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Mr Stephen Clark
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Project Marinus
TasNetworks
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Project Specification Consultation Report

Dear Stephen,

UPC is pleased to have the opportunity to respond to the Project Specification Consultation Report for Project Marinus. UPC is a strong supporter of more interconnection between Tasmania and Victoria. Our interest is in being able to unlock the significant potential for renewable energy projects in Tasmania, initially focused on delivering over 1,000 MW from the Robbins Island and Jim's Plain projects. More interconnection will enable further wind development, unleash the full potential of the existing hydro system and enable cost effective development of the pumped hydro potential in Tasmania. The combination of low cost wind, low cost pumped hydro and low cost hydro generation will deliver a solution to the trilemma of affordable, renewable and dispatchable electricity for the ultimate benefit of Tasmanian and NEM consumers.

We would like to raise a number of questions and concerns in regard to the Project Specification Consultation Report for Project Marinus. These relate to :

- the assumptions to be used to assess the benefits of a further interconnection;
- the scenario to be considered in evaluating the benefits of further interconnection;
- the costing assumptions for the next interconnector; and
- other value contributions related to more interconnection.

We have addressed these questions and concerns in the following sections.

Assumptions

General

UPC has been concerned about the assumptions used in the Integrated System Plan (ISP) and the potential for these to distort the value proposition of more interconnection between Tasmania and Victoria. UPC considers the initial ISP assumptions should be tested and we have outlined a set of ISP assumptions (refer Table 1 - appended) that should be refined in any future modelling. UPC has already written to AEMO in regard to these assumptions for future revision in the next ISP version. More specific discussion on some of the key areas of concern are discussed below.

Wind Farm

In terms of modelling the value and hence viability of a regulated second interconnector, UPC believes that more work is required to ensure the assumptions reflect the realities in the market. In more recent modelling work, broad based assumptions on renewable development, battery or pumped hydro opportunities across NEM regions have understated the potential value attributable on a regional basis. This is particularly the case with the Tasmanian opportunities and one of the key reasons why the potential value of further interconnection has been undervalued in the past. For example, assumptions that wind or solar have the same cost and capacity factors across all regions is an over simplification and fundamentally incorrect and hence leads to incorrect results and decision making. In the case of the wind projects UPC is developing in Tasmania, we expect capacity factors close to 50 percent (Refer Figure 2 and Figure 3 attached for Robbins Island Stage 1) when compared to the ISP assumption of 40 percent across the NEM regions (refer Figure 1 attached for a comparison of historical performance of operating wind farms), and capex costs 10-20 percent lower than indicated in the recent ISP modelling by AEMO.

We also believe that actual projects that have been announced should be directly modelled and only in the case where there are no announced projects in a region, the general assumptions for a region in terms of capacity, capacity factor and cost are then used.

Pumped hydro

A more specific observation in terms of the ISP modelling is related to pumped hydro, where all pumped hydro is considered the same cost across the NEM. Pumped hydro opportunities are bespoke based on the conditions at a particular site and the infrastructure needed. This can range from needing to build up to two storages and significant variation in head and penstock sizes of the schemes. UPC also considers that the assumptions in the ISP for pumped hydro costs are too low given the projects announced in the NEM and the historical lack of pumped hydro development in Australia. The recently announced projects on the mainland have cost ranges from a low of

$1.6M/MW up to $2.25M/MW (upper estimate of Snowy 2.0). In comparison, the ISP assumes $1.4M/MW.

More recent work by ARENA and Hydro Tasmania[1] has demonstrated that the Tasmanian pumped hydro opportunities have a capex of between $1.1M/MW and $2.3M/MW. We also believe the cost per MW installed for the Tasmanian opportunities are an exception to the norm, as a significant proportion of the infrastructure for the lowest cost options is already built.

In the same report[1], it also indicates that for pumped hydro built around the world the costs have ranged from $0.5M/MW to $4.3M/MW, with an average of $2.3M/MW. It was also clear that developing countries have much lower costs, and when these are removed, the average pumped hydro cost was closer to $2.8M/MW. UPC has also engaged an international consultant to review the likely cost of pumped hydro based on historical projects developed around the world in the past 15 years. This analysis indicated a typical range of $1.6M/MW to $2.5M/MW(AUD) depending on how many new storages were required[2]. Consequently UPC is of the view that in the absence of a specifically defined pumped hydro project, an average in the order of $2.0M to $2.5M/MW is more realistic for potential future projects (as lower cost projects could be expected to be highlighted already).

