NZ Battery – Review of Development Pipeline Costs

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MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
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aurecon

Contents

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Executive Summary

Introduction and summary

Ministry of Business, Innovation and Employment (MBIE) appointed Aurecon to:

1) Review existing wind (onshore), solar and geothermal project cost information (capital and operational costs), identifying gaps and highlighting limitations to existing input assumptions.

2) Review and update the breakdown and derivation of costs that have informed MBIE's capital and operating cost assumptions to date, as outlined in the supporting reports for MBIE's Energy Generation and Demand Scenarios for geothermal, utility scale solar and wind. MBIE has provided supporting spreadsheets to assist in this process.

3) Provide context on the potential project cost range for each technology given the level of uncertainty and risk. Provide a relevant upside and downside sensitivity cost range, depending on site location, MW capacity, energy yield, transmission, consenting etc.

This assignment is to assist MBIE understand the counterfactual scenarios relative to the NZ Battery option. The costs presented in this briefing paper reflect our knowledge of current market projects and our evaluation of how costs might trend in the future.

Aurecon's sub-consultant MTL, has carried out the review of geothermal cost assumptions for this assignment.

Solar

The New Zealand solar market is beginning to emerge in New Zealand but is still immature. The largest grid scale solar project commissioned to date is a 2MW project at Kapuni in South Taranaki and total project costs for larger sized projects remain uncertain. However, Aurecon has a good understanding of grid scale solar project costs in Australia and we have benchmarked MBIE's solar cost assumptions against our extensive knowledge of the Australian solar market, converted into a New Zealand context.

The key findings, gaps and recommendations from our solar review are outlined as follows:

- Total capital costs to increase across all plant sizes by between 30-50%, mainly due to an increased allocation for non-module related costs, such as civil and enabling works.
- Total operating costs to vary across plant sizes by -15% to 36% on a $/KW basis.
- Simplification of cost breakdown categories (from 9 to 6).

Total capital costs over the coming decades are expected to reduce mainly due to a steady reduction in module costs (through increased scale and market size), partially offset by an increase in other costs such as transmission and land related costs (inflation). The solar labour market in New Zealand is expected to remain relatively flat over time.

The solar cost learning curve (4.6% decrease p.a.), as outlined by Allan Miller Consulting (AMC) is deemed appropriate and is expected to continue at this rate until 2050, reducing to 2.3% p.a from 2050 to 2065.

Solar			MWac Scale (2022 NZD)						
		Description	10MW	20MW	50MW	100MW	150MW	200MW	Cost Range
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Total Capital costs (excluding transmission)	$2.5/W	$2.3/W	$2.0/W	$1.8/W	$1.7/W	$1.6/W	Class 5 -20% to +30%
DC/AC ratio 1.3 Fixed Tilt	OPEX	Total OPEX ($/kW/year)	$ 36.0	$ 33.6	$ 30.7	$ 28.8	$ 27.8	$ 27.1	

Wind (onshore)

The onshore wind market in New Zealand is relatively mature with a number of large scale projects in operation. The Roaring 40s report provides a good overview of regional zones and potential MW capacity, although average capacity factor across some regions requires further refinement.

The key findings, gaps and recommendations from our wind review are summarised as follows:

- Total capital costs for project sizes under 150MW to increase, with project sizes above 150MW remaining valid.
- Total operating costs to increase for all project sizes by between 6%-45% due to economies of scale and better benchmarking.
- Transmission costs for new / upgraded transmission lines and substation works are to be further investigated to ensure consistency.
- Learning curves of 1% p.a to 2035, 0.7%p.a to 2050 and 0.2% to 2065 are considered reasonable.

Executive Summary

Wind		MWac Scale (2022 NZD)						
	Description	10MW	20MW	50MW	100MW	150MW	200MW	Cost Range
CAPEX	Total Capital costs (excluding HV transmission)	$ 5,100	$ 3,400	$ 2,400	$ 2,100	$ 2,000	$ 1,900	Class 4 -15% to +20%
OPEX	Total Operating costs ($/kW/year)	$ 52	$ 51	$ 50	$ 48	$ 46	$ 44	

Geothermal

The geothermal market is well established globally and a number of large scale projects have been commissioned in New Zealand over the last ten years, leading to a good understanding of current project development costs across a range of plant sizes.

The key findings, gaps and recommendations from our geothermal review are outlined as follows:

- Lawless Report provides a fair estimate of the total cost of a geothermal project (2020) and their base capital cost estimate of $5,500/KW (US$3,600/KW @0.65) is considered reasonable.
- Project costs are site-specific and will vary depending on reservoir characteristics, drilling campaign and technology selection.
- Project values generally reflect the international view of geothermal project costs.
- Opportunity to build a “bottom up” model to provide additional cost information such as establishment (land acquisition, geoscience modelling, consenting), drilling (production & injection wells, mobilisation / demobilisation), construction (power plant and steamfield) and developers costs (engineering design, finance, legal).

Total capital costs are expected to vary by relative commodity indices and inflation over the coming decades. The technology learning curve for geothermal is expected to be relatively flat compared to solar and wind technologies.

Other considerations

Project ranking

Although not explicit within our scope, we believe there is an opportunity for MBIE to review its project ranking methodology and rank future projects by calculating the levelized cost of energy (LCOE). This is a common approach to assess renewable energy development projects and is a good way of ranking future projects from an investor perspective, although different approaches to calculating LCOEs between organisations (including cost of capital) can lead to inconsistent results.

Our recommendation is as follows:

- Provide a consistent assumption data set of capital cost ($/KW), operational cost ($/MWh), capacity factor (%) and a standard weighted average cost of capital (WACC) across all technologies. This would enable MBIE to calculate LCOE for different projects for cost comparison purposes
- Assess Generation Weighted Average Price (GWAP) for potential projects considering electricity price forecasts and the match of daily and seasonal generation profile with demand and price profiles. The GWAP that a project can earn compared to its LCOE is a robust assessment of commercial viability.

Energy / Transmission zones

There is an opportunity to review other key assumptions including:

- Energy zones and their relative capacity factors for solar and wind projects, utilising Aurecon’s latest energy yield assessment tools.
- Transmission zones and their relative costs ($/km)

Note: For reference, all MBIE related assumptions are based on previous workbooks:

- Utility-scale solar *https://www.mbie.govt.nz/assets/Uploads/utility-scale-solar-forecast-in-aotearoa-new-zealand-v3.pdf* Supplemented by estimates in AEMO 2020 Costs and Technical Parameter Review
- Wind *https://www.mbie.govt.nz/assets/wind-generation-stack-update.pdf*
- Geothermal *https://www.mbie.govt.nz/assets/future-geothermal-generation-stack.pdf*

Executive Summary

Limitations and Levels of Uncertainties

- Technology learning curve expected to be realised going forward
- Less certainty with items such as consenting, escalation, and access, especially for more complex projects

For a general cost estimate, covering a range of projects in an industry where there is available data on historical cost from multiple international agencies, these values appear appropriate.

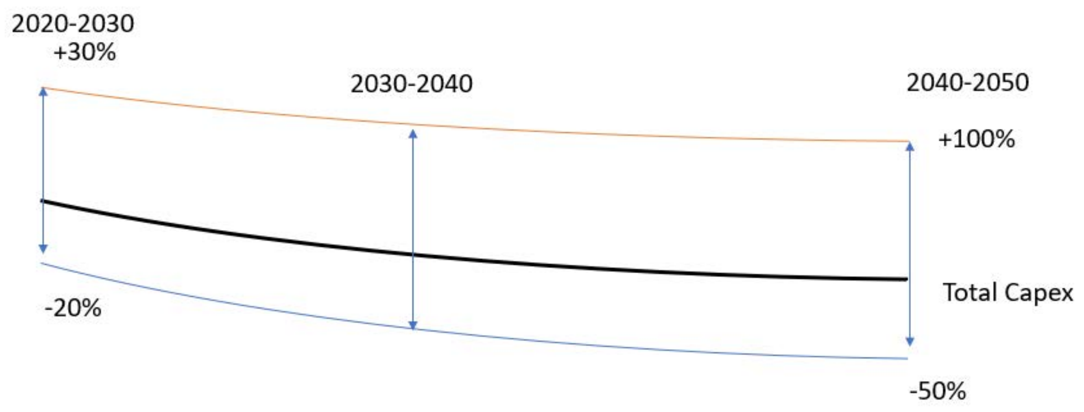
<u>Solar</u>

- **Based on AACE Class 5 estimate**
- This AACE Class 5 is based on a maturity level of project definition deliverables of 0% to 2%.

Low range: -20% (2020-2030) to -50% (2040-2050)

High range: +30% (2020-2030) to +100% (2040-2050)

- Transmission / distribution costs dependant on distance of stack from connection, to reflect progressive buildout and regional considerations.



<u>Wind</u>

- **Based on AACE Class 4 estimate**:
- This AACE Class 4 is based on a maturity level of project definition deliverables of 1% to 15%. Excludes off-shore developments and potential. Consider opening off-shore regions in model to project cost from learning curve point of view.

Low range: -15% (2020-2030) to -50% (2040-2050)

High range: +20% (2020-2030) to +50% (2040-2050)

<u>Geothermal</u>

- **Based on AACE Class 4 estimate**:

Low range: -15% (2020-2030) to -50% (2040-2050)

High range: +20% (2020-2030) - +50% (2040-2050)

- This AACE Class 4 is based on a maturity level of project definition deliverables of 1% to 15%.
- Assume no variable O&M costs at this stage. Going forward there may be variation due to carbon change and royalties.

Solar

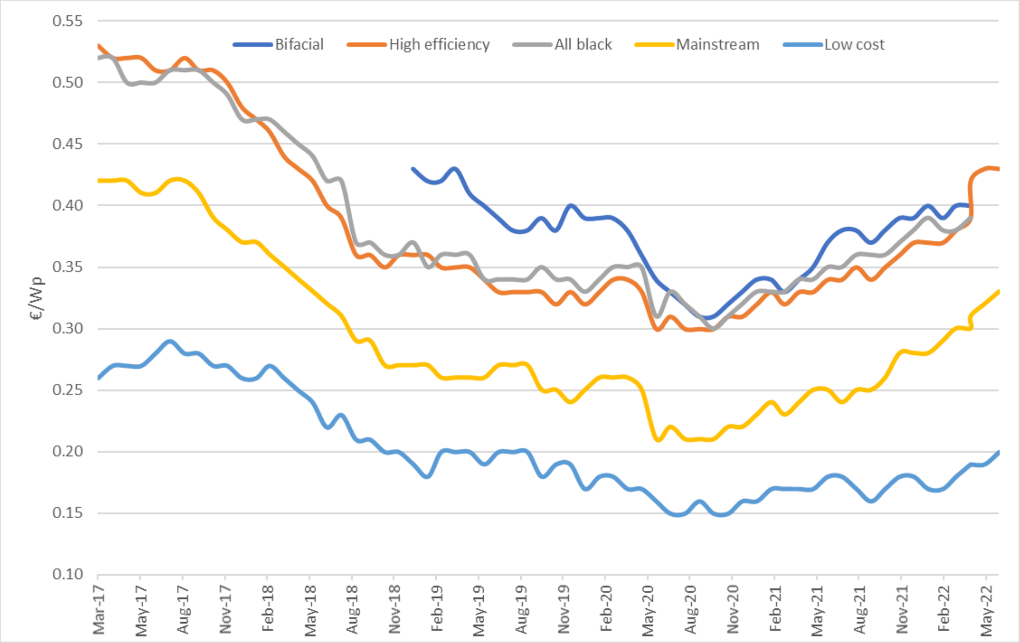
Key Insights / Gaps Overview

Solar DC/AC Ratio and Tracking

- 1.3 ratio (module / invertor) most likely scenario in NZ context, 1.0 ratio generally not applicable
- Single Axis Tracking (SAT) or fixed mounting expected to have similar economics across most of New Zealand
- Dual Axis Tracking (DAT) not widely adopted globally at utility scale

Cost Breakdown

- Potential for further simplification (from 9 to 5 categories)
  - EPC - Module
  - EPC Other
    - Install labour and equipment
    - Electrical BOS
    - Structural BOS
    - Inverter
  - Front End Feasibility (including Consenting and Developer Overhead)
  - Transmission
  - Land
  - Contingency
- Unit costs in $/W (based on previous benchmark workbooks)



PV module cost data (excludes tax)

Total Project Cost

- Aurecon costs higher particularly for smaller projects – *although lower level of confidence due to lack of benchmark data*
  - Mainly other EPC costs (civil and enabling works) and contingency
  - MBIE assumption for modules remain constant irrespective of scale (we recommend slightly reduced cost scale) due to streamlining of logistics
  - Module price movements short term (compared to assumptions based on 2020 pricing)

Key Insights / Gaps Overview

Project Costs

- Structural Balance of System (BOS) does not seem to include civil works
    - Site-specific impacts of terrain – variation in site location
    - land preparation and early works component is significant for solar and appears to be missing
- Transmission costs (i.e. all step up transformer and high voltage equipment such as substation, transformers, new lines and other network upgrades) and land procurement are not included in assumption set spreadsheet – we understand these are separate from the AMC report.
    - The only transmission related costs included in the assumption set relate to the 33kV switchroom (electrical BOS)
- Foreign exchange rates, currency fluctuations for module costing – *key risk and cost differential between Aurecon pricing and ANSA pricing*

Project Ranking

- No indication of capacity factor
- Rank projects by levelised cost of energy (LCOE) – *cheapest to most expensive energy then assess electricity price the projects can earn based on daily and seasonal generation profiles to rank by economic viability*

Updated Non-Inflow Assumptions (30 April 2022 Version 2.0)

- Have seen materials pricing for grid battery (current) higher than assumed entry costs NZ$/MWh
- Capacity factor uplift of ~10-30% for single axis tracking (CF 22-23%) relative to fixed tilt (CF 18-20%) for sites with typical DC:AC ratio of 1.2-1.3
- Capacity factors 18 to 20% AC (generally in this range) for typical utility scale solar in NZ but this varies significantly by location

Total Costs Comparison Charts (2022 NZD)

Key Configurations compared: Inverter Load Ratio (ILR) 1.0 and 1.3, Fixed Tilt and Horizontal Single Axis Tracking (HSAT)

