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<tr>
<td>MWh</td>
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Foreword

In June 2010, the Tasmanian Government announced that it would establish an independent expert panel to conduct an investigation into, and provide guidance to Parliament on, the current position and future development of Tasmania’s electricity industry. The Electricity Supply Industry Expert Panel was established under the Electricity Supply Industry Expert Panel Act 2010, and granted wide ranging information gathering powers to enable it to perform its intended function, as set out in its Terms of Reference.

Volume 2 provides further background analysis to the findings presented in the main body of the Final Report. Specifically, it contains significant additional detail on the Panel’s key findings with regard to a number of its Terms of Reference, including:

Terms of Reference 1, which required the Panel to examine the current efficiency and effectiveness of the Tasmanian energy industry with particular reference to the existing regulatory framework and the cost and operation of the energy industry elsewhere in Australia;

Terms of Reference 2, which required the Panel to investigate and report on major infrastructure development decisions affecting the electricity sector and the impact that those decisions have had on Tasmanian electricity prices; and

Terms of Reference 4, which required the Panel to assess the financial position of the state-owned energy businesses: Transend Networks, Hydro Tasmania and Aurora Energy.

Effectively, each of the parts contained in Volume 2 corresponds with one of the five substantive Supporting Volumes that were released with the Panel’s Draft Report on 15 December 2011, namely:

- Basslink: Decision Making, Expectations and Outcomes;
- Tamar Valley Power Station: Development, Acquisition and Operation;
- A Review of the Efficiency and Effectiveness of the State-owned Energy Businesses;
- A Review of the Financial Position of the State-owned Energy Businesses; and
- Governance: Issues and Reforms

The Basslink and TVPS parts examine, respectively, the development of the Basslink interconnector and Aurora Energy’s acquisition of the TVPS and the outcomes that both of these projects have delivered relative to expectations, including the impact (if any) on electricity prices and the financial position of the SOEBs.
Taken together, the Efficiency and Effectiveness and Financial parts provide a detailed analysis of both the technical and financial performance of Tasmania’s SOEBs between 2004 and 2010.

And, finally, the Governance part discusses the evidence that the Panel has obtained in relation to how well current governance arrangements are meeting good practice principles and explains the Panel’s recommended reforms.

The analysis that the Panel has undertaken on all of the above matters has significantly informed the identification of issues on which the Panel’s reform recommendations have been based, particularly with regard to further improving oversight of the SOEBs.

The Panel drew on the expertise of external consultants to assist in undertaking this significant part of its work program. Wilson Cook and Ernst and Young were engaged with regard to investigating the efficiency and effectiveness and financial performance of the SOEBs, respectively.

In its analysis, the Panel has also drawn on a wide range of information, including briefings from senior representatives from both the Government and the SOEBs. The Panel has also used its extensive information gathering powers to access a wide range of otherwise confidential documents, including relevant Cabinet materials, internal briefing notes and advice and SOEB board papers and meeting minutes.

While issues of Cabinet confidentiality and commercial sensitivity preclude the release of much of this source material, the Tasmanian community should be confident that the Panel has been able to arrive at its own, independent understanding of key decisions and actions based on this information.
Part A

Basslink: Decision making, expectation and outcomes
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Executive summary

When the Rundle Liberal Government announced in 1997 its intention to proceed with the development of an undersea interconnector linking the Tasmanian and Victorian electricity grids, the idea of a submarine cable across Bass Strait was not new. The economic and technical feasibility of interconnection had been considered numerous times by the Hydro-Electric Commission (HEC) and others over the preceding 50 years, but never managed to gain the support needed for it to become a reality.

However, the end of large-scale hydro-electric development in Tasmania and the need to secure the next electricity supply option for the State, along with the long-standing issue of hydrological risk management and the development of the National Electricity Market, led the Rundle Government to seek expressions of interest through a competitive selection process for a private sector party to develop Basslink, and to progress the project as a Project of State Significance. Basslink was to form a central element that enabled a package of electricity sector reforms to be implemented.

While aspects of the proposed reforms, such as the sale of the HEC’s transmission, distribution and retail businesses, did not survive the change of Government that occurred in 1998, the incoming Bacon Labor Government endorsed the development of an undersea interconnector, and the process that had been set in motion to find a private sector developer for Basslink continued. The new Government did, however, revise the previous Government’s goals and strategic objectives for Basslink to the following:

- improve the security of electricity supply and reduce the exposure to drought conditions in Tasmania;
- provide Tasmania with access to electricity prices determined competitively in the NEM;
- provide a means by which electricity generated in Tasmania can be sold into the NEM and provide a new source of peak generating capacity in the NEM;
- ensure that, through a competitive selection process, the cost of Basslink to users is minimised; and
- ensure that the returns to the State from the State Owned Electricity Businesses are maximised.
While some within the community appear to hold the view that Basslink was proposed on the basis that it was predominantly, or solely, intended to be used to enable the sale of electricity from Tasmania to Victoria, it is clear from the Government’s strategic objectives that, from the outset, the link was intended to be used as a net supply option for Tasmania in times of low hydrological inflows (drought), as well as for net exports in times of high inflows.

Once the initial commitment to Basslink was made, the Basslink project had a lengthy gestation period, during which a selection process was conducted to find a private sector developer for the link.

The two final proposals to emerge from the competitive process both involved commercial arrangements between Hydro Tasmania and the proposed developer to fund the project. The option of the interconnector being developed as a ‘regulated link’ and funded directly by customers through transmission charges was not considered viable by developers.

Hydro Tasmania examined the business case for interconnection repeatedly. The business case evolved significantly during the project’s development, and the early iterations considered by Hydro Tasmania were markedly different from the business case that underpinned the final decision to proceed with Basslink.

For example, between the Board of Hydro Tasmania agreeing in February 2000 to enter into a preliminary non-binding agreement with private sector developers to build, own and operate Basslink and Hydro Tasmania issuing a notice to proceed in November 2002, the projected cost of constructing Basslink increased from approximately $500 million to almost $875 million – much of the increase driven by the outcomes of the joint Commonwealth, Victorian and Tasmanian environmental assessment process. The identified commercial benefits of Basslink for Hydro Tasmania, as the counterparty to the development, also evolved over time as the opportunities from interconnection became better understood.

The business case for Basslink was regularly reviewed by the Board of Hydro Tasmania, which subjected the business case to scrutiny independently of Hydro Tasmania’s management. The Basslink project was also reviewed by the State Government and independent expert advisers on multiple occasions, in the wider context of energy reform.

Those investigations repeatedly showed Basslink to be a positive commercial proposition for Hydro Tasmania’s business, even with the significant increase in the project’s cost. Basslink’s ability to add value to Hydro Tasmania’s business was also assessed as being robust to the likely range of sensitivities which reflected the key risks to the business case.
Accordingly, the Hydro Tasmania Board made a commercial decision that, having regard to the risks and returns associated with the project, it was in the best interests of Hydro Tasmania to proceed with the development of Basslink.

