compared by calculating an average equivalent gas price that would result in an equivalent operating cost for continuation of generation using natural gas from the Amadeus Gas Pipeline, including any impact from the Australian Federal Government's proposed Safeguard Mechanism Reforms (see Appendix A for a detailed description of the calculation methodology for equivalent gas price).

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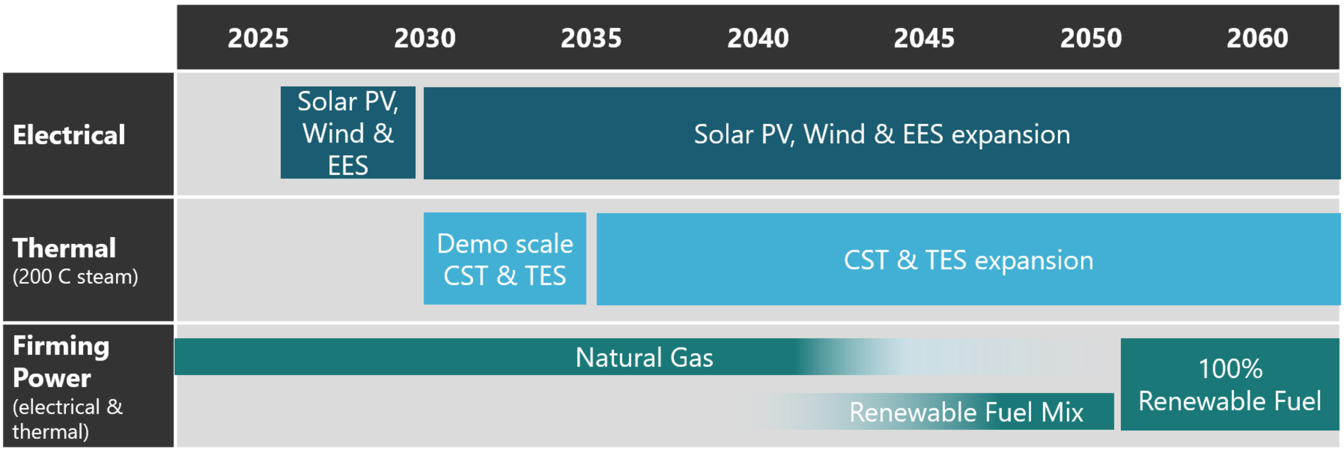
The chosen pathway consists of renewable sources for electrical power (e.g. solar photovoltaics (**PV**), wind power and batteries), combined with large-scale thermal energy storage (**TES**) to provide a consistent source of renewable thermal energy for steam generation. The TES will be heated from concentrated solar thermal (**CST**).

The chosen pathway takes advantage of:

- Low cost of solar PV and wind power for electricity generation.
- Large proportion of energy required as steam (roughly three times the electricity requirement).
- Relatively low cost of TES compared to electrical energy storage (**EES**).

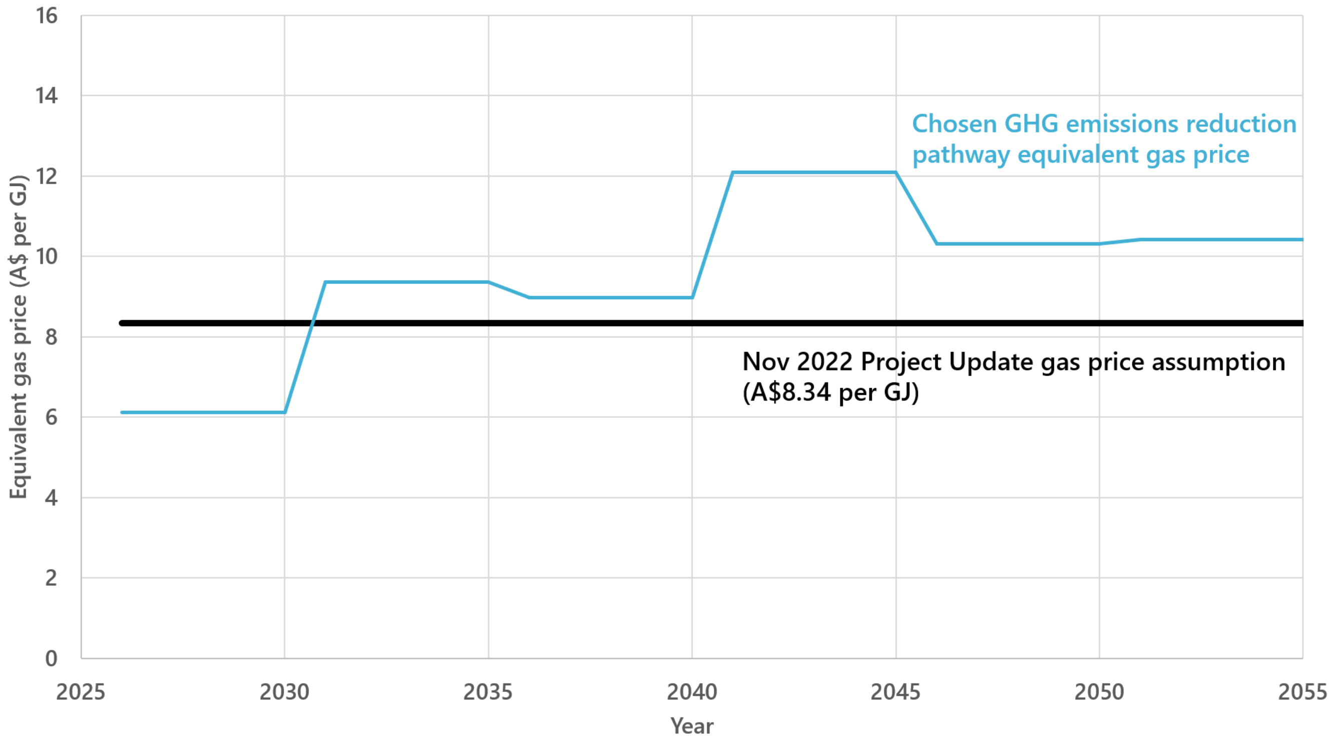
An approximate timeline for the implementation of the selected GHG emissions reduction pathway is shown below.



The chosen pathway is based on the Company's current understanding of the Project energy requirements, forecast costs of emissions reduction options and assumptions on the maturity and pace of development of emissions reductions technologies. Arafura anticipates that the pathway will evolve as the Project definition increases and emissions reduction technologies are identified, matured or reduce in cost.

The figure below presents the energy cost as an equivalent gas price for the chosen pathway. This provides a comparison to the current Project base case of continued generation using natural gas at an assumed gas price of A$8.34 per GJ (inclusive of transport costs). This approach is consistent with the financial model of the project presented in the latest Project Update, which procures all energy as an operating expense from an Independent Power Provider (**IPP**) (*see ASX announcement dated 11 November 2022*).

The process for selecting the chosen pathway and calculating the annual equivalent gas price of this pathway is described in further detail in the attached report.



As previously communicated, Arafura intends to procure electrical power and steam from an IPP under a build-own operate (**BOO**) model for the Project (*refer to ASX announcement 11 November 2022*). The Company is running a tender process for the IPP and Arafura intends to work closely with the selected IPP to deliver on a mutually acceptable GHG emissions reduction pathway that meets Arafura's established emissions reduction targets. This partnership approach, which will enable Arafura to access the decarbonisation expertise of the IPP, means that the GHG emissions reduction pathway will be refined following selection of our IPP partner (anticipated Q1 2023) and subsequent joint work to further develop the pathway.

