Tasmanian Gas Pipeline

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Mr Geoff Willis
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Dear Mr Willis

REVIEW OF TASMANIA'S ENERGY SECURITY

On behalf of the Tasmanian Gas Pipeline (TGP), I would like to express our appreciation to the Taskforce and its Secretariat for allowing TGP to make a late submission to the Tasmanian Energy Security Taskforce.

Attached is a paper prepared by Value Adviser Associates (VAA), which outlines the Tasmanian Government's role in facilitating the entry of gas to Tasmania, a comparison of energy security options and VAA's views on the viability of a second interconnector.

I look forward to discussing TGP's submission in further detail when we meet on Wednesday 12 October 2016.

Yours sincerely

L.J. Ward.

Lindsay Ward
Chief Executive Officer

YOUR TRUSTED VALUE ADVISER

Tasmanian Gas Pipeline

Supporting paper for Energy Security Taskforce submission

27 September 2016

Tasmanian
Gas Pipeline

Qualification

This report has been prepared for Tasmanian Gas Pipeline Pty Ltd on the understanding that it would be made public. However, in no event shall Value Adviser Associates Pty Ltd assume any responsibility to any third party that accesses the report or any other information that is disclosed, whether or not consent has been provided.

VAA has acted independently in preparing this report. VAA is being remunerated on the basis of time spent and no part of the fee is contingent upon the contents, the conclusions reached or the future use of this report. Value Adviser Associates has no conflict of interest in relation to the work undertaken.

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Executive summary

Tasmania has maintained thermal generation assets for the purposes of energy security for over four decades. Initially the Bell Bay Power Station (BBPS) played the key role in providing energy security.

Energy supply in the State changed fundamentally from 2001, with the entry of gas via the Tasmanian Gas Pipeline, development of the Basslink interconnector and restructuring the electricity supply industry to establish a market structure as a region of the National Electricity Market (NEM).

Gas was at the core of this energy reform framework.

Throughout this process, the State Government played a key role in facilitating and supporting the development of the gas assets. There were several detailed studies from a whole-of-state perspective on the impact of Basslink and introducing natural gas, which found that the combination of gas and Basslink were in the best interests of Tasmania.

Subsequently, the Tamar Valley Power Station (TVPS) was developed as a greenfield project to compete with Hydro Tasmania, rather than the original intention that the BBPS assets, once repowered, would fulfil this role. However, the TVPS was acquired and completed by the State, through Aurora Energy, in response to deteriorating hydrological conditions and low storages.

The TVPS is now owned by Hydro Tasmania, which sought to decommission and sell the combined cycle gas turbine (CCGT) unit, until the assets were required to perform a critical role in recovering from the energy supply situation that developed with record low inflows and Basslink's outage in late 2015.

The Government has stated that the potential sale of the CCGT has been withdrawn. However, in the absence of any long-term plans for the TVPS gas generation assets, the owners of the Tasmanian Gas Pipeline and major industrial energy consumers are concerned with the lack of information on the future of the TVPS, which cannot serve any purpose unless a new gas transportation agreement (GTA) for the TGP is executed.

If the TGP's keystone contract — which was originally facilitated by the State and is now used to service the TVPS — is allowed to lapse, material increases in delivered gas prices may occur. This would jeopardise investments in existing and future infrastructure made by commercial and industrial customers, small businesses and households associated with gas.

In considering future energy security arrangements, the performance of Basslink is important. Given the recent submarine cable fault and international benchmarking, it is reasonable to assume that a Basslink cable fault is a credible future scenario and, given the long repair times, it can also be concluded that Basslink cannot always be relied upon to provide energy security for Tasmania and its consumer base.

Other options for providing energy security include:

- increasing on-island generation, eg:
    - building new large-scale generation capacity (most likely several wind farms, possibly with some medium scale solar farms)
    - ensuring that the CCGT operates and is supported by a new GTA
    - embedded and small-scale renewable energy;
- energy efficiency;
- demand side management;
- raising the hydro storage targets; and
- a second interconnector.

Hydro Tasmania is now aiming to maintain storage levels at 40 per cent of the full storage level in coming months, and targeting 30 per cent by 30 June 2017, which is higher than the targets in previous years.

Raising the storage targets effectively builds a larger energy security buffer for low inflow periods. At face value this appears to be a straightforward option to improve energy security. However, this has a significant opportunity cost in lost trading opportunities — including both energy sales and large renewable generation certificates (LGCs) — and the increased risk of storages spilling.

The need to maintain larger buffers can be mitigated by operating the CCGT for part of each year and as supplementary generation to rebuild storages during low inflow periods.

If it is accepted that increasing Tasmania's on-island supply is the preferred route to enhancing energy security, development of new renewables projects, particularly wind, is an important option.

Wind generation is intermittent and non-synchronous, which results in well-known drawbacks, including a lack of inertia that is required to maintain frequency in the power system and inability to contribute to fault levels. These issues are exacerbated by the technical characteristics of Basslink.

Tasmania's transmission network has inherent network constraints as it is essentially radial and connects remotely-located generators to a range of dispersed load centres, and lacks the benefits of fully meshed networks typically found in other jurisdictions. The network is also operated at the limits of design and capability in meeting Tasmanian demand and, when relevant, Basslink exports. There is very little scope for new, unconstrained generation to be connected without further significant investment in the Tasmanian transmission network.

As a result, apart from the Cattle Hill Wind Farm, which is the most likely project to proceed and located in a strong part of the transmission network, major new wind farms will face significant barriers to development, including reliability, performance standards and likely requirements for substantial augmentation of the transmission network.

VAA has modelled the long run marginal cost (LRMC) of a new wind farm in Tasmania using Monte Carlo modelling. The resulting mid-point LRMC is $89/MWh, which <u>excludes the cost impact of the technical issues and cost of likely network augmentations</u>.

The national Renewable Energy Target scheme provides the necessary revenue support for wind farms to proceed. Despite the potential revenue streams under that mandated scheme, there are still commercial barriers that developers must overcome. These include securing power purchasing agreements if the developer prefers a lower risk option. Alternatively, a higher risk option is taking a degree of merchant risk, in which case the correlation of wind generation output at different sites may depress the spot price and hence revenue received by any wind farm owners taking merchant risk.

The variability in wind generation undermines its value as an energy security option, as it cannot provide predictable and timely supplies in a forward looking process. Accordingly, a strong conservative bias would need to be applied, which implies that for a given level of incremental supply at certain times of the year, a degree of overbuilding would be required, which is inefficient and has consequences that include inefficient investment in generation and network assets, lower market prices and returns to government and increased reliance on renewable energy certificates rather than energy wholesaling and retailing to drive Hydro Tasmania's revenue.

A second interconnector faces many of the same challenges as major new wind farms. In particular, significant network augmentations will be required to allow increased power flows, while additions and/or modifications to the existing complex system protection schemes will be required. To maximise power transfers across the second interconnector, additional load and generation interruptibility contracts will need to be established with existing Tasmanian major Industrial customers (MIs) and generators respectively. For the MIs this potentially doubles their risk exposure to curtailed production.

It is also premised that these MIs will be still operating in 40 years' time (based on the economic life of the interconnector assets). If any of the MIs leave the State then there may be a risk of stranding the second interconnector or having its flows significantly constrained.

Maintaining and operating the CCGT is a key energy security option, which is currently available and does not face any of the network or technical challenges of other options.

The total cost of maintaining the CCGT in an operational state is $12 million. It is estimated that it would cost $72/MWh to produce 550 GWh and $67/MWh to produce 700 GWh. Allowing for potential revenue, the effective energy security insurance premium is estimated to be between $4 million and $6 million per annum, which is well below the cost of other options.

When compared against alternatives, it is clear that gas-fired generation, utilising the existing CCGT at TVPS, should be a core element of Tasmania's future energy mix and the preferred option for energy security.

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Tables and Figures

1. Background

This paper has been prepared as an addendum to the submission provided by Tasmanian Gas Pipeline Pty Ltd (TGP Pty Ltd) to the Tasmanian Energy Security Taskforce.

The paper presents Value Adviser Associates' views on the role of gas in Tasmania's energy mix from a historical perspective and, looking forward, how it should contribute to meeting Tasmania's future energy security needs.

Specific focus areas include:

- the State's role in developing the Tasmanian Gas Pipeline;
- the energy security background to thermal generation in Tasmania;
- the economic role of gas in Tasmania;
- the costs and effective insurance premium of the Tamar Valley Power Station; and
- an assessment of options to address Tasmania's energy security challenges, including major new wind farms and a second interconnector.

2. State's role in facilitating gas and thermal generation

2.1 Bell Bay Power Station

Tasmania has maintained thermal generation assets for the purposes of energy security for over four decades.

In 1967-68, a sustained drought and declines in the hydro storages led to power rationing for major industrial customers (that had been attracted to Tasmania by the hydro-industrialisation strategy), commercial retail customers and eventually households. In March 1968, storages fell to 14.3 per cent of the full supply level, and electricity supplies were supplemented by oil-fired generation on ships in the Tamar River.

As a result, the Hydro-Electric Commission developed the Bell Bay Power Station (BBPS), which comprised two 120 MW units that were commissioned from 1971.

Development of the BBPS recognised that the hydrological conditions were highly variable, and that thermal generation provided energy security during periods when the hydro storages were depleted by below-average inflows.

As it operated on heavy fuel oil that led to a very high marginal cost and inflexible operating profile, the BBPS operated at high capacity factors for sustained periods. In effect, it provided capacity that could be brought into production as required rather than a regular generation source thus serving its primary purpose of energy security.

2.2 Gas and energy reform

Energy supply in the State changed fundamentally from 2001, with the entry of gas via the Tasmanian Gas Pipeline, development of the Basslink interconnector and restructuring the electricity supply industry to establish a market structure as a region of the National Electricity Market (NEM).

The TGP and BBBPS were at the core of the energy reform agenda through formal agreements and commitments, particularly:

- a heads of agreement between Duke and Hydro Tasmania, which was a part of the broader development agreement in April 2001 for the Tasmanian Natural Gas Pipeline; and
- Tasmania's NEM entry arrangements, including commitments on market structure and transitional arrangements that were made to the Australian Competition and Consumer Commission (ACCC) and finalised in November 2001.