The consultants engaged by the Department of Treasury and Finance to consider the range of risks associated with the Basslink project from the State’s perspective highlighted that the State Government was not in a strong position to influence or control the key financial risks arising from the project – namely national market pricing outcomes and hydrology. However, they also highlighted that without Basslink, and in the face of new on-island gas-fired generation, the outlook over the following ten years was for a decline in Hydro Tasmania’s financial performance and for returns to Government.

It was also noted that the State Government had flagged Basslink as a strategically important project for Tasmania, and that it was intended to facilitate further development of Tasmanian wind resources, reduce drought risk and facilitate the development of competition into the Tasmanian electricity supply industry.

Hydro Tasmania’s business case for Basslink was driven primarily by the arbitrage opportunities made possible by interconnection with Victoria. Over 50 per cent of the anticipated revenue gains factored into the business case were attributed to the ability to ‘buy in’ energy to meet Tasmanian demand at times of low prices in Victoria, and then sell the same volume of electricity over the link when Victorian prices were higher than Tasmania’s. While arbitrage would, by definition, have no impact on the total volume of electricity generated by Hydro Tasmania, it was expected to have a significant positive impact on the value of that energy because of the flexibility available in the timing of its generation.

Arbitrage alone was not, however, expected to cover the ongoing cost of Basslink, and Hydro Tasmania identified a number of other sources of value which it believed would make the link commercially viable from its perspective. These included the opportunity to sell capacity contracts in Victoria, value from the additional yield that Hydro Tasmania expected to be able to generate as a result of improvements in its capacity to manage its water storages, as well as the revenue derived from the creation and sale of additional Renewable Energy Certificates (RECs) as the result of that improvement in yield. Two other primary financial benefits were the value of net ‘exports’ of electricity, that is, the net difference between north and south bound flows of electricity across Basslink, and the ability to transition major industrial pricing to market-related levels.

The final November 2002 business case showed that, if the base-case’s assumptions held, the Basslink project would produce an estimated Net Present Value (NPV) to Hydro Tasmania of around $260 million ($2002), with a benefit/cost ratio of 1.44:1. The business case also considered a wide range of sensitivities around the base-case which had both positive and negative impacts on the net value of the link to Hydro Tasmania.
Although Basslink is expected to have an economic life of up to 40 years, given the often conflicting public perceptions regarding the financial performance of Basslink, the Panel has examined the extent to which the link’s performance to date has measured up against Hydro Tasmania’s expectations regarding the commerciality of the project.

In its first five full years of operation, Basslink’s financial performance has not fulfilled the expectations contained in the final business case on a number of fronts. This is largely a reflection of hydrological factors. Other assumptions that underpinned the final business case, such as the projected differences between Victorian peak and off peak prices, have been borne out by experience to date.

Hydrological issues were consistently recognised as one of the key risks in the Basslink business case. Variations in the yield from Hydro Tasmania’s water catchments were expected, and it was recognised that low inflow levels would impact on a number of components of Basslink’s trading value, particularly Hydro Tasmania’s opportunities to be a net ‘exporter’ of energy and the creation of additional RECs.

In this sense, the low hydrological inflow sequences that occurred prior to and immediately after Basslink’s commissioning reflect the anticipated variability in the value created for Hydro Tasmania by Basslink. The return to more typical hydrological inflows in recent years has resulted in financial outcomes for Hydro Tasmania associated with Basslink that have been more consistent with the expectations in the final business case.

Taking into account only the direct realised benefits attributable to Basslink, Hydro Tasmania’s overall Basslink-related costs have been around $130 million ($ nominal) greater than the actual revenue benefits that it has generated since Basslink began delivering energy in April 2006.

Illustrating the importance of hydrology in driving these outcomes, in 2009-10 and 2010-11, with inflows at more typical levels, the direct realised revenues associated with Basslink were around $25 million in excess of Hydro Tasmania’s overall Basslink-related costs.

In its evaluation of Basslink’s performance, Hydro Tasmania looks beyond the direct costs and benefits identified in the business case and considers a number of indirect sources of value that it attributes to Basslink. Those additional sources of value are based on a comparison of the outcomes made possible by Basslink with the hypothetical outcomes that might have been realised had Hydro Tasmania been required to supply Tasmania’s electricity needs over the past five years without interconnection.
In the absence of Basslink, Hydro Tasmania assumes that the shortfall in the capacity of its hydro generation schemes to meet Tasmania’s demand for electricity would have been met using a combination of natural gas fired generation – owned and operated by Hydro Tasmania – and, in times of extremely low inflows into Hydro Tasmania’s storages, negotiated load shedding by major industrial customers. The Hydro Tasmania analysis compares the estimated costs associated with such a scenario with the actual costs of the energy supplied through Basslink, and concludes that Basslink has enabled Hydro Tasmania to avoid costs in excess of $300 million since the link commenced commercial operations.

Taking both direct and indirect sources of value together, Hydro Tasmania concludes that over the period 2006-07 to 2010-11 the average net benefit of Basslink to its business is in excess of $40 million per annum.

The Panel has developed its own estimates of the alternative supply costs that may have arisen in the absence of Basslink. Like Hydro Tasmania, the Panel considered that the use of natural gas fired generation to meet the shortfall in the capacity of hydro-generation to meet on-island demand was the most plausible alternative to Basslink. However, the Panel also considered a second scenario involving the use of large-scale wind generation to meet the State’s electricity needs.

The Panel has estimated that when compared with its gas scenario, Basslink resulted in lower wholesale energy costs for Tasmania of around $200 million over the period 2007 to 2011, and approximately $350 million when compared with the hypothetical wind scenario.

On this basis, Basslink has – as Hydro Tasmania contends – enabled Tasmania’s demand for electricity to be met at a materially lower wholesale energy cost than would have been the case under either of the two alternative scenarios evaluated. If not for Basslink, the prolonged dry period experienced by Tasmania in the middle of the previous decade would have had far more severe negative financial consequences for Hydro Tasmania than the trading losses associated with Basslink to date. The drought would also have had potentially undesirable consequences for customers, to the extent that the higher wholesale energy prices that would have been likely in the Tasmanian market without Basslink in place would have been passed on.

When the indirect benefits of Basslink (as a net supply option during times of drought, for example) are added to the trading performance of the link, the financial benefits of Basslink to Hydro Tasmania in the first five years of its operation are positive, despite the under-performance of the trading outcomes, relative to the business case.
In reaching this conclusion, the Panel has deliberately taken a conservative approach has been applied to the valuation of the benefits to Hydro Tasmania that can be attributed to Basslink. For example, a number of sources of value that Hydro Tasmania includes in its own analysis of the contribution Basslink makes to its business have been excluded from consideration, such as an uplift in the contract prices struck with energy intensive industrial customers.

While these benefits may have enhanced Hydro Tasmania’s financial performance they have not been ascribed as direct Basslink value by the Panel. The analysis also does not consider yet-to-be-realised financial benefits that Basslink could deliver, such as the ability of Hydro Tasmania to build storages in anticipation of the introduction of carbon pricing and the realisation of that value in the coming years.

