Broome Clean Energy Study

TECHNICAL REPORT

This report demonstrated that electricity generation in the town of Broome can be achieved with over 80% renewable energy at three quarters of the price of gas-fired (LNG) generation. This will achieve total lifetime savings of $321m.

BROOME'S Electricty Generation

achieved with

>80% Renewable ENERGY

Costing less than

3/4 Price of LNG Generation

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Broome Clean Energy Study 2022: Technical Report

1. Technology costs

This document provides the technical background underpinning the cost assumptions used in modelling renewable energy in the Broome Clean Energy Study 2022.

The cost of a particular technology is calculated from the Capital Expenditure (CAPEX) per MW installed, converted to an annualised capital cost. Operational Expenditure (OPEX) costs are made up of Fixed and Variable components. Operations and Maintenance (O&M) costs are added to give fixed annual costs per MW generated per year. Variable Operations costs per MWh, made up of fuel costs and other operating costs per MWh, are added to obtain the cost of electricity generated.

The costs used here are representative estimates derived largely from two Australian-based studies commissioned by the Australian Energy Market Operator. These two sources are CSIRO's 'GenCost 2020-21' report (Graham et al. 2021), and the 'Technical Parameter Review' carried out by GHD for AEMO (2018).

The base figures are the GenCost Capital Expenditure and Operations and Maintenance predictions for 2024 (Graham et al. 2021) for their High VRE (Variable Renewable Energy) scenario. The year 2024 has been chosen as the current electricity supply for Broome is contracted until 2026 and this allows two years for proposal development. The High VRE scenario is the most 'aggressive' of the three considered by GenCost (Graham et al. 2021).

The baseline GenCost figures have been uplifted by ratios determined for each of the five Regional cost factors for the 'WA high' region (GHD 2018 Table 73, Regional Cost Factors), which is most relevant for the Kimberley.

A second adjustment was made to account for the extreme weather conditions which can be experienced in the Kimberley region. The justification of the regional and extreme weather adjustments are described in Sections 2 & 3 respectively.

The inputs to the modelling, with explanations in Sections 1, 2 & 3, are shown in Table 1.

Table 1. Summary of the CAPEX and OPEX costs used in this study for each technology.

Technology	CAPEX ($/MW)	Fixed OPEX ($/MW)	Variable OPEX ($/MWh)	Fuel ($/MWh)
Fixed PV	1,282,000	26,000		
Rooftop PV	1,261,000			
Onshore Wind	2,850,000	38,000		
Gas-LNG	1,794,000	36,000	11.40	193.00
Battery (1hr)*	811,000	12,000		
Battery (2hr)*	507,000	12,000		
Battery (4hr)*	374,000	12,000		
Battery (8hr)*	312,000	12,000		

* ($/MWh)

1.1. Capital costs

Tables 2a and b summarise capital cost inputs and uplift factors used to derive the final technology costs used in this modelling. Table 2a summarises *generation* costs in MW, while Table 2b summarises *storage* costs per MWh.

Capital costs for each technology have been derived from the GenCost High VRE scenario for 2024 (Column 2). These costs are for new projects that will provide the nominated capacity and performance for the nominated design life without the need for additional capital costs or refurbishment (that is not already included in operating and maintenance costs). Column 3 lists regional factors based on GHD (2018 Table 73), discussed in Section 2. The values for extreme weather uplifts are discussed in Section 3 and shown in Column 4.

The fifth column sums the regional and weather factors, which are multiplied by the Base cost in Column 2 to derive a total cost in kW or MW.

Table 2a. Summary of capital cost inputs and uplift factors used to derive final generation technology costs.