Scenarios

In regard to the modelling, the scenario chosen should reflect decisions that are realistic rather than using general assumptions that could risk losing interdependencies between individual projects. For example, assuming the low cost wind and pumped hydro developments occur in Tasmania without more interconnection is unrealistic. Simply adding the interconnector and running the same suite of projects throughout the NEM may not produce a realistic outcome (in past modelling this has occurred). For example building the full scale of the Robbins Island and Jim's Plain projects of over 1000 MW will not occur without another interconnector. Without a second interconnector approximately 500 MW of wind will be possible on Robbins Island and Jim's Plain and it is likely that no large scale pumped hydro will occur. UPC is committed to developing the first 500 MW in stage 1 of the Robbins Island and Jim's Plain wind farms. The development of stage 1 will mean a lower $/MW development of the second stage (circa additional 500 MW) of these wind farms[3]. UPC is of the view that wind, pumped hydro and interconnection should be analysed as a combined project in order to estimate the full benefits of these projects. UPC has provided a set of scenarios (refer Table 2 appended) that should be considered when examining the value of a second interconnector. This

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[1] https://www.hydro.com.au/docs/default-source/clean-energy/battery-of-the-nation/pumped-hydro-knowledge-sharing-report.pdf?sfvrsn=de58e528_4

[2] The work commissioned by UPC is available for your consideration if required.

[3] Scale of the Robbins Island and Jim's Plain Development are publicly available at https://robbinsislandwindfarm.com/faq/

case is a good example of the short comings of the current RiT-T and the inclusions of potential projects other than committed/advanced projects.

The modelling approach using time series of wind generation outlined in the Project Specification Consultation Report should deliver more realistic outcomes while also capturing the value of geographic diversity of wind resources. A previous limitation observed was the use of average profiles which mask the value of the geographical diversity of wind farms. UPC has done its own analysis of 5 minute NEM data for 2017 which demonstrates that the correlation between operating Victorian and Tasmanian wind farms is very low (i.e. R- Squares below 0.2 in most cases – refer Table 3 appended). This points to the value of development in geographical diverse locations to minimise coincidently high or low output and hence avoid the issues that coincident generation or lack thereof brings. It is very likely this will enhance the value of having more wind in Tasmania particularly considering the better resource and likely lower cost basis that can also be achieved.

UPC feels it is critical to go to a detailed level to understand the real value of greater interconnection. The potential value that more wind and pumped hydro brings will be limited or non-existent without greater interconnection. We would encourage TasNetworks to consider the scenarios modelled and the way various parameters are modelled carefully to ensure value is appropriately captured in this analysis.

Costings

UPC is concerned with the cost escalations attributed to a second interconnector, particularly since the Tamblyn report. In the Project Specification Consultation Report, it points out the Tamblyn cost estimate in 2016 was $1.1billion (including +/- 30 percent and substantial AC network costs), but the new cost estimate is between $300M-$800M greater than this estimate. The difference is difficult to reconcile, but would infer significantly more AC network upgrades are included, as increases attributable to CPI escalation would only be in the order of 5 percent. UPC is concerned that an unrealistically high estimate of cost will undermine the cost/benefit analysis. A more detailed reconciliation of costs is required to help understand the overall cost of such a project. For example in the Tambyln cost estimate, there is $160M (assuming a 7 percent discount rate) in ongoing operational costs and it is unclear if a similar amount is included in the project costs in the Project Specification Consultation Report (i.e. better definitions between actual capital cost and ongoing O&M costs would be beneficial).

Value considerations

In terms of more specific value discussions in the Project Specification Consultation Report:

- It would be useful to include the cost of voluntary and involuntary load reductions, although the value is very specific to the region and the type of loads involved. It is also unclear what the costs are, due to the commercial nature of such costs. However, effort should be made to ensure such costs are realistic and included in the analysis undertaken.
- The value of additional Frequency Control Ancillary Services (FCAS) supply needs to be included based on the current conditions. While the Tamblyn report concluded there was sufficient synchronous generation to provide the required FCAS, this conclusion neglects the cost of such services. As indicated by the Office of the Tasmanian Economic Regulator, FCAS costs have increased nearly 10 fold over the last 5 years to $43M[4] in 2017 financial year. It is likely that another interconnector will provide access to lower cost ancillary services. A return to 2015-16 levels would see the cost decrease by nearly $25M per annum and hence a significant value attributable to more interconnection.
- Modelling should test assumptions around coal closure. While the current ISP provides the ideal timing, in places like the USA the lifespan of coal generation has been substantially less (up to 10 years). Changes in the life of these assets are material in the current NEM where supply and demand are closely balanced. This issue is considered in the suggested scenarios in Table 2 attached.