Given the focus of its Terms of Reference, the Panel has not sought to undertake an assessment of the impact that Basslink has had on the wider Tasmanian economy. Accordingly, this assessment of Basslink has not considered the benefits for the Tasmanian economy that might be attributed to interconnection. For example, Hydro Tasmania contends\(^1\) that the security of supply provided by Basslink has provided a number of large energy intensive businesses with the confidence to invest in upgrades of their Tasmanian production facilities and enter into new long-term contracts.

Finally, a number of stakeholders have asserted that regulated customers are effectively underwriting Basslink. Having examined the detailed financial performance of Basslink from Hydro Tasmania’s perspective, as well as transmission network pricing in Tasmania, and having regard to the way in which prices for regulated customers are set, the Panel concludes that regulated customers are not paying for Basslink through their electricity prices.

\(^1\) Hydro Tasmania’s confidential submission to the Panel, “Basslink and trading performance”.

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Basslink: Decision making, expectations and outcomes
1. **The case for interconnection**

In April 1997, as part of a broader statement of intent, the then Tasmanian Premier, the Hon Tony Rundle MHA, announced a number of major policy initiatives relating to Tasmania’s future energy strategy. One of those initiatives was a commitment to proceed with the development of Basslink, an undersea interconnector linking the Tasmanian and Victorian electricity grids. The Government also announced its intention to break up the Hydro-Electric Corporation into separate generation, transmission and distribution/retail businesses, with a view to selling the transmission, distribution and retail businesses, and using the proceeds to retire Government sector debt.

The State Government’s announcement regarding Basslink was strongly supported by the Victorian and Commonwealth Governments, both of which undertook to assist and cooperate with the Tasmanian Government in its development of the link.

The idea of a submarine cable linking Tasmania with interstate electricity grids was not new. Labor MHR Arthur Calwell mooted the idea in Federal Parliament in April 1943 and interconnection had been the subject of informal discussions between the Hydro-Electric Commission (HEC) and State Electricity Commission of Victoria (SEC) during the 1950s. In the early 1960s the HEC Commissioner, Sir Allan Knight, decided to investigate the feasibility of an undersea cable across Bass Strait, as an alternative to ongoing calls for Hydro Tasmania to consider thermal – and even nuclear – power generation as a means of increasing the State’s capacity to generate electricity.

Interconnection of the Tasmanian and Victorian electricity grids was again examined during the 1980s, with a focus on identifying the potential economic benefits of energy exchange between an energy-constrained hydro power system in Tasmania and Victoria’s mainly capacity-constrained thermal power system, as well as mitigating the risk of drought on the Tasmanian power system. In the early 1990s, the HEC and SEC collaborated on a series of feasibility studies, including a real-time simulation of how a national energy market might operate. The simulation ran for six months and at its conclusion showed an ‘imaginary’ Basslink cable yielding the HEC a paper profit of $47 million.

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2 ‘Directions Statement – Tasmania’s Future Energy Strategy’
3 For example, the Call for Expressions of Interest from developers released by the BDB contains statements of support from the Prime Minister and the Victorian Premie and both jurisdictions agreed to the joint assessment process to facilitate the project.
4 See “Lifeblood – Tasmania’s Hydro Power” by Roger Lupton, Focus Publishing Pty Ltd.
In 1997 there were a number of considerations that prompted the Tasmanian Government and its agencies to revisit the idea of interconnection. These included:

- the end of large scale hydro-electric development in Tasmania and the need to identify the next electricity supply option for Tasmania;
- proposals for a National Electricity Market (NEM), which would require physical interconnection of the Tasmanian and Victorian electricity grids should Tasmania decide to participate in that market;
- the desire to further examine the hydrological risk management potential of Basslink (commonly referred to as ‘drought proofing’);
- concerns about the economic and financial impacts on the State should a major energy consumer decide to cease operations in Tasmania;
- the need to evaluate the extent to which the State Government’s reform agenda for the electricity supply industry in Tasmania would position the Tasmanian electricity market for competition with and without interconnection; and
- the need to examine the potential contribution of interconnection to achieving the Government’s stated objective of ensuring that Tasmanian businesses and electricity users generally have access to competitively priced electricity.

The Basslink Development Steering Committee (BDSC) was established in June 1997 to advise the Government on the economic, technical and environmental feasibility of Basslink, with a view to having an interconnector built and operated as a private sector project that would see the link operational within four years. The BDSC’s November 1997 report to Government included the following findings:

- interconnection with Victoria was technically feasible, and would benefit from the major technological advances which had occurred as a result of an increasing number of undersea connectors being installed around the world;
- Basslink would be economically viable, with proponents indicating that the development cost was likely to range between $350 and $400 million for a 300MW interconnector;
- Basslink could be progressed as either a ‘regulated’ or ‘non-regulated’ interconnector under the National Electricity Code;
- there was widespread interest in Basslink from Australian and overseas private sector companies, in both the regulated and non-regulated business models;
- Basslink could be constructed and operational by March 2002;

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5 The Tasmanian Government’s subsequent decision to direct Aurora Energy to acquire the partially completed Tamar Valley Power Station from Babcock and Brown Power in 2008 suggests that Basslink was later considered insufficient to ‘drought proof’ Tasmania.

6 Under a regulated model the development and operating costs of an interconnector are recovered from customers via network transmission charges. Under the non-regulated alternative, the interconnector is classified as a Market Network Service Provider (MNSP) and those same costs are recouped via revenue earned through participation in the market from Inter-Regional Revenue (IRR) settlements, which are the price differences between the two regions the link connects, multiplied by the volume of electricity the link carries.
for the project to succeed, the support (non-financial) of the Tasmanian and Victorian Governments, in areas such as environmental approvals and negotiations with national electricity bodies like NEMMCO\textsuperscript{7}, would be critical; and

\begin{itemize}
  \item the construction and operation of Basslink would have to be considered and approved through a public assessment process.
\end{itemize}

Based on these findings, the BDSC recommended that the Tasmanian Government, with the agreement of the Victorian Government, call for Expressions of Interest from potential proponents in the development of Basslink as either a regulated or non-regulated interconnector.

The Tasmanian Government accepted the BDSC’s recommendations in December 1997 and, in February 1998, established the Basslink Development Board (BDB) to take the lead role, on behalf of the State, in facilitating the development of Basslink as a commercial opportunity\textsuperscript{8} in the NEM. The BDB’s responsibilities would also include conducting the selection process to identify a preferred proponent to take the project forward.

Having made the commitment to Basslink and established the BDB to facilitate its development, Premier Rundle called an early election. A change in Government ensued and the incoming Bacon Labor Government endorsed the development of Basslink, and the process that had been set in motion to find a private sector developer for Basslink continued. The new Government did, however, revise the previous Government’s goals and strategic objectives for Basslink to the following:

\begin{itemize}
  \item improve the security of electricity supply and reduce the exposure to drought conditions in Tasmania;
  \item provide Tasmania with access to electricity prices determined competitively in the NEM;
  \item provide a means by which electricity generated in Tasmania can be sold into the NEM and provide a new source of peak generating capacity in the NEM;
  \item ensure that, through a competitive selection process, the cost of Basslink to users is minimised; and
  \item ensure that the returns to the State from the State owned electricity businesses are maximised.
\end{itemize}

\textsuperscript{7} National Electricity Market Management Company

\textsuperscript{8} The Expression of Interest document refers to ‘a commercially viable business, developed in the NEM within a Build, Own, Operate framework’ without ‘any financial contribution by the Government, either direct or contingent.’
2. The search for a developer

The search for a private sector developer to construct and operate Basslink began with the release of a Call for Expressions of Interest by the BDB in July 1998. The Call closed in September 1998, with 14 national and international consortia responding.