The next steps in Arafura's roadmap to net zero include:

- Updating of Arafura's projected total GHG emissions estimate, including the results of this work.
- Analyse the data from the sonic detection and ranging (**SODAR**) unit that Arafura has currently installed and operating at site to better evaluate the wind resources available.
- Completion of a study to determine most appropriate mix of solar PV, wind and batteries to deliver approximately 50% of the Project's electrical power from renewable sources.
- Implementation into various aspects of the current plant design features to facilitate rapid incorporation of solar PV, wind and batteries into the Project's energy mix.
- Optimisation study of renewable thermal energy generation options to determine most appropriate thermal energy sources and energy storage technologies.
- Planning of a demonstration scale renewable thermal energy generation and storage plant for implementation prior to 2030.

Full details of the analysis, assumption used, and sources of data are included below.

GREENHOUSE GAS EMISSIONS REDUCTION PATHWAY

Important notice

The purpose of this announcement is to provide general information in relation to the Company. It should be read in conjunction with the Company's other periodic and continuous disclosure announcements lodged with ASX Limited, which are available at www.asx.com.au. It is not recommended that any person makes any investment decision in relation to Arafura based on this announcement.

This announcement contains certain statements which may constitute "forward-looking statements." Such statements are only expectations or beliefs and are subject to inherent risks and uncertainties which could cause actual values, results or performance achievements to differ materially from those expressed or implied in this announcement. No representation or warranty, express or implied is made by the Company that any forward-looking statement contained in this announcement will occur, be achieved or prove to be correct. No one should place any reliance on any forward-looking statement.

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Additional information

Certain forecast financial information in this announcement relating to gas prices is derived from the Company's ASX announcement dated 11 November 2022 (Nolans Project Update). The Company confirms that all material assumptions underpinning such forecast financial information (including any assumptions referred to in the Company's ASX announcement dated 11 November 2022 that were used from the DFS as set out in the Company's ASX announcement dated 7 February 2019 (Nolans Project Definitive Feasibility Study) or from the Updated Mining Study as set out in the Company's ASX announcement dated 16 March 2020 (Major Increase in Mine Life for the Nolans Project)) continue to apply and have not materially changed.

-ENDS-

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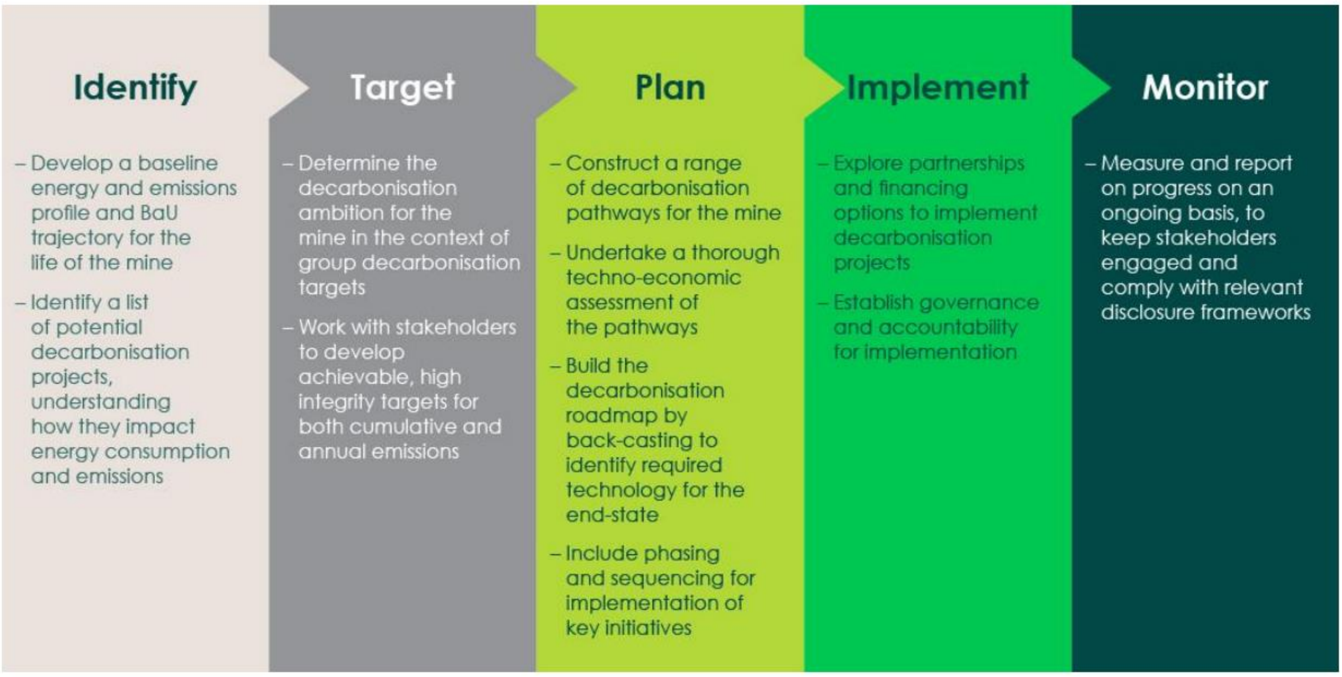
METHODOLOGY

Arafura has adapted a methodology developed by the Clean Energy Finance Corporation and the Minerals Research Institute of Western Australia (**MRIWA**) (1) to develop a GHG emissions reduction pathway for the Project. Key steps in the MRIWA process for developing a decarbonisation roadmap are shown in Figure 1.

Figure 1: MRIWA Steps to Decarbonisation (image credit: MRIWA)



This approach is based on the development of several different candidate GHG emissions reduction pathways for comparison. The candidate pathways are chosen to represent a broad range of approaches to achieving the project's decarbonisation goals. These are used to explore the financial and emissions risks and opportunities associated with the application of different approaches to emissions reduction. Following this analysis one pathway is then chosen as the basis for further planning and implementation.

For the Project, annual costs and emissions have been estimated for five different candidate pathways, as well as for a business-as-usual (**BAU**) pathway, which consists of continued use of natural gas combustion for all electrical and thermal power generation. The annual cost estimates include the cost of financing capital investments in emissions reduction technologies, fuel, operations and maintenance and meeting emissions liabilities under the proposed Safeguard Mechanism Reforms (2). All modelling has been carried out in real Australian dollars in 2022 to allow a for a simple comparison, as all pathways are impacted similarly by time value of money.

The input assumptions to the pathway modelling are described in Appendix B. All pathway modelling and analysis presented in this announcement (and the ultimate implementation of the chosen pathway) is dependent on a number of factors, including securing remaining offtake agreements, procuring electrical power and steam from an IPP under a BOO model on terms acceptable to the Company, securing funding to develop the Project on terms acceptable to the Company, a final investment decision being made and successful construction, commissioning and ramp up of the Project. There is no guarantee or certainty that these milestones will be reached. The key risks to implementing the chosen pathway are set out on page 15.

Forecast costs and emissions have been used to compare the candidate pathways and inform development of a chosen planning pathway, around which implementation plans will be developed. Whilst reference is made to capital costs as inputs to the modelling, this is only for the purposes of estimating the annual costs associated with the supply of energy. This is consistent with the financial assumptions provided in the most recent Project Update (*refer ASX announcement 11 November 2022*) which treats all stationary energy costs as an operational expense. The Project's stated intention is to procure stationary energy from an IPP under a BOO model.