ILR 1.0 Standard Fixed Tilt

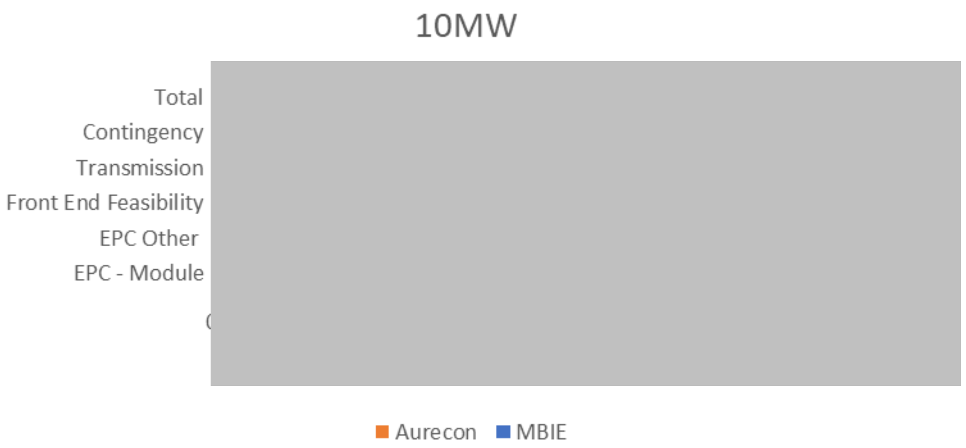
ILR 1.3 Standard Fixed Tilt

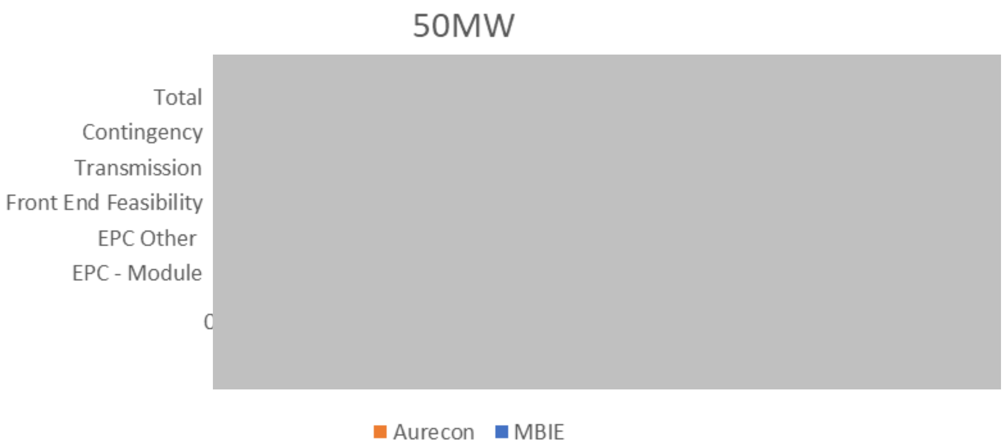
ILR 1.0 Standard HSAT

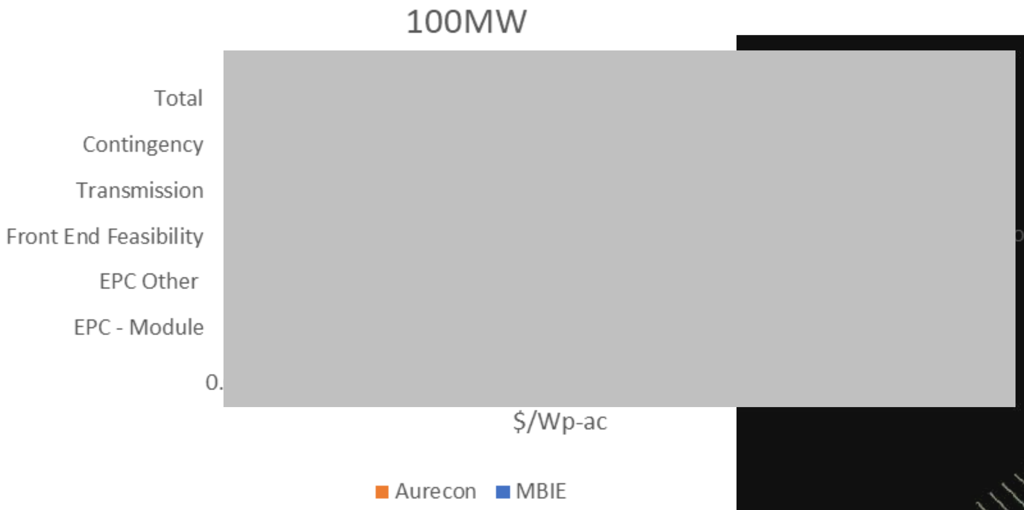
ILR 1.3 Standard HSAT

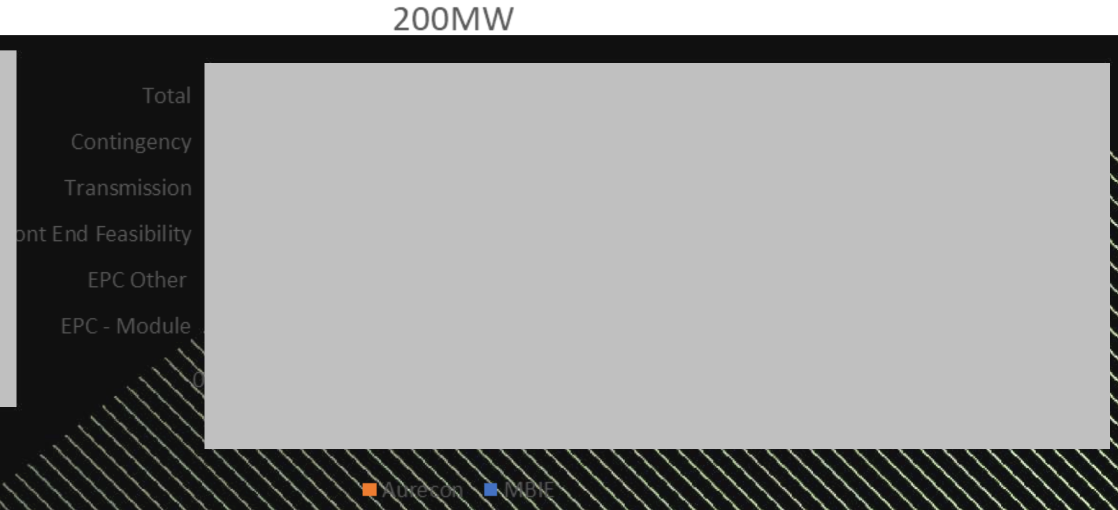
Note: MBIE values as provided from ANSA workbook dated 4 June 2022

Cost Category Comparison – ILR 1.3 Standard Fixed Tilt



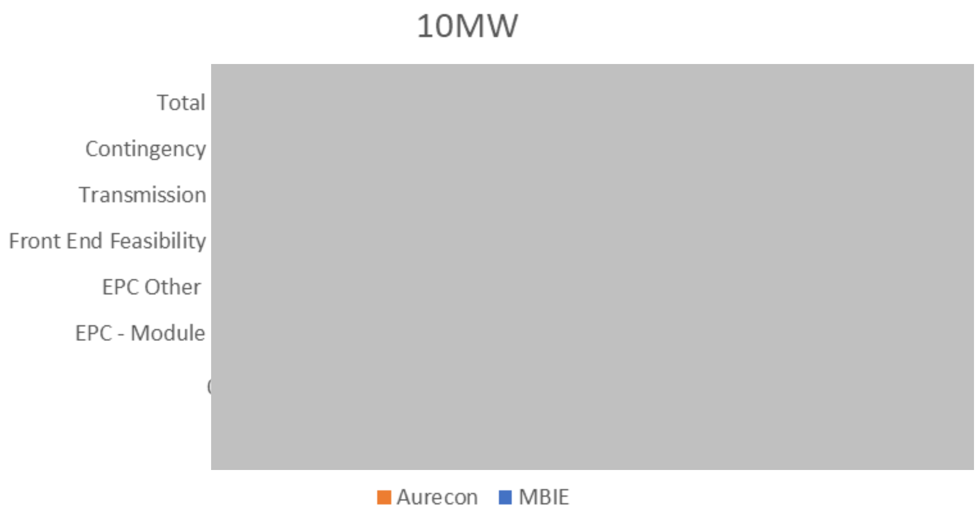


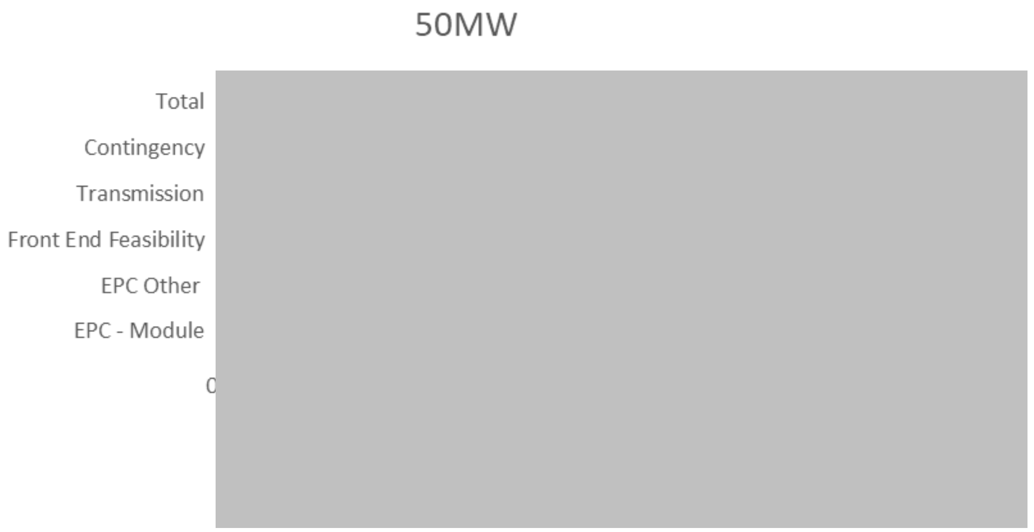


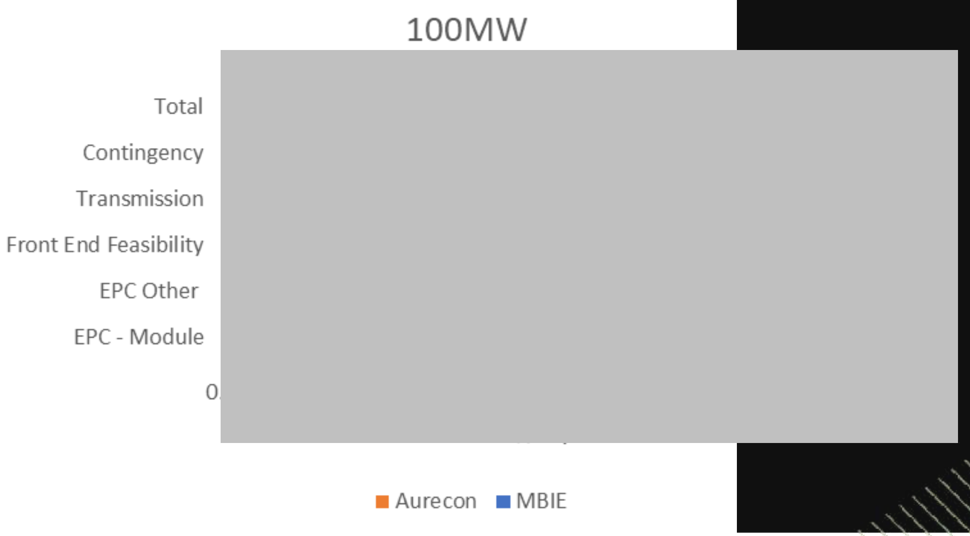


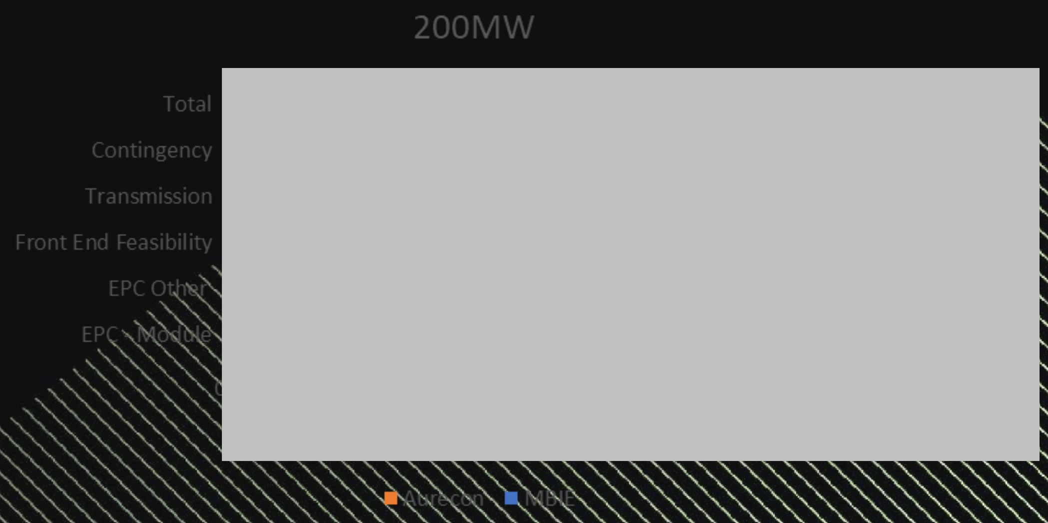
Note: MBIE values as provided from ANSA workbook dated 4 June 2022

Solar Cost Category Comparison – ILR 1.3 Standard HSAT









Note: MBIE values as provided from ANSA workbook dated 4 June 2022

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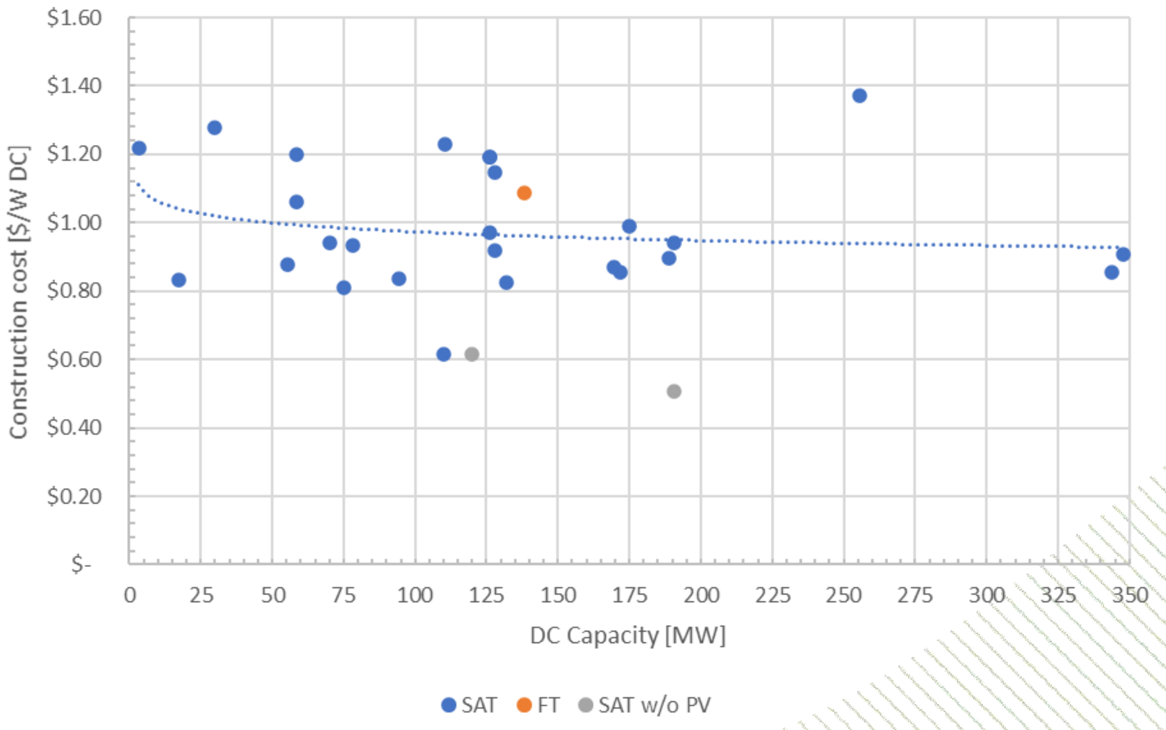
Capital Project Costs / Breakdown - *Detail*

EPC Costs

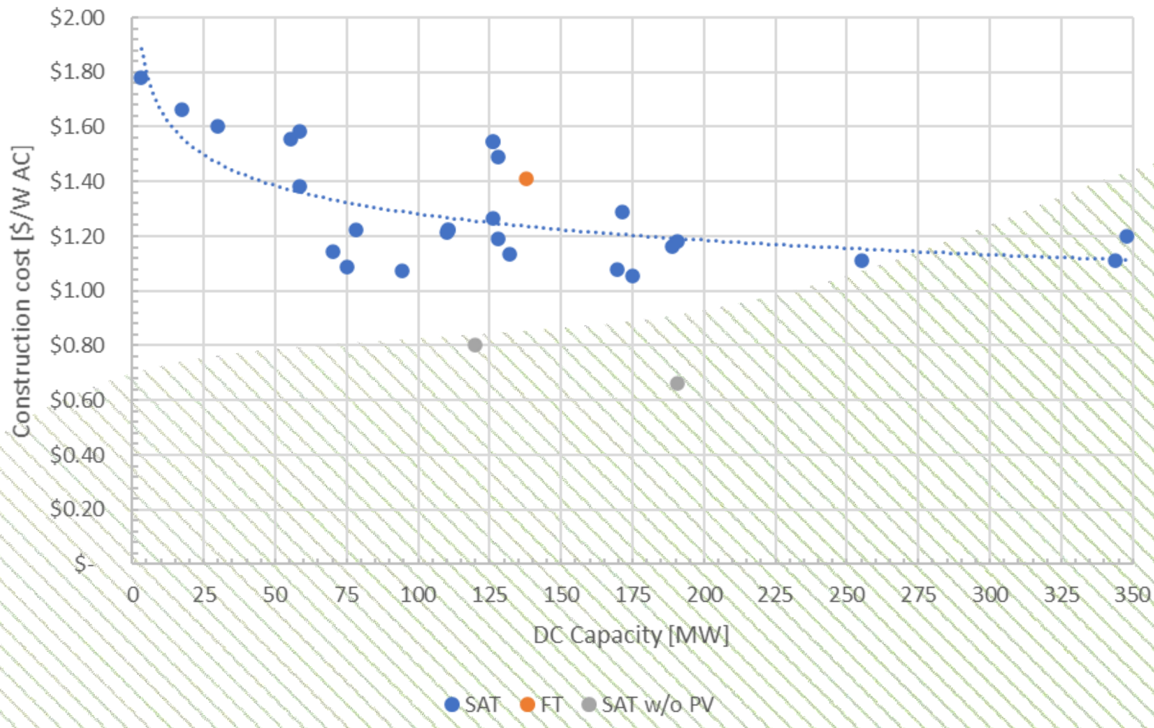
Aurecon maintains benchmarks for EPC Project Costs in Australia on a $/W DC basis as shown in the chart below. To provide guidance on costs in New Zealand, we have adjusted the figures for:

- Exchange rate to June 2022 (1.1 NZD/AUD)
- Productivity differences between Australia and New Zealand from 2016-2019 (~3.7%)
- Current labour cost index and trade weighted currency
- Current module price index
- Fixed tilt/SAT

Assuming DC/AC ratio 1.3, equivalent chart in $/W - DC



Assuming DC/AC ratio 1.3, equivalent chart in $/W - AC



Capital Project Costs / Breakdown - *Detail*

Other EPC costs (civil)

Civil enabling works can typically make up ~20% of total project cost, balance of plant (BOP) facilities (O&M building and warehouse) can make up to 5% of total project cost and design can make up a further 5%. These seem to be missing from MBIE’s current assumption set.