From those expressions of interest, four proponents\(^9\) were short-listed to respond to a detailed Project Brief prepared by the BDB. The Project Brief was released in December 1998 with proponents required to submit their responses by October 1999.

The Project Brief provided to the short-listed proponents specified a number of minimum technical requirements for Basslink. Those requirements included:

- a continuous transfer capacity both to and from Tasmania of at least 200MW, although proponents could submit proposals involving higher transfer capacities;
- a minimum design life of 40 years;
- a cable failure rate of less than 1 in 10 years;
- a maximum number of five unplanned interruptions per annum;
- implementation, by the proponent, of load and/or generation reduction systems to protect the integrity and stability of the Tasmanian power system in the event of a sudden unplanned interruption to the flow of power over Basslink\(^10\); and
- the availability of spare cable and cable repair facilities that would enable a cable failure to be repaired within two months.

The proponents were free to lodge proposals for progressing Basslink as either a regulated or non-regulated interconnector. While the BDB facilitated the proponents' discussions with each of the State Owned Electricity Businesses (SOEBs)\(^11\) and undertook various studies (the results of which were made available to the successful proponents), it was made clear that there would be no financial contribution to the project by the State, either direct, indirect or contingent.

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\(^9\) The four short listed proponents were Australian Energy International (Basslink) Consortium, Taslink Consortium, National Grid International Ltd and South East Australia Link Consortium. With the agreement of the BDB, the South East Australia Link Consortium withdrew its bid in January 1999, after one of its members pulled out and the remaining members were unable to recruit a replacement.

\(^10\) Without a System Protection Scheme (SPS) Basslink imports to Tasmania would have been limited to around 100 MW during certain periods of the day, while exports to Victoria would also be limited under certain Tasmanian hydro generation scenarios.

\(^11\) The former Hydro Electric Commission was disaggregated on 1 July 1998, creating separate generation, transmission and distribution/retail businesses (Hydro Tasmania, Transend and Aurora Energy).
Following evaluation by the BDB of the three remaining proponent's responses to the Project Brief, two final short-listed proponents were chosen in November 1999 - Australian Energy International (Basslink) Consortium (AEI) and National Grid International Ltd (NGIL). Each was asked to finalise its project development arrangements with the State, as well as any commercial and other arrangements required with Tasmania's SOEBs (principally Hydro Tasmania), with a view to the BDB evaluating their final proposals in February 2000.

In preparing their final proposals, misgivings about the level of sovereign and counter-party risk associated with the development of Basslink as a non-regulated interconnector prompted the short-listed proponents to seek clarification of the future direction of the Tasmanian electricity market, in particular the likely structural arrangements for the newly created Hydro Tasmania.12 Both proponents were of the view that a non-regulated development would face significant hurdles if the structural changes to Hydro Tasmania being considered by Government at the time resulted in counter-parties whose financial standing and risk management capabilities could not support a project the size and scale of Basslink.

In their discussions with the BDB, the proponents also expressed doubts regarding the development of Basslink as a regulated interconnector. Their concerns related, in part, to the uncertainty and lack of clarity associated with the market benefits test13 applied by NEMMCO under the National Electricity Code to applications for new interconnectors, which Basslink would be required to satisfy in order for the link's operators to receive regulated revenue, as well as the lengthy approval process. Accordingly, the BDB engaged consultants, Intelligent Energy Systems (IES), to advise whether the economic benefits provided to Tasmanian and Victorian electricity consumers by Basslink would 'pass' the market benefits test.14

During this stage of the selection process Aurora Energy withdrew from direct negotiations with both proponents for the purchase of Basslink import capacity. As a result, Hydro Tasmania agreed to become the lead negotiator in the commercial negotiations with the short-listed proponents regarding both export and import capacity.

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12 The Tasmanian Government had commissioned a review of the structure of the HEC's generation and system control functions which culminated in a report in May 1999 (the Garlick Report) which recommended the establishment of three independent trading generators within the HEC parent entity. The Government did not accept the report's recommendation.

13 The purpose of the market benefit test was to assess the merits of proposed investments in regulated electricity networks, in terms of their economic costs and benefits, in order to ensure that there were not more cost effective alternatives to the capital expenditure being proposed.

14 IES concluded that Basslink would have difficulty passing the economic benefits test, and that if it did, it would be Victorian rather than Tasmanian customers that would meet the bulk of the regulated revenue payments. It was considered by proponents that this would decrease the likelihood of a regulated Basslink meeting with regulatory approval, particularly in Victoria, thus reducing the commercial attractiveness of developing Basslink as a regulated interconnector. Further, the economic benefit test did not consider the same range of factors that were taken into account by Hydro Tasmania when establishing whether there was a commercial basis for the project.
To overcome possible concerns on the part of the Australian Competition and Consumer Commission (ACCC) regarding the impact on competition of Aurora Energy’s withdrawal from the negotiations, Hydro Tasmania included in the commercial agreements with proponents a provision which allowed assignment of all or part of the import capacity to Aurora Energy, plus a commitment to make any capacity not taken up by Aurora Energy available to the market.15

The selection criteria against which the two short listed proponents’ proposals were evaluated by the BDB consisted of a ‘Business Delivery’ related criterion and an Economic Benefits (net economic Impact on Tasmania) criterion. Both criteria were detailed in the information provided to the competing proponents, as were the weightings to be used by the BDB in evaluating their proposals.

2.1. The proposals

The final NGIL and AEI bids submitted to the BDB for evaluation in February 2000 both proposed the development of Basslink as a monopole HVDC16 link operating at 400kV DC, with subsea electrodes and earth providing the return path for the DC current. Both proponents proposed to install a fibre optic telecommunications cable, to be laid with the main Basslink cable. The telecommunications cable would not be part of the Basslink facilities, however, and would be funded and developed by the proponents to provide a separate revenue stream, independent of the energy revenues arising from the Basslink project.

Both bids also met the minimum technical requirements set by the BDB and both proposals required the development of a System Protection Scheme (SPS) to enable the proposed transfer capability to and from Tasmania to be realised without affecting the integrity and stability of the Tasmanian power system, should there be a sudden unplanned interruption to Basslink’s power flow.17

Despite these similarities, there were, however, clear points of difference between the two proposals. While NGIL offered a cable with a continuous rating of 480 MW and a short term dynamic rating of up to 600 MW for periods of up to ten hours per day, AEI offered a cable with a continuous capacity of 600 MW, but no short-term dynamic rating capacity.

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15 Aurora Energy subsequently continued to negotiate with Hydro Tasmania, resulting in the parties entering into a Memorandum of Understanding in December 1999 which envisaged Aurora Energy contracting for some of Basslink’s import capability prior to the project’s financial close. Those negotiations were ultimately unsuccessful, with Aurora Energy making a commercial decision not to proceed.