The current chosen pathway addresses stationary power requirements for electricity and steam. These represent approximately 85% of the project's forecast emissions. Future pathway updates will also address other emissions sources within the Project, such as mobile mining equipment and chemical processes.

DESIGN BASIS

Estimates of the relative costs and emissions for the Project for the candidate pathways have been developed based on a simplified model of the processing plant's operation and power requirements. The power requirements have been modelled on a steady state over the LOM as follows:

- Average electrical load of 44 MWe, with a peak requirement of 55MWe.
- Average thermal (steam) load of 140 MWt with a peak requirement of 150 MWt.
- 85% processing plant availability.
- 99.9% power availability required.

These figures are a reasonable approximation of the current average power demand forecast for the project, in line with the recently published Project Update (*see ASX announcement dated 11 November 2022*).

Firming Power

To meet the above reliability requirement and have no impact on the desired processing plant availability, it has been assumed that conventional power generation capacity[1] capable of meeting the complete facility demand will continue to be required throughout the LOM under all the candidate pathways. This will be used when sufficient power from directly connected renewable sources is not available (due to the inherently variable nature of the renewable energy sources). This is referred to as the firming power requirement for the facility.

For the modelling of all candidate pathways it has been assumed that the fuel for providing firming power can be changed to a renewable fuel later in the project's life[2]. This provides a future source of firming power without creating emissions (providing the fuel has a net zero emissions lifecycle). Assuming a single, generic renewable fuel type and price is a simplifying modelling assumption, which is appropriate to the current high-level nature of the GHG emissions reduction pathway planning. A more detailed investigation of options for providing zero emissions firming power will be required in future.

No additional capital expenditure has been included in the modelling to account for the change in fuel type to renewable fuel in the later years of the candidate pathways. It is assumed that the current conventional power generation assets will be able to burn the new fuel without modification, since the fuel will be chemically identical to current fuels. However, a change in the assumed fuel price has been modelled, to reflect a change to increasing use of renewable fuels, and associated demand and price, across the economy over time.

[1] Fuel combustion for electrical and thermal power generation

[2] For example: bio fuels or synthetic fuels derived from renewable hydrogen and captured carbon dioxide

The assumed future prices of renewable fuels, and basis of the assumption, are described in Appendix B.

GHG EMISSIONS REDUCTION PATHWAYS

Identification of Emissions Reduction Options

Each candidate pathway is constructed by implementing specific emissions reduction options at different scales and different times. A pathway can consist of one or more emissions reduction options.

Emissions reductions options were identified through expert consultation with internal and external power and renewable energy experts. The emissions reduction options identified, and the approximate years at which they are expected to be available at an industrial scale, are shown in Table 1.

A more detailed description of each technology is provided in Appendix C.

Table 1: Power Generation & Conversion Emissions Reduction Options

	2025 – 2030 – 2035 – 2040 – 2045 – 2050
Electrical	Solar PV (PV)
	Wind
	Electrical Energy Storage (EES)
	Steam Turbine
Thermal (200 C steam)	Concentrated Solar Thermal (CST)
	Thermal Energy Storage (TES)
	Electric Boilers
	Heat Pumps
Firming Power (electrical & thermal)	Natural Gas
	Bio Fuels
	Synthetic Fuels
	Hydrogen or Ammonia

Wildcards: Geothermal anywhere; Electrical grid connection

Identification of Candidate GHG Emissions Reduction Pathways

Five different candidate emissions reduction pathways were selected for comparison. These are representative of a broad range of credible options for achieving net zero by 2050[3]. A summary of these, as well as the BAU pathway where all power is provided by natural gas for the whole duration of the Project, is provided in Table 2.

More detailed information on the implementation scale and timing of emissions reduction options for each pathway is presented in Table 3, Table 4, Table 5, Table 6 and Table 7.

[3] The 'wildcards' of geothermal power and an electrical grid connection were considered too unlikely and at too early stage of development to be credibly included in any of the candidate pathways.

The mix and ratio of emissions reduction technologies included in each pathway has been selected based on expert judgement, rather than a detailed optimisation analysis. This is appropriate for the early-stage decision making which the candidate pathway modelling supports. Future phases of the GHG emissions reduction pathway development will include optimisation studies to confirm the most appropriate technology mix to deploy.

Table 2: Summary of Modelled GHG Emissions Reduction Pathways

	Pathway 0	Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 5
Description	Business as usual (all gas)	Separate Electrical & Thermal Generation	Full Electrification	Thermal Energy for Electrical Power	Imported Renewable Fuel	Electric Heat to Thermal Energy Storage
Emissions target	None	Linear reduction to zero emissions by 2050				
Technology risk profile	Low	Medium – CST cost reductions	High – heat pump suitability	Medium – CST cost reductions	Medium – renewable fuel availability	Medium – solid TES at large scale
Electricity generation	Reciprocating gas engines	Solar PV, wind	Solar PV, wind	Solar PV, steam turbine	Solar PV, wind	Solar PV, wind
Electrical energy storage	None	Lithium-ion batteries	Lithium-ion batteries	None	Lithium-ion batteries	Lithium-ion batteries
Thermal generation	Gas boilers	Concentrated solar thermal	Heat pumps	Concentrated solar thermal	Gas boilers burning renewable fuel	Electrical heating of TES
Thermal energy storage	None	Molten salt	None	Molten salt	None	Solid TES

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Table 3: Pathway 1 – "Separate Electrical & Thermal Generation"

	2025	2030	2035	2040	2045	2050	2060
Electrical	PV (30 MW) Wind (60 MW)	PV (60 MW) Wind (90 MW) EES (50 MWh)	EES (150 MWh)				
Thermal (200 C steam)		CST (50 MWt) TES (300 MWh-th)	CST (200 MWt) TES (900 MWh-th)	CST (350 MWt) TES (1500 MWh-th)	CST (500 MWt) TES (2500 MWh-th)		
Firming Power (electrical & thermal)	Natural Gas (54 MWe + 150 MWt)			50% Ren. Fuel	75% Ren. Fuel	100% Renewable Fuel	

Table 4: Pathway 2 – "Full Electrification"

	2025	2030	2035	2040	2045	2050	2060
Electrical	PV (30 MW) Wind (60 MW)	PV (60 MW) Wind(90 MW) EES (50 MWh)	PV (90 MW) Wind (135 MW) EES (300 MWh)	PV (120 MW) Wind (200 MW) EES (400 MWh)			
Thermal (200 C steam)			Heat Pumps (60 MWt)	Heat Pumps (120 MWt)			
Firming Power (electrical & thermal)	Natural Gas (54 MWe + 150 MWt)			50% Ren. Fuel	75% Ren. Fuel	100% Renewable Fuel	

Table 5: Pathway 3 – "Thermal Energy for Electrical Power"

	2025	2030	2035	2040	2045	2050	2060
Electrical	PV (30 MW)		Steam Turbine (10 MW)	Steam Turbine (38 MW)			
Thermal (200 C steam)	CST (250 MWt) TES (1500 MWh-th)		CST (500 MWt) TES (2500 MWh-th)	CST (750 MWt) TES (3500 MWh-th)			
Firming Power (electrical & thermal)	Natural Gas (54 MWe + 150 MWt)			50% Ren. Fuel	75% Ren. Fuel	100% Renewable Fuel	

Table 6: Pathway 4 – "Imported Renewable Fuel"