Specific aspects of the intertwined commercial and policy frameworks included:

- separation of the BBPS into a new entity to compete with Hydro Tasmania in the wholesale market;
- a joint venture heads of agreement between Duke and Hydro Tasmania to repower BBPS Unit 2 to a combined cycle plant with capacity around 220 MW. This agreement would have been novated to the new independent business;
- Duke converted Unit 1 of the BBPS to gas in 2003, and Hydro Tasmania undertook a similar, but less extensive, conversion of unit 2 in 2004, ahead of the anticipated joint venture; and
- a take-or-pay pipeline capacity agreement that provided long-run revenue certainty for TGP and price certainty for the joint venture to operate the CCGT.

This framework was integral to Tasmania's National Electricity Market entry arrangements and commitments to the ACCC, including that Aurora Energy would source between 10 and 25 per cent of the load required to support non-contestable customers from a party other than Hydro Tasmania.

Further, there were several detailed studies from a whole-of-state perspective on the impact of Basslink and introducing natural gas. The nascent gas sector was an important factor in the Government's consideration of the Basslink business case. At a critical time in the decision-making process, and as the Basslink business case deteriorated, PricewaterhouseCoopers undertook detailed analysis for Tasmanian Treasury in May 2002, which considered the respective benefits of gas and Basslink, particularly the impact of Basslink on returns to Government, the risk to the State should Basslink proceed under scenarios with and without the TGP and gas-generation assets, and other commercial issues. (ESI Expert Panel, 2011)

A key finding in that study --- which has certainly been the actual experience — was that State Government was not in a strong position to influence or control the key financial risks arising from Basslink, particularly pricing in the national market and hydrology. By that stage, Duke Energy was already committed to the TGP, and the study was critical to the State Government supporting Hydro Tasmania's decision to proceed with Basslink.

The BBPS assets were decommissioned in 2009.

2.3 Tamar Valley Power Station

The TVPS incorporates:

- a 208 MW Mitsubishi combined cycle gas turbine (CCGT), comprising a 144 MW OCGT coupled with a 60 MW steam turbine[1]. A water treatment plant, cooling tower and the steam boiler also form part of the CCGT infrastructure;
- a 58 MW Rolls-Royce Trent 60 WLE OCGT. While this was a brand new engine, it was an early prototype of the engines used in the A380 Airbus and was therefore purchased at a discounted price; and
- three Pratt & Whitney FT8s OCGTs, which were originally rated at 35 MW each when they acquired by Hydro Tasmania in 2006, and were subsequently upgraded to 40 MW as part of the TVPS development.

Total capacity is 386 MW.

This configuration allows the station to provide base load and peaking generation, with the latter also fulfilling a role of providing back-up to the CCGT for planned and unplanned outages.

The history of the TVPS is well-known in Tasmania and was addressed in depth in the ESI Expert Panel's review. The discussion in this section focuses on the drivers for its development rather than the detail of the various transactions that led to the current ownership.

The second hand 35 MW Pratt & Whitney FT8s OCGTs were acquired in August 2005 to provide energy security. As Basslink had been delayed and inflows were below average for the eighth successive year, there were concerns that there was insufficient energy in storage if further unexpected delays were experienced. In effect, an insurance premium of $37 million was being paid by the State's instrumentalities without any cost recovery from customers.[2]

Earlier, Alinta had acquired Duke Energy International's Australian assets in April 2004. After multi-party negotiations around the model to establish a new competing business — particularly the Tasmanian Government, the independent Bell Bay Power board and Aurora Energy — it made a commercial decision to proceed with the greenfield development of the

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[1] As there is no steam bypass capacity in the configuration of the turbines, independent operation of the OCGT is not possible

[2] These assets were later incorporated in the TVPS when the BBPS site was sold to Alinta in 2007.

TVPS in October 2006. Its investment was backed by a hedge agreement with the State-owned Aurora Energy, which met regulatory commitments rather than a commercial imperative for new capacity.

Indeed, Alinta's commercial decision led to a significant increase in the on-island generation capacity relative to the originally envisaged agreements. Alinta's total investment would have been $480 million had the greenfield project been completed by its successor, Babcock & Brown Power (B&B Power), whereas the model envisaged in the Heads of Agreement between Duke Energy and Hydro Tasmania would have involved a much smaller investment and less complex business model to repower one of the BBPS thermal units.

Even though the purchase of the three FT8 OCGTs reflected concerns over energy security, the prominence of the issue in the eyes of the public did not increase until mid 2007.

In July and August that year, storages were around 17 per cent and falling. BBPS was out of service, and only Basslink and the Woolnorth Wind Farm were operating in support.

In August 2007, shortly after construction of the TVPS had commenced, Babcock & Brown acquired Alinta but the financial strength of its investment vehicles was being severely eroded by the Global Financial Crisis. In a short period, Babcock & Brown Power had insufficient funding to complete the construction of TVPS. As a result, the State (with the consent of Parliament) acquired the project for $100 million and committed the necessary $260 million to its completion in order to maintain energy security.

Once the CCGT was commissioned under Aurora Energy's ownership, its operating profile was dictated by:

- the wholesale gas supply and pipeline contracts that Aurora acquired in a separate transaction from B&B Power. These contracts were effectively the same ones that were agreed in 2001 to underpin development of the TGP and create the independent Bell Bay generation business; and
- a hedge contract with Hydro Tasmania, which was an internal portfolio transaction facilitated by the Government to mitigate Aurora's financial exposures resulting from its ownership of the TVPS.

This background shows that:

- the State's gas generation assets, and the earlier oil-fired thermal assets, have always involved non-commercial drivers, particularly energy security and establishing a market structure that was intended to facilitate competition in the wholesale and retail markets;
- the Government was closely involved in the TGP and its role in establishing a new market structure for energy in Tasmania. This goes well beyond the traditional model of gas pipelines being developed to facilitate market access for upstream gas suppliers or competition between different heating and generation fuels; and
- as the State had such a significant role in overseeing the projects that allowed Tasmania to enter the national electricity and gas markets within a short timeframe, it would be inappropriate for the current State Government to allow any of the same assets to become stranded through a focus on the publicly-owned power assets and Basslink.

The Government has stated that the CCGT will not be sold. However, we are not aware of any long-term plans for the TVPS gas generation assets, and also note that the Tasmanian Minerals and Energy Council has raised concerns with the lack of information on the future of the TVPS.

This lack of clarity is particularly important for the TGP. If the Government is committed to retaining ownership of the TVPS — including the CCGT and various OCGT units — then they cannot serve any purpose without access to gas. In other words, if the TVPS is to be retained, a pipeline capacity agreement should be secured, with appropriate flexibility, to support its ongoing availability beyond the expiry of the current agreement in December 2017.

3. Gas transportation agreement

There is clearly a delicate balance that needs to be found in future pricing for the TGP, which incorporates:

- sufficient throughput and pricing so that its owners are able to earn a commercial return;
- competitive and stable prices so that the economic value of gas in Tasmania is preserved;
- ensuring that major industrials remain competitive and preserve jobs; and
- long-term certainty that the TGP is available to provide energy security.

In our discussions with TGP and perusal of confidential material, VAA believes that the company is cognisant of its obligations to find this balance.

However, as a statement of principle, if the TGP's keystone contract — which was originally facilitated by the State and is now used to service the TVPS — is allowed to lapse, material increases in delivered gas prices for other customers is likely to occur.

This would jeopardise investments in existing and future infrastructure made by commercial and industrial customers, small businesses and households associated with gas.

Further, any material price rises may in the medium to long run:

- undermine the future viability of some of Tasmania's largest employers that are exposed to global commodity markets;
- add to the cost pressures and increasing import competition faced by manufacturers; and
- impact on the growth in tourism as many hotels are (when connected to the Tas Gas distribution network) significant gas consumers.

The impacts would spread through local communities given multiplier effects associated with reduced sales to suppliers and lower spending by employees and contractors.

Importantly, it is difficult to substitute gas for other energy sources. For instance, Hydro Tasmania's recent experience in responding to the energy supply situation demonstrates the difficulties in using diesel as a direct energy supply given the costs of capital, fuel and supply chain. However, some industrial processes could substitute other energy sources (including diesel, heavy oils and coal) that have higher carbon emissions profiles, and would work against State and Australian government emissions policies without an explicit price on carbon.

4. Context of energy security

VAA notes that the Taskforce is yet to define energy security. It is important that it finds an alignment between the community's understanding and a technical definition.

For the purposes of this paper, VAA considers that energy security means:

- energy suppliers and network service providers are able to meet the needs of people, employers and other consumers for energy services; and
- the community has adequate physical energy such that normal activities are not disrupted, and has confidence that adequate supplies can be maintained into the future.

While this definition does not include the cost of providing energy security, the community would expect that this is provided at the lowest sustainable net cost.

In Tasmania's case, the hydro-electric system is energy-constrained due to the impact of hydrological conditions, rather than capacity-constrained which is more common in other markets. Notwithstanding serious threats to energy security over the past decade, the energy constraints have been mitigated for over four decades by thermal generation and, in the last decade, through Basslink and the development of wind farms at Woolnorth and Musselroe.

The experience from Spring 2015 to Autumn 2016 shows that removing a key risk mitigant — the CCGT's thermal generation capacity — increased the reliance on Basslink and intermittent generation. which significantly increased energy security risks beyond levels acceptable to the community.