Contingency

A higher contingency allocation is recommended (10% at 10MW, 5% at 200MW) which is more typical of development projects. MBIE’s current assumptions are 2.8% at 10MW and ~1.9% at 200MW.

Transmission and Distribution

The Allan Miller report breaks down transmission connection costs as follows:

- 66kV – $5m
- 110kV – $10m
- 220kV – $15m
- Flat $10m for GSUT
- $0.5m/km to $1m/km

Distribution connection costs are deemed reasonable. We would recommend the 10-30 MW systems are likely to be connected at distribution level or behind the meter which may have an impact on capital cost as the solar farm’s intermediate voltages generally match with distribution voltage and as such no transformer costs would be required.

Land costs

Land costs vary from $10k to $40k per hectare which in our view could be regionalised to account for higher relative land costs in regions such as Auckland which AMC has adequately represented relative to urban/rural centres.

Operating Costs

MBIE's inputs

The AMC report for O&M costs reports the following:

Total annual operation and maintenance cost is based on a cost of $20/kWp-ac per annum. Studies such as the National Renewable Energy Laboratory study (Fu, Feldman, & Margolis, 2018) and the Lawrence Berkeley National Laboratory study (Bolinger, Seel, & Robson, 2019) confirm this value.

We understand that:

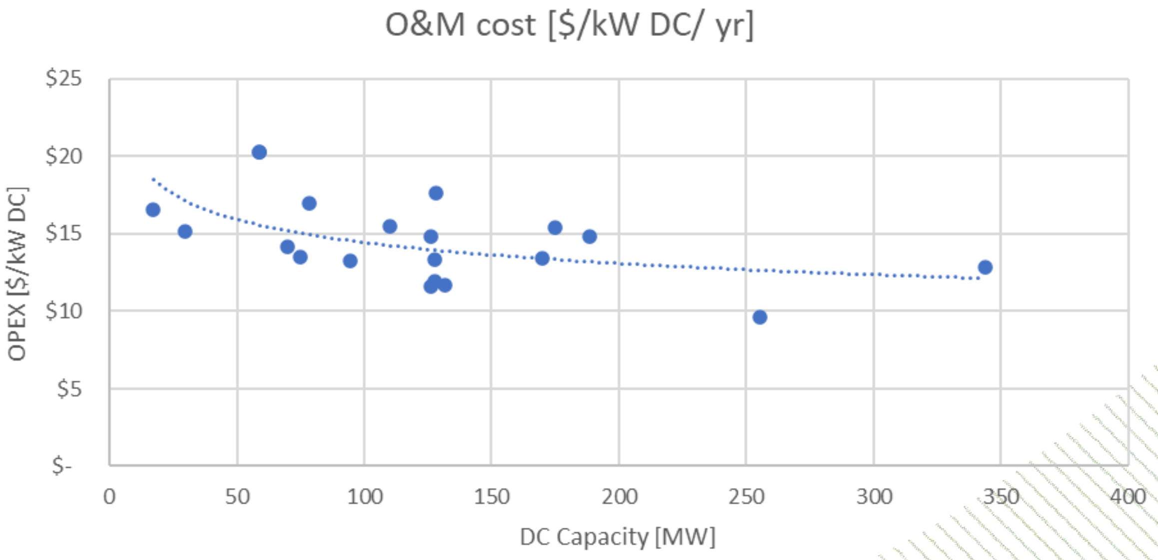
- Total OPEX of $26/kW p.a has been used in the model
- 25 year life
- Module degradation 0.8% (MBIE)

Aurecon views

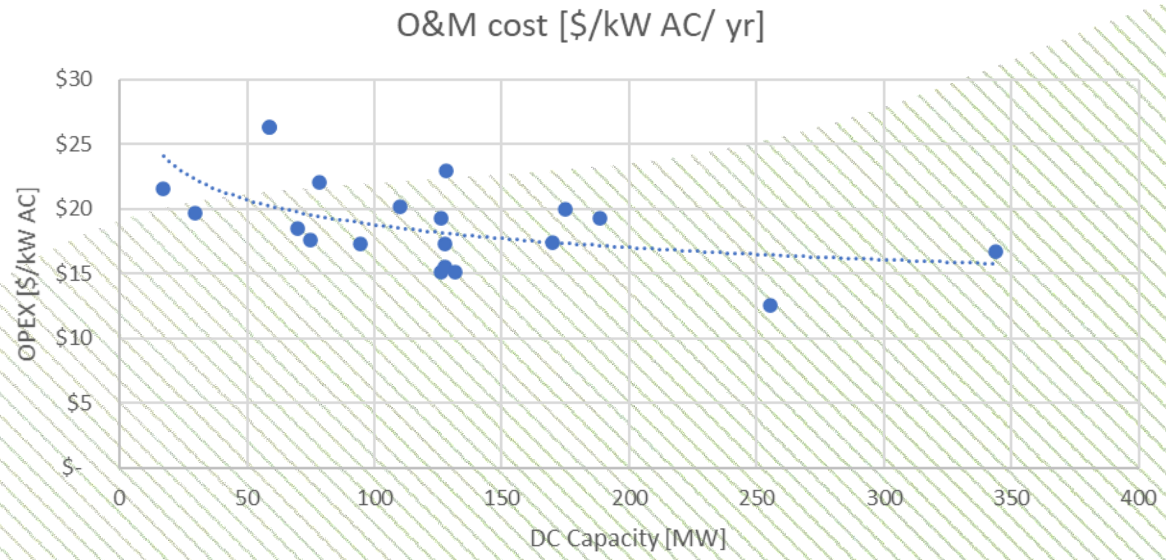
We concur on life and module degradation assumptions, for O&M (charts shown).

Aurecon's benchmark O&M and OPEX costs are size dependent from our Australian benchmark (in NZD) and are DC capacity based.

<u>Assuming DC/AC ratio 1.3 in DC</u>



<u>Assuming DC/AC ratio 1.3 in AC -</u>



Operating Costs

Other OPEX costs

In addition to O&M additional OPEX expenditure includes:

- Land lease / or rates
- Transmission
- Insurances
- Asset Management Fees

We would suggest that Other OPEX costs are an additional **$10/kW.**

Based on a variety of projects all in these additional costs equate to broadly 44% of total OPEX with the bulk (56%) being O&M.

For the purposes of modelling we would suggest for a **$/kW for total OPEX independent of module type.**

Total OPEX costs ($/kW - AC)

MW (AC)	ILR	10MW	20MW	50MW	100MW	150MW	200MW
FT	1.0	$ 30.0	$ 28.2	$ 26.0	$ 24.5	$ 23.7	$ 23.1
FT	1.3	$ 36.0	$ 33.6	$ 30.7	$ 28.8	$ 27.8	$ 27.1
HSAT	1.0	$ 32.0	$ 30.0	$ 27.6	$ 25.9	$ 25.0	$ 24.4
HSAT	1.3	$ 38.6	$ 36.0	$ 32.8	$ 30.7	$ 29.5	$ 28.8

Learning Curve - *New Zealand Market*

We have completed a review of historical and forecast solar costs and LCOE estimates in the Australian, USA and European markets, as outlined in slides 19 to 22 below. To derive an estimate learning curve for the New Zealand grid scale solar market, we have applied the following principles and assumptions:

- Applied learning curves on a 'total cost' cost approach, rather than for separate cost components - *lack of research for specific cost components over a 30 year period was problematic and total cost estimates were more commonly available.*
- Used the Australian solar market as a proxy for how grid scale solar costs may trend in New Zealand, including other relevant adjustments to account for scale, timing and exchange rate - *solar costs are expected to reduce in Australia from AU$1.0/W in 2020 to AU$0.3/W by 2035 based on the Australian Government Low Emissions Technology Statement 2021.*
- Extended AMC's learning curve of 4.6% p.a from 2020 to 2050 (currently 4.6% p.a from 2020 to 2035, reducing to 1.7% p.a from 2035 to 2050)
- Applied a 4.6% p.a cost reduction to 2050 for a 200MW Fixed Tilt project, at a cost estimate of NZ$1.6/W ac, is outlined as follows:

	2022	2025	2035	2040	2050	Notes
NZ$/W ac	1.60	1.39	0.87	0.69	0.43	*Recommended - cost reduction of 4.6% p.a to 2050*

- A cost estimate of NZ$0.43/W in 2050 is considered reasonable based on a cost estimate in the Australian grid scale solar market of AU$0.30/W by 2035 (refer to slide 19). A higher cost estimate is based on the following:
  - The New Zealand grid scale solar market is unlikely to achieve the full cost reduction as expected in Australia mainly due to smaller project sizes and smaller total market size
  - The New Zealand grid scale solar market is relatively immature and is circa seven years behind the Australian market in terms of development.
  - Exchange rate differential (average NZD/AUD exchange rate of 0.85 since 1990)
- We were unable to source forecast data post-2050. However due to expected technology advancements over time we have estimated the learning curve to remain but reduced by 50% (to 2.3% p.a.) from 2050 to 2065.

Learning Curve – *Australian Market*

HISTORICAL

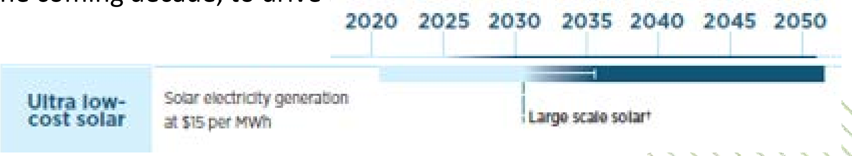
The capital cost of grid scale solar projects in Australia have decreased by 26% between 2015 and 2020 (from $1.87 to $1.39 /W), reflecting a 6% p.a decrease over this period.
https://arena.gov.au/renewable-energy/large-scale-solar

FORECAST ***- Australian Government Low Emissions Technology Statement 2021***

The Australian Government released its second Low Emissions Technology Statement (LETS) in 2021 and introduced ultra low-cost solar electricity generation as another priority technology.

The Australian Government has set an **economic stretch goal for solar electricity generation at AU$15 per MWh**, or approximately a third of today’s costs. This would fast-track Australia’s ability to meet the clean hydrogen stretch goal of production under $2 per kg, and increase competitiveness in hydrogen export markets. This has been set taking into consideration current and projected costs for utility-scale solar electricity, and alignment with international benchmarks.

The Technology Investment Roadmap and the LETS set out Australia’s technology-led approach to accelerating the development of technologies essential to achieving net zero emissions. To achieve the goals set out in the LETS, the Australian Government is investing more than $20 billion in new energy technologies over the coming decade, to drive between $80 billion and up to $120 billion of combined public and private investment and creating 160,000 jobs.



Solar 30 30 30

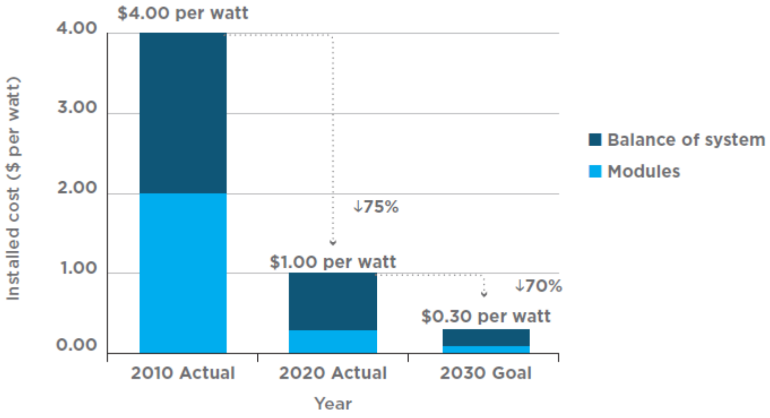
Reaching the stretch goal will require further innovation in the efficiency of solar modules and optimisation of large scale deployment. The government will work toward achieving 30% module efficiency at **30c/W by 2030 (stretch) to 2035 (further confidence), equivalent to a 7.7% p.a reduction from a cost base of $1/W in 2020**.

In particular, there are two significant levers to facilitate cost reductions for solar electricity:

- Improving module efficiency from about 22% to 30%
- Reducing balance of plant costs by approximately 70%

Achieving improved module efficiency will require further R&D into many aspects of solar cell design. Further reductions in the installed cost of solar will come from reducing the balance of system costs. Over the past 10 years, as module costs have declined, the fraction represented by the balance of system costs has increased from about 50% of the installed cost in 2010 to about 70%.

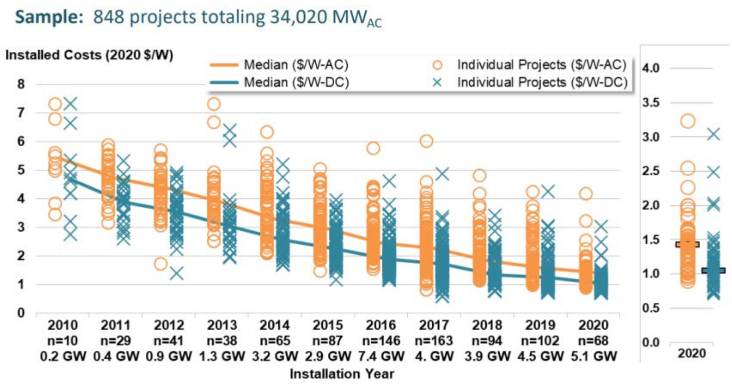
Key opportunities for reducing balance of system costs include: lowering the cost of construction materials by using less or using cheaper materials, increasing the solar module size, increasing the cell and module efficiency, increasing the scale of solar farms, lower cost inverters and high throughput deployment methodologies.