16 High Voltage Direct Current

17 Without protective measures in place, a sudden and unexpected outage of Basslink whilst carrying energy in either direction would have serious ramifications for Tasmania’s electricity system. For example, if energy is flowing into Tasmania from Victoria and the link ‘trips’, the failure creates an immediate imbalance between the supply of, and demand for, electricity that could cause widespread system disruption, unless either the shortfall in the production of electricity can be rectified in time or the demand for electricity can be curtailed. The System Protection Scheme uses controlled load shedding by major industrial users of electricity and/or generation interruption to ensure that supply and demand remains balanced in the event of a link failure. Without the SPS, the volume of electricity able to be carried into Tasmania by Basslink would be limited to the capacity of the largest on-island generator available to instantly match the loss of Basslink. This would mean Basslink’s import capacity would be limited to just over 140MW, instead of up to 500MW.
There were also differences in the costs of the two proposals. While the total cost of the project under both proposals was in the order of $500 million and the total costs quoted by the two developers were within ten per cent of each other, the cost of NGIL’s proposal was lower than the AEI proposal and NGIL’s initial facility fee was substantially lower than that proposed by AEI. AEI’s higher facility fee was also to be indexed by CPI in the out years, whereas NGIL proposed that its facility fee be indexed at a discounted rate, based on a percentage of the movement in the CPI.

The AEI costing did, however, include an amount for assuming the foreign exchange and interest rate risk associated with the construction of the project, which represented a large proportion (35 per cent) of the cost differential between the two proposals. Under the NGIL proposal, no allowance was made for assuming either risk, leaving the exposures for Hydro Tasmania to manage.

Prior to the proponents submitting their final proposals to the BDB, Hydro Tasmania had negotiated arrangements with both proponents to limit cost ‘pass throughs’. Both proponents noted, however, that they were unable to quantify certain costs until, amongst other things, the outcomes arising from the development approvals process were known, and that those costs would need to be added to the project’s cost when determining the final cost to complete at the point of financial close. In particular, potential changes to the project scope and costs that could arise from the joint Commonwealth, Victorian and Tasmanian assessment process\(^\text{18}\) were considered likely to have a potentially significant impact on the cost to complete the project.

While the arrangements struck with the two proponents by Hydro Tasmania in relation to pass throughs were subtly different, both included scope to negotiate an increase in the annual facility fee to reflect the impact of higher costs arising as a result of the development approvals process.

Both proponents also indicated that the 24/25 month timeframe specified for completion could be affected by outcomes of the development approvals process, as well as other HVDC projects being developed at that time in other parts of the world\(^\text{19}\) which, if approved, could impact on the capacity of their nominated cable suppliers to meet the delivery timelines assumed in the proponents’ project plans.

One other significant difference between the proposals from NGIL and AEI was their level of ‘completeness’, in terms of the commercial agreements reached with Hydro Tasmania and the project development arrangements made with the State. While NGIL and Hydro Tasmania had agreed on key contractual conditions, including the price of accessing Basslink’s capacity, a similar commercial agreement had not been reached with AEI, and significant differences remained between the negotiation positions of AEI and Hydro Tasmania in relation to a range of fundamental issues and contract conditions.

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\(^\text{18}\) The JAP process was established by the three jurisdictions concerned as a means of expediting the environmental and regulatory approvals required for the project.

\(^\text{19}\) If it had proceeded, the 1 000MW Bakun HVDC project from Sarawak to Malaysia would have tied up the subsea cable manufacturing capacity of ABB and Pirelli for up to two years, as well as the limited number of cable transport and cable laying vessels.
2.2. The final selection process

The assessment process and associated BDB deliberations, including confirmation of the weightings assigned by the BDB to each of the proponents’ proposals, were overseen and monitored by an independent Probity Auditor. The BDB also engaged a number of specialist advisers to assist in the evaluation of the proponents’ proposals, and obtained advice from the Department of Treasury and Finance on the proposed contractual arrangements with the SOEBs, and the impact of the proponents’ proposals on the Tasmanian Government’s fiscal strategy.

Treasury’s advice to the BDB was that while both proposals were consistent with the Government’s reform agenda, in the absence of major changes, AEI’s proposal should not be considered as an alternative to the NGIL proposal. The NGIL proposal was considered by Treasury to provide better fiscal outcomes for the State than the AEI proposal, in terms of its potential to generate profits for Hydro Tasmania and returns to the State Government.

While not a participant itself in the assessment process, Hydro Tasmania also briefed the BDB on the status of its Basslink business case studies, prior to the BDB commencing its evaluation of the final bids.

Drawing on its own analysis of the two competing proposals, as well as independent advice obtained from Macquarie Bank, which had global experience in the energy sector, Hydro Tasmania had formed the view that the commercial returns likely to be delivered under the AEI proposal were not commensurate with the undertakings that Hydro Tasmania would be required to make as the counter party to the proposed 25 year commercial agreement, and that only the NGIL bid proposal was acceptable.

The BDB’s own evaluation of the NGIL and AEI proposals, based solely on the BDB’s selection criteria and weightings, also clearly showed the NGIL proposal to meet the selection criteria to a higher standard than AEI’s proposal.

The BDB’s recommendation to select NGIL as the preferred developer of Basslink went to the Government on 25 February 2000. Cabinet, at its meeting of 28 February 2000, accepted the BDB’s recommendation that NGIL be selected as the Government’s preferred proponent to build, own and operate Basslink and gave its authority for the State to be a party to the project’s contractual documents, particularly the Basslink Development Agreement (BDA), which was the commercial agreement that bound NGIL to deliver the project in accordance with the Project Requirements.
2.3. Achieving financial close

Following the selection of NGIL as Basslink’s developer, changes occurred in the roles played by a number of the parties involved in the task of delivering Basslink.

NGIL established Basslink Pty Ltd (BPL) as a special purpose project vehicle to take the project forward. As a consequence, the agreements entered into by NGIL on 29 February 2000 were novated to BPL on 21 March 2000.

Having successfully completed the selection of a proponent to develop Basslink, the BDB’s role changed to one of ensuring that the obligations of the developer, BPL, and the State, under the BDA, were met and that the project reached financial close as soon as possible. The BDB also continued to coordinate the key public communications and stakeholder management issues associated with Basslink.

The BDA was the primary contract governing the design, construction, installation and commissioning of Basslink. The BDA was conditional on the satisfaction of various Conditions Precedent (CPs), with the State, Hydro Tasmania and BPL each having responsibility for meeting a number of CPs.

One of those CPs was the requirement for BPL to obtain the necessary environmental and regulatory approvals from the three jurisdictions impacted by the project: the Tasmanian and Victorian Governments and, as the subsea cable would be laid across Bass Strait in waters under the Commonwealth’s jurisdiction, the Australian Government. The three jurisdictions had already agreed in April 1999 to establish a single combined assessment process, facilitated by an independent Joint Advisory Panel (the JAP) made up of representatives from each jurisdiction.