UPC appreciates the opportunity to provide input into this work and looks forward to progressing this opportunity with you and your team. We would welcome further discussions to elaborate on our comments to ensure the best outcomes can be achieved.

Yours sincerely

David Pollington
Chief Operating Officer

[4] Figure 2.4 in “Energy in Tasmania Report 2016-17”, OTTER Jan 2018.

Table 1 Modelling Assumptions

Assumption	Comment	ISP Assumption	Suggested
New development assumptions	Where there are defined projects these should be used instead of broad assumptions below (ie projects add in defined increment)	Committed projects included	Ensure actual projects are modelled (i.e. announced and committed) and then use general assumptions (see below) to fill any supply shortfalls.
Wind farm costs	Cost seems too high	\$2.0M/MW	\$1.6-\$1.7M/MW (exc transmission)
Wind farm capacity factor	Seems too high and needs resolution in terms of variation across NEM regions	40 percent	35 percent (refer Figure 1 attached for historical capacity factors of operating wind farms in the NEM) for mainland regions. Tas projects are likely to exceed 45 percent due to the superior wind resource.
Pumped Storage cost	Cost seems too low	\$1.49M/MW	\$2-\$2.5M/MW
Solar plant costs	Cost seems too high	\$2.0M/MW	\$1.5M/MW – more reflective of current market pricing
Solar plant capacity factors	Seems too high	32 percent	Should vary across jurisdiction based on solar resource (i.e. higher in QLD/Northern NSW)
Robbins Island /Jim's Plain stage 1	Suggest this is specifically included	None	500 MW, Capacity factor 0.5, cost \$900 M (Inc. Transmission costs) - refer Figure 2 and Figure 3
Robbins Island/Jim's Plain stage 2	Should be included with 2IC modelling	None	1000 MW (i.e. additional 500 MW), Capacity factor 0.47, total cost \$1.7B (Inc. Transmission costs)
VRET	While legislated, targets will be set in the future but still uncertain	25 percent by 2020 40 percent by 2025	25 percent by 2020 as its dependent on who is in Government to set the actual targets post 2020.
Connection Costs	Concern that the connection costs per MW should be the same per region, no reason for Biomass to be cheaper and Tasmania seems too high	See ISP	Needs to be reviewed
Coal Closure	Seems optimistic in the ISP and does not seem to consider early closure potential	See ISP	Note Origins announced commitment to close Eraring in 2032 rather than 2034 in the ISP.

Table 2 Scenario to be modelled

Case	Scenario	Description
1	Base case – No 2IC	Utilise ESOO/revise ISP assumptions for medium case (i.e. demand). Granville Harbour/Cattehill built in 2019. (UPC consider 500 MW in North West should also be assumed)
2	Case 1 with 2IC	Same as Base case with 1000 MW of wind in North West/ Pumped hydro developed (i.e. 600 MW – Cethana - $1.1M/MW)
3	Low demand – No 2IC	Same as 1 but use low demand assumption align to Tas demand (i.e. major load leaves)
4	Same as Case 3 but with 2IC	Same as case 3 with 2IC, 1000 MW of wind in North West
5	Same as Case 2 but with 1200 MW 2IC	Same as case 2 with larger 2IC
6	High mainland demand- no 2IC	Utilise ESOO/revise ISP assumptions for high demand case (i.e. demand). Granville Harbour/Cattehill built in 2019. (UPC consider 500 MW in North West should also be assumed)
7	High mainland Demand – 2IC	Same as case 6 with 1000 MW of wind in North West/ Pumped hydro developed (i.e. 600 MW – Cethana - $1.1M/MW)
8	Coal closes earlier	Same as case 1 with Vales point/Gladstone/Yallourn (examples only) closing 5 years earlier – no 2IC
9	Coal closes earlier with 2IC/North west Wind/PHES	Same as case 8 with 1000 MW of wind in North West/ Pumped hydro developed (i.e. 600 MW – Cethana - $1.1M/MW)
10	Same as case 1 but more ambitious emissions targets	Same as Case 1 but increase emissions reduction target to 45 percent by 2030.
11	Same as case 10 with 2IC/North West Tas Wind and PHES	Same as Case 10 with 1000 MW of wind in North West/ Pumped hydro developed (i.e. 600 MW – Cethana - $1.1M/MW)

Table 3 Correlation of determination between wind farms on the NEM using 5-minute SCADA dispatch data from 2017. Grouped by wind regime (2018 total registered capacity shown). Red cells are strongly correlated, yellow loosely correlated, and green cells week