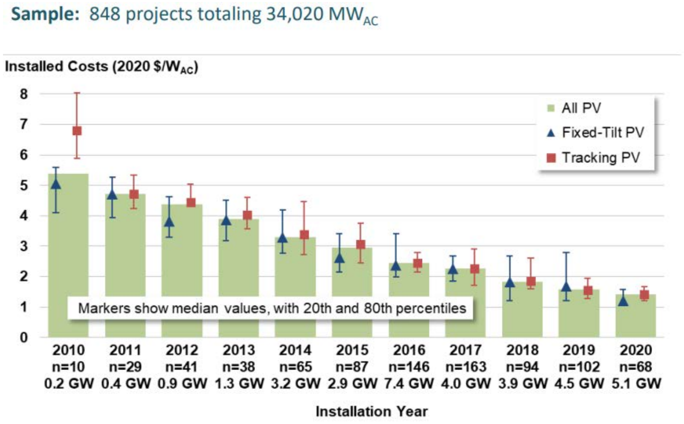
Learning Curve – *USA Market*

Historical Trends

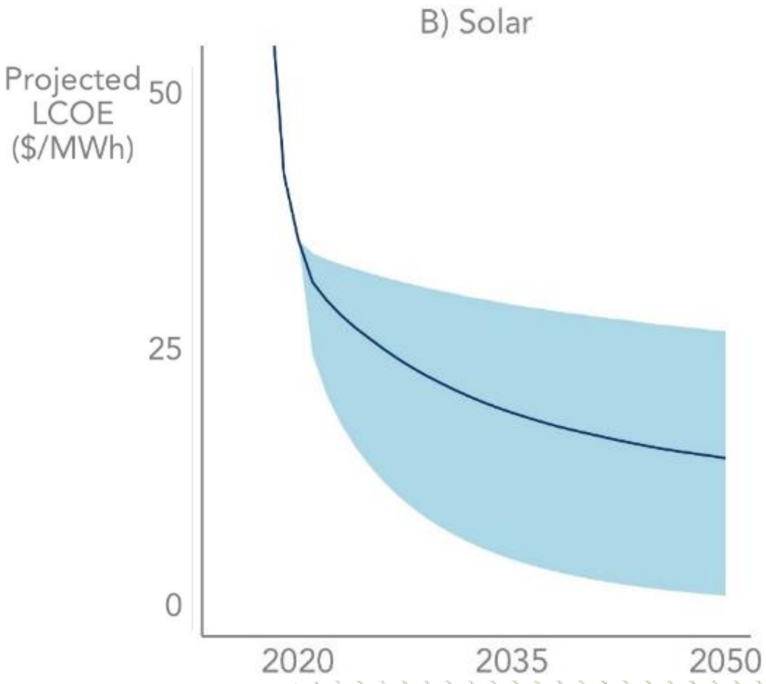
Median installed costs of PV have fallen by 74% since 2010 and 12% annually to $1.42/W AC ($1.05/W DC) in 2020.



Cost premium for tracking projects relative to fixed tilt projects has diminished over time.



Forecast



The chart above depicts LCOE projections based on full-period learning rates and central estimates of future deployment (IEA, 2020; EIA, 2019; DNV, 2020; BloombergNEF, 2020; IRENA, 2020; Wood, 2020

The learning rate suggests a 47% LCOE reduction by 2035 (4.2% p.a), or as much as 83% based on the lower bound of the 95% confidence interval.

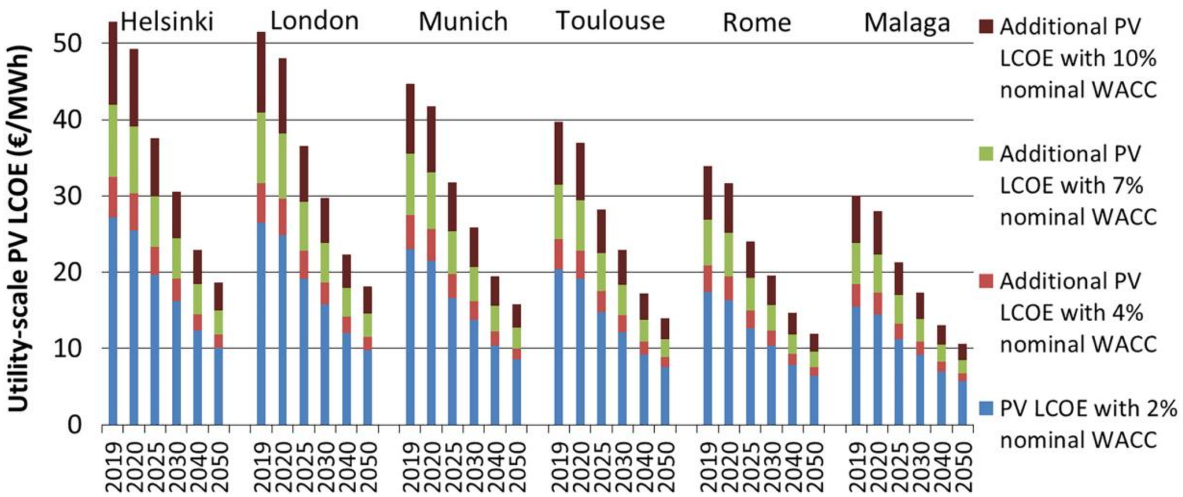
https://emp.lbl.gov/technology-trends

Learning Curve – *European Market*

Forecast – Europe

European solar LCOE forecasts are expected to reduce by circa 3% p.a from 2019 to 2050. The learning curve rate is significantly lower than Australia's learning curve rate but Australia is coming from a higher cost base.

PV LCOE 2019-2050



https://www.reutersevents.com/renewables/solar/europe-solar-storage-costs-fall-below-markets-learnings-kick

Learning Curves – *Summary Tables*

Historical Trend

	$/W (Start)	$/W (2020)	Total decrease (%)	Duration (Years)	p.a decrease (%)	Notes
Australia (AU$)	1.87	1.39	-26	5	*6%*	*2015 to 2020 Capital cost of LSS projects https://arena.gov.au/renewable-energy/large-scale-solar*
USA (US$)	5.50	1.42	-74	10	*13%*	*2010 to 2020 Median installed costs of PV https://emp.lbl.gov/technology-trends*
Europe (EUR)	5.91	1.02	-83	10	*16%*	*2010 to 2020 Total installed cost trend https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jun/IRENA_Power_Generation_Costs_2020.pdf*

Forecast Trends

Australia

Unit cost (AU$/W)					Percentage Decreases							
2020	2025	2035	2040	2050	2025	2035	2040	2050	Total decrease % 2020-2035	% p.a decrease 2020-2035	Total decrease % 2020-2050	% p.a decrease 2020-2050
1.0	N/A	0.3	N/A	N/A	N/A	70%	N/A	N/A	*70%*	*7.7%*	*N/A*	*N/A*

LOW EMISSIONS TECHNOLOGY STATEMENT 2021 (dcceew.gov.au)

USA

LCOE (USD $/MWh)					Percentage Decreases							
2020	2025	2035	2040	2050	2025	2035	2040	2050	Total decrease % 2020-2035	% p.a decrease 2020-2035	Total decrease % 2020-2050	% p.a decrease 2020-2050
34	25	18	17	16	26%	28%	6%	6%	*47%*	*4.2%*	*53%*	*2.5%*

https://emp.lbl.gov/news/new-study-refocuses-learning-curve-analysis

Europe

	LCOE (Euro/MWh)					Percentage Decreases							
	2020	2025	2035	2040	2050	2025	2035	2040	2050	Total decrease % 2020-2035	% p.a decrease 2020-2035	Total decrease % 2020-2050	% p.a decrease 2020-2050
London	39	30	23	19	16	23%	23%	17%	16%	*41%*	*3.5%*	*59%*	*2.9%*
Toulouse	30	22	19	15	11	27%	14%	21%	27%	*37%*	*3.0%*	*63%*	*3.3%*
Malaga	22	17	14	12	10	23%	18%	14%	17%	*36%*	*3.0%*	*55%*	*2.6%*

https://www.reutersevents.com/renewables/solar/europe-solar-storage-costs-fall-below-markets-learnings-kick

Solar Key Assumptions – *Recommendation*

Key Configuration: DC/AC ratio 1.3, Fixed Tilt

Solar			MW Scale ($/W ac – 2022 NZD)											
		Key Category	10MW		20MW		50MW		100MW		150MW		200MW	
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Modules (EPC)	$ 0.82		$ 0.75		$ 0.67		$ 0.62		$ 0.59		$ 0.57	
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Inverters (EPC)	$ 0.13		$ 0.13		$ 0.12		$ 0.12		$ 0.11		$ 0.11	
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Other EPC (Balance of System)	$ 1.28		$ 1.17		$ 1.04		$ 0.95		$ 0.90		$ 0.87	
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Other (ie: Front End Feasibility, Consenting, Procurement)	$ 0.05		$ 0.04		$ 0.04		$ 0.04		$ 0.03		$ 0.03	
DC/AC ratio 1.3 Fixed Tilt	CAPEX	Contingency	$ 0.22	*10.0%*	$ 0.20	*9.7%*	$ 0.16	*8.9%*	$ 0.13	*7.6%*	$ 0.10	*6.3%*	$0.08	*5.0%*
DC/AC ratio 1.3 Fixed Tilt	**CAPEX**	**Total Capital costs (excluding HV transmission)**	**$2.5/W**		**$2.3/W**		**$2.0/W**		**$1.8/W**		**$1.7/W**		**$1.6/W**	
DC/AC ratio 1.3 Fixed Tilt	OPEX	O&M ($/kW/year)	$ 26.0		$ 23.6		$ 20.7		$ 18.8		$ 17.8		$ 17.1	
DC/AC ratio 1.3 Fixed Tilt	**OPEX**	**Total Operating costs ($/kW/year)**	**$ 36.0**		**$ 33.6**		**$ 30.7**		**$ 28.8**		**$ 27.8**		**$ 27.1**	

Solar Key Assumptions – *Recommendation*

Key Configuration: DC/AC ratio 1.3, Horizontal Single Axis Tracking (HSAT)

Solar			MW Scale ($/W ac – 2022 NZD)											
		Key Category	10MW		20MW		50MW		100MW		150MW		200MW	
DC/AC ratio 1.3 HSAT	CAPEX	Modules (EPC)	$ 0.82		$ 0.75		$ 0.67		$ 0.62		$ 0.59		$ 0.57	
DC/AC ratio 1.3 HSAT	CAPEX	Inverters and Trackers (EPC)	$ 0.47		$ 0.45		$ 0.43		$ 0.41		$ 0.40		$ 0.40	
DC/AC ratio 1.3 HSAT	CAPEX	Other EPC (Balance of System)	$ 1.11		$ 1.00		$ 0.87		$ 0.78		$ 0.73		$ 0.70	
DC/AC ratio 1.3 HSAT	CAPEX	Other (ie: Front End Feasibility, Consenting, Procurement)	$ 0.05		$ 0.05		$ 0.04		$ 0.04		$ 0.04		$ 0.03	
DC/AC ratio 1.3 HSAT	CAPEX	Contingency	$ 0.24	*10.0%*	$ 0.21	*9.7%*	$ 0.18	*8.9%*	$ 0.14	*7.6%*	$ 0.11	*6.3%*	$ 0.08	*5.0%*
DC/AC ratio 1.3 HSAT	**CAPEX**	**Total Capital costs (excluding HV transmission)**	**$2.7/W**		**$2.5/W**		**$2.2/W**		**$2.0/W**		**$1.9/W**		**$1.8/W**	
DC/AC ratio 1.3 HSAT	OPEX	O&M ($/kW/year)	$ 28.6		$ 26.0		$ 22.8		$ 20.7		$ 19.5		$ 18.8	
DC/AC ratio 1.3 HSAT	**OPEX**	**Total Operating costs ($/kW/year)**	**$ 38.6**		**$ 36.0**		**$ 32.8**		**$ 30.7**		**$ 29.5**		**$ 28.8**	

DC:AC Ratios / Technology - *Detail*

DC:AC Ratio or ILR

The ratio of installed module capacity (MWp or MWdc) compared to the grid connection's AC capacity (where typically inverter capacity matches grid capacity).

Typically we see most farms have a ratio of between 1.2 to 1.3, so a higher DC capacity over the grid connection. DC capacity degrades by around 0.6% per annum which slowly erodes the effective DC capacity over the project life.

Note that in terms of CAPEX we may see additional inverter (AC) capacity (ie inverter capacity exceeding the grid connection capacity) in order to provide additional reactive power capability in locations of the grid that required additional support.

Other Technology Considerations

Module type: High Efficiency / Mainstream / Bifacial

Module type impacts energy yield significantly and energy capacity vs cost is an ongoing optimisation requirement for solar farms. Bifacial module prices have reduced more rapidly than other technologies in recent years as the technology transitions from R&D and early commercialisation to mainstream adoption.

Use of bifacial modules to capture diffuse irradiance can improve viability however additional land is typically required and higher mounting heights. Land and mounting costs vs energy production therefore becomes a relevant optimisation consideration.

Bifacial modules are around 10% higher in price than monofacial modules and the cost differential has improved significantly in recent years. The albedo effect on most New Zealand sites is expected to be quite low (due to grass being dominant ground covering) compared to sites in drier countries like Australia which has more reflection.

Dual axis tracking Very few utility scale projects (10MW+) globally have deployed dual axis tracking as the benefits typically do not outweigh costs. The only potential application in the NZ context would be for use on beef or dairy land where dual axis trackers are located at greater elevations than SAT, however the wind loadings common in NZ may prove to be a challenge. Generally we would exclude DAT from the future generation stack.

Single Axis Tracking:
Tracking technology typically demands a 5-10% cost premium to fixed tilt technology (EPC costs only) but can achieve a greater capacity factor depending on location.

Variables impacting tracking value
Tracking technologies improve solar farm performance by increasing the extent to which the plane of array is normally incident to direct irradiance from the sun. Considering this, the following factors may impact the effectiveness of tracking at a given location:

Latitude effect
Tracking becomes less effective at higher latitudes (further from the equator), because although they track in the E-W plane, they are not tilted towards the sun in the N-S plane. This means at higher latitudes; the plane of array becomes less normally oriented to the sun. This effect also produces a more significant diurnal effect, as the variation in the elevation of the sun in the sky becomes more extreme through the seasons at higher latitudes.

Diffuse fraction effect
Similarly, tracking becomes less effective at sites that have a high diffuse fraction due to cloud. At sites with more cloud, there is less direct normal irradiance which means there is less uplift achieved by tracking the sun through the sky.

Tracker row spacing effect (fixed tilt only)
Finally, at sites with higher latitude and a lower average angle of elevation of the sun in the sky, the greater spacing required between tracker rows before self-shading impacts production. This means that the same piece of land can host less generation capacity at higher latitudes. Aurecon notes that this effect applies primarily to fixed tilt.

Wind

Wind – Key Insights / Gaps

Cost Assessment

- Capital cost ($/kW)
    - Slightly low for projects below 100MW
    - Reasonable for projects above 100MW
- Wind Turbine Unit Costs ($/kW) expected to change due to scale (model currently assumes constant $/kW across all projects)
- Turbine O&M fixed cost ($/kW/year) and Other fixed cost ($/kW/year) expected to change due to scale
- BOP costs - consider sliding scale proportional to project size as fixed BOP costs (O&M facilities, enabling works and laydown) are similar regardless of total project size
- Wind turbine size expected to increase in each block as minimum size moves up, this is expected to result in a reduction in specific $/kW for the turbines nominally
- Substation transformer size should be factored from total windfarm capacity – similar to solar
- Transmission line costs ($/kW) – variable cost allocation per km – similar to solar
- Unit costs in $/kW (based on previous benchmark workbooks)

Project Ranking

- Rank projects by levelised cost of energy (LCOE) – best methodology to evaluate competitiveness
    - *cheapest to most expensive energy then assess electricity price the projects can earn based on daily and seasonal generation profiles to rank by economic viability*

Wind – Key Insights

Updated Non-Inflow Assumptions (30 April 2022 Version 2.0)

- Capacity factor – West Coast capacity factor appears to have risen significantly since previous version. We recommend the capacity factor reverts to the previous version (refer slide 28 R40s assumptions).
- Onshore Wind Costs
  - Capital costs – Turbine price index expect to be benchmarked higher at $1500 NZD / kW based on actual delivered projects in the recent Australian market
    - The R40 report in part relies on lower costs contributed by Goldwind turbines which have not entered the New Zealand market.
    - We agree broadly with the R40 conclusion that “We believe that the current LCOE range of the more favourable NZ sites is in the order of NZ$60 - $70/MWh, with some of the best opportunities being even lower than this, and in the $55 - $60/MWh range”. However after the report was written, turbine prices have risen by 10-15%, which would increase LCOE.
- Note: AEMO Aurecon report on only EPC and O&M costs, excludes non-O&M OPEX costs and other project costs (land development approvals etc)

Learning Curve and Key Findings

Wind (onshore)

The wind market in New Zealand is relatively mature with a number of large scale projects in operation. The Roaring 40s report provides a good overview of regional zones, potential MW capacity and relative capacity factors that are still relevant.