By February 2002, due to a number of factors including potential outcomes from the JAP’s environmental assessment process, significant changes had occurred in the project’s scope, cost and risk profile. As a result, the parties to the development decided that it was no longer practical to separate the State’s responsibility for delivery of the infrastructure under the BDA from the commercial, financial and business case issues involving Hydro Tasmania. Therefore, it was agreed that a changed governance structure was required in order to enable Hydro Tasmania and BPL to negotiate directly on key project matters.

Consequently, in April 2002 the State Government and Hydro Tasmania entered into a Memorandum of Understanding (MOU) appointing Hydro Tasmania as the State’s Agent with respect to the Basslink project. In this capacity, Hydro Tasmania was authorised to discharge all of the State’s obligations and exercise all of the State’s rights under the BDA, and any other agreements pertaining to the project.

As a result, Hydro Tasmania was able to negotiate directly with BPL in relation to the project, including variations in the project’s scope and cost. Most importantly, however, under the terms of the MOU, Hydro Tasmania – together with BPL – became responsible for, or party to, any significant decisions that might impact on the continued technical and commercial viability of the project.
An important issue facing the parties in their efforts to satisfy the CPs in the BDA was whether to seek ACCC authorisation of the Basslink Services Agreement (BSA) between Hydro Tasmania and BPL, in order to avoid the possibility of a future challenge to the BSA under Part IV\(^20\) of the Trade Practices Act 1974 (TPA). The concerns about a possible challenge had their origins in the terms of the BSA itself, which – in return for a ‘facility fee’ paid to BPL by Hydro Tasmania – provided Hydro Tasmania with all of the market revenues earned by BPL from the flow of electricity in either direction across Basslink, along with certain rights that would enable Hydro Tasmania to determine how the link would be offered in the market. Given Hydro Tasmania’s position as the sole generator in Tasmania at that time, there were reservations that the BSA might be seen by the ACCC as substantially lessening competition.

Hydro Tasmania and NGIL jointly considered the risks to the project from the potential unwinding of elements of the BSA\(^21\) as an outcome of the ACCC’s authorisation process against the risks of the ACCC subsequently challenging the agreement under the TPA and decided not to seek ACCC authorisation of the BSA. However, the ACCC was asked to undertake a legal review of the BSA, including market enquiries, with a view to providing the parties to the BSA with a ‘letter of comfort’. The ACCC did this, although it reserved the right to bring proceedings against the parties to the contract if it subsequently came to the conclusion that the effect of the BSA was to substantially lessen competition.

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**Basslink Services Agreement (BSA)**

The BSA between Hydro Tasmania and Basslink Pty Ltd commenced when Basslink was commissioned on 28 April 2006. The BSA establishes the rights and obligations of both parties with respect to the operation of Basslink. Basslink earns revenue for its owners in a similar way to generators in the NEM, by bidding into the spot market its capacity to transmit energy, with the returns determined by price differences and the energy flows between Victoria and Tasmania. The BSA provides for the owners of Basslink to swap that market-based revenue for an agreed fixed facility fee plus performance-related payments, which are consolidated annually via monthly payments. The agreement also gives Hydro Tasmania the rights to control the way in which Basslink Pty Ltd bids its interconnector capacity, although these provisions have been partly curtailed by Tasmanian legislation. The initial term of the BSA was set at 25 years, with an option to extend the term for a further 15 years.

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\(^20\) Part IV of the Trade Practices Act 1974 dealt with the use of market power for anti-competitive purposes, amongst other things. The Trade Practices Act has been superseded by the Competition and Consumer Act 2010.

\(^21\) Had the ACCC insisted, for example, that BPL contract with another counter-party, other than Hydro Tasmania, in relation to the southward bound Inter-Regional Revenues, the project would have been likely to stall, as the revenue from southbound flows of electricity were crucial to Hydro Tasmania’s Basslink business case.
2.4. Cost implications of the joint approvals process

The CP that had the most impact on the project’s scope, cost and delivery timeframe, was the gaining of the required environmental and development approvals. In order to obtain those approvals, BPL (in consultation with the State and Hydro Tasmania) was required to make major changes to the interconnector’s design, including the provision of a metallic return (in lieu of sea electrodes) to provide the return path for the DC current.\(^{22}\) Significant changes to the underground and overhead transmission route in Victoria were also made as a result of opposition to the construction of overhead transmission lines in Victoria.

The changes resulted in a major increase in the cost to complete the project, and delayed both the project’s construction start and completion dates, which had further consequences in terms of Basslink’s cost.\(^{23}\) When combined with other variations imposed by external stakeholders, such as changes to the subsea cable’s burial regime required by marine insurers to reduce the risk of damage from fishing activity along the Victorian coast, changes to Basslink’s design were beginning to threaten the viability of the project and the strength of Hydro Tasmania’s business case.

By November 2001, increasing concerns about the viability of the Basslink project saw Hydro Tasmania, BPL and BPL’s UK parent, National Grid, undertake an intense period of review, investigation, joint work programs, cost analysis and renegotiation, which culminated in the signing of two Heads of Agreement (Commercial and Telecoms) in early May 2002. The Agreements confirmed the viability of the project and the parties’ commitment to making Basslink a reality, but extended the project delivery period from the 24 months specified in the original Project Brief to 33 months. Based on the assumption that financial close would be achieved in December 2002, the extended timeframe would see Basslink commencing commercial operations in early 2005.

The Commercial Heads of Agreement detailed the agreed changes to the project’s scope and the associated increases in capital cost, the increases in project development costs, the increased costs associated with the revised subsea burial regime and the increased construction and marine insurance costs arising from the disruptions in worldwide insurance markets following the terrorist attacks on New York City on September 11, 2001.

\(^{22}\) The use of a metallic return, rather than less costly electrodes, was made a condition of approval by the Joint Advisory Panel, with the aim of reducing the level of stray current emanating from the cable and, therefore, any impact the cable’s operation might have on the marine environment, commercial fisheries and surrounding metallic infrastructure. Aside from the increased cost, the use of a metallic return was also expected to result in higher transmission losses and, therefore, reduce Basslink’s trading value to Hydro Tasmania on an ongoing basis.

\(^{23}\) The Basslink Development Board’s environmental consultants, based on their experience of other major projects, estimated that the JAP process should have been completed by November or December 2000, i.e. around 10 months after selection of the preferred proponent. The process took some 30 months to complete, with the final JAP Report issued in June 2002, resulting in a significant increase in BPL’s project development costs and an extension of the project completion timeline.
The total increase in Basslink’s cost from the selection of NGIL as the preferred proponent was in the order of $250 million, taking the estimated total cost to complete the project - to the point at which commercial operations would commence - to around $750 million.

The increase was comprised of a $204 million increase in Engineering, Procurement and Construction (EPC) contractor and related costs and a $35 million increase in project costs not included in the EPC contract. The largest single contributor to the increase in the project’s cost was the provision of the metallic return that the JAP had made a prerequisite of the project gaining the required environmental and development approvals.