	2025	2030	2035	2040	2045	2050	2060
Electrical	PV (30 MW)	PV (60 MW)					
	Wind (60 MW)	Wind (90 MW)					
		EES (50 MWh)	EES (150 MWh)				
Thermal (200 C steam)	*Renewable thermal energy provided from burning of sustainable fuel in gas boilers*						
Firming Power (electrical & thermal)	Natural Gas (54 MWe + 150 MWt)					100% Renewable Fuel	
			25% Ren. Fuel	70% Ren. Fuel	90% Ren. Fuel		

Table 7: Pathway 5 – "Electric Heat to Thermal Energy Storage"

	2025	2030	2035	2040	2045	2050	2060
Electrical	PV (30 MW)	PV (60 MW)	PV (120 MW)	PV (180 MW)	PV (240 MW)		
	Wind (60 MW)	Wind(90 MW)	Wind (180 MW)	Wind (220 MW)	Wind (290 MW)		
		EES (50 MWh)					
Thermal (200 C steam)			TES (150 MWh-th)	TES (1200 MWh-th)			
Firming Power (electrical & thermal)	Natural Gas (54 MWe + 150 MWt)					100% Renewable Fuel	
				50% Ren. Fuel	75% Ren. Fuel		

ANALYSIS OF CANDIDATE PATHWAYS

To compare the average equivalent costs of each candidate pathway, the annual cost of providing energy under each pathway was converted back to an average equivalent gas price that would result in an equivalent operating cost for Pathway 0 (the BAU pathway, where all stationary energy requirements are met from natural gas combustion). This includes a modelled cost impact from the Safeguard Mechanism Reforms (2). This approach is consistent with the financial model of the project presented in the latest Project Update, which procures all energy as an operating expense (*see ASX announcement dated 11 November 2022*). See Appendix A for detailed description of the average equivalent gas price calculation methodology.

Comparisons of the relative emissions reduction for each candidate pathway are provided in Table 8 and comparisons of the annual average equivalent gas price for each candidate pathway are provided in Table 9. The relative annual emissions and equivalent gas prices for each pathway are shown in

Figure 2 and Figure 3 respectively.

Note that these figures are preliminary estimates, generated only for the purpose of providing relative comparisons between the candidate pathways and the BAU pathway.

An estimate of the high and low ranges of the equivalent gas prices presented is provided in Appendix D.

Table 8: Emissions Relative to BAU for Candidate Pathways[4]

	Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 5
2026 - 2030	75%	75%	72%	75%	75%
2031 - 2035	65%	69%	72%	69%	69%
2036 - 2040	49%	53%	50%	51%	47%
2041 - 2045	18%	19%	14%	20%	17%
2046 - 2050	6%	10%	7%	7%	7%
2051 onwards	0%	0%	0%	0%	0%
LOM average	**31%**	**32%**	**31%**	**32%**	**31%**

Table 9: Annual Average Equivalent Gas Price for Candidate Pathways (A$ per GJ)

	Pathway 0	Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 5
2026 - 2030	8.34	6.10	6.10	8.20	6.10	6.10
2031 - 2035		9.40	9.50	7.90	9.50	9.50
2036 - 2040		9.00	13.10	7.80	17.70	10.30
2041 - 2045		12.10	17.00	11.20	19.90	13.50
2046 - 2050		10.30	16.20	11.00	17.50	13.90
2051 onwards		10.40	15.90	11.10	16.40	13.80
LOM average		**9.70**	**13.50**	**9.80**	**14.90**	**11.70**

[4] Compared to Pathway 0 (business as usual) emissions. Emissions are only those from electrical and thermal stationary power generation, which are forecast to be over 85% of the Project's total emissions under Pathway 0.

Figure 2: Comparison of Pathway Annual Emissions for Candidate Pathways[5]

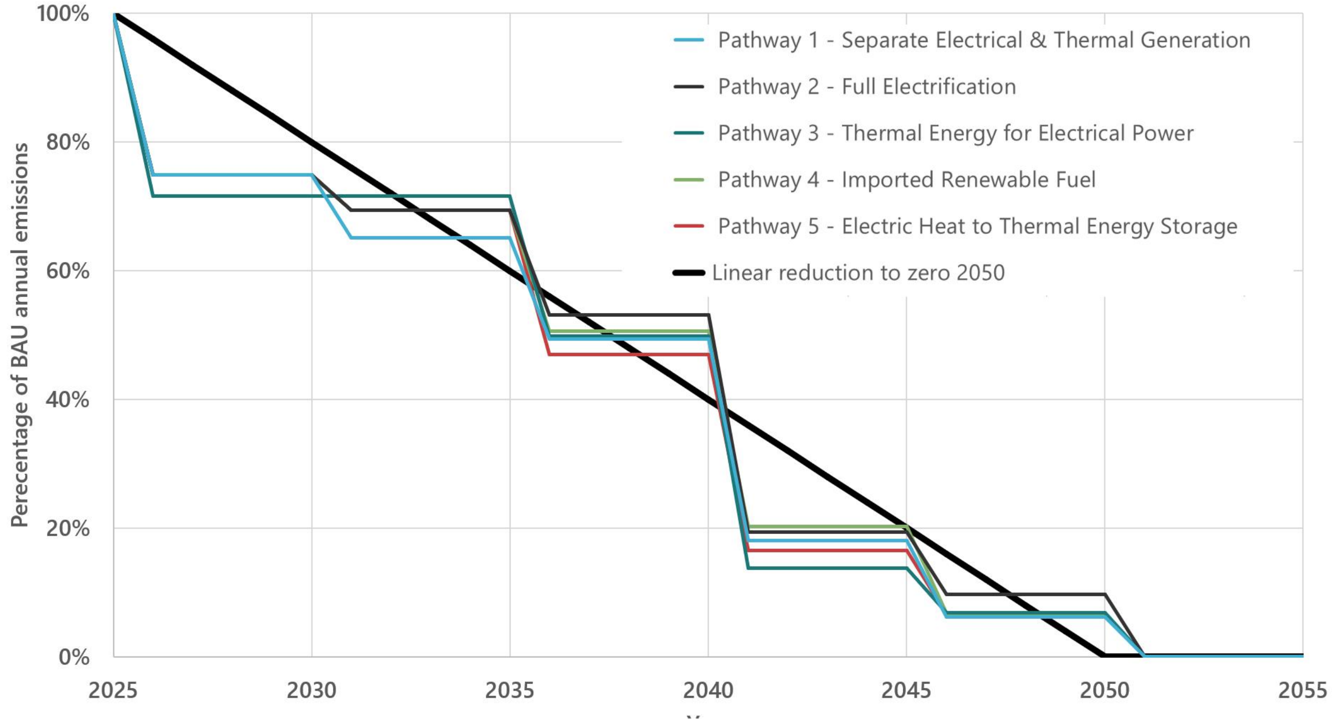
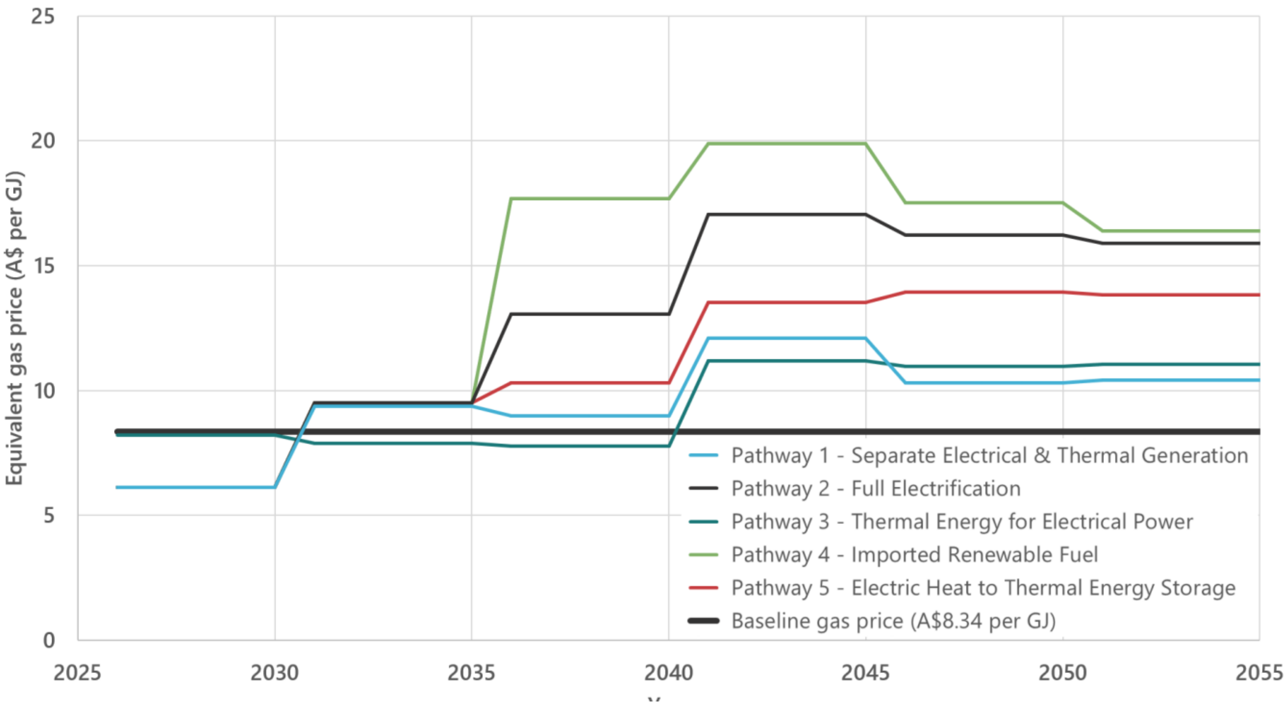