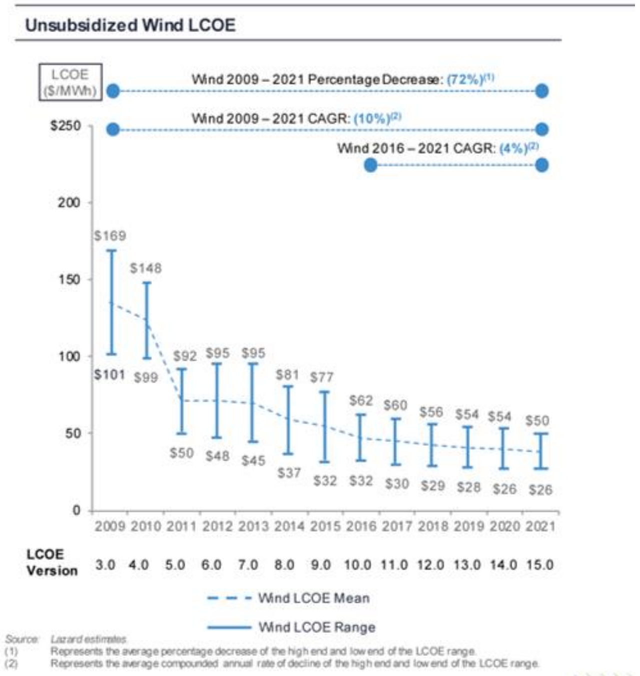
In the case of learning curve we would point to the Lazard LCOE 15 report again as a reference. Both New Zealand and the US share a common long term adoption of wind generation and as such would not anticipate the types of cost reductions anticipated in solar.

Incremental gains on turbine size and cost efficiency are expected to mitigate cost escalations to some extent. Therefore we expect the wind learning curve to be relatively flat over time.

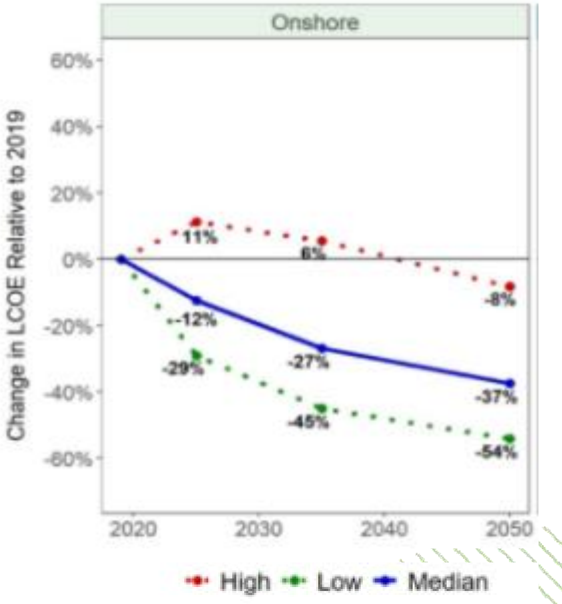
It is likely in the New Zealand market the LCOE will continue to decrease particularly with repowering of existing sites which offers savings in some key infrastructure such as grid, site access and O&M facilities. Balance of system costs are expected to continue to decrease as well.

A survey led by Lawrence Berkeley National Laboratory (Berkeley Lab) of the world's foremost wind power experts anticipate cost reductions of 17%-35% by 2035 and 37%-49% by 2050, driven by bigger and more efficient turbines, lower capital and operating costs, and other advancements. However there is considerable uncertainty in those future costs. *https://emp.lbl.gov/news/experts-predictions-future-wind-energy-costs*

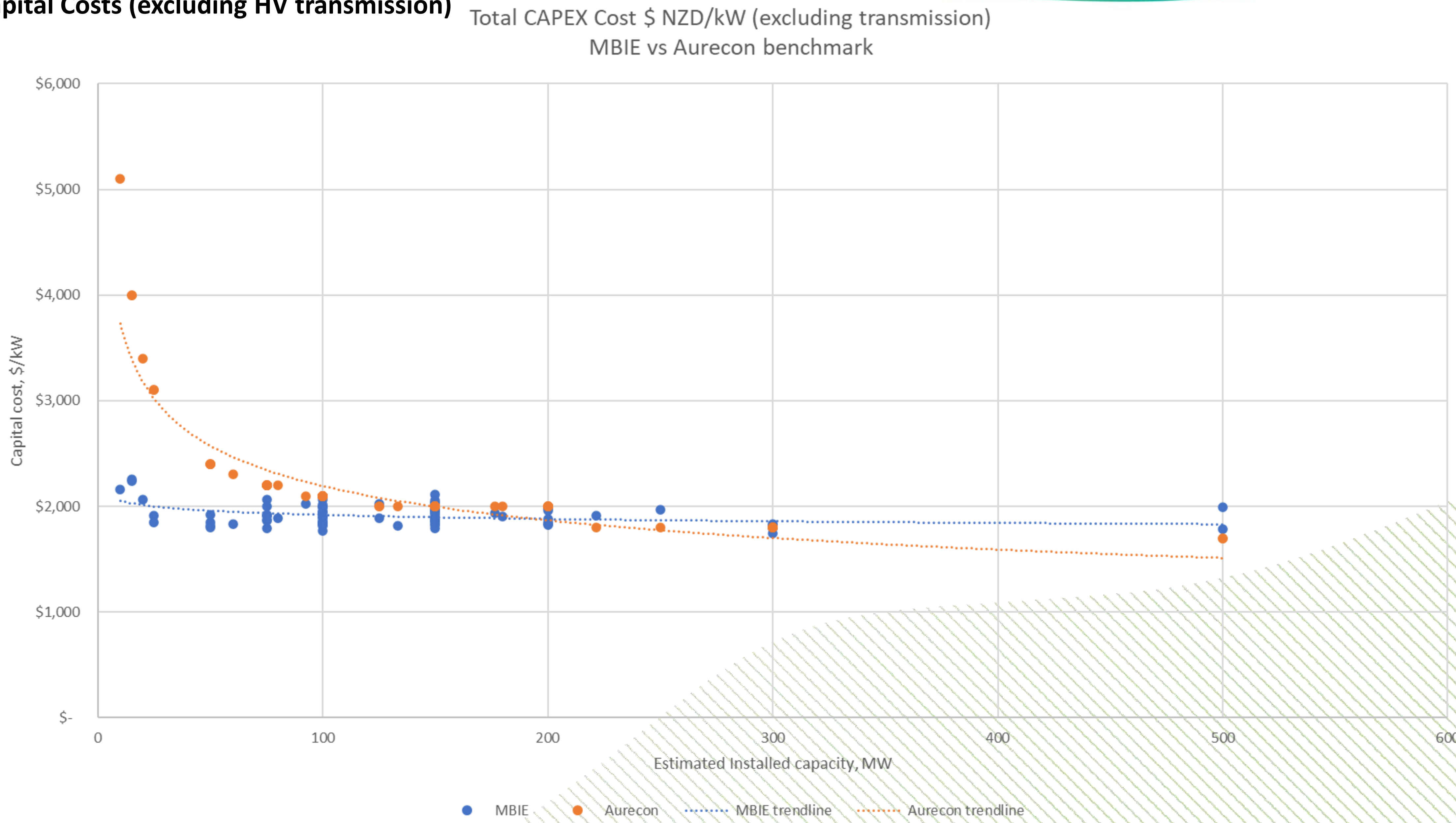
The learning curve rates currently applied by MBIE (1% p.a to 2035 and 0.7% p.a to 2050) equate to a total cost reduction of 21% by 2050. Although this is towards the lower bound of cost reduction estimates in the Lawrence Barkeley National Laboratory survey, the current estimate applied by MBIE is not unreasonable.



Lawrence Berkeley National Laboratory survey



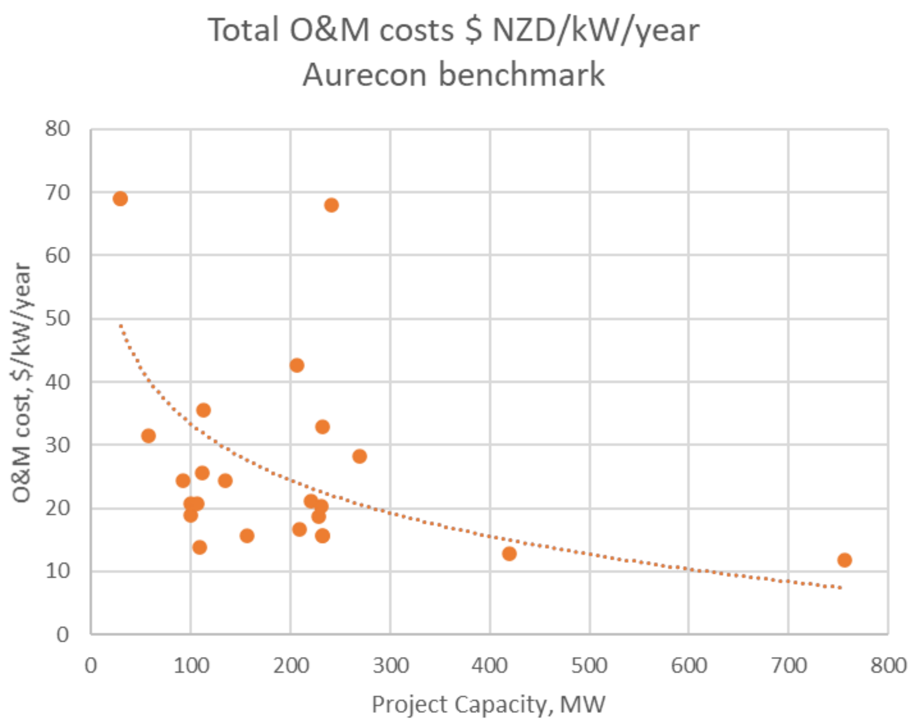
Wind Capital Costs (excluding HV transmission)

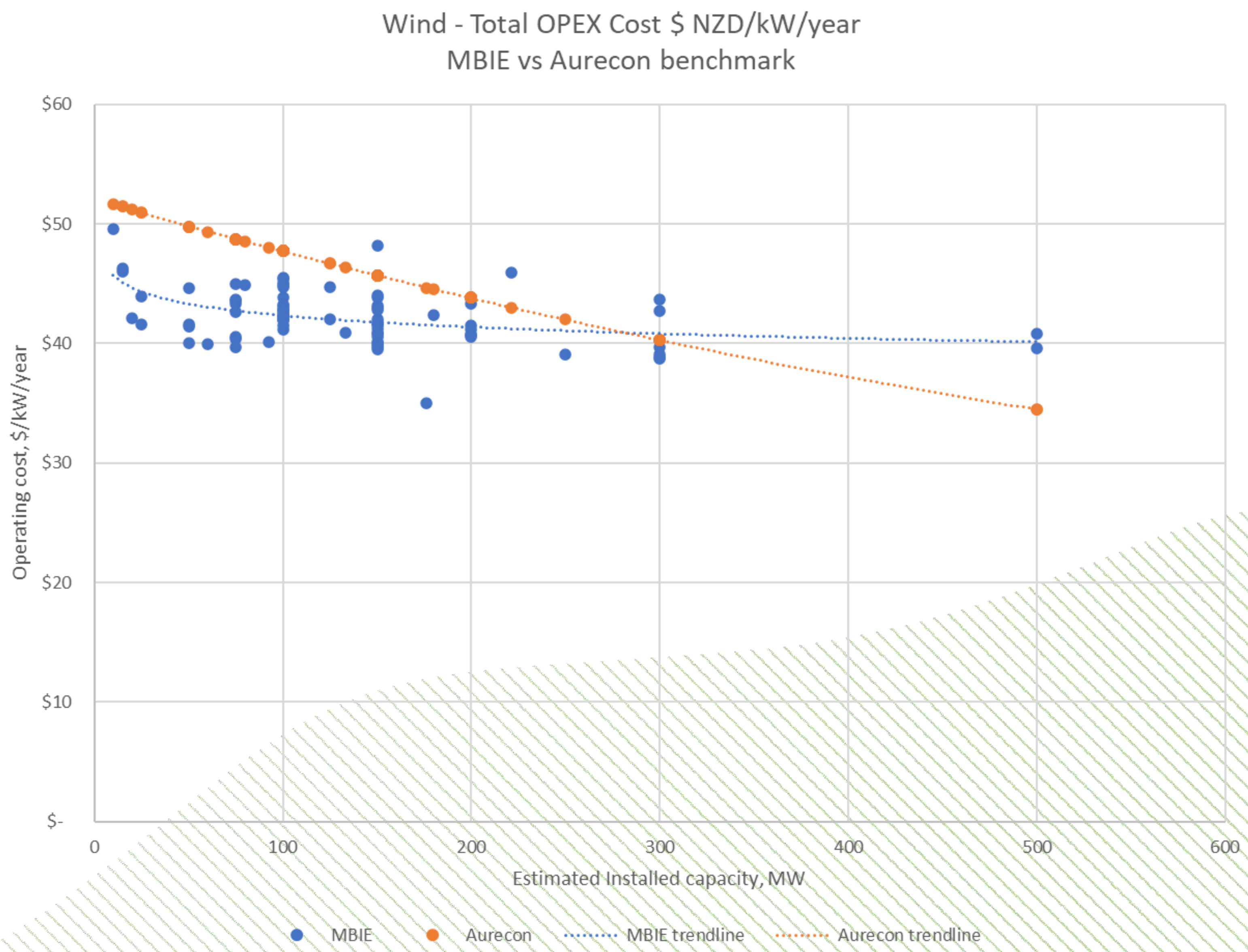


Note: Total CAPEX costs include electrical 'balance of plant' costs but exclude all step up transformer, grid connection and high voltage equipment costs (including new transmission lines).

Note: MBIE values as provided from WGS workbook dated 5 February 2020

Wind Operating Costs





Variable / Fixed O&M split

- Average split between variable and fixed O&M costs equates to 15% variable, 85% fixed.

Note: MBIE values as provided from WGS workbook dated 5 February 2020

Wind Assessment – R40’s assumptions

Updated Version

Region	Wind Speed @ 120m (m/s)	Lower Generation TWh/y	Upper Generation TWh/y	Lower CF	Upper CF	Capacity (GW)	Wind Farm Area (kha)	Locally Embedded	Distance to grid km	Average TWh	Average CF	kW/ha
Far North	8.5	1.2	1.4	40.6%	46.1%	0.4	9	67%	25	1.3	43.4%	40
Northland	8.3	3.3	3.7	39.3%	44.6%	1.0	22	14%	19	3.5	41.9%	44
Auckland	8.2	1.7	1.9	38.8%	44.0%	0.5	10	20%	15	1.8	41.4%	50
Waikato	7.9	2.1	2.3	37.6%	42.6%	0.6	18	50%	19	2.2	40.1%	34
BOP-Taupo	7.7	3.7	4.2	36.3%	41.2%	1.2	47	13%	8	3.9	38.8%	25
Eastland	8.3	1.6	1.8	38.5%	43.7%	0.5	18	25%	45	1.7	41.1%	26
Central Plateau	8.3	2.3	2.6	39.4%	44.7%	0.7	20	-	11	2.5	42.1%	34
Hawkes Bay	8.4	0.4	0.4	41.1%	46.6%	0.1	2	-	5	0.4	43.8%	66
Taranaki	8.6	1.6	1.8	37.2%	42.2%	0.5	18	-	9	1.7	39.7%	27
Manawatu	7.8	2.8	3.2	37.7%	42.8%	0.9	25	-	7	3.0	40.2%	34
Wairarapa	9.8	4.8	5.4	43.8%	49.6%	1.3	36	-	21	5.1	46.7%	35
Wellington	9.7	0.8	0.9	41.4%	46.8%	0.2	2	-	4	0.8	44.1%	100
Southern Wairarapa	8.9	0.9	1.0	39.0%	44.2%	0.3	4	-	22	0.9	41.6%	63
Marlborough	9.3	0.4	0.4	32.5%	36.8%	0.1	3	100%	29	0.4	34.7%	38
West Coast	6.6	0.3	0.3	41.2%	46.7%	0.1	1	-	5	0.3	44.0%	54
Canterbury	8.9	1.9	2.2	40.0%	45.3%	0.5	25	20%	15	2.0	42.7%	22
Otago	8.5	4.1	4.7	37.6%	42.6%	1.3	34	-	13	4.4	40.1%	37
Southland	9.2	3.1	3.5	40.7%	46.2%	0.9	15	25%	11	3.3	43.5%	60
Total Onshore	**8.5**	**36.9**	**41.9**	**39.1%**	**44.3%**	**10.8**	**310**	**19%**	**15.8**	**39**	**41.7%**	**35**
Total NI	8.5	27.2	30.8	39.2%	44.4%	7.9	232	14%	16.2	29	41.8%	34
Total SI	8.5	9.8	11.1	38.9%	44.1%	2.9	78	29%	14.7	10	41.5%	37