Technology	Base Cost ($/kW) *	Regional Factor †	Weather Factor §	Total Uplift Factor	Final Cost ($/kW)	Final Cost ($/MW)
Utility Solar PV	$903	1.13	1.29	1.42	$1,282	$1,282,000
Rooftop Solar PV	$888	1.13	1.29	1.42	$1,261	$1,261,000
Wind (Onshore)	$1921	1.18	1.3	1.48	$2,850	$2,850,000
Gas Reciprocating Engine	$1,460	1.13	1.10	1.23	$1,794	$1,794,000

* (Graham et al. 2021 Table B.2)

† Derived in Section 2.

§ Derived in Section 3

Table 2b. Summary of capital cost inputs and uplift factors used to derive final costs of battery storage.

Technology	Base Cost ($/kWhr) *	Regional Factor †	Weather Factor §	Total Uplift Factor	Final Cost ($/kWhr)	Final Cost ($/MWhr)
Battery (1hr)	$588	1.24	1.14	1.38	$811	$811,000
Battery (2hr)	$368	1.24	1.14	1.38	$507	$507,000
Battery (4hr)	$271	1.24	1.14	1.38	$374	$374,000
Battery (8hr)	$226	1.24	1.14	1.38	$312	$312,000

* (Graham et al. 2021 Tables B.4 & B.5)

† Derived in Section 2.

§ Derived in Section 3

1.1.1. Cost of Capital (WACC)

The Weighted Average Cost of Capital (WACC) averages the rate of return required by the investor and the borrowing rate. This is applied to capital expenditures to defray expenses over the expected minimum working life of the project (the amortisation period).

A WACC for all technologies of 7.25% was used. This is slightly higher than the figure of 7.1% used in 2018 (Phillips, Rose, and Bunn 2018).

The amortisation period is used to calculate the fixed annual costs of a technology. In this modelling, the amortisation periods were 25 years for wind and PV, 25 years for internal combustion generators (based on Graham et al. (2021 Table B.8)) and 20 years for batteries (based on Graham et al. (2021, Page 14).

GHD used an average WACC for Renewables of 6.25% (2018 Table 9), so a figure of 7.25% is considered both reasonable and conservative. Given the power purchaser is a government body in the form of Horizon Power, a relatively low WACC is appropriate and in line with the reduced risk profile it represents.

A sensitivity analysis showed that the WACC value had a relatively small effect on model outcomes.

1.1.2. Capital cost changes since 2018

Table 3 compares the changes in capital costs used here with those used in Phillips et al. (2018). Over that period, and based on different assumptions, Utility PV has become 26% less expensive. Rooftop PV was not explicitly considered in 2018, existing capacity was simply assumed to exist, and all modelling was done on Utility PV.

Table 3. Comparison of CAPEX assumptions between 2018 and 2022.

Technology	KCER 2018‡	This Report	Percent change 2022-2018
Utility PV $m/ MW *	$1.74	$1.28	-26%
Rooftop PV $m/ MW†	$0.00	$1.26	
Onshore Wind $m/ MW	$1.86	$2.85	53%
Gas reciprocating engine $m/ MW	$1.40	$1.79	28%
Battery storage 1 Hr $m/ MWh[¥]	$0.73	0.811	12%

* Reduced to $1.30m in the 2018 AEMO Integrated System Plan (Australian Energy Market Operator 2018). This results in only a 2% difference.
[†] Costs borne by the customer
[‡]from Table F.1 of Phillips et al. (2018)
[¥]4 hrs, 2 hrs and 1 hr capacity, respectively – needs more explanation

Onshore Wind costs increased by 53% due to several factors. In 2018, the non-cyclone rated V150 turbine was used, while the cyclone-rated V117 was used in this work. The output of the V117 is approximately 9% less than the V150. Once the total regional and weather uplift factor of 1.48 in Table 2a is included, 2018 and current values are comparable.

The change in costs of gas reciprocal engines are consistent with the use of an uplift factor of 1.23.

In 2018, battery capacity of 15 minutes was the only case considered. This work considers battery discharge rates of 1, 2, 4 & 8 hours. In Table 3, a 1 hour battery is compared with the 15 minute battery used in 2018. The current 1 hour battery cost is 12% greater than the 2018 value, due to uplift factors. However, Table 2b, indicates that larger capacity batteries are considerably less expensive than in 2018.