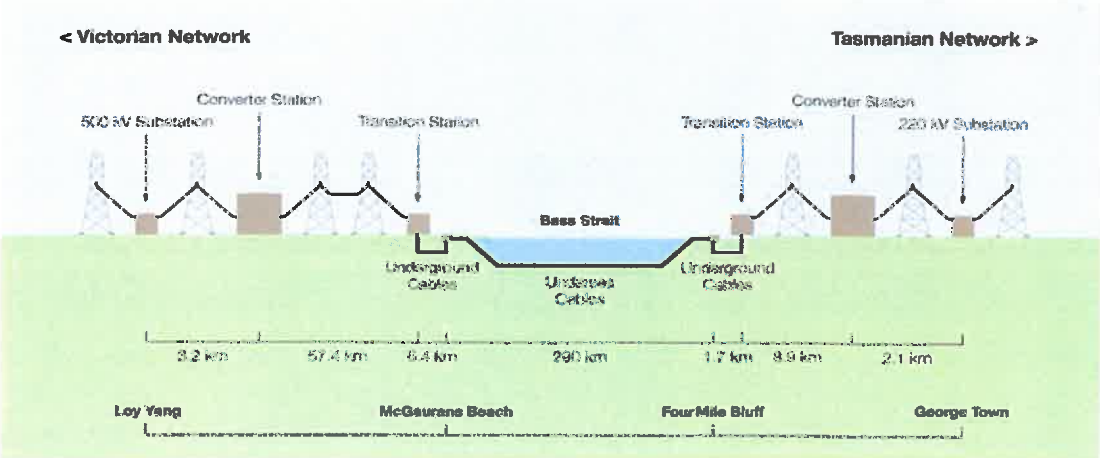
4.1 Basslink reliability

4.1.1 Basslink assets

Basslink was installed in 2006 and is an HVDC transmission line between George Town Substation in the north of Tasmania and Loy Yang power station in Victoria. Basslink is designed to export (Tasmania to Victoria) up to 630MW and import (Victoria to Tasmania) up to 480MW.

Basslink comprises approximately 290 kms of submarine cable, 9 kms of underground cable, 2 transition stations, 2 converter stations and approximately 70 kms of overhead transmission lines, as shown in Figure 1.

Figure 1: Basslink schematic diagram



It is clear that when talking about reliability or availability of Basslink it is important to take into account the exposure of other circuit elements that can contribute to Basslink operational performance and not just the submarine cable itself.

4.1.2 Associated System Protection Schemes

The extent of Basslink's power transfer capability relies significantly on system protection schemes (SPS). Without these schemes, significant investment and augmentation to the transmission network in Tasmania would be required to allow the present Basslink transfer capability.

The SPS comprises two separate protection schemes which mitigate issues which would otherwise occur following the loss of Basslink. These schemes are the:

- Frequency Control System Protection Scheme (FCSPS) that ensures power system frequency remains within frequency operating standards; and
- Network Control System Protection Scheme (NCSPS) that prevents transmission line overloads when Basslink is exporting.

To maximise Basslink's transfer capacity for exporting power across Bass Strait, 17 of TasNetworks' backbone transmission circuits have to be operated at levels approaching their thermal limits and would quickly exceed their design temperatures in the event of a fault on one of these circuits. (Normal operation for double circuit transmission lines is to load them to 50 per cent of their design limits so that if a contingent event occurs the adjacent circuit can take the full load without the need to trip customer load).

If Basslink were to trip whilst on maximum power export, there will be a large generation and load imbalance equivalent of losing a 480 MW generator or a 630 MW load. To mitigate against a major disruption to all customers, a fast-acting SPS is required to maintain system security in Tasmania.

The SPS is a complex computer-based primary protection scheme that has a network wide influence design to deal with an unplanned outage on Basslink. In the event of a trip on Basslink, the SPS will either trip generation (when Basslink is exporting) or load (when Basslink is importing) to maintain the power frequency within the network frequency standards in order to ensure the Tasmanian power system remains in a secure state. Specific contracts are required with Hydro to trip generation (on Basslink export) and major industrial customers to trip load (on Basslink import).

The impact of continually operating TasNetworks backbone transmission circuits to their upper design rating limit will likely contribute to advanced aging of these assets resulting in higher frequencies of maintenance and an increased risk of failure over time. Any prolonged outages on these circuits will potentially constrain the import/export power flows across Basslink.

4.1.3 Basslink performance

Since Basslink was commissioned in 2006, there have been a total of 41[3] unplanned outages on Basslink. Except for the recent submarine failure, all other outages were attributable to the ancillary equipment (other assets) associated with the submarine cable.

Table 1 shows Basslink's performance[4] since it was commissioned in 2006.

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[3] Number of unplanned outages up until June 2015

[4] Summarised from the Tasmanian Energy Supply Industry Performance Reports compiled by the Office of the Tasmanian Energy Regulator

Table 1: Historical Basslink performance

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Basslink availability (%)	99.32	96.31	97.23	97.39	99.62	98.67	99.89	98.77	98.71
Minutes unavailable	2,175	19,468	14,543	13,974	1,197	6,990	578	6462	6,780
Total unplanned outages	9	5	7	5	1	3	5	4	2

Overall, Basslink's physical performance since it began operating commercially in April 2006, in terms of its availability, has generally been consistent with the targets set out in the Basslink Operating Agreement. Up until before the cable failure in December 2015, the unplanned outages did not have a material impact on the link's availability.

A survey[5] conducted by International Council on Large Electrical Systems (CIGRE) in 2005 on cable failures compiled from global utilities and cable manufacturers shows that for a similar HVDC submarine cable installations (220–500 kV), the average cable failure rate is 0.0346/year/100 circuit kms. In terms of Basslink this indicates that you could expect to have a cable failure once every 10 years (0.0346 x 3). On this basis the recent cable failure could be deemed a credible event that was likely to occur at some point and should have been factored into Tasmanian energy security risk management modelling by Hydro Tasmania.

The CIGRE data also reported that on average the repair time for the reported cable failures is approximately 60 days. The Basslink cable fault took 174 days to repair. The main issue with cable faults is that they take a considerable time to locate and repair and there is only a small number of vessels available that can transport large lengths of cable and undertake cable repairs. The repair vessels require calm weather conditions to undertake cable repairs and the variability of the weather conditions across Bass Strait would potentially impact on repair times.

One of the main objectives of submarine cable installations is to limit the number of cable joints, in order to lower the risk of potential cable stress points and poor workmanship. During the installation of Basslink, it is understood that there were difficulties experienced in the cable laying operation which resulted in a number additional cable joints having to be installed as a consequence. While Basslink has stated that the major failure in 2015 is unrelated to one of these joints, it is likely that overtime the cable may have a greater susceptibility to failure given the number of joints in the cable.

Given the recent submarine cable fault, it can be safely concluded that a Basslink cable fault with a potential duration of six months every ten years is credible and, given the long repair times, it can also be concluded that Basslink cannot always be relied upon to provide energy security for Tasmania and its consumer base.

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[5] CIGRE Working Group B1.10, Update of service experience of HV and submarine cable systems, April 2009

4.2 Energy security options

Given the credible risks of another Basslink failure within the next 10 years, it is necessary to consider other options for providing energy security.

These may include:

- increasing on-island generation, eg:
  - building new large-scale generation capacity (most likely several wind farms, possibly with some medium scale solar farms)
  - ensuring that the CCGT operates and is supported by a new GTA
  - embedded and small-scale renewable energy;
- energy efficiency;
- demand side management;
- raising the hydro storage targets; and
- a second interconnector.

Raising the storage targets effectively builds a larger buffer for low inflows periods and at face value appears to be a straightforward option to improve energy security.

However, this has a significant opportunity cost. While the extremely high inflows in mid-2016 have allowed storages to rebuild rapidly, maintaining storages at current levels results in lost trading opportunities — including both energy sales and large renewable generation certificates (LGCs) — and the increased risk of storages spilling in future years.

The need to maintain larger buffers can be mitigated by operating the CCGT for part of each year and as supplementary generation to rebuild storages during low inflows periods. This has been highlighted by the ACIL Allen modelling that has been provided by TGP to the Taskforce.

Further, the combination of increased hydro generation and CCGT production would displace interstate generators with higher emissions profiles, such as coal (if the exports were sustained) or OCGTs (if the exports were offered as peaking capacity).

These costs of maintaining higher storages must be explicitly costed on the same basis as other energy security options.

Given the complexity of modelling required for this option, it is not considered in depth in this paper, which instead focuses on increasing on-island supply through the TVPS and major new renewables, and a second interconnector.

VAA has a detailed understanding of utility-scale energy storage solutions through its work with a client in the sector. At this point in the technical and market development, storage solutions as a general rule do not deliver the revenue required from energy arbitrage, capacity-based risk management or network capacity tariffs savings to be feasible in their own right once incremental costs such as connections and regulatory costs are included. As the cost of storage improves, utility-scale storage may address some of the problems of intermittency; however, as energy storage merely separates the timing of energy production from its delivery to the market or consumption, it does not add to supply and therefore will make little contribution to energy security in Tasmania in the foreseeable future.

5. New wind farms

If it is accepted that increasing Tasmania's on-island supply is the preferred route to enhancing energy security, development of new major wind and solar farms is an important option.

While no solar farms are currently planned, VAA is aware of some potential projects that are under consideration at a very early stage. However, the requirements of suitable land area, excellent solar resource and close proximity to transmission networks suggests that there are only limited opportunities for solar to materially enhance energy security. Similarly, biomass generation and other mid-scale technologies are unlikely to achieve the required scale.

On the other hand, wind farms can provide the incremental scale needed for energy security.

It appears likely that Cattle Hill, which has an expected capacity of 144 MW and is located near Lake Echo, appears to be the most likely major wind farm project to progress. The smaller Low Head project (around 30 MW, near George Town) is also a possibility.

While the transmission network is currently operating at the limits of its design and capability, Cattle Hill benefits from being located in a strong part of the transmission network.

However, other major new wind farms will face significant barriers to development, including reliability, performance standards and likely requirements for deep entry to, or substantial augmentation of, the transmission network.

The impact of large-scale wind (non-synchronous generation) connected to Tasmania's power system needs careful consideration.

Since synchronous — hydro, thermal and open cycle gas turbines[6] — generators supply the Tasmanian power system with the bulk of its inertia and frequency control ancillary services (FCAS), their displacement would make these services less available.

Further displacement of synchronous generation — such as high wind conditions occurring across the State — could ultimately place constraints upon the level of wind that could be securely dispatched into the power system. In Tasmania this is exacerbated by the presence of Basslink which is similar to wind generation, in that it can cause large frequency dips when recovering from system faults.

These issues are discussed in the following sections, along with the economics of new wind farms and performance characteristics that affect their suitability as an energy security option.

5.1 Technical issues with wind generation

The following is an overview of the issues related to the integration of large-scale wind generation in Tasmania.