		Wind Farm Correlation to:																																		
Wind Farm Correlation from:	Registered Capacity (MW)	Musselroe	Studland Bay / Bluff Point	Bald Hills	Boco Rock	Gunning	Cullerin Range	Capital	Woodlawn	Taralga	Gullen Range	Cathedral Rocks	Clements Gap	Mt Millar	Starfish Hill	Hornsdale Stage 1	Wattle Point	North Brown Hill	Snowtown	Snowtown Stage 2 North	The Bluff	Waterloo	Hallett 1	Snowtown Stage 2 South	Hallett 2	Waubra	Yambuk	Challicum Hills	Mt Mercer	Lake Bonney Stage 3	Mortons Lane	Oaklands Hill	Lake Bonney Stage 2	Portland	Lake Bonney Stage 1	Macarthur	Weighted Average Correlation
Musselroe	168	1.00	0.20	0.16	0.04	0.05	0.07	0.11	0.11	0.11	0.09	0.00	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.08	0.01	0.04	0.05	0.03	0.03	0.05	0.10	0.04	0.04	0.09
Studland Bay / Bluff Point	140	0.20	1.00	0.32	0.08	0.10	0.11	0.12	0.13	0.13	0.13	0.00	0.01	0.01	0.01	0.00	0.01	0.00	0.01	0.01	0.02	0.02	0.01	0.01	0.01	0.10	0.18	0.07	0.15	0.14	0.16	0.16	0.12	0.18	0.12	0.15	0.13
Bald Hills	107	0.16	0.32	1.00	0.13	0.22	0.25	0.26	0.27	0.25	0.27	0.00	0.00	0.00	0.03	0.00	0.02	0.00	0.01	0.01	0.02	0.03	0.02	0.02	0.02	0.11	0.23	0.07	0.18	0.17	0.16	0.17	0.15	0.25	0.14	0.13	0.15
Boco Rock	113	0.04	0.08	0.13	1.00	0.19	0.17	0.24	0.24	0.33	0.29	0.02	0.01	0.03	0.05	0.01	0.05	0.03	0.02	0.04	0.08	0.09	0.06	0.04	0.07	0.11	0.13	0.13	0.17	0.12	0.15	0.16	0.11	0.13	0.12	0.13	0.14
Gunning	47	0.05	0.10	0.22	0.19	1.00	0.81	0.56	0.60	0.52	0.76	0.02	0.05	0.02	0.09	0.03	0.05	0.05	0.05	0.04	0.06	0.10	0.07	0.07	0.09	0.09	0.11	0.09	0.12	0.11	0.12	0.13	0.11	0.14	0.10	0.10	0.17
Cullerin Range	30	0.07	0.11	0.25	0.17	0.81	1.00	0.67	0.70	0.55	0.75	0.02	0.04	0.01	0.07	0.02	0.04	0.04	0.04	0.04	0.05	0.09	0.06	0.06	0.07	0.09	0.11	0.08	0.11	0.11	0.12	0.13	0.11	0.13	0.10	0.10	0.18
Capital	140	0.11	0.12	0.26	0.24	0.56	0.67	1.00	0.83	0.59	0.65	0.01	0.02	0.01	0.07	0.01	0.04	0.02	0.03	0.04	0.07	0.08	0.05	0.05	0.07	0.09	0.14	0.09	0.14	0.13	0.13	0.15	0.13	0.16	0.13	0.11	0.19
Woodlawn	48	0.11	0.13	0.27	0.24	0.60	0.70	0.83	1.00	0.65	0.70	0.01	0.02	0.02	0.06	0.01	0.04	0.03	0.03	0.04	0.08	0.10	0.06	0.05	0.08	0.09	0.16	0.10	0.16	0.14	0.15	0.16	0.14	0.18	0.14	0.13	0.20
Taralga	107	0.11	0.13	0.25	0.33	0.52	0.55	0.59	0.65	1.00	0.76	0.01	0.02	0.03	0.07	0.02	0.05	0.04	0.03	0.04	0.09	0.11	0.07	0.05	0.09	0.10	0.16	0.12	0.20	0.15	0.17	0.18	0.14	0.18	0.15	0.15	0.21
Gullen Range	166	0.09	0.13	0.27	0.29	0.76	0.75	0.65	0.70	0.76	1.00	0.02	0.04	0.03	0.10	0.03	0.06	0.05	0.05	0.05	0.09	0.13	0.09	0.07	0.11	0.11	0.16	0.12	0.19	0.16	0.17	0.18	0.15	0.19	0.16	0.15	0.22