Many of the cost increases agreed to and listed in the May 2002 Commercial Heads of Agreement were not yet fixed, however, with some unable to be finalised until the conclusion of the JAP process. Others were to be finalised closer to the time of financial close, with the result that the final cost of completion was higher again than the total cost described in the Commercial Heads of Agreement. In order to gauge the full impact that the outcomes from the JAP process and other externalities had on the cost of Basslink, the following table presents a breakdown of the major contributors to the increase in the cost of Basslink listed in the Heads of Agreement, but based on the final cost to complete.

Table 1 - Increases in Basslink costs to complete

<table>
<thead>
<tr>
<th>Cost factor</th>
<th>Additional cost $ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Metallic return</td>
<td>93</td>
</tr>
<tr>
<td>Changes in route</td>
<td>48</td>
</tr>
<tr>
<td>Undergrounding in Victoria</td>
<td>14</td>
</tr>
<tr>
<td>Changes to subsea cable burial</td>
<td>46</td>
</tr>
<tr>
<td>Engineering, Procurement and Construction escalation</td>
<td>35</td>
</tr>
<tr>
<td>Construction insurance</td>
<td>54</td>
</tr>
<tr>
<td>Development costs not included in the Engineering, Procurement and Construction contract</td>
<td>39</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>329</strong></td>
</tr>
</tbody>
</table>

Source: Schedule 1 of the Agreed Financial Model, Hydro Tasmania

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24 NGIL had contracted with Siemens and Pirelli (now Prysmian) to design, construct and commission Basslink.
The Heads of Agreement (Telecoms) also detailed an agreement reached by the parties under which Hydro Tasmania would underwrite the risks of a shortfall in the telecommunications revenue associated with the 12 pair fibre optic cable which BPL would lay as part of the bundled subsea cable. Hydro Tasmania’s obligation was to meet any revenue shortfall (up to $2 million per annum for 15 years) if the revenue earned from the sale of dark fibre capacity to telecommunications carriers fell short of $3 million per annum.

The date for financial close was set at 31 May 2002, although in late May 2002, following approval by both Boards, this date was extended to 31 December 2002, to allow time for a number of outstanding commercial matters to be resolved and the project’s legal documentation to be completed.
3. Hydro Tasmania’s business case for Basslink

Hydro Tasmania’s business case for Basslink evolved through a process of iterative development that began in earnest in 1999 and concluded only when final agreement was reached with BPL and the Board of Hydro Tasmania issued a Notice to Proceed in November 2002.

The early business cases considered by Hydro Tasmania were markedly different from the business case that eventually underpinned the final decision to proceed with Basslink. In early 2000, Hydro Tasmania’s analysis was primarily focussed on the energy trading value of Basslink, as the most tangible benefit to its business, although discussion of the business case noted that its sensitivity to ‘wet’ and ‘dry’ inflow sequences, amongst other things, meant that the project was not easy to justify on the basis of trading value alone.

Nonetheless, the Basslink business case considered at the February 2000 meeting of the Hydro Tasmania Board showed a positive Net Present Value (NPV) based solely on the arbitrage value25 obtained from Basslink. The avoided costs from not having to operate the Bell Bay thermal power station to provide drought support were also taken into account. A number of other potential sources of value identified by Hydro Tasmania were noted but not taken into account in examining the financial case for the project, despite some of them being potentially significant in terms of their positive financial contribution.

The other benefits identified by Hydro Tasmania, but not quantified in the February 2000 business case, were:

- revenue from the sale of additional RECs associated with the development of wind generation and increased yield from Hydro Tasmania’s existing hydro generation portfolio that Basslink would facilitate, over and above the baseline established for Hydro Tasmania as part of the Mandatory Renewable Energy Target (MRET) scheme;

- the value extracted from the market as the national renewable energy requirement impacted on energy pricing within the NEM;

- profits from energy hedging products (insurance products, such as caps that could be sold to retailers in the NEM);

- the sale of Frequency Control Ancillary Services (FCAS) into the NEM;

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25 Arbitrage is the practice of taking advantage of a temporal price difference between two or more markets, with the difference between the market prices providing a source of additional profit. In practice, with Basslink, arbitrage involves Hydro Tasmania holding back its production of electricity at times of low prices in Victoria, allowing electricity to flow southward into Tasmania as a substitute for hydro generation, and then later producing that same volume and selling it into Victoria at a higher value, in the process displacing generation in Victoria. There are no ‘net’ energy flows under this arbitrage regime as it involves matching the highest priced exports with the lowest priced imports for equal volumes of energy. Basslink can also act as a supply option for either Victoria or Tasmania, however this reduces the periods of time available for arbitrage.
• the increases in yield and revenue from the use of cloud seeding; and

• strategic benefits, including greater flexibility in hydro and wind generation capacity utilisation and the avoidance of stranded assets in the event of the loss of a major industrial load and/or the introduction of gas fired generation into Tasmania.

The cost of construction used in the February 2000 business case was also significantly lower than would ultimately prove to be the case, being based on figures submitted by NGIL and AEI through the competitive bidding process that did not reflect the additional costs that were an outcome of the JAP.

It had previously been recognised that the outcomes of the development approvals process may have an impact on the project’s costs, with this being one of the principal risks to the business case. Sensitivity analysis undertaken in 2000 showed that, at that time, it was expected that the value to Hydro Tasmania of energy trading via Basslink would exceed the annual cost of the link for the majority of years. Negative values occurred when hydrological inflows were low, resulting in Basslink being used as a net source of supply and reducing the trading value of the link, although Hydro Tasmania noted in its briefing to the Board that the negative impact on trading value caused by a dry inflow sequence would be offset by the avoidance of costs that would otherwise be required to meet demand requirements.

The Board accepted the business case and concluded that it would enter into commercial arrangements that would take the project through the development and approval process. It was on the basis of the February 2000 business case that Hydro Tasmania entered into the preliminary, but non-binding, agreement with NGIL to build, own and operate Basslink.

The decision by the Hydro Tasmania Board in May 2002 to reaffirm its commitment to Basslink was based on a complete re-examination of the business case for interconnection. That analysis took into account the increased project costs detailed in the Commercial Heads of Agreement, the imminent availability of natural gas in Tasmania and the conversion of the Bell Bay Power Station from oil to natural gas, and the Woolnorth wind farm development.

The May 2002 Basslink business case was tabled at the June 2002 meeting of Hydro Tasmania’s Board, and showed that:

• the business case for Hydro Tasmania had ‘tightened’, relative to earlier assessments;

• there had been a reduction in the risk associated with the project’s development as a result of obtaining environmental and planning approval;

• the variability of returns to Hydro Tasmania and, consequently, the State Government had increased; and
the risk profile had also changed, with both Hydro Tasmania and the State having to accept more non-construction risk, such as underwriting the telecommunications revenue generated by the fibre optic cable laid with Basslink.

The business case concluded that the increased risk was acceptable and would be actively managed wherever possible.

While opportunities for arbitrage still represented over half of the revenue that Hydro Tasmania expected to realise through Basslink, the May 2002 business case took in a wider range of revenue streams for Hydro Tasmania, without which the now significantly higher cost of construction would have made the project commercially unviable.