Previous Version

	R40's Region	No. of projects	Wind Speed	Total MW	Low range (GWh's)	High range (GWh's)	Capacity Factor (Low range)	Capacity Factor (High range)
1	Far North	3	8.5	350	1,247	1,413	41%	46%
2	Northland	7	8.3	960	3,269	3,705	39%	44%
3	Auckland	5	8.2	500	1,685	1,909	38%	44%
4	Waikato	6	7.9	625	2,061	2,336	38%	43%
5	BOP-Taupo	8	7.7	1,160	3,645	4,131	36%	41%
6	Eastland	4	8.3	475	1,633	1,851	39%	44%
7	Central Plateau	4	8.3	675	2,226	2,523	38%	43%
8	Hawkes Bay	1	8.4	100	335	379	38%	43%
9	Taranaki	3	8.6	500	1,772	2,009	40%	46%
10	Manawatu	5	7.8	850	2,665	3,021	36%	41%
11	Wairarapa	6	9.8	1,250	4,847	5,494	44%	50%
12	Wellington	3	9.7	215	824	934	44%	50%
13	Southern Wairarapa	2	8.9	250	897	1,017	41%	46%
14	Marlborough	2	9.3	125	446	505	41%	46%
15	West Coast	1	6.6	75	181	205	28%	31%
16	Canterbury	5	8.9	545	1,914	2,169	40%	45%
17	Otago	5	8.5	1,250	4,116	4,665	38%	43%
18	Southland	8	9.2	875	3,123	3,539	41%	46%
	Total	**78**		**10,780**	**36,886**	**41,805**	**39%**	**44%**

Recommendations (updated version):

- West Coast - *reduce capacity factor given wind speed*
- Taranaki – *increase capacity factor given wind speed (doesn’t fit pattern)*
- Southern Wairarapa – *reduce capacity factor due to poor wind speed distribution*
- Marlborough – *increase capacity factor given wind speed*
- Canterbury – *reduce capacity factor due to poor wind speed distribution (assumed to be from North Canterbury area)*

Wind Key Assumptions

Merit Order	I.D.	Name	Technology	Status	Likelihood	Grid Zone	R40s Region	Location	Estimated Installed capacity, MW	Largest generating unit, MW	Capital cost, $/kW	Capital cost excl transmission, $/kW	CAPEX excl transmission $/kW	O&M OPEX $M p.a.	Turbine O&M fixed cost, $M p.a. Y1-5	Turbine O&M fixed cost, $/kW/year	Other OPEX $M p.a.	Other OPEX $/kW/year	O&M OPEX $/kW/year	Total OPEX $/kW/year	Decade of Deployment
									AUDNZD	1.1			Aurecon								
1	0.1	Waipipi	Wind - onshore	*Construction complete*	10	6	9	South Taranaki	133.3	4.3	$ 2,055	$ 1,817	$ 2,000	$ 4.19		$ 31.40	$ 2.39	$ 17.93	$ 28.48	$ 46.41	2020 - 2030
2	0.2	Turitea	Wind - onshore	*Under Construction*	10	7	10	Manawatu	221.4	3.6 (Stage 1); 3.8 (S	$ 2,090	$ 1,914	$ 1,800	$ 6.40		$ 28.92	$ 3.96	$ 17.89	$ 25.14	$ 43.03	2020 - 2030
3	0.3	Haripaki	Wind - onshore	*Under Construction*	10	5	8	Hawkes Bay	176.3	4.0 - 4.3	$ 2,055	$ 1,935	$ 2,000	$ 5.29		$ 30.01	$ 3.15	$ 17.87	$ 26.81	$ 44.68	2020 - 2030
4	0.4	Mt Cass	Wind - onshore	Construction being considered	10	10	16	North Canterbury	92.4	4.2	$ 2,134	$ 2,025	$ 2,100	$ 3.08		$ 33.32	$ 1.65	$ 17.86	$ 30.14	$ 47.99	2020 - 2030
5	49	Puketoi	Wind - onshore	*Unlikely to be further considered*	8	8	11	Wairarapa	300	4.0 - 5.0	$ 2,159	$ 1,742	$ 1,800	$ 8.26		$ 27.54	$ 5.36	$ 17.87	$ 22.42	$ 40.29	2020 - 2030
6	11	Castle Hill	Wind - onshore	Consented	8.5	8	11	Wairarapa	500	4.0 - 5.0	$ 2,193	$ 1,991	$ 1,700	$ 12.67		$ 25.35	$ 8.93	$ 17.86	$ 16.62	$ 34.48	2020 - 2030
7	23	Kaiwera Downs	Wind - onshore	Consented	8	14	18	Southland	200	4.0 - 5.0	$ 2,013	$ 1,850	$ 2,000	$ 5.88		$ 29.40	$ 3.58	$ 17.90	$ 25.92	$ 43.82	2020 - 2030
8	6	Awhitu	Wind - onshore	*N/a*	8	2	3	Auckland	25	4.0 - 5.0	$ 2,037	$ 1,909	$ 3,100	$ 1.03		$ 41.18	$ 0.45	$ 18.00	$ 33.01	$ 51.01	2020 - 2030
9	12	Central Wind	Wind - onshore	*Not proceeding*	8.5	7	7	Central Plateau	150	4.0 - 5.0	$ 2,296	$ 2,056	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2020 - 2030
10	38	Mt Munro	Wind - onshore	Currently Investigated	8	8	11	Wairarapa	100	4.0 - 5.0	$ 1,990	$ 1,771	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2020 - 2030
11	75	Waitahora	Wind - onshore	*N/a*	8	7	11	Wairarapa	150	4.0 - 5.0	$ 2,274	$ 1,824	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2020 - 2030
12	21	Kaimai	Wind - onshore	Currently Investigated	8	3	4	Waikato	100	4.0 - 5.0	$ 2,103	$ 1,947	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2020 - 2030
13	68	Flemington	Wind - onshore	Currently Investigated	8	7	11	Wairarapa	100	4.0 - 5.0	$ 2,203	$ 1,892	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2020 - 2030
14	30	Mahinerangi Stage 2	Wind - onshore	Consented	8	14	17	Otago	150	4.0 - 5.0	$ 2,104	$ 1,836	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2020 - 2030
15	19	Hurunui	Wind - onshore	Consented	9	10	16	Canterbury	80	4.0 - 5.0	$ 2,401	$ 1,884	$ 2,200	$ 2.73		$ 34.11	$ 1.43	$ 17.88	$ 30.65	$ 48.53	2020 - 2030
16	31		Wind - onshore	Potential new site	7	4	5		300	4.0 - 6.0	$ 1,889	$ 1,814	$ 1,800	$ 8.26		$ 27.54	$ 5.36	$ 17.87	$ 22.42	$ 40.29	2030 - 2040
17	41		Wind - onshore	Currently Investigated	7	1	2		60	4.0 - 6.0	$ 1,927	$ 1,829	$ 2,300	$ 2.14		$ 35.74	$ 1.07	$ 17.83	$ 31.50	$ 49.33	2030 - 2040
18	46		Wind - onshore	Previously Investigated	8	1	2		300	4.0 - 6.0	$ 2,267	$ 1,810	$ 1,800	$ 8.26		$ 27.54	$ 5.36	$ 17.87	$ 22.42	$ 40.29	2030 - 2040
19	26		Wind - onshore	Previously Consented	8	3	4		180	4.0 - 6.0	$ 2,293	$ 1,904	$ 2,000	$ 5.38		$ 29.91	$ 3.22	$ 17.89	$ 26.67	$ 44.56	2030 - 2040
20	73		Wind - onshore	Potential new site	8	3	4		200	4.0 - 6.0	$ 2,198	$ 1,883	$ 2,000	$ 5.88		$ 29.40	$ 3.58	$ 17.90	$ 25.92	$ 43.82	2030 - 2040
21	9		Wind - onshore	Potential new site	7	9	14		50	4.0 - 6.0	$ 1,994	$ 1,799	$ 2,400	$ 1.84		$ 36.81	$ 0.89	$ 17.80	$ 31.92	$ 49.72	2030 - 2040
22	28		Wind - onshore	Consented	8	8	12		15	4.0 - 6.0	$ 2,578	$ 2,257	$ 4,000	$ 0.67		$ 44.74	$ 0.27	$ 18.00	$ 33.45	$ 51.45	2030 - 2040
23	47		Wind - onshore	Currently Investigated	8	7	10		150	4.0 - 6.0	$ 2,183	$ 1,855	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2030 - 2040
24	51		Wind - onshore	Potential new site	7	7	5		300	4.0 - 6.0	$ 1,867	$ 1,794	$ 1,800	$ 8.26		$ 27.54	$ 5.36	$ 17.87	$ 22.42	$ 40.29	2040 - 2050
25	48		Wind - onshore	Previously Investigated	7	8	12		100	4.0 - 6.0	$ 2,282	$ 2,061	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
26	43		Wind - onshore	Previously Investigated	8	1	3		100	4.0 - 6.0	$ 2,331	$ 1,852	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
27	33		Wind - onshore	Potential new site	7	7	10		150	4.0 - 6.0	$ 1,981	$ 1,789	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2040 - 2050
28	80		Wind - onshore	Currently Investigated	7	1	3		100	4.0 - 6.0	$ 2,125	$ 1,843	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
29	77		Wind - onshore	Currently Investigated	7	1	2		150	4.0 - 6.0	$ 2,072	$ 1,865	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2040 - 2050
30	50		Wind - onshore	Potential new site	7	7	7		250	4.0 - 6.0	$ 2,059	$ 1,965	$ 1,800	$ 7.09		$ 28.36	$ 4.47	$ 17.88	$ 24.12	$ 42.00	2040 - 2050
31	24		Wind - onshore	Potential new site	8	4	5		150	4.0 - 6.0	$ 2,156	$ 1,925	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2040 - 2050
32	63		Wind - onshore	Potential new site	6	5	6		50	4.0 - 6.0	$ 1,906	$ 1,847	$ 2,400	$ 1.84		$ 36.81	$ 0.89	$ 17.80	$ 31.92	$ 49.72	2040 - 2050
33	2		Wind - onshore	Potential new site	7	1	2		100	4.0 - 6.0	$ 2,127	$ 1,838	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
34	8		Wind - onshore	Potential new site	8	4	5		100	4.0 - 6.0	$ 2,565	$ 2,002	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
35	67		Wind - onshore	Potential new site	6	14	18		100	4.0 - 6.0	$ 2,029	$ 1,850	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2040 - 2050
36	32		Wind - onshore	Potential new site	8	4	5		75	4.0 - 6.0	$ 2,193	$ 1,913	$ 2,200	$ 2.59		$ 34.47	$ 1.34	$ 17.87	$ 30.86	$ 48.73	2040 - 2050
37	1		Wind - onshore	Previously Investigated	7	1	1		75	4.0 - 6.0	$ 2,333	$ 1,919	$ 2,200	$ 2.59		$ 34.47	$ 1.34	$ 17.87	$ 30.86	$ 48.73	2040 - 2050
38	52		Wind - onshore	Previously Consented	6	14	17		500	4.0 - 6.0	$ 1,928	$ 1,786	$ 1,700	$ 12.67		$ 25.35	$ 8.93	$ 17.86	$ 16.62	$ 34.48	2050 - 2060
39	5		Wind - onshore	Currently Investigated	8	4	4		20	4.0 - 6.0	$ 2,303	$ 2,062	$ 3,400	$ 0.85		$ 42.70	$ 0.36	$ 18.00	$ 33.23	$ 51.23	2050 - 2060
40	20		Wind - onshore	Currently Investigated	7	14	18		25	4.0 - 6.0	$ 2,280	$ 1,852	$ 3,100	$ 1.03		$ 41.18	$ 0.45	$ 18.00	$ 33.01	$ 51.01	2050 - 2060
41	16		Wind - onshore	Previously Investigated	7	1	1		75	4.0 - 6.0	$ 2,359	$ 1,913	$ 2,200	$ 2.59		$ 34.47	$ 1.34	$ 17.87	$ 30.86	$ 48.73	2050 - 2060
42	57		Wind - onshore	Potential new site	8	5	6		75	4.0 - 6.0	$ 2,654	$ 2,003	$ 2,200	$ 2.59		$ 34.47	$ 1.34	$ 17.87	$ 30.86	$ 48.73	2050 - 2060
43	27		Wind - onshore	Previously Investigated	6	14	18		150	4.0 - 6.0	$ 2,055	$ 1,908	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2050 - 2060
44	61		Wind - onshore	Consented	7	3	4		50	4.0 - 6.0	$ 2,169	$ 1,814	$ 2,400	$ 1.84		$ 36.81	$ 0.89	$ 17.80	$ 31.92	$ 49.72	2050 - 2060
45	65		Wind - onshore	Potential new site	7	7	11		100	4.0 - 6.0	$ 2,568	$ 2,016	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2050 - 2060
46	35		Wind - onshore	Potential new site	7	5	6		200	4.0 - 6.0	$ 2,440	$ 1,962	$ 2,000	$ 5.88		$ 29.40	$ 3.58	$ 17.90	$ 25.92	$ 43.82	2050 - 2060
47	55		Wind - onshore	Potential new site	6	14	17		300	4.0 - 6.0	$ 1,992	$ 1,832	$ 1,800	$ 8.26		$ 27.54	$ 5.36	$ 17.87	$ 22.42	$ 40.29	2050 - 2060
48	76		Wind - onshore	Potential new site	6	7	10		150	4.0 - 6.0	$ 1,972	$ 1,867	$ 2,000	$ 4.62		$ 30.81	$ 2.68	$ 17.87	$ 27.82	$ 45.69	2050 - 2060
49	58		Wind - onshore	Previously Investigated	6	14	18		100	4.0 - 6.0	$ 2,150	$ 1,832	$ 2,100	$ 3.29		$ 32.90	$ 1.79	$ 17.90	$ 29.82	$ 47.72	2050 - 2060
50	25		Wind - onshore	Potential new site	7	7	5		75	4.0 - 6.0	$ 2,511	$ 2,067	$ 2,200	$ 2.59		$ 34.47	$ 1.34	$ 17.87	$ 30.86	$ 48.73	2050 - 2060

Recommendations

- Capital and operational cost recommendations are highlighted in 'blue'.
- Likelihood ratings to be revised

Clarifications

- Turbine O&M fixed cost per year and other OPEX cost per year

Wind Key Assumptions - *Recommendation*

Wind (onshore)		MW Scale ($/kW – 2022 NZD)					
	Key Category	**10MW**	**20MW**	**50MW**	**100MW**	**150MW**	**200MW**
CAPEX	Wind turbines (EPC)	$ 1,260	$ 1,240	$ 1,230	$ 1,240	$ 1,250	$ 1,220
CAPEX	Other EPC (Balance of Plant)	$ 3,320	$ 1,780	$ 860	$ 570	$ 480	$ 420
CAPEX	Other (ie: Front End Feasibility, Consenting, Procurement)	$ 250	$ 210	$ 190	$ 180	$ 180	$ 170
CAPEX	Contingency	$ 240 *5%*	$ *5%*	$ 110 *5%*	$ 100 *5%*	$ 100 *5%*	$ 90 *5%*
CAPEX	**Total Capital costs (excluding HV transmission)**	**$ 5,100**	**$ 3,400**	**$ 2,400**	**$ 2,100**	**$ 2,000**	**$ 1,900**
OPEX	Total O&M $/kW/year	$ 34	$ 33	$ 32	$ 30	$ 28	$ 26
OPEX	**Total Operating costs $/kW/year**	**$ 52**	**$ 51**	**$ 50**	**$ 48**	**$ 46**	**$ 44**

Geothermal

Geothermal Plant - Review of Lawless Report - Future Geothermal Generation Stack

MBIE's commissioned report by Lawless Geo Consultancy 2020:

This report is one of a number of reports published by various agencies re geothermal project costs.

Jim Lawless' report is specific to NZ and specific to providing capital and O&M costs for the Future Geothermal Generation Stack.

Lawless' report selects a specific capital cost figure (NZ$/kW installed), deriving this figure from other cost reports, and benchmarks the number against recent NZ project costs.

Referenced against international capital cost benchmarks, the costs provided in the Lawless report are consistent with a whole of project capital cost including all client costs.