- **Inertia** — Synchronous generators spin at a constant speed that is directly proportional to the power system frequency. The rate at which frequency deviates following a loss of generation or load is influenced by the spinning mass of the generators remaining in the power system. The spinning mass is termed a generator's inertia. The greater the total

[6] OCGTs must be specifically equipped and registered with AEMO as synchronous generators, which allows them to operate as spinning reserve (ie. without producing electricity) in the ancillary services market. The Pratt & Whitney FT8s located at TVPS are registered for these services, but are dependent on remaining operational.

inertia in a power system, the more slowly frequency will deviate following a contingency event. Non-synchronous generators do not rotate at a constant speed (e.g. wind turbines). In the event of a contingency event, non-synchronous generators react differently to synchronous generation and some will cease generating altogether or reduce their output significantly. This is because the turbine blades are electronically and not mechanically connected to the electrical generator. The effect of this is that the electrical generator does not have the benefit of the inertia of the turbine blades. That is, they do not contribute to the inertia (or spinning mass) of a power system following a contingency event.

The lack of inertia leads to some difficulties that become more pronounced as wind generation becomes an increasingly larger proportion of the total generation mix within a power system. In effect the larger proportion of wind generation reduces the overall inertia of the power system and reduces its capability to deal with frequency changes due to contingency (fault) events such as large load changes or loss of significant generation.

- **Fault levels** — a power system having a high quantity of on-line synchronous generation and little non-synchronous generation connected, provide larger fault currents and are categorised as strong systems. Due to their design, synchronous generators will continue to operate during a fault and force electrical current to flow through the faulted part of the network. Having a high fault level ensures that fast acting protection schemes will operate and clear faulted network elements thereby making sure the power system remains stable and secure in response to network disturbances.

  Parts of the power system with non-synchronous generation which are distant from synchronous generation are more likely to provide limited contribution to fault levels. As mentioned above, in the event of a contingency event, non-synchronous generators react differently to synchronous generation and some will cease generating altogether or reduce their output significantly thereby not contributing to fault levels. Low system strength generally leads to increased volatility of network voltages during system normal and network disturbances because a system dominated with non-synchronous generators can't react to adjust system voltage or frequency. Low system strength (having low fault levels) can also compromise the correct operation of protection systems and result in the non-synchronous generation disconnecting during network events. These may potentially lead to wider disturbances on the network.

- **Reactive power** — current wind generators generally do not provide any reactive support to the power system. Most system loads require reactive power for their operations. Synchronous generators provide sufficient reactive support to accommodate the various type of loads being supplied by the power system. The larger proportion of wind generation connected to a power system increases the need for synchronous generators to be available either on line or in synchronous condenser mode. The use of shunt capacitors also provide reactive support to the power system. It is understood that wind generator technology is advancing and may well be able to provide reactive power but at this time it is not well advanced.

The displacement of conventional, centrally dispatched synchronous generation by intermittent, non-synchronous generation presents particular power system security challenges that are difficult to manage. This was highlighted with the recent experiences in South Australia.

5.2 Impact on Basslink operation

Basslink is Tasmania's only electricity interconnection to the NEM. Any new wind farm developments in Tasmania could constrain the energy production mix from Tasmanian based generators and hence the transfer capability across Basslink. Basslink requires a certain level of support from the power system in order to maintain its energy transfer. This has generally been provided by synchronous generation. The design and performance characteristics of renewable generation (notably wind) are such that they are not equivalent and cannot be directly substituted in place of synchronous generators.

Two characteristics which are relevant to the operation of Basslink and the Tasmanian power system more broadly, are the limited contribution of inertia and fault level coming from wind generation (as described above). Other aspects such as voltage and frequency control capability can also indirectly affect Basslink's ability to operate unconstrained.

The capacity of wind generation in Tasmania now exceeds 300 MW. Connecting this non-synchronous generation to the power system has provided the first insights into the types of new operational constraints that can result from the increased connection of non-synchronous generation to the power system. Modifications to frequency control ancillary services will need to be considered to maintain power system security. If mechanisms are not identified to ensure the dispatch of sufficient inertia and fault levels then further operating constraints may need to be imposed that potentially will limit the dispatch targets of Basslink and/or wind generation.

The loss of Basslink concurrently with any Tasmanian transmission line disturbance is deemed to be a credible contingency event during Basslink import into Tasmania. Therefore the FCAS requirements must be sourced within Tasmania (from local generation and contracted load) since Basslink cannot always transfer FCAS from the mainland. TVPS can provide or contribute to FCAS support whereas wind (and other forms of non-synchronous) generation cannot.

5.3 Tasmania's transmission network

Tasmania's transmission system was developed predominantly to connect remotely-located hydro generators to a range of dispersed load centres. The economics of providing transmission infrastructure between relatively small, geographically dispersed generators and relatively small load centres, has meant that large parts of the State are not strongly linked to the backbone transmission network. This has led inherent network constraints being present within the network.

Network constraints occur where the power flow through elements of the transmission network must be restricted to avoid exceeding a known technical limit on equipment connected in the network. Constraint equations are written and influence how a generator's or Basslink's dispatch targets should be reduced to avoid exceeding these technical limits. Constraint equations are contained within AEMO's automated National Electricity Market Dispatch Engine to ensure that the power system remains secure and that the available transmission capacity is maximised.

As part of NEM entry, all radial transmission lines connecting Hydro Tasmania's hydro generation to the network are presently 'grandfathered' as prescribed services under the National Electricity Rules (ie. deemed to be part of the shared network and paid by consumers not the generator). For all new generation connections (e.g. wind), the cost of connection is required to be funded by the new generation proponent. Dependent on its location in relation to the network, the cost for any new generation connection and the potential strengthening of the existing network to remove network constraints can be a major part of connection costs. For instance the 168 MW Musselroe windfarm required a new 38 km 110 kV transmission line to Derby Substation and a connection bay at the substation, which was funded by the windfarm proponent.

5.4 Network operation

The Tasmanian transmission system is essentially radial and designed to distribute power from remote hydro power stations to major load centres. As a result, it lacks the flexibility and full redundancy of fully meshed networks typically found in other jurisdictions and is already operated by TasNetworks at the limits of design and capability in meeting Tasmanian demand and, when relevant, Basslink exports.

Tasmania's transmission network is the only Network Service Provider in the NEM that fully operates all of its transmission lines in the network dynamically or real-time. This is achieved by having a number of strategically placed weather stations throughout the State that telemeter real-time meteorological data (ambient temperature, wind speed and cloud emissivity) which may allow the lines to be operated above their thermal design based on the cooling effect of the ambient conditions. This data is also used for managing thermal constraints on the network. By running the network dynamically in Tasmania it potentially has allowed an increase in operational transfers of up to 20 per cent. This has negated or deferred capital investment in the network for its current operating requirements.

With the use of special protection schemes, load and generation curtailment contracts, and operating the transmission network dynamically, maximum power flows are already achieved and realised to manage daily generation dispatch and load supply configurations that occur in Tasmania, as well as maximising Basslink transfers. There is very little scope for new generation to be connected without further significant investment in the Tasmanian transmission network.

Binding constraints occur if the actual power flow must be constrained, and violating constraints occur if the technical limit is exceeded. The map at Attachment A shows the prevalence of these constraints in the major elements of the Tasmanian transmission network in 2014-15.

At a regional level, the barriers to new development, which are well-known within Tasmanian industry circles, include:

- **North-west**: Potential need for a new 220 kV transmission line into Burnie Substation (eg. the potential Robbins Island windfarm project)
- **West coast**: New wind farm (eg Granville Harbour) may increase fault levels at Farrell, which would constrain dispatch of Reece hydro power station, and exacerbate binding thermal limits on the Farrell-Sheffield 220 kV transmission line particularly during high-inflow and high-wind conditions. Depending on the size of generation installed, augmentation of the 220 kV Farrell-Sheffield transmission lines may be required to increase the thermal limits and/or a new 220 kV transmission line into Burnie Substation may be required.
- **North-east**: With the 168 MW Musselroe Windfarm already connected to Derby Substation, the existing 110 kV transmission lines from Derby and Scottsdale substations will need to be significantly augmented or a new transmission line constructed, most likely into Norwood or George Town substations.
- **Central**: With the recent construction of the 220 kV Waddamana-Lindisfarne transmission lines and the 220 kV Waddamana Substation, this area has sufficient capacity for generation connections (noting that the proposed 144 MW Cattle Hill Windfarm is proposed to connect to Waddamana Substation). However, additional wind farms or other new generation in the area are likely to require significant augmentations for:
  - the Tarraleah to South 110 kV transmission network, which supports the 220 kV network and is already nearing capacity; and
  - the Palmerston-Sheffield and Hadspen-George Town 220 kV transmission lines that potentially will become constrained and require a higher thermal operating design limits.
- **South:** New generation connections south of Hobart will require either new transmission lines or augmentation to the existing 110 kV lines into Chapel St Substation. The Palmerston-Sheffield and Hadspen-George Town 220 kV transmission lines potentially will become constrained and require augmentation to a higher thermal operating design.

The map at Attachment A also shows the impact of new generation on the network and possible augmentations that may be required to overcome these issues.

In addition to the cost of connecting new generation to the transmission network, the strength and capacity of the existing backbone and shared network will need to be assessed for any specific generation development scenarios, which may raise further augmentation requirements.

While VAA is not in a position to undertake detailed costings for strengthening and/or augmenting the transmission network to facilitate new windfarm developments, a rule of thumb that can be applied is the cost of constructing a new transmission line could be up to $1m per km, dependent on its configuration and operating voltage. The cost for increasing the thermal limits of existing transmission lines could be up to $500,000 per km depending on the upgrade methodology used.

Importantly, the pre-feasibility study for the second interconnector noted that there is a mutual dependency between the prospective development of several major wind farms and a second interconnector. However, that study did not address the issues with the Tasmanian transmission network and the consequent cost of augmenting the network for these developments, as raised in this section.

5.5 Connection standards

The connection standards for new wind farms are under review by individual transmission network service providers (including TasNetworks) and AEMO to ensure that power system security and reliability standards can be adequately maintained as the penetration of intermittent generation and non-synchronous generation grows. VAA's assessment — which is supported by industry consultations in Tasmania and nationally — is that connection standards for intermittent generation technologies are likely to be strengthened, such that developers will need to pass higher hurdles and with tighter operating parameters than many of the minimum access standards currently defined in the National Electricity Rules.