1.2. OPEX costs

Fixed (Table 4) and Variable (Table 5) OPEX costs for generation technologies were taken from GenCost (Graham et al. 2021 Table B.9). OPEX costs for battery storage were not reported in GenCost, so relevant figures from GHD (2018 Table 42) were used.

A Regional Cost Factor for 'WA High' of 1.50 GHD (2018 Table 73) was applied to the OPEX costs for all the technologies considered.

Table 4. OPEX Fixed Costs for each technology

Technology	Initial Cost $/kW	Factor	Final Cost $/kW	Cost $/MW
Utility solar PV	$17.00	1.50	$25.50	$26,000
Rooftop solar PV	$0.00	1.50	$0.00	$0
Wind (Onshore)	$25.00	1.50	$37.50	$38,000
Gas reciprocating engine	$24.10	1.50	$36.15	$36,000
Battery (1hr)	$8.00	1.50	$12.00	$12,000

Table 5. OPEX Variable Costs for each technology

Technology	Initial Cost $/MWh	Factor	Final Cost $/MWh
Utility solar PV	$0.00	1.50	$0.00
Rooftop solar PV	$0.00	1.50	$0.00
Wind (Onshore)	$0.00	1.50	$0.00
Gas reciprocating engine	$7.60	1.50	$11.40
Battery (1hr)	$0.00	1.50	$0.00

1.3. Fuel costs

The Broome gas generators are fuelled by LNG delivered by road train from Karratha.

For LNG, a fuel cost of $22/GJ was assumed. This was taken from the LNG base case (2027) in Table G.2 of the original KCER report (Phillips, Rose, and Bunn 2018)

The fuel costs used in this work are shown in Table 6.

Table 6. Fuel costs used for each of the fossil felled scenarios.

	LNG
Fuel $/GJ	$22.00
Generator efficiency	41%
Fuel $/MWh	$193.18
Factor	1.00
Final Fuel Cost $/MWh	$193.00

2. Technology Regional Factors

GHD reported Regional Cost Factors for the 'WA High' region (GHD 2018 Table 73), broken down into components. These provide a conservative basis for costs:

- Equipment costs – 1.10
- Fuel connection costs – 1.38
- Cost of land and development – 1.00
- Installation costs – 1.67

GHD (2018) provides typical costs for each component for each technology. In Tables 7a-d, these component costs (column 2) have been multiplied by the Regional Cost Factors (column 3) to calculate a scaled cost (column 4). The ratio of the total scaled cost to the total initial costs provides an overall regional factor for each technology, e.g. 1.13 in Table 6a.

This calculation results in the Regional Factors displayed in column 3 of Table 2.

Table 7a. Regional Factor for PV. Data from GHD (2018 Table 62).

Factor	**Initial Cost**	**Regional Factor**	**Scaled cost**
Equipment costs	$137,640,000	1.10	$151,404,000
Cost of land and development	$9,447,000	1.00	$9,447,000
Installation costs	$10,360,000	1.67	$17,301,200
Total costs	$157,447,000	**1.13**	$178,152,200

Table 7b. Regional Factor for Wind – onshore. Data from GHD (2018 Table 68).

Factor	**Initial Cost**	**Regional Factor**	**Final cost**

Equipment costs	$165,750,000	1.10	$182,325,000
Cost of land and development	$6,825,000	1.00	$6,825,000
Installation costs	$29,250,000	1.67	$48,847,500
Total costs	$201,825,000	**1.18**	$237,997,500

Table 7c. Regional Factor for Gas reciprocating engine. Data from GHD (2018 Table 21).