Cathedral Rocks	66	0.00	0.00	0.00	0.02	0.02	0.02	0.01	0.01	0.01	0.02	1.00	0.13	0.13	0.20	0.17	0.16	0.21	0.16	0.11	0.15	0.21	0.22	0.17	0.21	0.03	0.04	0.05	0.06	0.14	0.06	0.07	0.14	0.08	0.13	0.07	0.11
Clements Gap	57	0.00	0.01	0.00	0.01	0.05	0.04	0.02	0.02	0.02	0.04	0.13	1.00	0.26	0.22	0.46	0.23	0.47	0.60	0.57	0.31	0.33	0.39	0.57	0.39	0.11	0.04	0.12	0.05	0.07	0.07	0.09	0.08	0.05	0.08	0.07	0.19
Mt Millar	70	0.00	0.01	0.00	0.03	0.02	0.01	0.01	0.02	0.03	0.03	0.13	0.26	1.00	0.26	0.25	0.37	0.29	0.41	0.46	0.30	0.26	0.29	0.42	0.30	0.16	0.10	0.21	0.14	0.13	0.17	0.18	0.15	0.11	0.17	0.19	0.19
Starfish Hill	35	0.00	0.01	0.03	0.05	0.09	0.07	0.07	0.06	0.07	0.10	0.20	0.22	0.26	1.00	0.21	0.44	0.26	0.29	0.28	0.27	0.28	0.26	0.30	0.27	0.14	0.11	0.19	0.13	0.28	0.18	0.20	0.29	0.19	0.30	0.22	0.19
Hornsdale Stage 1	102	0.01	0.00	0.00	0.01	0.03	0.02	0.01	0.01	0.02	0.03	0.17	0.46	0.25	0.21	1.00	0.20	0.77	0.44	0.38	0.46	0.47	0.65	0.43	0.58	0.10	0.04	0.11	0.07	0.09	0.07	0.09	0.09	0.06	0.09	0.08	0.20
Wattle Point	91	0.00	0.01	0.02	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.16	0.23	0.37	0.44	0.20	1.00	0.23	0.33	0.39	0.27	0.25	0.25	0.37	0.27	0.22	0.17	0.26	0.14	0.23	0.18	0.20	0.26	0.21	0.28	0.21	0.21
North Brown Hill	132	0.01	0.00	0.00	0.03	0.05	0.04	0.02	0.03	0.04	0.05	0.21	0.47	0.29	0.26	0.77	0.23	1.00	0.49	0.43	0.65	0.60	0.82	0.49	0.73	0.11	0.06	0.14	0.10	0.12	0.11	0.13	0.13	0.09	0.13	0.12	0.24
Snowtown	99	0.01	0.01	0.01	0.02	0.05	0.04	0.03	0.03	0.03	0.05	0.16	0.60	0.41	0.29	0.44	0.33	0.49	1.00	0.83	0.42	0.39	0.47	0.84	0.49	0.17	0.07	0.19	0.09	0.13	0.13	0.15	0.13	0.09	0.14	0.13	0.24
Snowtown Stage 2 North	144	0.00	0.01	0.01	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.11	0.57	0.46	0.28	0.38	0.39	0.43	0.83	1.00	0.47	0.37	0.44	0.84	0.46	0.21	0.10	0.24	0.13	0.14	0.16	0.19	0.15	0.11	0.17	0.17	0.26
The Bluff	53	0.00	0.02	0.02	0.08	0.06	0.05	0.07	0.08	0.09	0.09	0.15	0.31	0.30	0.27	0.46	0.27	0.65	0.42	0.47	1.00	0.59	0.71	0.48	0.70	0.14	0.13	0.22	0.21	0.22	0.21	0.22	0.22	0.17	0.23	0.23	0.26
Waterloo	131	0.00	0.02	0.03	0.09	0.10	0.09	0.08	0.10	0.11	0.13	0.21	0.33	0.26	0.28	0.47	0.25	0.60	0.39	0.37	0.59	1.00	0.66	0.47	0.70	0.13	0.12	0.20	0.20	0.21	0.20	0.21	0.21	0.18	0.21	0.20	0.26
Hallett 1	95	0.00	0.01	0.02	0.06	0.07	0.06	0.05	0.06	0.07	0.09	0.22	0.39	0.29	0.26	0.65	0.25	0.82	0.47	0.44	0.71	0.66	1.00	0.51	0.81	0.13	0.10	0.18	0.16	0.18	0.17	0.19	0.19	0.15	0.19	0.17	0.27