Figure 3: Comparison of Equivalent Gas Price for Candidate Pathways



[5] Emissions are only those from electrical and thermal stationary power generation, which are forecast to be over 85% of the Project's total emissions under Pathway 0.

CHOSEN GHG REDUCTION PATHWAY

Pathway 1 has been selected as the chosen GHG emissions reduction pathway for the Project. This was one of the two lowest cost pathways modelled. Pathway 3 has a similar average cost over the LOM but is more expensive in the first five years. On this basis it was decided to select a pathway that delivers additional benefit in the early years of the Project with a lower risk, using more widely understood technologies.

Under the chosen pathway an initial deployment of solar PV, wind power and EES will be installed before 2030 to achieve a reduction in emissions from electricity generation of at least 50%.

Renewable thermal steam power will be delivered by concentrated solar power to provide energy for charging (heating) thermal energy storage, then discharging this to generate steam when required. This will be achieved at a demonstration scale before 2030 to provide a proof of concept and then will be expanded progressively between 2030 and 2040 to achieve up to 80% of thermal power from on-site renewable power generation.

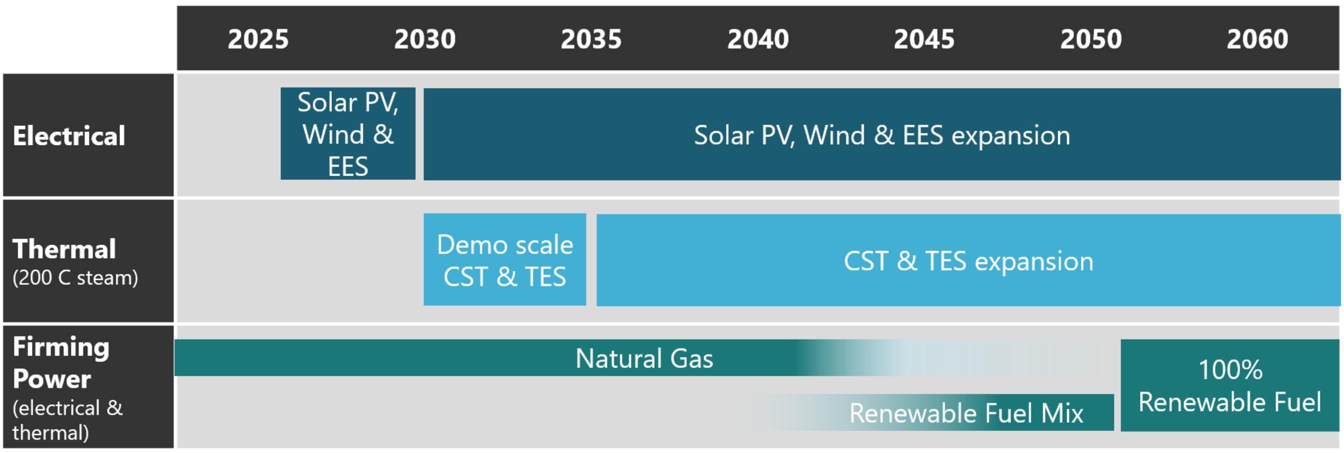
The potential advantages of the chosen pathway are:

- Relatively low cost of thermal energy storage compared to electrical energy storage.
- Relatively high 'round trip' efficiency of thermal energy storage (when used to meet a thermal load).
- Option in future to charge the storage from both solar and wind resources, particularly excess energy generation, if electrical heating of thermal energy storage is also used.

Further studies will be required to determine the appropriate mix of technologies for the charging and discharging of the thermal energy storage, and most appropriate type of thermal energy storage to employ.

The chosen pathway is shown in Table 10.

Table 10: Chosen GHG Reduction Pathway



RISK ASSESSMENT

The following risks to implementation of the chosen pathway have been identified:

- **Wind resource provides less power than expected.** There is a risk that the renewable energy that can be generated for a given installed wind capacity at the Project site is lower than expected. This will impact the costs and/or feasibility of the chosen pathway. Arafura is currently gathering data on the available wind resource at the Project site. This data will be used to plan in more detail the most cost-effective mix of PV, wind and batteries to meet 50% of the Project's electrical power requirements from renewable sources by 2030.
- **Emissions reduction technology costs are higher than expected.** Increases in the cost of emissions reduction technologies will impact the cost and/or feasibility of the chosen pathway, or potentially all candidate pathways. Future design studies will be undertaken to develop cost estimates which are based on more detailed engineering studies and, where possible, on supplier quotes (the current estimates are based on publicly published metrics, as detailed in Appendix B).
- **Supply chain constraints delay schedule of implementation.** If system components are not available this may delay the installation of emissions reduction technologies. Future engineering studies will be undertaken which will identify system components with long lead times, which will enable Arafura to place early orders as required to mitigate supply chain risk.
- **Performance of thermal energy storage is poorer than expected.** If the charge and discharge rates, energy storage capacity or ability to retain energy over time are poorer than assumed for thermal energy storage this will impact the cost and/ or feasibility of the chosen pathway. These will be investigated further during the study into thermal energy generation options (see Table 11).
- **Unable to secure an appropriate IPP.** The chosen pathway requires higher capital investment than the BAU pathway and, as referred to above, the Company's modelling provides that the IPP will bear the capital costs of the chosen pathway as all electrical power and steam will be procured from an IPP under a BOO model for the Project. There is a risk that the Company is unable to secure an appropriate IPP that will have the infrastructure available to meet the power generation demands of the chosen pathway.