For any new non-synchronous generation connected the standards need to be such that there is no impact or constraints on existing customers or generators. The potential impacts on FCAS and Network Support and Control Ancillary Service (NSCAS) are two examples where non-synchronous generation does nothing to support the operation of the network that ultimately will have negative cost impacts on consumers.

As part of this regime, new wind farms are treated as semi-dispatchable generators, which means that to manage system constraints, wind turbines can be constrained down (ie. generation output is below the output that they would be producing in the prevailing wind conditions). While this is not currently a material issue for Musselroe, it is likely to be an issue for new wind farms that do not contribute to fault levels and lie behind congested parts of the transmission network.[7]

Technological development will play an important role in overcoming these challenges, For instance, licence conditions for new wind farms in South Australia require Devars (mini-static VAR compensators that dynamically control network voltage at its coupling point) to assist the turbines' capacity to ride-through faults.

However, the currently available technologies place additional cost burdens on developers that may impact on feasibility. Further, they do not provide a full solution to the power system challenges, and accordingly do not necessarily mitigating the risk of new or upgraded transmission augmentations.

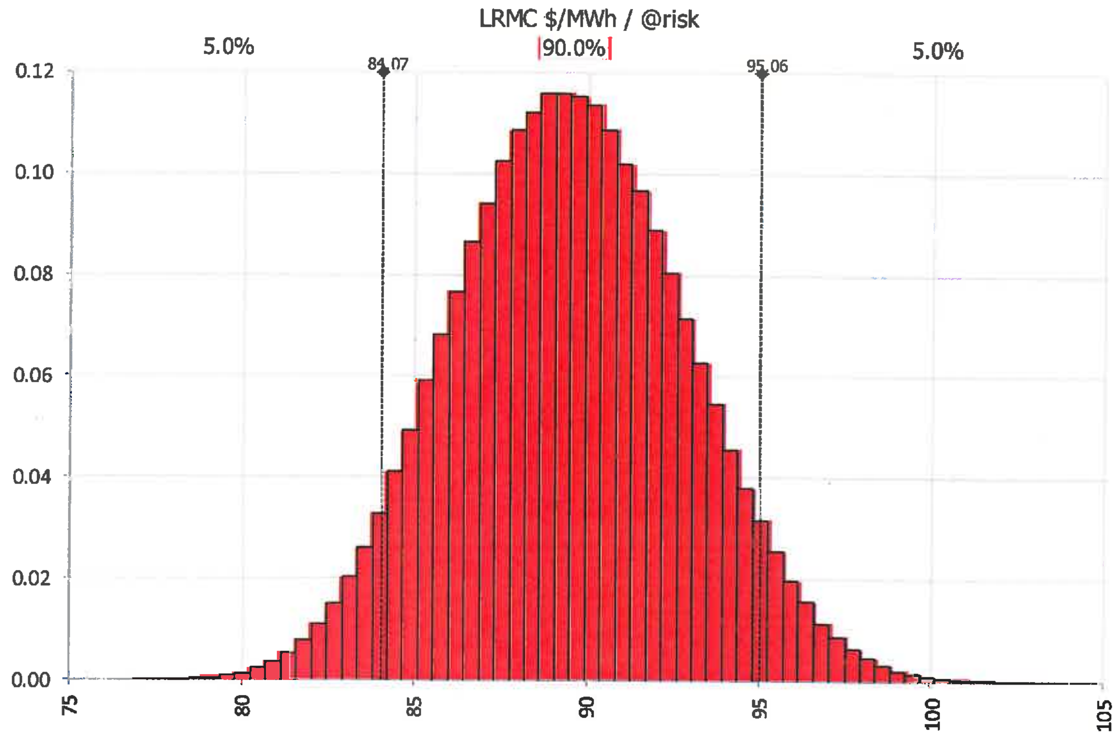
[7] Woolnorth has a grandfathered arrangement under which its output is automatically dispatched into the grid.

5.6 Economics of wind generation in Tasmania

The preceding discussion highlights the technical challenges that impede the development of major wind farms in Tasmania. This section considers the economic case for wind development in Tasmania.

VAA has modelled the long run marginal cost of a new wind farm in Tasmania, with a central case in its Monte Carlo modelling of $89/MWh. Modelling parameters are in Attachment B. The results are shown in Figure 2.

Figure 2: Monte Carlo modelling of Tasmanian wind farms costings(a)



(a) The cost of developing major wind farms is generally insensitive to the capacity of the wind farm. Capital costs are calculated on a per MW basis as sunk costs such as mobilisation are relatively small.

These results exclude the cost impact of the technical issues discussed earlier, including:

- higher connection standards, which may require higher capital expenditure on technical solutions such as Devars; and
- possible requirements for deep entry connections and/or network augmentations, depending on the wind farm location and impact on the transmission network.

These costings also reflect an assumption that the median capacity factor for a new wind farm in Tasmania is 38 per cent, within a range of 36 per cent to 40 per cent. This is consistent with the performance of the Woolnorth Wind Farms. However, it is higher than Musselroe Wind Farm, which has had an average capacity of 34 per cent in the 2014 and 2015 calendar years since it was commissioned in 2013.

From a financial perspective, most wind farms that have been developed in Australia to date have been supported by long-term offtake agreements (or power purchasing agreements, PPAs) that are a hedge against low prices and short-term price volatility, and accordingly provide financial certainty to investors.

While developing new wind farms is more expensive than operating the CCGT for the same amounts of energy, the price of LGCs has risen to over $80/MWh for the next few years and is then expected to settle in the mid $40s until the scheme closes in 2030. These prices would make new wind farms viable, in isolation of other factors.

However, it is often suggested that one of the barriers to developing renewables projects is the thin market for PPAs, as an increasing number of potential projects across the national market are competing with each other to reach agreements with market participants (particularly the major retailers that must remit the LGCs for their retail loads) that have little incentive to sign sufficient PPAs to deliver these projects.[8]

This is compounded by the Tasmanian market structure. While the LGCs can be sold to any party across the market, there are only a few natural counterparties (primarily Hydro Tasmania, Aurora Energy and ERM Power) for the energy output. As they all have their energy trading strategies largely locked-in, there may be limited opportunities for developers to secure PPAs.

An alternative strategy for developers is taking some degree of merchant risk, particularly exposure to the NEM spot market for the energy output.

However, as the penetration of renewable energy grows, the correlation of intermittent output from additional wind and solar farms — both within regions and between regions — will reduce the spot price received by spot-exposed generators relative to prices received by other generators when intermittent generation is lower.

This is evident in South Australia, as shown by recent analysis (McArdle, 2016) of Infigen's Lake Bonney Wind Farm, which has spot market exposures:

> This penalty is effectively paid by Infigen (in revenue forfeited) because their output is highly correlated with that of other wind farms across South Australia. All these wind farms, operating in tandem, are driving collective returns lower because they are all operating at the same time, and incapable of running when the wind's not blowing (without major investment in storage, for instance)...
>
> *Even if* the base-load futures prices for South Australia are increasing on the ASX, **Infigen may be at risk of *increasingly missing out*** on the full share of the benefits as the wind farms have been effectively creating their own sub-market in South Australia increasingly divorced from the 24×7x365 nature of flat contract prices across the year.

In other times, there will be more opportunities for flexible plant, including hydro and OCGTs, to provide the output required to meet the load at higher prices. This dynamic is contributing to the increasing price volatility in South Australia.

The spot price impact of adding several wind farms, as contemplated in the second interconnector pre-feasibility study, will be exacerbated in Tasmania during high inflow periods, as Hydro Tasmania's bidding will often be at very low prices to ensure its production from smaller storages is dispatched to avoid spilling.

There is also some risk that output from these hydro generators or wind farms would be constrained to preserve the safe operation of the transmission network.

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[8] VAA is not involved in any PPA negotiations for projects in Tasmania. A related business, Climate Capital, is in the early stages of developing a solar and wind farm project in South Australia.

In this environment, the lower risk option for developers is to seek PPAs that provide financial certainty. However, the perceived lack of appetite amongst retailers to execute PPAs and competition between developers — arguably compounded by the Tasmanian market structure — is a challenge. However, exposure to merchant risk presents different risks for wind farm owners.

If the CCGT operates over the summer period — when inflows are lower — instead of constructing new wind farms to provide the same energy output, there will be less market volatility and a more predictable operating environment.

5.7 Performance implications for energy security

The performance characteristics of wind farms affect their potential contribution to energy security, as well as their integration into complex energy systems and economic viability.

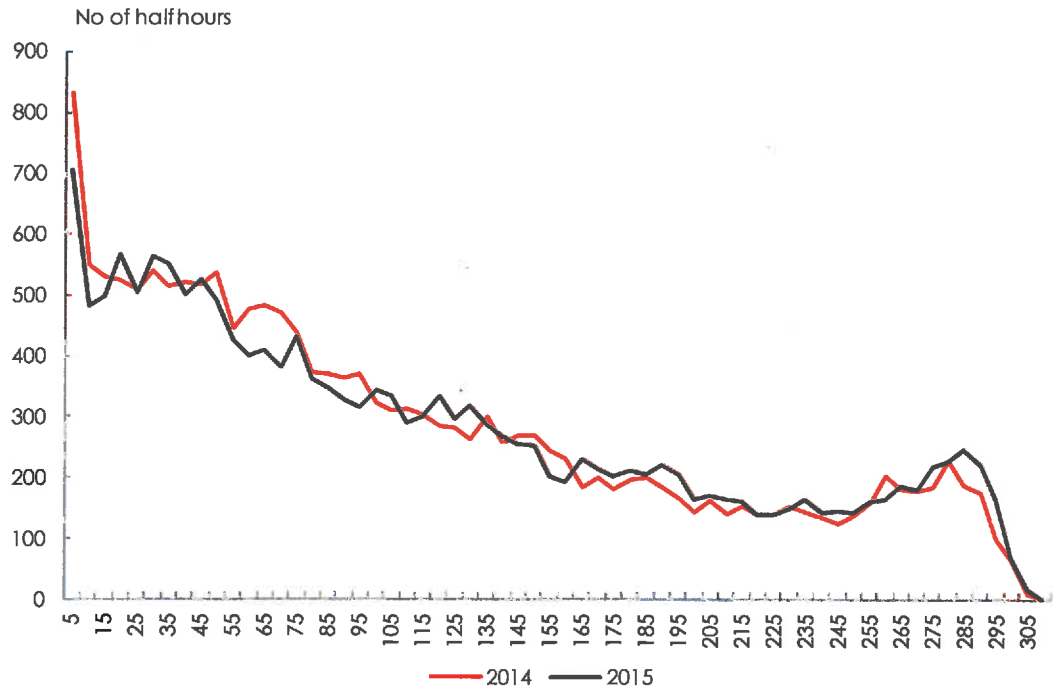
Tasmania's existing wind farms — Woolnorth Bluff Point, Woolnorth Studland Bay and Musselroe — have a total capacity of 310 MW.[9]

Between the period of analysis, from 1 January 2014 to 26 August 2016, the combined assets had:

- maximum output of 303 MW, ie. the assets never operated at full capacity concurrently;
- average output f of 114 MW, or a capacity factor of 36.9 per cent; and
- median output of 94 MW.