Snowtown Stage 2 South	126	0.00	0.01	0.02	0.04	0.07	0.06	0.05	0.05	0.05	0.07	0.17	0.57	0.42	0.30	0.43	0.37	0.49	0.84	0.84	0.48	0.47	0.51	1.00	0.54	0.20	0.10	0.24	0.14	0.17	0.17	0.20	0.18	0.14	0.18	0.18	0.27
Hallett 2	71	0.00	0.01	0.02	0.07	0.09	0.07	0.07	0.08	0.09	0.11	0.21	0.39	0.30	0.27	0.58	0.27	0.73	0.49	0.46	0.70	0.70	0.81	0.54	1.00	0.16	0.11	0.22	0.18	0.21	0.19	0.21	0.21	0.17	0.21	0.19	0.28
Waubra	192	0.01	0.10	0.11	0.11	0.09	0.09	0.09	0.09	0.10	0.11	0.03	0.11	0.16	0.14	0.10	0.22	0.11	0.17	0.21	0.14	0.13	0.13	0.20	0.16	1.00	0.29	0.61	0.37	0.21	0.33	0.41	0.23	0.23	0.25	0.30	0.22
Yambuk	30	0.08	0.18	0.23	0.13	0.11	0.11	0.14	0.16	0.16	0.16	0.04	0.04	0.10	0.11	0.04	0.17	0.06	0.07	0.10	0.13	0.12	0.10	0.10	0.11	0.29	1.00	0.28	0.34	0.41	0.40	0.39	0.42	0.59	0.43	0.44	0.23
Challicum Hills	53	0.01	0.07	0.07	0.13	0.09	0.08	0.09	0.10	0.12	0.12	0.05	0.12	0.21	0.19	0.11	0.26	0.14	0.19	0.24	0.22	0.20	0.18	0.24	0.22	0.61	0.28	1.00	0.51	0.27	0.47	0.52	0.29	0.28	0.31	0.47	0.26
Mt Mercer	131	0.04	0.15	0.18	0.17	0.12	0.11	0.14	0.16	0.20	0.19	0.06	0.05	0.14	0.13	0.07	0.14	0.10	0.09	0.13	0.21	0.20	0.16	0.14	0.18	0.37	0.34	0.51	1.00	0.37	0.57	0.54	0.37	0.42	0.38	0.54	0.27
Lake Bonney Stage 3	39	0.05	0.14	0.17	0.12	0.11	0.11	0.13	0.14	0.15	0.16	0.14	0.07	0.13	0.28	0.09	0.23	0.12	0.13	0.14	0.22	0.21	0.18	0.17	0.21	0.21	0.41	0.27	0.37	1.00	0.43	0.43	0.91	0.66	0.80	0.47	0.28
Mortons Lane	20	0.03	0.16	0.16	0.15	0.12	0.12	0.13	0.15	0.17	0.17	0.06	0.07	0.17	0.18	0.07	0.18	0.11	0.13	0.16	0.21	0.20	0.17	0.17	0.19	0.33	0.40	0.47	0.57	0.43	1.00	0.70	0.43	0.47	0.43	0.68	0.29
Oaklands Hill	67	0.03	0.16	0.17	0.16	0.13	0.13	0.15	0.16	0.18	0.18	0.07	0.09	0.18	0.20	0.09	0.20	0.13	0.15	0.19	0.22	0.21	0.19	0.20	0.21	0.41	0.39	0.52	0.54	0.43	0.70	1.00	0.44	0.44	0.45	0.58	0.29
Lake Bonney Stage 2	159	0.05	0.12	0.15	0.11	0.11	0.11	0.13	0.14	0.14	0.15	0.14	0.08	0.15	0.29	0.09	0.26	0.13	0.13	0.15	0.22	0.21	0.19	0.18	0.21	0.23	0.42	0.29	0.37	0.91	0.43	0.44	1.00	0.67	0.89	0.47	0.29
Portland	148	0.10	0.18	0.25	0.13	0.14	0.13	0.16	0.18	0.18	0.19	0.08	0.05	0.11	0.19	0.06	0.21	0.09	0.09	0.11	0.17	0.18	0.15	0.14	0.17	0.23	0.59	0.28	0.42	0.66	0.47	0.44	0.67	1.00	0.63	0.53	0.29
Lake Bonney Stage 1	81	0.04	0.12	0.14	0.12	0.10	0.10	0.13	0.14	0.15	0.16	0.13	0.08	0.17	0.30	0.09	0.28	0.13	0.14	0.17	0.23	0.21	0.19	0.18	0.21	0.25	0.43	0.31	0.38	0.80	0.43	0.45	0.89	0.63	1.00	0.49	0.29
Macarthur	420	0.04	0.15	0.13	0.13	0.10	0.10	0.11	0.13	0.15	0.15	0.07	0.07	0.19	0.22	0.08	0.21	0.12	0.13	0.17	0.23	0.20	0.17	0.18	0.19	0.30	0.44	0.47	0.54	0.47	0.68	0.58	0.47	0.53	0.49	1.00	0.32