Factor	**Initial Cost**	**Regional Factor**	**Final cost**
Equipment costs	$291,611,000	1.10	$320,772,100
Cost of land and development	$28,325,000	1.00	$28,325,000
Installation costs	$23,110,000	1.67	$38,593,700
Total costs	$343,046,000	**1.13**	$387,690,800

Note: No pipeline connection costs have been included here as the LNG scenario is delivered by roadtrain, and pipeline connection costs are already included in the Fracked gas unit cost.

Table 7d. Regional Factor for Battery. Data from GHD (2018 Table 43)

Factor	**Initial Cost**	**Regional Factor**	**Final cost**
Equipment costs	$9,500,000	1.10	$10,450,000
Cost of land and development	$978,000	1.00	$978,000
Installation costs	$3,500,000	1.67	$5,845,000
Total costs	$13,978,000	**1.24**	$17,273,000

3. Technology Weather Requirements Factors

The Kimberley region is subject to extreme weather events on a regular basis, including torrential rain and cyclonic winds. The costs from GenCost (Graham et al. 2021) are for standard equipment and installations in typical mild weather conditions only. Consequently, project costs in the Kimberley region will be higher than those in published in the GenCost report.

No Australian data was readily available for extreme weather, so the following analysis is based on real-life knowledge of an experienced engineer.

As a general principle, equipment supplied will be required to be more robust in key areas and have higher water ingress ratings. In some cases, higher temperature tolerances may be required. Installation will require more substantial frames and footings and potentially protection against flying debris. Installations may need to accommodate water flow and flooding. In all cases, substation and power lines are expected to be more expensive.

Considerations for each technology are summarised below.

PV

- There is a need for more robust panel frames, mounting brackets, as well as higher specification against water ingress for seals and enclosures. Larger and more robust foundations and support structures are needed.
- PV and associated electrical components are expected to be similar.

Wind - onshore

- There is a need for higher specification towers, gearbox frontend, enclosures, blades and blade mountings, along with larger foundations
- Electrical, electronic and control systems are expected to be similar, as are internal structures, and the generator and backend gearbox.
- Cyclone-rated wind turbines have smaller towers and blades to accommodate high winds, and this leads to reduced performance in low wind situations. The System Advisory Model used in the SIREN software accounts for this automatically in the model selection and consequent detailed simulation.

Gas reciprocating engine

- More robust enclosures and higher specification for water ingress for seals and enclosures are needed.
- Engine and peripherals/accessories within the more substantial installation are expected to be similar.

Battery

- More robust enclosures and higher specifications for water ingress for seals and enclosures are needed.
- Battery and electrical components within the more robust enclosures are expected to be similar.

Best estimates of multipliers associated with weather factors associated with components of capital expenditure are shown in column 3 of Tables 8a-d. These are multiplied by the GHD (2018) cost data (column 2) in the same was as in Section 2 to derive a final cost for each component. An overall Weather Factor is then back-calculated for each technology, shown in bold in Tables 8a-d.

This calculation results in the Weather Factors displayed in column 4 of Table 2.

Table 8a. Weather Factor for PV. Cost data from GHD (2018 Table 62).

Factor	Initial Cost	Weather Factor	Final cost
Equipment costs	$137,640,000	1.30	$178,932,000
Cost of land and development	$9,447,000	1.00	$9,447,000
Installation costs	$10,360,000	1.40	$14,504,000
Total costs	$157,447,000	**1.29**	$202,883,000

Table 8b. Weather Factor for Wind – onshore. Cost data from (2018 Table 68).

Factor	Initial Cost	Weather Factor	Final cost
Equipment costs	$165,750,000	1.30	$215,475,000
Cost of land and development	$6,825,000	1.00	$6,825,000
Installation costs	$29,250,000	1.40	$40,950,000
Total costs	$201,825,000	**1.30**	$263,250,000

Table 8c. Weather Factor for Gas reciprocating engine. Cost data from GHD (2018 Table 21).