Figure 3 shows the distribution of total output, for each 30 minute trading interval, in 2014 and 2015.

Figure 3: Frequency of Tasmanian wind farm output levels (MW)



The two wind farms are highly correlated, ranging from 47.3 per cent in 2014 to 51.5 per cent in 2016, although the aggregated ramp rates (or changes in half hourly production) do not

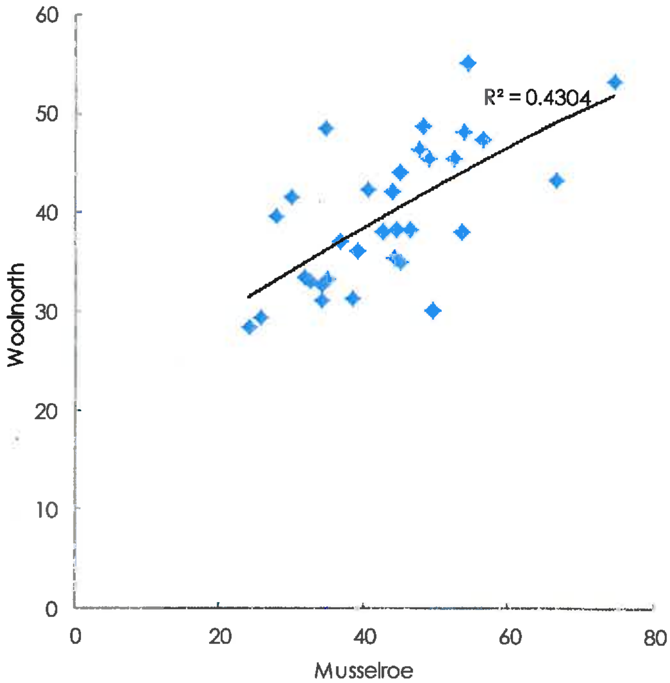
[9] For this analysis, the two Woolnorth wind farms are treated a single asset.

appear to significantly compound the intermittency effects presented by individual wind farms.

From a power system management perspective, additional wind farms are likely to increase the inertia and FCAS requirements across the whole Tasmanian market, although the required increases are unlikely to reflect the full capacity of the new wind farms. Alternatively, the new wind farms might lead to some turbines being constrained below their notional instantaneous output, such that expected levels of output are not available to support energy security.

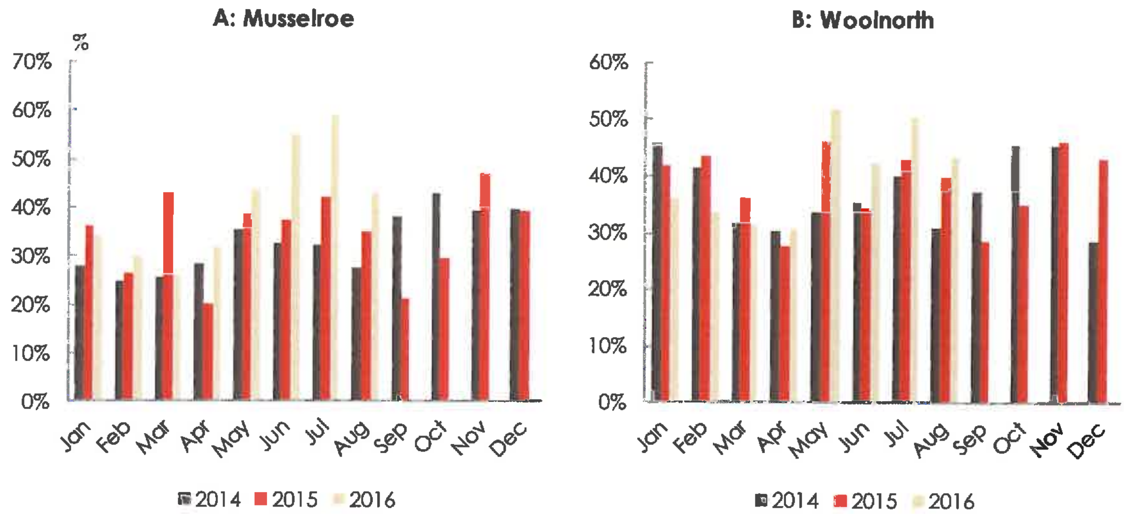
Despite the strong correlations at a 30 minute time period, over a longer time period there is little certainty that a high capacity factor for one wind farm implies a similar capacity factor for another. Figure 4 shows a general relationship between monthly wind farm output levels but it is also clear that this relationship is not strong.

Figure 4: Monthly output from Tasmania's wind farms (GWh)



Further, Figure 5 shows the disparity in capacity factors for any given month of the year. Notably, the capacity factor can vary by almost 100 per cent, as shown in the performance of Musselroe in June and July 2014 compared to the same months in 2016.

Figure 5: Monthly capacity factors for Tasmanian wind farms



While on-site wind data does not appear to be publicly available, it is intuitively obvious that this variability largely reflects the effect of different medium to long-term weather patterns, although there may be occasional issues with turbine availability that have a lesser impact on production.[10]

However, this is *ex post* analysis, whereas energy security is essentially an *ex ante* analytical exercise that incorporates current supply, projections of available supply and demand, and consideration of options to fill any potential shortfalls.

The past year demonstrated that there is clearly a large margin for error in this process.

The variability in intra-year wind generation has significant implications for the management of energy security. In particular, when looking forward, energy supplies must be predictable and timely, which cannot be achieved using wind generation. A strong conservative bias would need to be applied, which implies that for a given level of incremental supply as certain times of the year, a degree of overbuilding would be required.

By overbuilding capacity, some of the potential consequences include:
- an economically inefficient allocation of resources, including the State's capital;
- unnecessary over investment in network infrastructure, at the cost of Tasmanian consumers, project developers and/or PPA counterparties;
- artificially lower market prices;
- increased reliance on the LGCs to drive Hydro Tasmania's revenue; and
- lower returns to government.

[10] VAA is not aware of any constraints on turbine availability in mid 2014 that may have impacted on Mussleroe's production.

6. Second Interconnector

A second interconnector is currently being considered by the Australian Government's Tasmanian Energy Taskforce, now led by Dr John Tamblyn. This study will include detailed analysis of the power system and scope for integrating a second interconnector into the Tasmanian system, as well as the potential benefits to the National Electricity Market.

While there has been extensive discussion on the possible value drivers for a second interconnector — including additional energy export capacity, contributing to frequency control in the NEM as the penetration of renewables increases and coal-fired generators close, and increasing the import capacity to support energy security — VAA is not aware that a robust strategic analysis has been undertaken that identifies one or more specific problems that it would be addressing.

Given this, it may be possible to develop a business case that identifies a number of opportunities, without ever identifying whether the second interconnector is the best option to address any specific problem in the NEM. This approach is akin to picking winners, and could lead to a significant excess investment in electrical infrastructure or an unnecessary drain on any public funding (including direct government contributions or the Clean Energy Finance Corporation) that may be necessary for the project to be feasible.

VAA considers that it will be extremely difficult to justify a second interconnector if the full economic effects are incorporated, even allowing for the benefits of increasing the existing import capacity (up to 480 MW) when required by hydrological conditions.

For instance, a second interconnector will have significant impacts on existing asset owners that must be explicitly costed in an economic cost-benefit analysis. In addition to effectively stranding the TGP, if a second interconnector was to proceed as a regulated link, it will have significant impacts on the sources of value to both Hydro Tasmania and Basslink Pty Ltd that are contained in the current Basslink Services Agreement. As a result, it is likely that this agreement will need to be renegotiated and/or the existing interconnector will be converted to regulated status. Funding would be required to mitigate any financial impacts or loss of value on the existing asset, in addition to the development of the second interconnector.

If the key driver for the second interconnector is to export renewable power to mainland Australia, then further analysis needs to be considered on the impact on Tasmania's power system. The only renewable generation source that is plausible to supply at least an additional 500 MW[11] of non-synchronous generation is wind (and potentially a lesser contribution from solar).

Given the long gestation period experienced by wind farm developers in Tasmania (eg Cattle Hill wind farm is the most likely to proceed given its location and shallow entry to the network, but has been in deliberation for the last 10 years), there is a considerable issue whether developers would consider significant investments before the second interconnector is at least committed. The question then becomes who pays if it is justified as a regulated link under the current Regulated Investment Test for Transmission.

Consideration will also need to be given to how much strengthening would be required for the existing transmission network in Tasmania (and mainland) to remove the existing constraints and alleviate likely new constraints that reflect the significant increase in power flows with two interconnectors. Strengthening of the 220 kV network is likely to be significant.

[11] This is the minimum generation level to justify a second interconnector that was discussed in the pre-feasibility study.

Notwithstanding technological developments — such as voltage source converters that permit the transfer of ancillary services on high voltage direct current transmission assets — since Basslink was commissioned, increasing non-synchronous generation will require more ancillary services (FCAS and reactive support) in Tasmania, which also must be costed.