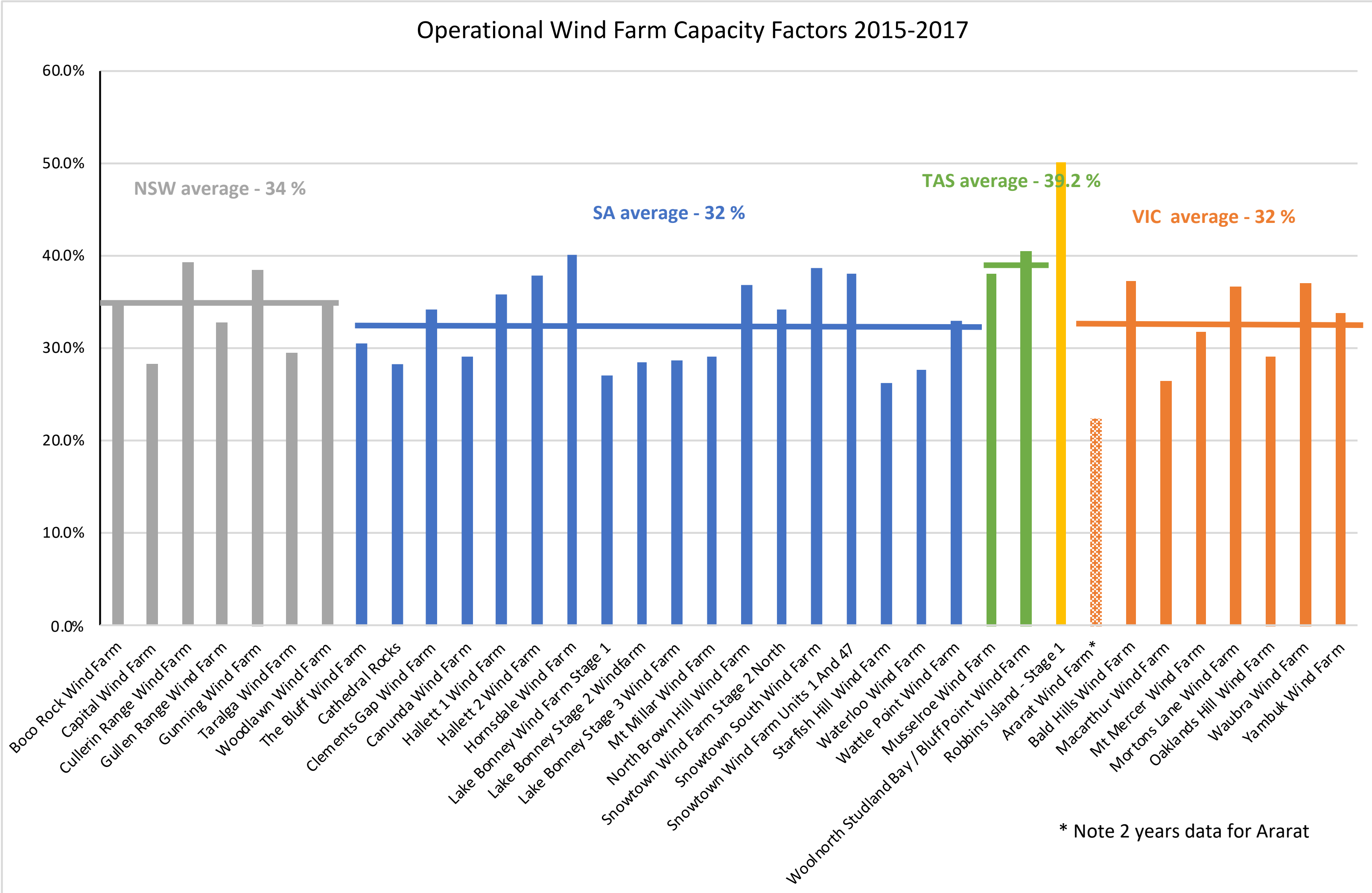

Figure 1 Historical capacity factors for 2015 -2017 for operating wind farms in the NEM