NEXT STEPS

The development and implementation of a GHG emissions reduction pathway will be an ongoing program of work for Arafura throughout the life of the Project. The current high-level plan for the implementation of the pathway to 2030 is shown in Table 11.

These are the main activities to deliver the chosen pathway. Arafura will also maintain a technology watch for emerging cost-effective energy generation, conversion and storage solutions. This may include conducting studies into alternative technologies which are not part of the chosen pathway. The chosen pathway will be updated if these studies or other work demonstrate the superior value of emergent alternative emissions reduction technologies.

Table 11: High-level Plan for Implementation of Chosen Pathway to 2030

	Now	2023 – 2025 Project Construction	2026 – 2030 Project Operations
Electrical	SODAR for on-site wind and solar resource data collection. Incorporation of electrical interfaces for renewable power into facility design.	Confirm initial renewable electrical power requirements (e.g. target renewable energy fraction). Design of PV, wind and EES power solution.	Construction and operation of solar PV field, wind turbines and EES and supporting infrastructure.
Thermal (200 C steam)	Incorporation of interfaces for renewable steam into facility design.	Detailed investigation of thermal generation and TES options to confirm appropriate technology mix.	Design, construction and start-up of demonstration scale thermal generation and TES.
Firming power (electrical and thermal)	Consider ability of power generation equipment to run on alternative fuels during equipment selection.	Technology watch on availability and prices of 'drop-in' low emission sustainable fuels.	
Other emissions sources (e.g. mobile plant, high temperature heat and process emissions)		Studies on options for GHG emission reduction for other emission sources. Update of GHG emissions reduction pathway to include other emissions sources.	

The tender process for the IPP, which is currently underway, includes a flow-down of the Arafura Net Zero 2050 emissions goal to the IPP. Once the IPP is selected, Arafura and the successful IPP will jointly review the GHG emissions reduction pathway to determine if it requires refinement, based on the IPP's capabilities and expertise.

Arafura also intends to explore renewable technology development partnerships with funding agencies, such as the Australian Renewable Energy Agency (**ARENA**). This may include collaborative trials of emerging technologies (such as large-scale thermal energy storage) where these offer significant potential for cost-effective decarbonisation of the Project. Where appropriate Arafura will also engage third party experts in specific technologies to assist with the further development of the GHG emissions reduction pathway.

As stated above, all pathway modelling and analysis presented in this announcement (and the ultimate implementation of the chosen pathway) is dependent on a number of factors, including securing remaining offtake agreements, procuring electrical power and steam from an IPP under a BOO model on terms acceptable to the Company, securing funding on appropriate terms to develop the Project, a final investment decision being made and successful construction, commissioning and ramp up of the Project. There is no guarantee or certainty that these milestones will be reached. The key risks to implementing the chosen pathway are set out on page 15.

GLOSSARY

Item	Description
ARENA	Australian Renewable Energy Agency
BAU	Business As Usual (the conventional power generation pathway)
BOO	Build-Own-Operate
CST	Concentrated Solar Thermal
EES	Electrical Energy Storage
GHG	Greenhouse Gas
IPP	Independent Power Provider
MRIWA	Minerals Research Institute of Western Australia
MWe	Megawatt (electrical)
MWt	Megawatt (thermal)
MWh	Megawatt-hour (electrical)
MWt-hr	Megawatt-hour (thermal)
PV	Photovoltaic
SODAR	Sonic Detection and Ranging
TES	Thermal Energy Storage

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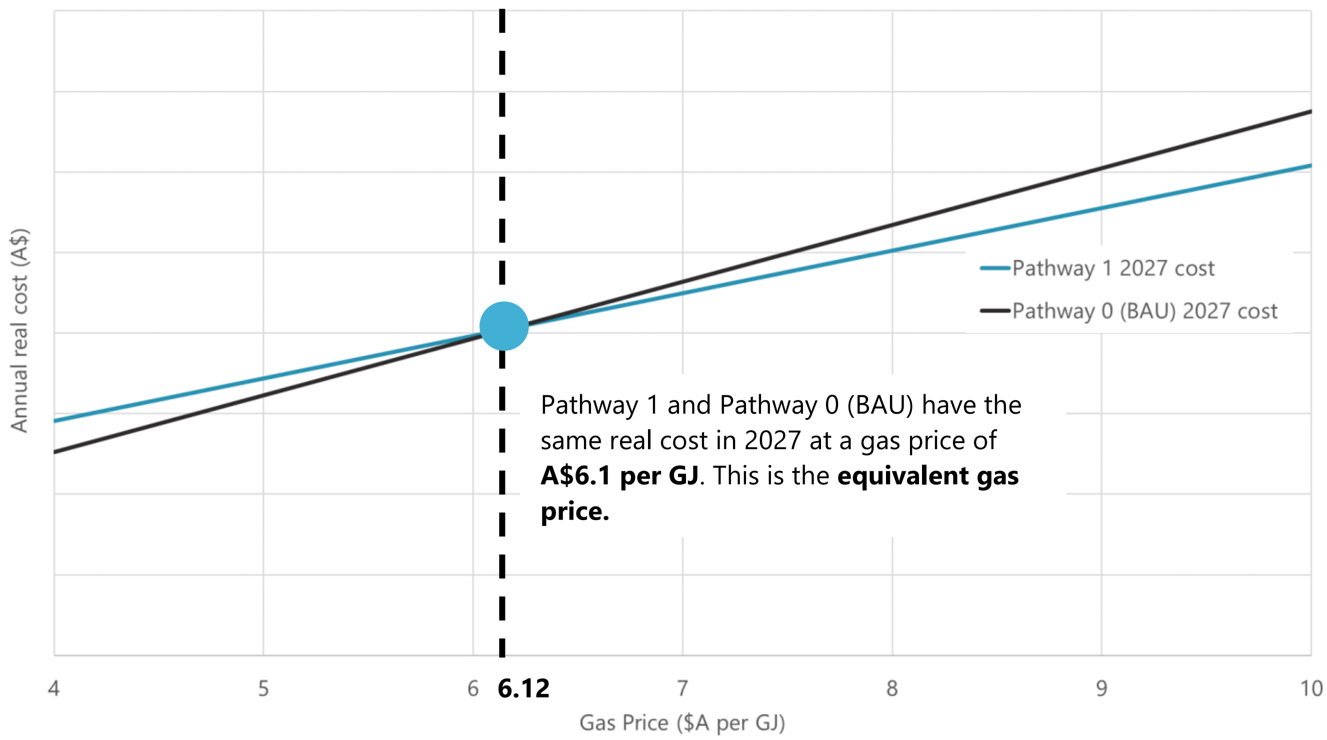
APPENDIX A: EQUIVALENT GAS PRICE CALCULATION

The cost of each pathway is presented as an equivalent gas price. For a given year, this is the gas price at which the total annual cost of meeting the Project's stationary energy requirements under the pathway is equivalent to meeting the cost of the Project's stationary energy requirements through the combustion of natural gas.

Figure 4 illustrates this approach for an example year (2027) and pathway (Pathway 1). The annual real cost of both the BAU pathway (Pathway 0) and the example pathway (Pathway 1) have been calculated for a range of gas prices. This enables the gas price at which the pathway's costs are equivalent (the 'cross over' point) to be calculated.

As can be seen from Figure 4, both the BAU pathway (Pathway 0) and the example pathway (Pathway 1) are dependent on the gas price. All the pathways include use of natural gas for firming power prior to 2050. This is progressively reduced over time for all pathways except the BAU pathway.