It is envisaged that additions and/or modifications to the existing complex system protection schemes will be required. To maximise power transfers across the second interconnector, additional load and generation interruptibility contracts will need to be established with existing Tasmanian major Industrial customers (MIs) and generators respectively. For the MIs this potentially doubles their risk exposure to curtailed production in their already challenging global commodity markets.

It is also premised that these MIs will be still operating in 40 years' time (based on the economic life of the interconnector assets). If any of the MIs leave Tasmania then there may be a risk of stranding the second interconnector or having its flows significantly constrained.

It is understood that further detailed analysis will be required on the feasibility of a second interconnector, in doing so, careful analysis on the full costs (including strengthening the existing network), power system security implications for Tasmania, and the impact on consumers in terms of future power prices, electricity supply quality and reliability.

7. Tamar Valley Power Station

TGP's submission to the Taskforce detailed the costs of maintaining the CCGT in a state where it can be brought back into service at a month's notice. VAA contributed to that analysis and concurs with its findings.

To support that analysis, VAA has conducted Monte Carlo modelling to identify the range of costs to operate the CCGT.

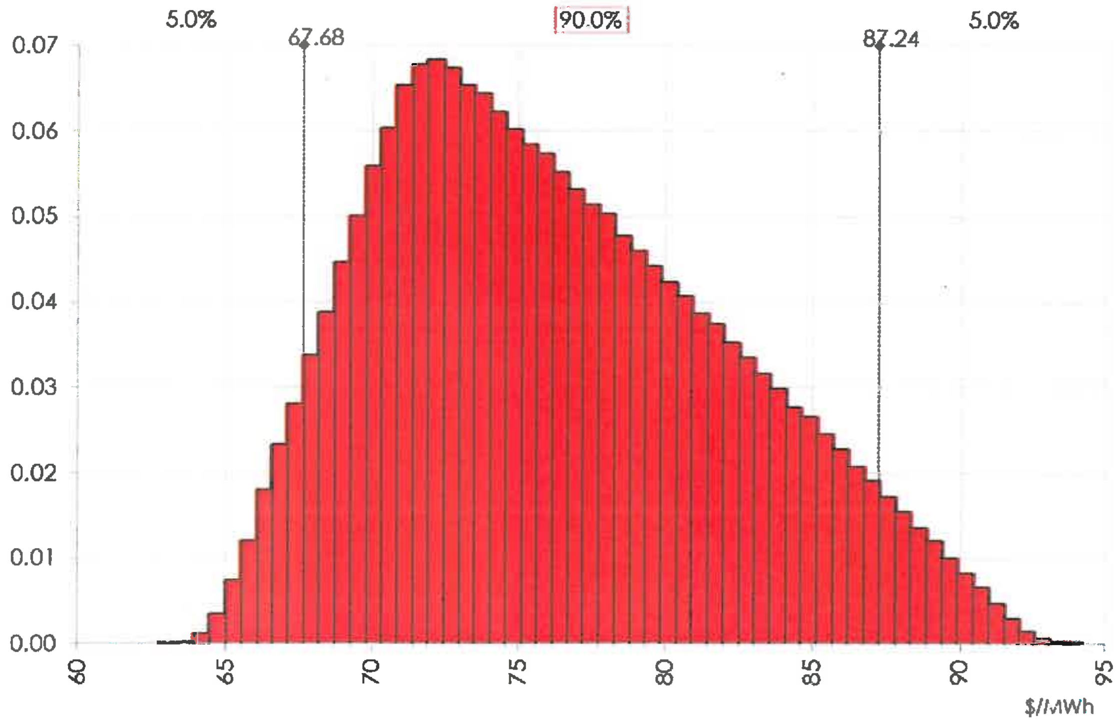
Results for the 550GWh and 700 GWh scenarios are in Table 2 and Figure 6.

Table 2: Cost of CCGT production ($ per MWh)

Scenario	Median	One standard deviation	90% confidence interval
550 GWh	72	68–87	65–90
700 GWh	67	62–82	60–85

Figure 6: Monte Carlo modelling of CCGT production costs

A: 550 GWh scenario



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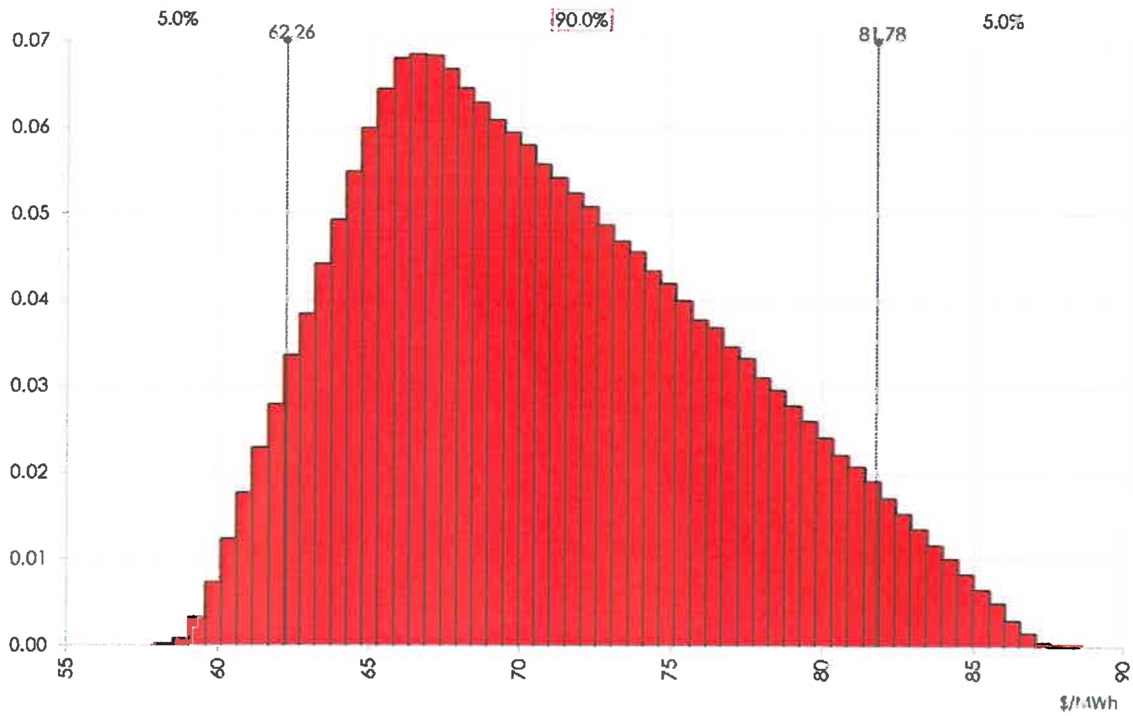
B: 700 GWh scenario



The long tail in these distributions is explained by a relatively wide allowance for gas commodity prices, which are the largest variable cost incurred in operating the TVPS. While VAA supports the assumption that the gas commodity price will be around $6/GJ for summer delivery, we have allowed a range of 5/GJ to $9/GJ for conservatism.

The parameters for this modelling are aligned with those contained in TGP's submission, and are shown in Attachment B.

Consistent with the expectation that the CCGT would most likely operate over the summer season — and possibly late spring and/or early autumn depending on hydrological conditions — Hydro Tasmania's regulated contract prices for the first quarter of coming years illustrates the revenue potential, without considering other gains from portfolio optimisation.

In particular, its flat contract prices for the first quarter (Jan-March) of 2018 and 2019 as at 6 September 2016 were $58/MWh and $62/MWh respectively. If these prices were realised for the CCGT output, the net cost would be $5.65 million pa in the 550 GWh scenario and $3.80 million pa in the 700 GWh scenario. [12]

This demonstrates that, from a commercial perspective, the costs of operating the CCGT are largely offset by the revenue opportunities.

VAA acknowledges that there will be some impact on the prevailing spot price, and hence contract price, from sustained CCGT operations. On the other hand, it is likely that the CCGT output facilitates other trading opportunities, particularly more aggressively trading hydro generation (including energy sales, LGCs and cap contracts) or mitigating the backing required for Momentum's retail sales.

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[12] TVPS was previously considered by the ESI Expert Panel in the context of energy security. It noted the financial challenges for the TVPS under Aurora Energy's ownership, and suggested that "a difference between its acquisition and completion costs and its market value, under normal hydrological conditions, of around $150 million, [is] interpreted as an energy supply risk 'insurance premium'".

8. Comparative assessment of energy security options

8.1 Assessment framework

Options for providing energy security should be assessed in a robust framework that incorporates strategic and financial analysis.

In particular, gas-fired generation must be considered on a level playing field against other options, and without considering the State's commercial interests in the State-owned electricity businesses.

To facilitate this process, the following criteria are suggested as being appropriate to assess relevant options to provide energy security:

- **volume** — sufficient volume to materially affect the balance between supply and demand of electrical energy and eliminate the risk of unserved energy;
- **predictability** — delivery of the desired volume with a high degree of certainty;
- **timeliness** — delivery of the desired volumes when it is required, with flexibility to serve as a pre-emptive risk mitigant or in response to an emerging hydrological situation, and without significant lead times;
- **cost-effectiveness** — the effective insurance premium taking into account capital and operating costs, and offsetting revenue potential, as well as opportunity costs for any public funding required;
- **efficient use of capital stock** — the extent to which existing capital stock is used to meet a policy objective; and
- **economic consequences** — the direct and indirect impact on other industries in Tasmania, including employment and investment.

8.2 Assessment against criteria

As noted in section 4.2, the main options for energy security are:

- increasing on-island generation, eg:
  - ensuring that the CCGT operates and is supported by a new GTA
  - building new large-scale generation capacity (most likely several wind farms, possibly with some medium scale solar farms)
  - embedded and small-scale renewable energy;
- energy efficiency;
- demand side management;
- raising the hydro storage targets; and
- a second interconnector.

Table 1 provides VAA's assessment of these options against the criteria identified above.