Lawless' report scales the power plant portion (40% of the total cost) of the project cost for enthalpy (low, medium, high), plant size (referenced to a 50MW base), and GHG emissions.

Geothermal - Key Assumptions / Insights

New Zealand Future Geothermal Stack

Item	Enthalpy	MW	Capital Cost per kW - NZ$/kW	Capital Cost per kW - US$/kW	Capital Cost $m
Ngawha 3	L	25	$ 7,802.00	$ 5,071.30	$ 195.00
Tauhara 2a	M	125	$ 4,734.00	$ 3,077.10	$ 592.00
Tauhara 2b	M	125	$ 4,734.00	$ 3,077.10	$ 592.00
Ngawha 4	L	25	$ 7,802.00	$ 5,071.30	$ 195.00
Mangakino	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Mokai 4	L	25	$ 7,802.00	$ 5,071.30	$ 195.00
Ngatamariki 2	M	50	$ 5,568.00	$ 3,619.20	$ 278.00
Rotokawa 3	M	50	$ 5,568.00	$ 3,619.20	$ 278.00
Kawerau 2	M	50	$ 5,568.00	$ 3,619.20	$ 278.00
Rotoma 1	L	25	$ 7,802.00	$ 5,071.30	$ 195.00
Tokaanu 1	M	20	$ 6,335.00	$ 4,117.75	$ 127.00
Tikitere 1	H	50	$ 5,023.00	$ 3,264.95	$ 251.00
Taheke 1	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Reporoa 1	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Tauhara 3	M	30	$ 5,968.00	$ 3,879.20	$ 179.00
Horohoro	L	5	$ 9,767.00	$ 6,348.55	$ 49.00
Atiamuri	L	5	$ 9,767.00	$ 6,348.55	$ 49.00
Rotokawa 4	M	50	$ 5,568.00	$ 3,619.20	$ 278.00
Tokaanu 2	M	100	$ 5,119.00	$ 3,327.35	$ 512.00
Tikitere 2	M	50	$ 5,568.00	$ 3,619.20	$ 278.00
Taheke 2	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Reporoa 2	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Ngawha 5	L	25	$ 7,802.00	$ 5,071.30	$ 195.00
Takeke 3	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Reporoa 3	M	25	$ 6,127.00	$ 3,982.55	$ 153.00
Ngawha 6	L	25	$ 7,802.00	$ 5,071.30	$ 195.00

International Comparisons

- IRENA US$3,000 – 5,000 /kW installed
- SKM 2009 – NZ$4,300 – $5,300 /kW (50MW medium enthalpy)
  - Indexed to 2020 = NZ$4,900 – $6,100 /kW (CEPCI Index)
    - US$3,200 – $3900 /kW
- UN2019 – US$3,000-5,000 /kW (Indonesian project costs)
- US EIA – US$3,076 /kW (2025 for 50MW)
- Lawless base capital cost:
  - NZ$5,500 /kW
  - US$3,600 /kW (@ $0.65)

- Lawless cost vs International:
  - Lawless base capital cost is within the international project estimates, below the international average cost
  - Lawless references recent geothermal projects to benchmark the base value, notes the NZ cost is below international averages and provides reasons

- Converting the geothermal stack to US$/kW, the proposed values fit within the international range of US$3,000 -5,000 /kW with 2 exceptions:
  - Two small projects (5MW) with Low enthalpy.
  - It is reasonable for these 2 projects to be outliers

Recommendation

Current assumption set is deemed reasonable.

Geothermal – NZ Benchmarks

Project	MW	NZ$	NZ$/kW	US$ (@$0.65)
TAOM	26MW net	$149m	$5,730	US$3,700
Ngawha 3	28MW net	$182m	$6,500	US$4,200
Ngatamariki A	82MW net	$466m	$5,700	US$3,693
Te Mihi	166MW	$633m Power Plant only	$3,813	US$2,480
Tauhara	168MW	$818m	$4,870	US$3,170

- **Lawless base capital cost:**
  - **NZ$5,500 /kW**
  - US$3,600 /kW (@ $0.65)

Geothermal - Key Assumptions Cost Estimates

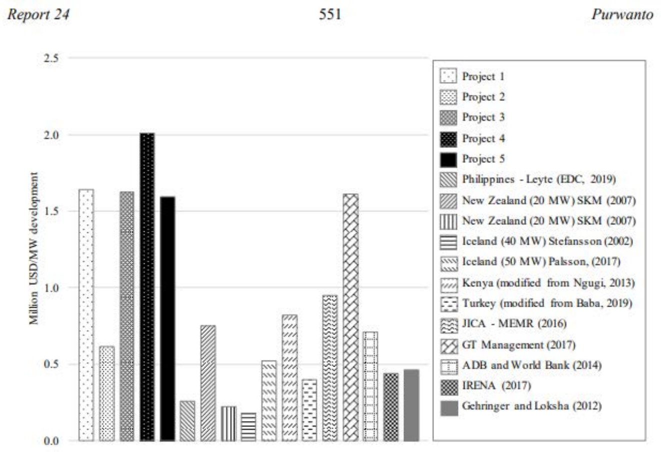
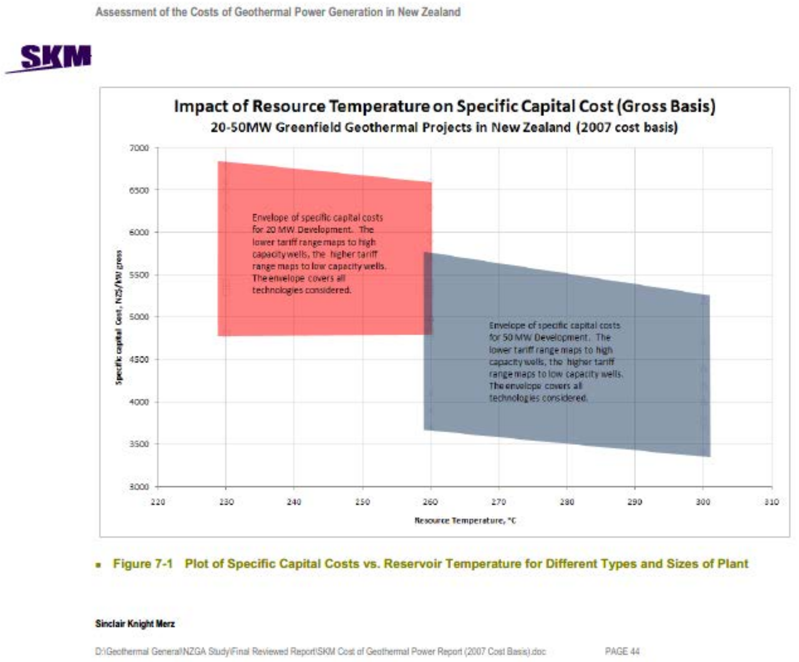
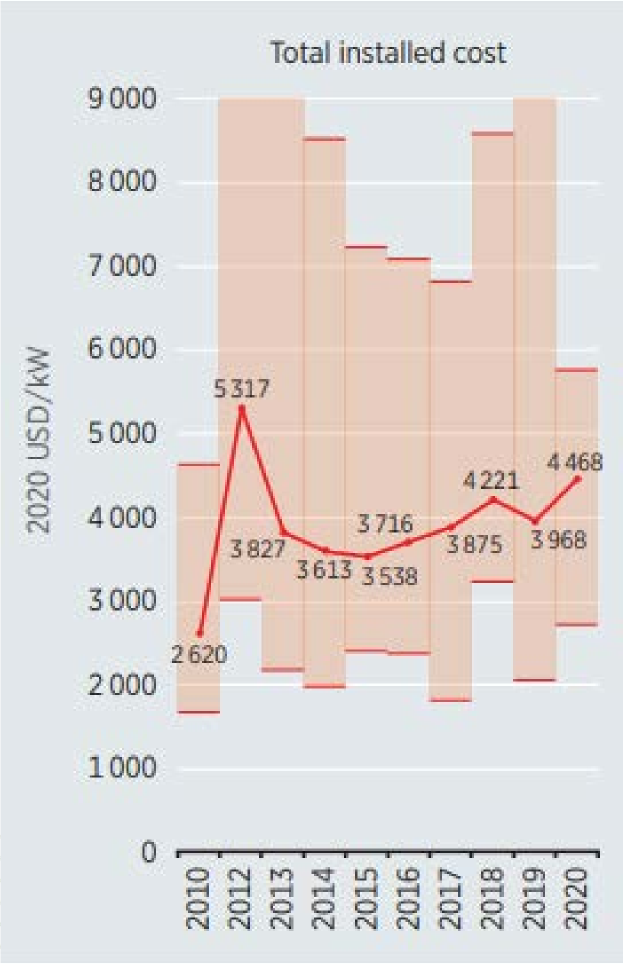


FIGURE 8: Worldwide comparison of geothermal exploration cost per MW

International drilling costs



Project Capital costs by resource type



Source: *IRENA Renewable Cost Database.*

- Total project cost variability - Class 4 ±25%
- Geothermal project costs can vary significantly depending on reservoir characteristics, drilling campaign and technology selection

Note:

- Total installed costs include a variety of project sizes

Geothermal Plant Parameters

Establishment Costs
- Land acquisition
- Geoscientific & Well testing
- Civil work & Infrastructure & site operation
- Consenting

Construction Costs
- Power Plant Capital Cost
- Steamfield Costs
- Electrical transmission costs & grid connection

Drilling Costs
- Rig Mob & Demob
- Cost per well (variable)
  - # of Production wells
  - # of injection wells

Developers Costs
- Finance & legal
- Engineering Design & PM

Resource Parameters determining Power Plant (Cycle Type)
- Reservoir temperature
- Well flow envelope
- Steam field area
- # of wells
- Reservoir depth

Power Plant Cycle Types:
- Single & Double Flash
- Hybrid Binary
- Binary Organic Rankine Cycle

O&M Costs

Figure 7.4 LCOE of geothermal power projects by technology and project size, 2007-2021

Source: IRENA Renewable Cost Database.

- Lawless report presents a fixed value of **NZ$190 per kW** per year O&M costs
- This includes make up wells ($157 pa for plant and $30 pa for make up wells)
- IRENA O&M cost US$115 per kW per year including make up production and reinjection wells
  - **NZ$175 per kW per year**
- USDOE EIA US$144/kW year = **NZ$222/kW year**
- O&M costs will vary between technologies, with owner's fleet size and geographic location
- Graph on left shows range of LCOE, and some trends on plant size and technology
- Lawless report:
  - O&M cost difference between technologies varies within a limited range.
  - The international cost data we have does not distinguish between technologies.
  - Make up well costs discussed at length, but not O&M costs differences relating to technology.
- SKM 2007 does not differentiate O&M costs for technologies.

Recommendation

Current OPEX assumption is deemed reasonable.

Typical Cost Split Local vs Foreign Content

- **Table 7-4 Assessed Split of Development Costs into Local / Overseas Components**

	Option 18. Low envelope. 260°C. 50 MW. SF.			
	Assessed Local Content	Total Cost	Local Cost	Foreign Cost
	%	NZD M	NZD M	NZD M
Establishment Cost	90%	3.5	3.2	0.4
Drilling Cost	40%	89.0	35.6	53.4
Steamfield Cost	80%	33.0	26.4	6.6
Power Plant Cost	25%	95.0	23.8	71.3
Transmission Interconnection Cost	40%	7.0	2.8	4.2
Developer Cost	90%	16.0	14.4	1.6
Total		243.5	106.1	137.4
			44%	56%

aurecon

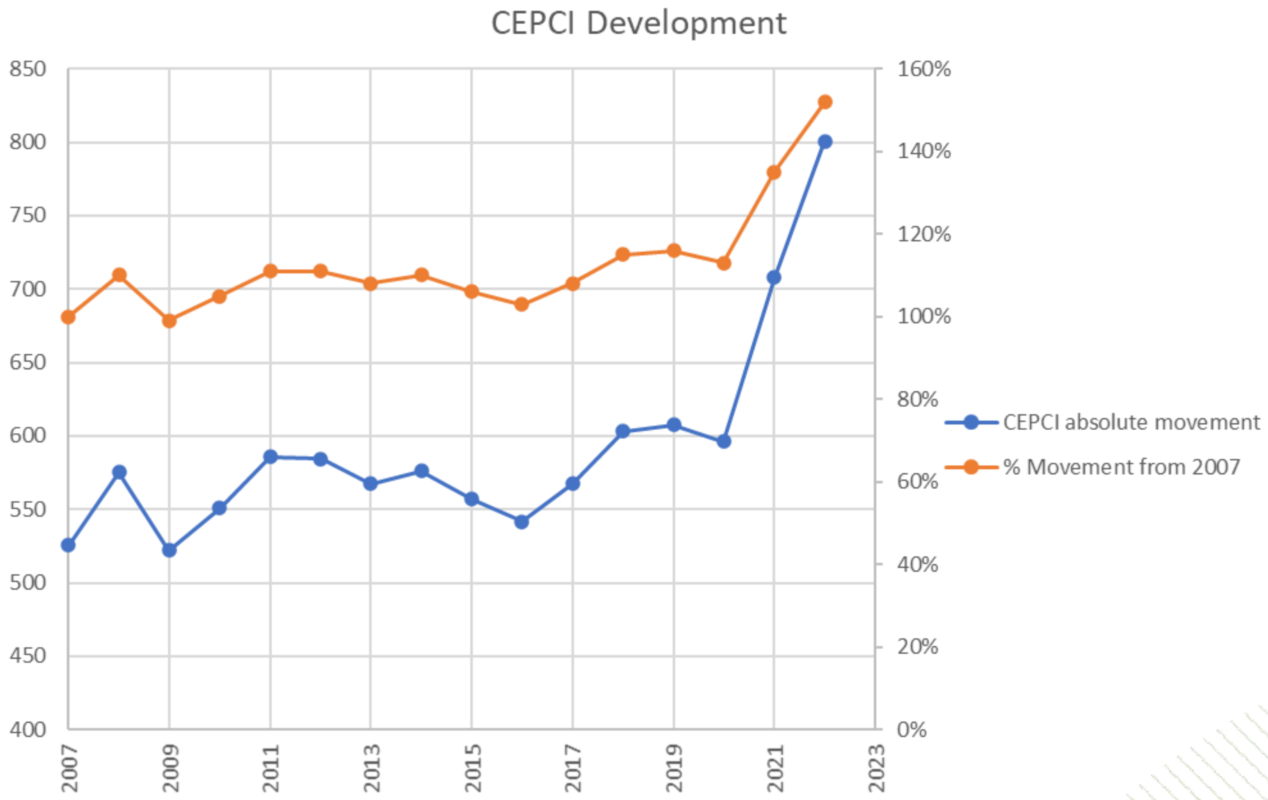
Typical Cost Split

- Table 7-2 Estimate of Capital Costs for High Envelope Developments

CAPTAL COSTS - HIGH FLOW ENVELOPE	Option	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Res T	300	260	260	230	300	260	260	230	300	260	260	230	300	260	260	230
	Cycle	SF	SF	SF	SF	DF	DF	DF	DF	Hybrid	Hybrid	Hybrid	Hybrid	ORC	ORC	ORC	ORC
	MW gross	50	50	20	20	50	50	20	20	50	50	20	20	50	50	20	20
Establishment Costs																	
Permitting	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Land acquisition	NZ $ M	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Geoscientific / Environmental	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Well Testing	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Civil works and Infrastructure	NZ $ M	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5	1.0	1.0	0.5	0.5
Site Operations	NZ $ M	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Pre Feas/ Feas Repors	NZ $ M	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commerical negotiations	NZ $ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ $ M	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0	3.5	3.5	3.0	3.0
Construction Costs														2550		2710	
Power plant capital cost	NZ$/kW installed	1,900	1,900	2,200	2,200	2,100	2,100	2,450	2,450	2,200	2,200	2,600	2,600	2,700	2,700	2,700	2,700
	NZ$ M	95	95	44	44	105	105	49	49	110	110	52	52	135	135	54	54
Spares*	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Steamfield costs	NZ$/kW installed	650	650	790	790	770	770	940	940	650	650	790	790	650	650	790	790
	NZ$ M	33	33	16	16	39	39	19	19	33	33	16	16	33	33	16	16
Electrical transmission - 10km	NZ$ M	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Grid connection	NZ$ M	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0	3.0	3.0	2.0	2.0
	NZ$ M	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0
Switchyard *	NZ$ M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S/T	NZ$ M	135	135	66	66	151	151	74	74	150	150	74	74	175	175	76	76
Drilling Costs																	
Rig Mob/Demob	NZ$ M	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Cost per Well	NZ$ M /well	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Production wells	Wells required	2	4	2	2	2	4	2	2	2	3	2	2	3	4	2	2
	NZ$ M	10	21	10	10	10	21	10	10	10	16	10	10	16	21	10	10
Cost per Well	NZ $ M /well	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Injection wells	Wells required	2	3	2	2	2	3	2	2	2	3	2	2	3	4	2	2
	NZ$ M	8	13	8	8	8	13	8	8	8	13	8	8	13	17	8	8
S/T	NZ$ M	21	36	21	21	21	36	21	21	21	31	21	21	31	40	21	21
Developers Costs																	
Legal	NZ$ M	1.6	1.7	0.9	0.9	1.8	1.9	1.0	1.0	1.7	1.8	1.0	1.0	2.1	2.2	1.0	1.0
Financing	NZ$ M	1.6	1.7	0.9	0.9	1.8	1.9	1.0	1.0	1.7	1.8	1.0	1.0	2.1	2.2	1.0	1.0
Engineering & PM mgt	NZ$ M	8	9	5	5	9	10	5	5	9	9	5	5	10	11	5	5
Others	NZ$ M																
S/T	NZ $ M	11	12	6	6	12	13	7	7	12	13	7	7	15	15	7	7
Total Project Costs	**NZ$ M**	**171**	**186**	**97**	**97**	**188**	**203**	**105**	**105**	**187**	**197**	**105**	**105**	**223**	**233**	**107**	**107**
Ratios	NZD / kW gross	3,400	3,700	4,800	4,800	3,800	4,100	5,300	5,300	3,700	3,900	5,300	5,300	4,500	4,700	5,400	5,400
At USD/NZD 0.70	USD / kW gross	2,400	2,600	3,400	3,400	2,700	2,900	3,700	3,700	2,600	2,700	3,700	3,700	3,200	3,300	3,800	3,800

Terms Clarification
As defined in SKM report –
Gross = electricity generated at the generator terminals, before deduction of in house electricity consumption.
Net = electricity generated at the plant outlet (boundary) after the in house electricity demand is deducted.
For a large flash geothermal plant (>50MW), typical electrical parasitic load (in house electricity consumption) is around 4-6% of the Gross output.