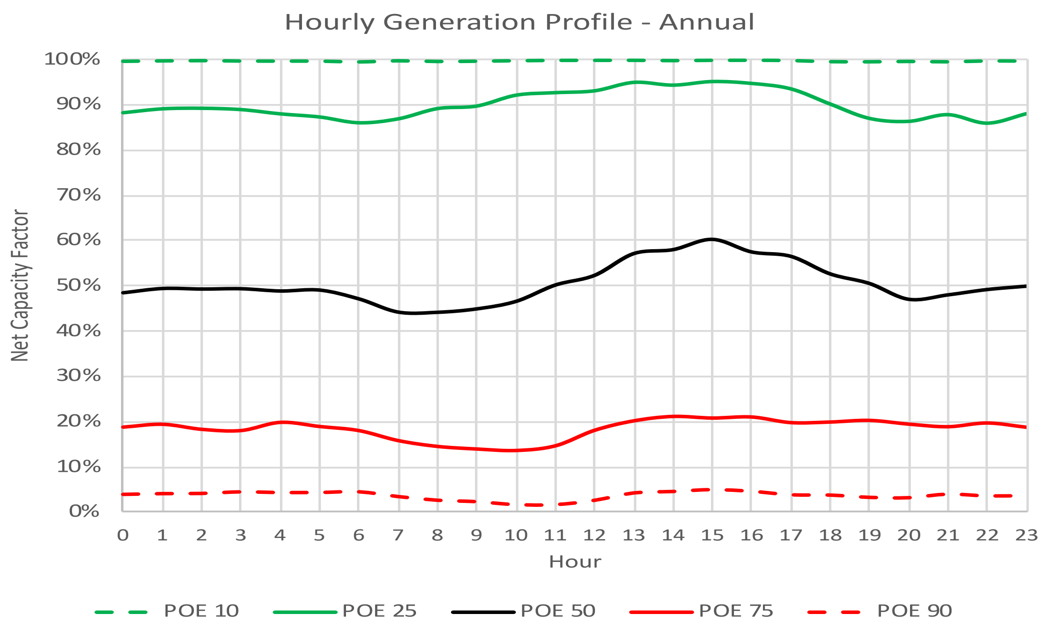

Figure 2 Robbins Island Stage 1 - Wind Generation Profile

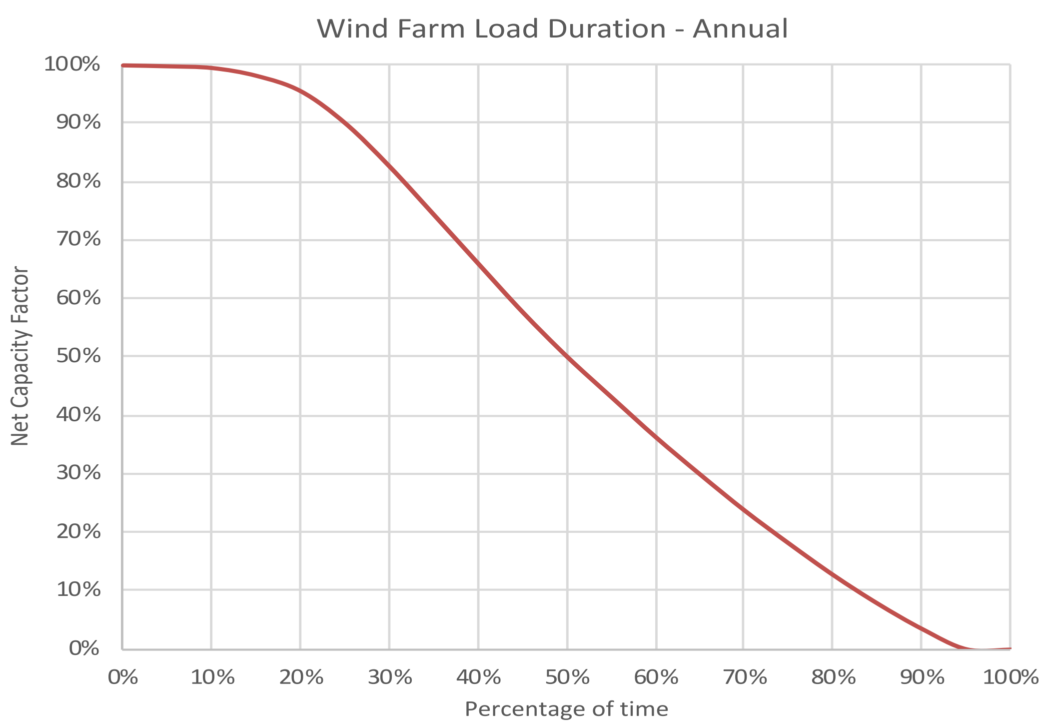

Figure 3 Robbins Island Stage 1 Annual Duration Curve