Table 3: Assessment of energy security options

Option	Volume	Predictability	Timeliness	Cost-effectiveness	Use of capital stock	Economic consequences	Comment
CCGT operations	✓	✓	✓	✓	✓	✓	▸ Proven capability to provide significant, predictable and timely volumes ▸ Effective cost of insurance is modest ▸ Facilitates more aggressive storage management to maximise value ▸ ensures that pipeline capacity charges remain at competitive levels for industrial customers in Tasmania and that the risk of substantial employment and investment losses are averted.
New generation capacity (wind)	✓	✗	✗	✗	✗	✓	▸ Significant technical and commercial barriers, including possible substantial transmission augmentations ▸ Variability undermines suitability for energy security and resulting overbuild is inefficient ▸ Mutual dependency with new interconnector
New generation capacity (embedded & small-scale renewables)	~	~	~	✓	~	✓	▸ Uncertain cost and timing profile for sufficient capacity to materially increase supply ▸ Significant resource commitments to negotiate connections
Energy efficiency	✗	✗	✗	✓	✓	~	▸ Difficult to procure sufficient and timely volumes to address energy shortfalls in low inflow conditions

Option	Volume	Predictability	Timeliness	Cost-effectiveness	Use of capital stock	Economic consequences	Comment
Demand side management	✓	✓	✓	✗	✗	✗	▸ High economic and financial cost of reducing major industrials' load ▸ Loss of output reduces efficiency of capital stock
Higher hydro storage targets	✓	✗	✗	✗	✗	~	▸ Significant opportunity cost as HT loses flexibility on inter-regional trading ▸ Difficult to rebuild storages if below target in timely and predictable manner during low inflow periods ▸ Existing assets are under-utilised
Second interconnector	✓	✓	✗	✗	✗	✓	▸ Significant technical barriers and extensive network augmentations will be required ▸ Leads to existing assets being stranded, and exposed to being stranded if an MI leaves ▸ Very high financial cost ▸ Material changes in supply-demand balance may occur during ten year development timeframe ▸ Uncertain operating profile but capacity to import for energy security will require MIs to participate in load shedding contracts

Most of these options have some merit from a commercial and market development perspective. However, when considered from an energy security perspective — consistent with the terms of reference of the Taskforce — generation from the CCGT provides a robust and proven capability.

The CCGT also provides complementary benefits, including contributing inertia and FCAS services to the market and allowing more aggressive storage management strategies to take advantage of elevated prices in wholesale and renewable markets.

9. Conclusion

Successive State governments were deeply involved in facilitating the entry of gas and development of the TGP, in conjunction with Basslink, as part of a broad energy reform framework.

Energy security and other non-commercial drivers have been common factors in the development and operation of Tasmania's gas generation assets for over four decades, including the acquisition of the TVPS at a time of deteriorating hydrological conditions.

As the State had such a significant role in overseeing the projects that allowed Tasmania to enter the national electricity and gas markets within a short timeframe, the State should not allow any of the same assets to become stranded through a focus on the publicly-owned power assets and Basslink.

TVPS also offers fuel diversification, consistent with the long-term objectives of various State governments and government businesses to facilitate a mix of hydro, wind and gas-fired electricity generation.

Gas also continues to have an important role in the Tasmanian economy. If a new GTA is not executed to replace the current agreement when it expires in December 2017, there is a risk that existing consumers could face material price rises and significant economic impacts could occur over time in key sectors.

The State's gas assets, including the TGP and TVPS, proved their capability in addressing energy security during the most recent situation and, as this paper has shown, continue to offer substantial value for energy security at relatively low cost.

The effective operating costs of $12 million in dry lay-up mode, $72/MWh to operate for 550 GWh a year or $67/MWh for 700 GWh a year are largely offset by the revenue opportunities, including through direct sales and the more aggressive hydro generation trading strategies that thermal generation facilitates.

The net cost of operating the CCGT in these two scenarios has been estimated at $5.65 million and $3.80 million per annum respectively.

In contrast, other options involve larger economic and financial costs and technical barriers, including:

- maintaining higher hydro storages has a significant opportunity cost;
- major new wind farms likely face several challenges, including increased capital costs, deep transmission connections and/or network augmentations to overcome the technical issues in the State's transmission network that is already operating at the limits of its design and operational capacity, and variability in performance that undermine win farms' suitability for energy security;
- a second interconnector, which will cost up to $1 billion and will likely require its own network augmentations to facilitate increased power flows and is mutually dependent on the excess supply created by new wind farms. It will also take 10 years to develop and build.

For these reasons, VAA concludes that gas-fired generation, utilising the existing CCGT at TVPS, should be a core element of Tasmania's future energy mix and the preferred option for energy security.

Attachments

A: Tasmanian transmission constraints map with impact of new wind farms or second interconnector

B: Modelling parameters

References

Australian and Tasmanian governments. (2016). *Feasibility Study of a second Tasmanian interconnector - Preliminary Report.*

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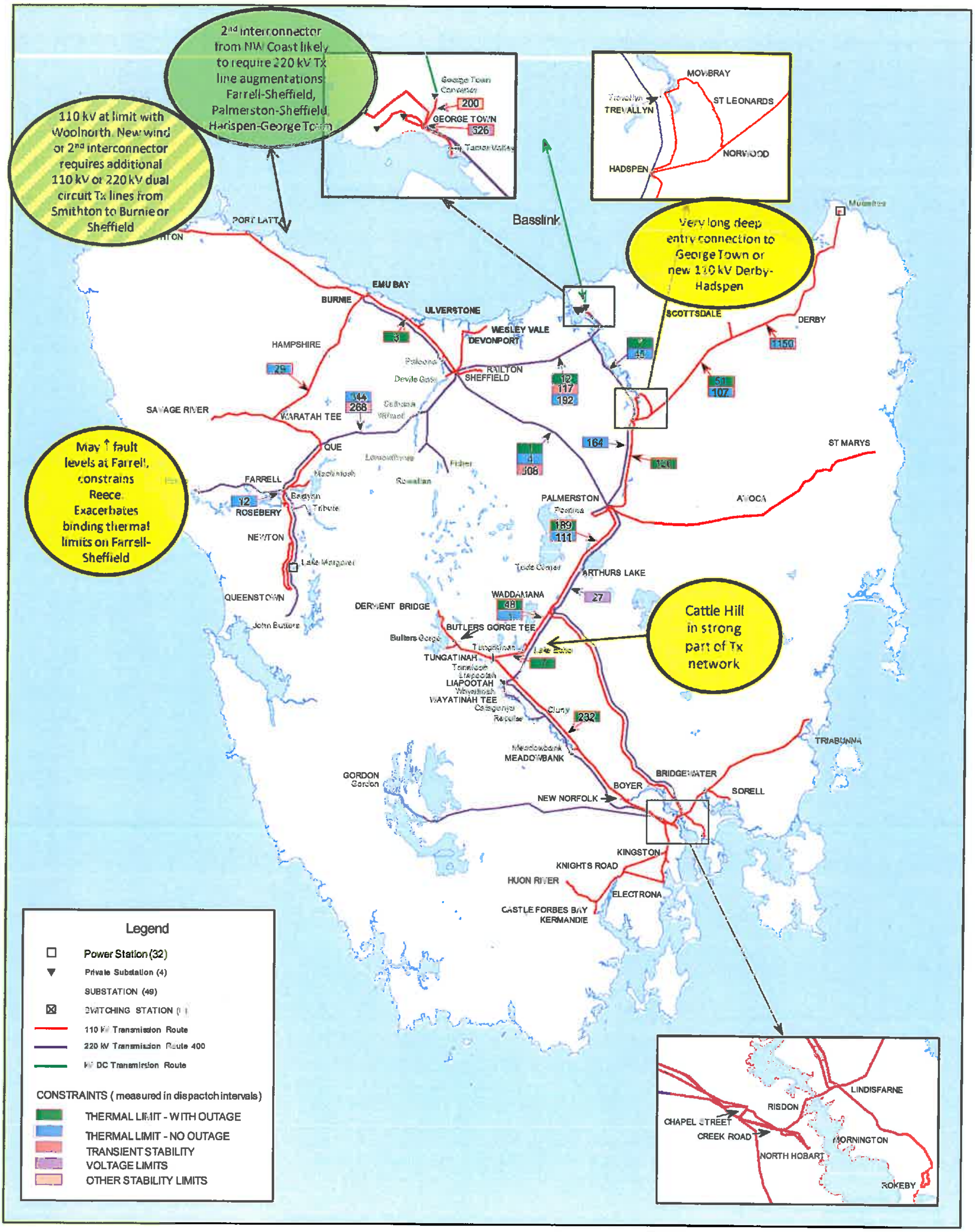
Attachment A: Network constraints and impact of new wind generation and second interconnector



Attachment B: Modelling parameters

Wind generation

Fixed parameters

Asset life	25
Unit	1,000,000
Project interest rate	7.0%
Debt ratio	70%
Average capacity factor	38%

Scenario 1

GWh Target	550
MW capacity	165

Scenario 2

GWh Target	700
MW capacity	210

Costs

	Inc in @risk	Low	High	Median
			Per MW, per annum	
Capex $m	✔	2.0	2.4	2.2
Depreciation $m				
O&M and other $m	✔	0.08	0.1	0.09
Interest cost annualised $m				

Output variables

	Inc in @risk	Low	High	Median
Capacity factor	✔	36%	40%	38%
Transmission loss adjustment	✔	94%	98%	96%

Combined cycle gas turbine

Fixed parameters	
Asset life	25
Unit	1,000,000
Project interest rate	7.0%
Debt ratio	70%
Heat rate	7.0

Scenario 1	
GWh Target	550
PJ	3.9

Scenario 2	
GWh Target	700
PJ	4.9

Costs	**ic in @ris**	**Variable costs**			**Fixed costs**		
		Low	High Per GJ	Median	Low	High	Median
Gas commodity $	✓	5.0	9.0	6.0			
Pipeline capacity(a)							
Firm $m	✓						
Flexible $	✓						
Depreciation $m	✓						
O&M $m							
Base	✓				0.6	0.6	0.60
Annual inspections	✓				0.5	0.5	0.50
Recall mobilisation	✓				0.04	0.04	0.04
CCGT operations (per month)	✓	0.29	0.29	0.29			
Parts (per hour)	✓	0.00	0.00	0.00			
Water	✓				0.4	0.4	0.4
Tx entry	✓				1.7	1.7	1.7
Insurance and overheads	✓				1.6	1.6	1.6
Interest cost annualised $m	✓						
Output variables							
Transmission loss adjustment		100%	100%	100%			

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