Significant inflation 2020- 2022
Chemical Engineering Plant Cost Index (CEPCI)



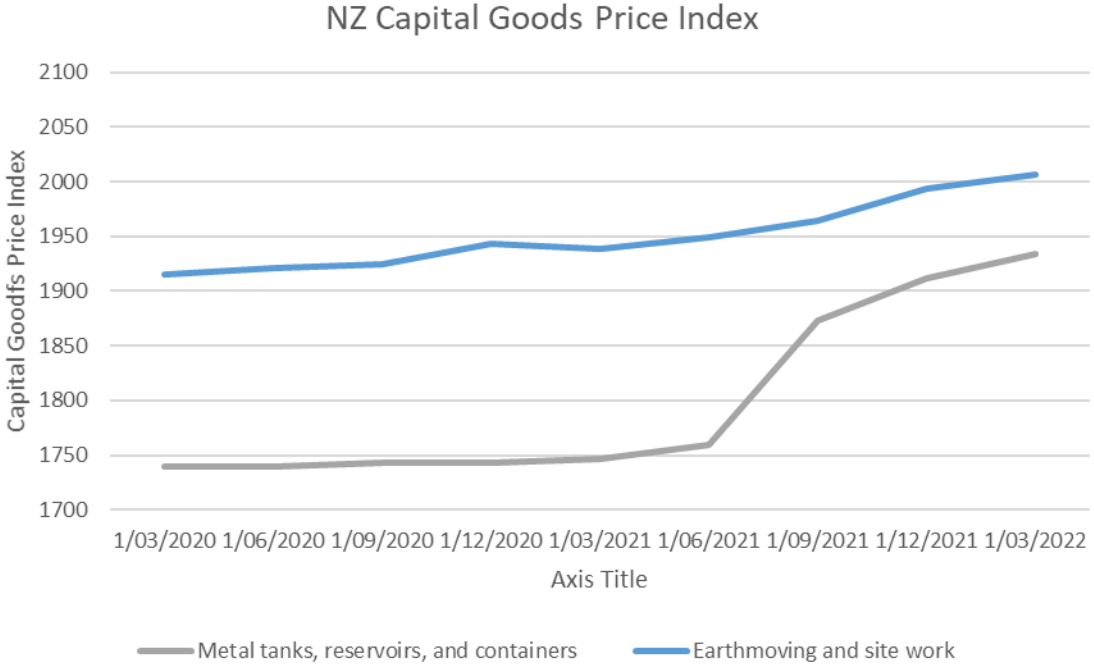
CEPCI
The index data is provided from the U.S. Bureau of Labor Statistics (BLS), calculated based on a set of Producer Price Index.

Categories include equipment, heat exchangers & tanks, process machinery, piping, valving, fittings and instruments & structural supports, pumps and compressors, electrical equipment, as well as construction labour, buildings and engineering supervision.

The index baseline of 100 was set in the base period 1957-1959. The index is updated every 3 month.

Note: 2022 data only available until April 2022

Significant inflation 2020- 2022
New Zealand Capital Goods Price Index



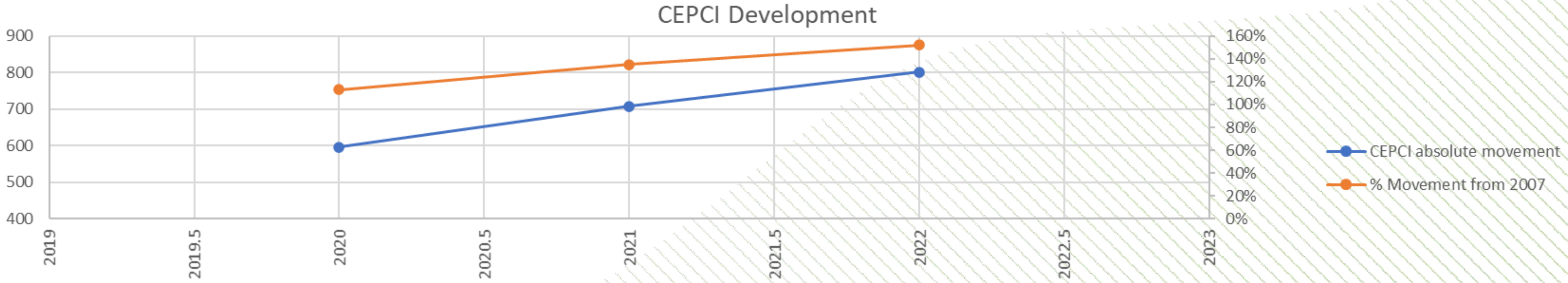
NZ Cost Data

NZ Capital Goods Price Index
Base – September 1999 Quarter = 1000

Category: Plant, Machinery and Equipment

- Electric motors, generators and transformers
- Metal tanks, reservoirs, and containers

NZ cost increase trends lower than Canadian. CEPCI absolute movement 30% increase since 2019, NZ 5% (Earthmoving) and 11% (metal tanks). Anecdotally, New Zealand project costs have increased more than 10% over the past 2 years.



Key Yield / Transmission Zones

Renewable Energy Zones and Transmission Gaps

Aurecon has previously been engaged in consultation for the identification of renewable energy zones in the Australian market. For this current mandate we have identified some potential gaps in the transmission network that may merit further consideration.

The general intent of the REZ policies is "without picking winners" to enable strengthening of the energy supply in regions with high renewable energy resources by removing barriers to entry, and add regional employment, similar to the aims of the Provincial Growth Fund. We understand Transpower is already engaged in consultations on this concept presently and in part we include our views where further attention may be merited.

In the context of the NZ Battery Project this approach might be considered as an alternative investment case by policy makers for further study if shown to be competitive in detailed modelling.

Prospecting Maps

In other engagements for clients entering or developing projects for the New Zealand electricity market we have developed number of Geographic Information System (GIS) prospecting maps that use weighting factors on layer of data to establish "hot" and "cold" prospecting areas and are shown in the following slides.

These prospecting maps provide general guidance on our view of where renewable energy zones might be adopted in New Zealand. The factors considered in our prospecting include:

- Industrial loads for behind the meter applications
- Distance to major transmission network
- Land values
- Population density
- Wind/Solar resource
- Existing/competing generation

These are similar factors considered by AMC for example in their generation stack costings.

Figure 11: Potential renewable generation and industrial clusters based on NZGP consultation and media releases

Transpower Renewable Energy Zones National Consultation 2022

Energy Yield Zones

Prospecting Maps

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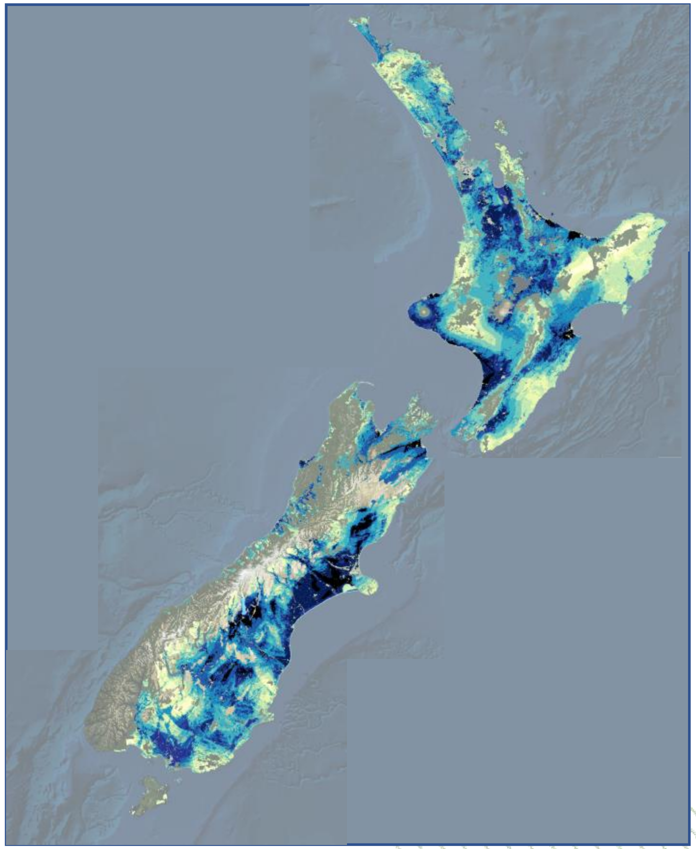

Solar map (dark blue represents good locations)

Key zones

- Waikato
- Bay of Plenty
- Taranaki / Whanganui
- Hawkes Bay / Napier
- Nelson / Blenheim
- Canterbury
- Central Otago / Southland

Wind map (dark green represents good locations)

Key Zones

- Northland
- Waikato
- Taranaki / Palmerston North
- Wairarapa
- Marlborough
- Canterbury
- Central Otago / Southland

Transmission

Phase 1 – Enhance Grid Backbone (view to 2035)

Three key focus areas:
- Wairakei ring capacity
- Central NI capacity
- HVDC capacity

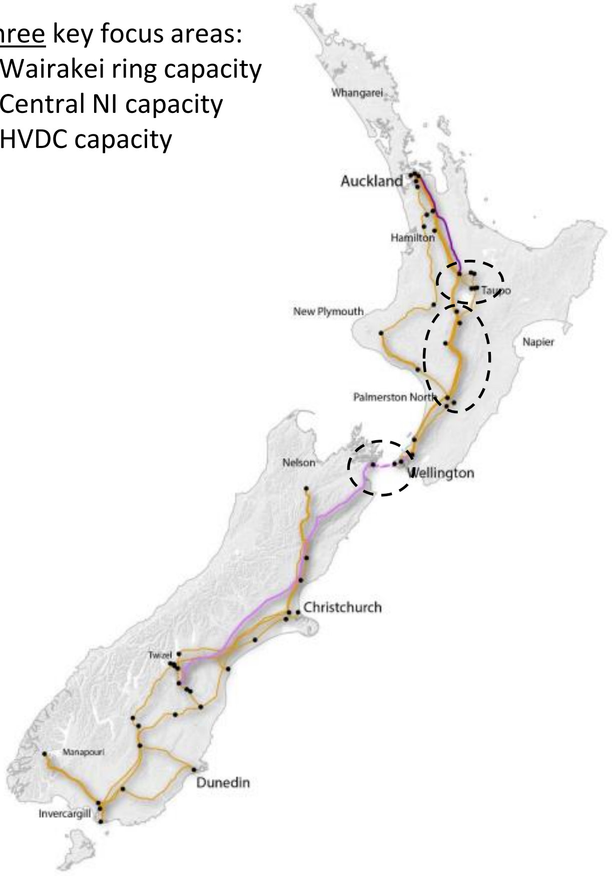

Figure 0-2 – New Zealand transmission grid backbone – the focus of NZGP Phase 1

Phase 2 – Additional Capacity (view to 2050)

Seven areas identified:
- Northland
- BOP
- Central NI
- Hawkes Bay
- Wairarapa
- Nelson / Marlborough
- Southland

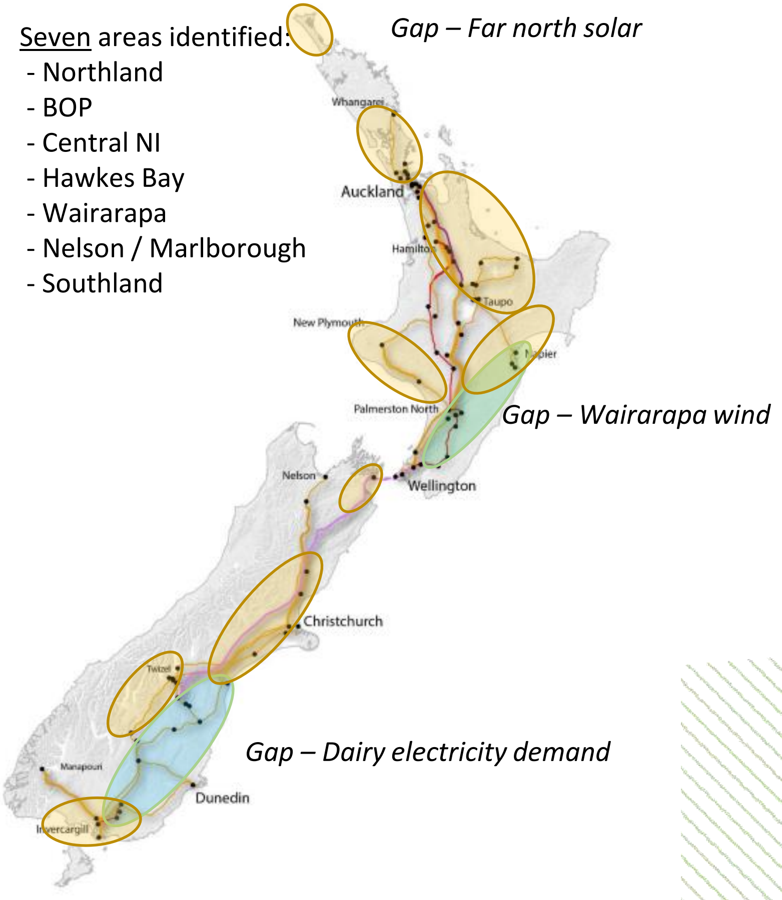

Figure 0-3 – New Zealand transmission grid backbone and interconnected regional grids – the focus of NZGP Phase 2

Appendices

Scope

- Review existing wind, solar and geothermal project cost information (capital and operational costs), identifying gaps and highlighting limitations to existing input assumptions.
- Review and update the breakdown and derivation of costs that have informed MBIE's capital and operating cost assumptions to date, as outlined in the supporting reports for MBIE's Energy Generation and Demand Scenarios for geothermal, utility scale solar and wind. MBIE has provided supporting spreadsheets to assist in this process.
- Provide context on the potential project cost range for each technology given the level of risk. Provide a relevant upside and downside sensitivity cost range, depending on site location, MW capacity, energy yield, transmission, consenting etc.

Note:

- Aurecon's sub-consultant MTL, has carried out the review of geothermal cost assumptions for this assignment.