Factor	Initial Cost	Weather Factor	Final cost
Equipment costs	$291,611,000	1.10	$320,772,100
Cost of land and development	$28,325,000	1.00	$28,325,000
Installation costs	$23,110,000	1.20	$27,732,000
Total costs	$343,046,000	**1.10**	$376,829,100

Note: No pipeline connection costs have been included as these may be delivered by LNG and are already included in the Fracked gas unit cost.

Table 8d. Weather Factor for Battery. Cost data from GHD (2018 Table 43).

Factor	Initial Cost	Weather Factor	Final cost
Equipment costs	$9,500,000	1.10	$10,450,000
Cost of land and development	$978,000	1.00	$978,000
Installation costs	$3,500,000	1.30	$4,550,000
Total costs	$13,978,000	**1.14**	$15,978,000

4. Emissions

Calculations for carbon dioxide equivalent emissions (CO_2-e) were derived from recognised sources. The methodology and breakdown of gas emissions components came from Blanton & Mosis (2021). Gas generators were assumed to be 41% efficient, and the unit conversion from GJ to kWh is 3.6. Combustion and fugitive emissions from burning fossil gas were taken from GHD (2018, Table 20). The calculation for the total emissions is summarised in Table 9, with the total emissions per MWh for LNG shown in the last row.

Table 9. Emissions components for LNG.

LNG Emissions (kg CO_2-e/GJ of fuel)	LNG*
Combustion Emissions	53.53
Fugitive Emissions	8.7
Upstream gas production, processing and transport emissions	10.37
Liquefaction emissions	6.85
Shipping emissions	3.32
Regasification emissions	0.21
Total emissions (kg CO_2-e/GJ of fuel)	82.98
Total emissions (tonnes CO_2-e/MWh of energy produced)	0.73

* Average fugitive emissions case

Emissions from renewable technologies (PV, Wind, Battery) were taken from NREL (Nicholson and Heath 2021). Carbon emissions for each technology are summarised in Table 10.

Table 10. Carbon emissions for each technology (tonnes CO2-e/ MWh of energy produced).

Name	Emissions
Battery (1hr)	0.033
Battery (2hr)	0.033
Battery (4hr)	0.033
Battery (8hr)	0.033
Diesel	0.850
Fixed PV	0.043
Gas-LNG	0.730
Onshore Wind	0.013
Rooftop PV	0.043

5. Gas Volumes

This section calculates the volumes of gas used in Broome in various units, assuming no renewable technologies are used. The total annual demand is 130,747 MWh, shown in Row 1 of Table 11.

Anecdotal local evidence is that there are approximately 1.5 LNG shipments per day to Broome. Some of this gas is used for non-power generation, including gas burned during the trip, gas lost during regasification and storage. Each road train has a capacity of 3000GJ (Woodside Energy n.d.).

The calculations in Table 11 indicate that 131 GWh per annum of fossil-fuelled generation equates to 1.05 road trains per day.

Table 11. Estimate of the amount of fossil gas used during a year, assuming no contribution from renewables.

Gas Usage	
Energy per annum (MWh)	130,747
Energy used (GJ) *	1,148,021
Quantity of LNG (tonnes) †	21,103
Qty of LNG per day (tonnes)	57.82
Shipments per day §	1.05

* based on 41% efficiency of the gas generator and 3.6 kWh per GJ)
† based on 54.4 GJ/tonne from (Commonwealth Parliamentary Library 2013)
§ based on max of 3000GJ per road train from (Woodside Energy n.d.)

Table 12. Estimate of the amount of fossil gas used during a year, assuming no contribution from renewables.

Gas Usage	
Energy per annum (MWhr)	130,747
Energy used (GJ) *	1,148,021
Quantity of LNG (tonnes) †	21,103
Qty of LNG per day (tonnes)	57.82
Shipments per day §	1.05

* based on 41% efficiency of the gas generator and 3.6 kWhr per GJ)
† based on 54.4 GJ/tonne from (Commonwealth Parliamentary Library 2013)
§ based on max of 3000GJ per road train from (Woodside Energy n.d.)

6. References

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