Figure 4: Example of Equivalent Gas Price Calculation for Pathway 1 in Calendar Year 2027



The annual real cost for both the BAU pathway and all the GHG emissions reduction pathways is inclusive of:

- Capital asset finance repayments.
- Fixed and variable operations and maintenance charges.
- Fuel consumed (including the cost of transport to site).
- The cost of purchasing Australian Carbon Credit Units (ACCUs) if these are required to meet the assumed annual Safeguard Mechanism baseline emissions for the Project.
- The revenue from the sale of Safeguard Mechanism Credits (at a value equal to the assumed ACCU price) if emissions are below the assumed annual Safeguard Mechanism baseline for the Project.

APPENDIX B: MODELLING ASSUMPTIONS

Emissions

- Emissions intensity of gas combustion: 51.5 tCO_2e/ TJ (4). Emissions of electrical and thermal power generation for of all forms of gas combustion assumed equal.
- Only project emissions from stationary power are addressed by this version of the GHG emissions reduction pathway.

Financial

- Weighted average cost of capital (**WACC**) of 7%. This is the same WACC as assumed in (1).
- Capital purchases 100% debt funded.
- Repayment is spread over life of capital asset funded.
- Capital replacement is at same price as original purchase.
- Capital costs are incurred in same year as asset is available for use (no construction time modelled). All costs incurred for operational expenses (e.g. fuel consumption) are assumed to be associated with an impact in the same year (e.g. associated emissions from combustion of the fuel).
- No allowance in model for end of LOM (e.g. repayment of remainder of loan, owar recovery of salvage costs).
- Costs for studies and engineering have not been modelled.
- Capacities of energy conversion assets (e.g. heat pumps, steam turbine and steam discharge generator) increased by 20% above average power requirement to account for peaking load requirements.
- All costs presented and modelled are in real Australian dollars at 2022. Any cost reductions shown in the following tables are forecast reductions in real costs (due to learning effects for a particular emissions reduction technology, for instance).
- Exchange rates: US$0.67 per A$, €0.64 per $A).
- Main model inputs (e.g. technology capacities) are varied in five-year increments (e.g. 2031 – 2035, 2036 – 2050 etc) and results are also presented in five-year increments.

Asset Life

	Gas engine (5)	Package boiler (6)	Solar PV (5)	Wind (5)	Li-ion battery (7)	Thermal energy storage (solid) (5)[6]	Heat pump[7]	Conc. solar thermal (5)	Thermal energy storage (molten salt) (5)[8]	Steam discharge generator (5)[9]	Steam turbine Storage (5)[10]
Assumed life (yrs)	25	20	30	25	15	25	20	25	25	25	25

- There is no degradation in the performance of assets over their life.

[6] Assumed same as life of CST stated in (5)

[7] Heat pumps are an emerging technology for providing steam at the temperatures required. No reliable information on equipment lifetime was found. The stated figure is an assumption based on the lifetime of similar existing equipment (e.g. large scale building air conditioning systems)

[8] Assumed same as life of CST stated in (5)

[9] Assumed same as life of CST stated in (5)

[10] Assumed same as life of CST stated in (5)

Energy Conversion Efficiencies

Energy type in	Energy type out	Gas engine (5)	Package boiler (6)	Thermal energy storage (solid) (8)	Heat pump[11]	Thermal energy storage (molten salt) (10)	Steam turbine (11)
Gas	Electricity	0.41					
Gas	Steam		0.9				
Salt	Steam					0.98	
Solid	Steam			0.98			
Steam	Electricity						0.47
Electricity	Steam				1.5		

[11] It was not clear from literature what coefficient of performance (efficiency) might be possible for a heat pump to produce steam at 160 – 180 C (the required temperature). Value stated is assumption based on performance of heat pumps in other higher temperature applications.

Capital Costs (in real Australian dollars at 2022)

	Gas engine (5)	Package boiler (6)	Solar PV (5)	Wind (5)	Li-ion battery (5)	Thermal energy storage (solid) (8)	Heat pump (9)	Conc. solar thermal (12)	Thermal energy storage (molten salt) (12)	Steam discharge generator (8)	Steam turbine (12)
Unit =>	A$m/ MWe	A$m/ MWt	A$m/ MWe	A$m/ MWe	A$m/ Mwe-hr	A$m/ MWt-hr	A$m/ MWt	A$m/ MWt	A$m/ MWt-hr	A$m/ MWt	A$m/ MWe
2025	1.6	0.15	1.5	2.0	0.4	0.022	0.6	0.46	0.026	0.075	2.4
2050	1.5	0.15	0.5	1.5	0.25	0.016	0.3	0.3	0.020	0.067	2.4
2062	1.5	0.15	0.5	1.5	0.25	0.016	0.3	0.3	0.020	0.067	2.4

- Note that most reference data is only available as a forecast to 2050. It has been assumed that there is no change in costs after 2050. Where forecast data to 2050 is not available a learning rate has been assumed and the value stated used.
- Costs between 2025 and 2050 are linearly interpolated to the relevant year.

Operational Costs (fixed) in real Australian dollars in 2022

	Gas engine (5)	Package boiler (6)	Solar PV (5)	Wind (5)	Li-ion Battery (13)	Thermal energy storage (solid)[12]	Heat pump[13]	Conc. Solar thermal (12)	Thermal energy storage (molten salt) (12)	Steam discharge generator [14]	Steam turbine (12)
Unit =>	A$m/ MWe	A$m/ MWt	A$m/ MWe	A$m/ MWe	A$m/ MWe-hr	A$m/ MWt-hr	A$m/ MWt	A$m/ MWt	A$m/ MWt-hr	A$m/ MWt	A$m/ MWe
All years	0.024	0.003	0.017	0.025	0.01	0.00044	0.012	0.0092	0.00052	0.015	0.048

- No change in operational costs over time.

[12] Assumed 2% of capital cost
[13] Assumed 2% of capital cost
[14] Assumed 2% of capital cost

Operational Costs (variable) in real Australian dollars in 2022

	Gas engine (5)	Package boiler (6)	Heat pump	Electric boiler	Steam discharge generator	Steam turbine
Unit =>	A$/ MWh	A$/ MWh	A$/ MWh	A$/ MWh	A$/ MWh	A$/ MWh
All years	7.6	2.0	2.0	2.0	2.0	5.0

- No change in operational costs over time.
- These costs do not include fuel.
- Variable costs for heat pumps, electric boiler, steam discharge generator and steam turbine are estimated (no reference data available).
- Variable operational costs for all solar PV, wind power, EES and TES assumed negligible.

Renewable Fuel Price in real Australian dollars in 2022

DNV (14) estimate the cost of renewable hydrogen produced from grid-based electrolysis as approximately USD$3 per kg in 2025 and USD$1.5 per kg in 2050. This equates to a hydrogen cost of approximately A$37 / GJ in 2025 and A$19 per GJ in 2050, assuming the energy content of hydrogen as 120 MJ / kg and an exchange rate of 0.67 US$ per A$. 25% has then been added to this assumed hydrogen price as an estimate of the costs of processing the hydrogen into a synthetic fuel and subsequent transport to site.

All forms of renewable fuel are assumed to have the same energy conversion efficiency (e.g. from chemical to electrical energy) as natural gas.

Costs between 2025 and 2050 are linearly interpolated to the relevant year.

	Renewable fuel
Unit =>	A$/ GJ
2025	47
2050	23
2062	23

Australian Carbon Credit Unit (ACCU) Price in real Australian dollars at 2022

The price of an ACCU was $30 per tCO_2e in September 2022 (15). The forecast prices include an assumption of increasing ACCU prices over time. This is considered likely, due to potential increases in demand for ACCUs from voluntary corporate net zero commitments and future obligations on facilities to offset their emissions under the proposed Safeguard Mechanism Reforms.

Costs between 2025 and 2050 are linearly interpolated to the relevant year.

	ACCU price
Unit =>	A$/ tCO_2e
2025	30
2050	65
2062	65

Renewable energy fraction

The annual renewable electrical energy available from PV, wind and batteries is a function of:

- PV, wind and battery capacities.
- Representative hourly weather data for a year.
- Target electrical load.

To estimate renewable electrical energy available from different PV, wind and battery combinations a Homer Pro software model of a PV, wind and battery system at the Project location was developed. Further information on Homer Pro is available at https://www.homerenergy.com/products/pro/index.html.

The annual renewable thermal energy available from CST combined with TES is a function of:

- CST and TES capacities.
- Representative hourly weather data for a year.
- Target thermal load.

To estimate renewable thermal energy available for different pathways a System Advisor Model (SAM) of a CST and TES at Alice Springs was used (the closest location to the Project where appropriate weather data was publicly available). Further information on SAM is available at https://sam.nrel.gov/.

Information on the application of SAM to Australian CST and TES projects, including weather data for Alice Springs in a suitable format, is available at https://www.austela.net.au/resources.

The annual renewable thermal energy available from solar PV and wind providing electrical power to heat thermal energy storage was also estimated using the Homer Pro model (for Pathway 5). It was assumed that the renewable energy fraction achieved for thermal energy storage meeting a thermal load and powered by electrical renewables would be similar to that achieved for electrical storage meeting an electrical load powered by electrical renewables.

APPENDIX C: DESCRIPTION OF CANDIDATE TECHNOLOGIES AND RELEVANCE TO THE PROJECT

More detailed summaries of many of the technologies listed are provided in (3).

Emissions reduction technology	Description	Advantages	Disadvantages	Relevance to Project
Solar PV (PV)	Solar panels.	Low cost per unit energy generation.	Variable generation depending on weather conditions and time of day.	Able to meet proportion of electrical requirements at lowest cost.
Wind power	Wind turbines.	Low cost per unit energy generation. Depending on local wind conditions can complement solar PV.	Variable generation depending on weather conditions.	Initial studies indicate wind resource sufficient to complement solar PV generation.
Electrical energy storage (EES)	Batteries. Lithium ion and vanadium redox flow batteries are examples of technologies available.	Store electrical power until required (e.g. at night).	Increase levelized cost of energy compared to solar PV and / or wind alone.	Likely to be necessary at some scale, given 24/7 operation requirements.

Emissions reduction technology	Description	Advantages	Disadvantages	Relevance to Project
Thermal energy storage (TES)	Thermal masses (either liquid or solid) which charge by being heated and discharge by exchanging their heat to a useful heat source for the plant.	Good 'round trip' efficiency of energy storage, if the output energy required is thermal (not electrical).	Charge and discharge rates may limit usefulness.	Significant thermal steam load makes TES a potentially important energy storage option.
Electric boilers	Resistance heating of water to generate steam.	Proven, low-cost technology, applicable to broad range of temperatures.	Lower heating efficiency than heat pumps.	May be required for steam generation in high electrification pathways.
Heat pumps	Expansion and compression of a working fluid to move heat energy between locations.	Very high coefficient of performance (efficiency), particularly for lower heating temperatures.	May not be able to meet steam temperature requirements (or may have unacceptable drop in efficiency at required temperatures).	Could be a very efficient form of steam generation but depends on maturing technology.
Fossil fuels	Natural gas or other fossil fuels.	High energy density, handling characteristics understood, mature technology.	High emissions.	Will be required to provide initial firming power to the project.

<table>
<tr><th>Emissions reduction technology</th><th>Description</th><th>Advantages</th><th>Disadvantages</th><th>Relevance to Project</th></tr>
<tr><td>Bio fuels</td><td>Fuels that can be combusted in existing engines/ boilers which are derived from bio sources.</td><td rowspan="4">Very low lifecycle emissions, if sustainably sourced.</td><td rowspan="4">Uncertainty on future costs and availability.</td><td rowspan="4">Potential renewable fuel options for providing net zero emission firming power in future.</td></tr>
<tr><td>Synthetic fuels</td><td>Fuels that can be combusted in existing engines/ boilers which are synthesised from captured carbon dioxide and renewably produced hydrogen.</td></tr>
<tr><td>Hydrogen</td><td>Renewable hydrogen produced from either water electrolysis or steam methane reforming with carbon capture.</td></tr>
<tr><td>Ammonia</td><td>Renewable ammonia produced from renewable hydrogen and nitrogen.</td></tr>
</table>

APPENDIX D: RANGE ESTIMATES OF EQUIVALENT GAS PRICE FOR CANDIDATE PATHWAYS

Low and high estimates for the equivalent gas prices (in A$/ GJ) presented in Table 9 are provided in the table below.

	Pathway 0	Pathway 1	Pathway 2	Pathway 3	Pathway 4	Pathway 5
2026 - 2030	8.34	5.50 - 6.70	5.50 - 6.70	7.70 - 8.70	5.50 - 6.70	5.50 - 6.70
2031 - 2035		8.60 – 10.00	8.70 - 10.20	7.30 - 8.40	8.70 - 10.20	8.70 - 10.20
2036 - 2040		8.30 - 9.70	12.20 – 14.00	7.10 - 8.40	16.70 - 18.50	9.40 - 11.10
2041 - 2045		11.30 - 12.90	16.10 – 18.00	10.50 - 11.90	18.10 - 21.80	12.60 - 14.40
2046 - 2050		9.40 - 11.30	14.80 - 17.50	10.10 – 12.00	15.10 - 20.20	12.80 - 14.90
2051 onwards		9.40 – 11.60	14.30 - 17.50	10.00 - 12.50	13.70 - 19.40	12.50 – 15.00
LOM average		**9.00 - 10.40**	**12.50 - 14.40**	**9.00- 10.60**	**13.40 - 16.50**	**10.80 - 12.50**

The ranges were generated by varying the model inputs below in accordance with a normal probability distribution that delivered the 5th and 95th percentile variations listed in the table below around a mean of the input values previously listed in Appendix B. The low estimate presented above is the 5th percentile result, and the high estimate is the 95th percentile result. The model was run 100 times.

	5th / 95th percentile variation from input value listed in Appendix B								
	Solar PV	Wind	Li-ion Battery	Thermal energy storage (solid)	Heat pump	Conc. Solar thermal	Thermal energy storage (molten salt)	Steam discharge generator	Steam turbine
Capital costs in 2050	+/- 5%	+/- 10%	+/- 10%	+/- 10%	+/- 15%	+/- 15%	+/- 90%	+/- 5%	+/- 5%
Renewable technology capacities (to achieve same power output)	+/- 0%	+/- 10%	+/- 10%	+/- 10%	+/- 0%	+/- 10%	+/- 10%	+/- 0%	+/- 0%
Renewable fuel price in 2050	+/- 15%								
ACCU price in 2050	+/- 15%								

Where a variation is described above as being applied in 2050, it is progressively and linearly applied between 2025 and 2050 (i.e. 0% variability at 2025, rising to variability shown by 2050).