The business case took into account the following revenue streams:

- an increase in revenue associated with the arbitrage opportunities made possible by Basslink;
- the value of the additional yield that Hydro Tasmania expected to be able to generate as a result of improvements in its capacity to manage its water storages (i.e. reduced spill in periods of high inflows when on-island demand is not sufficient to use the available energy);
- the revenue derived from the creation and sale of additional RECs as the result of improved yield; and
- the net ‘export’ of electricity, that is, the difference between northern and southern-bound flows of electricity.

This last item, while not as critical to the business case as arbitrage, was a nonetheless important source of potential revenue for Hydro Tasmania, particularly early in the cable’s operational life, when it was assumed that positive cash flows would be generated from the ‘selling-down’ of some of the water reserves that had been required as a buffer for hydrological risk management in the absence of Basslink.
In terms of the ongoing costs associated with Basslink, the following expenses and negative revenue outcomes were taken into consideration:

- the Basslink facility fee;
- the costs of hedging\(^{26}\) against movements in interest rates and foreign currency exchange rates, in terms of the impact that these variables might have on the facility fee;
- the payment of a $50 million ‘security deposit’, essentially an up-front contribution to lower the annual ongoing cost; and
- the impact of on-island sales lost to gas and wind generation, noting that the value of the energy sales lost to gas and wind was offset by exporting the surplus energy associated with the lost sales.

The May 2002 business case also assumed that gas-fired generation would be operational and result in surplus generation being available for export.

The May 2002 business case showed that, on what Hydro Tasmania termed an Annualised Present Value (APV)\(^{27}\) basis, Basslink would return to Hydro Tasmania the equivalent of an annuity of $11 million per annum over the life of the BSA. Further, if two other revenue sources – which had been evaluated but not included in the February 2000 business case – were added, the estimated return to Hydro Tasmania attributable to Basslink increased to an APV of $24 million. The two other sources of revenue in question were revenue from the sale of insurance products (cap contracts) in the Victorian market and increases in the revenue associated with the renewal of major industrial customer contracts.

The following chart shows the relative contributions that the various sources of value identified by Hydro Tasmania in the May 2002 business case were expected to make to the net annual value of Basslink for Hydro Tasmania. As can be seen from the chart, the revenue associated with arbitrage was expected to be the largest single contributor to the viability of Basslink by a significant margin, although not sufficient to cover the cost of the link in its own right.

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\(^{26}\) In finance, a hedge is a position established in one market in an attempt to offset exposure to the price risk of an equal but opposite obligation or position in another market — usually, but not always, in the context of a business’s commercial activity. For example, one of the oldest means of hedging against risk is insurance to protect against financial loss due to accidental property damage or loss. Between 7 March 2000 and 29 November 2002, Hydro Tasmania entered into a number of foreign exchange and interest rate hedging transactions, prior to entering into firm contracts in relation to the construction of Basslink.

\(^{27}\) Given the potential variability in the annual trading outcomes generated by Basslink, the Hydro Tasmania Board sought a measure to examine ‘typical’ annual outcomes. The Board utilised the concept of Annualised Present Value (APV), which Hydro Tasmania defines as the annuity that would generate the same Net Present Value (NPV) as the variable net cash-flows (revenue less costs) projected to be generated by Basslink. For example, a positive cash flow over four years of $80, $50, $100, $120 might yield an NPV of $287 and, based on the same discount rate, an APV of $86. APV is not a commonly used measure but, for the purposes of presentation the Panel has elected to use APV throughout this paper as an accurate representation of the advice provided to the Board of Hydro Tasmania at the time.
The May 2002 business case and its underlying assumptions were also ‘stress tested’, by applying different scenarios for growth in the Tasmanian load, alternative hydrological inflow sequences, different Victorian price spreads and delays in the commencement of Basslink’s commercial operation, Bell Bay repowering and planned wind developments in Tasmania.

The sensitivity analysis confirmed that the project returns were robust to the likely range of sensitivities. The worst-case hydrological inflow sequence analysed reduced the APV from $24 million to $3 million, while the worst case Victorian price scenario analysed reduced the annualised PV from $24 million to $19 million. In terms of cash flow, analysis based on the May 2002 business case concluded that the cash flows generated by Basslink would be strongly positive in the initial years following Basslink becoming operational.
The projected cash flows reflected expectations about the state of Hydro Tasmania’s water storages at the time Basslink would be commissioned and the expectation that Basslink would enable Hydro Tasmania to run down its inventory of water in order to generate net sales from Tasmania without compromising its defences against low inflows.28

There has been some public comment that Basslink was proposed on the basis that it was predominantly, or solely, intended to be used to enable the sale of electricity from Tasmania to Victoria, and that the link’s use as a net supply option for Tasmania in recent years indicates that Basslink has failed to achieve its purpose. These views are at odds with the grounds on which both the State Government and Hydro Tasmania proceeded with the project. The Hydro Tasmania business case clearly anticipated that Basslink would be used for net supply in times of low inflows, as well as net exports in times of high inflows.

The May 2002 business case also confirmed that, under the BSA, Hydro Tasmania would receive both the ‘export’ and ‘import’ IRRs29 in exchange for the payment of the Basslink Facility Fee (BFF). The BFF would be subject to a commercial risk sharing arrangement with BPL being rewarded with a significantly higher fee when the arbitrage value provided by the link was high, provided the maximum dynamic transfer capacity was available during periods of high Victorian prices. Conversely, the BFF could be substantially reduced if the link’s dynamic transfer capacity was not fully available during these high priced periods or the arbitrage value was low. In this way, the ongoing cost to Hydro Tasmania of Basslink would be a function of the spread between peak and off-peak electricity prices in Victoria, which corresponds with the value to Hydro Tasmania from having Basslink.

Although the State Government had stated previously, in the Expression of Interest document released by the Basslink Development Board in July 1998, that there would be no financial contribution to the project by the State, by mid-2002 Hydro Tasmania had entered into ongoing discussions with the Government regarding a number of financial issues, including:

- payment of the $50 million Security Deposit being contemplated by Hydro Tasmania;

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28 While the business case noted that outcomes in individual years would be influenced by hydrological inflows, the February 2000 business case had assumed a starting storage level of over 60 per cent, with sensitivity analysis being conducted for opening storage levels based on materially lower than average, and higher than average scenarios. By May 2002, however, below average rainfall had resulted in Hydro Tasmania’s water storages falling to be just under 30 per cent of capacity, and by the time Basslink became operational at the end of April 2006, storage levels had only recovered to 33 per cent. The reduction in value arising from the difference in starting storages has been estimated by Hydro Tasmania to be in the order of $115 million.

29 Inter Regional Revenue (IRR) is the revenue Basslink earns from the market, being the value of the price difference between the Tasmanian and Victorian system marginal prices multiplied by the volume of electricity flowing across Basslink.
a proposal that the State take on Hydro Tasmania’s commitment under the Heads of Agreement (Telecoms) to underwrite the telecommunications revenue associated with the optical fibre cable being buried with the interconnector (which represented a potential cost of up to $2 million per annum for 15 years);

BPL’s requirement for the State to guarantee (should Hydro Tasmania default) the floating interest portion of the BFF; and

an acknowledgement from the State that the operational insurance cost pass-through arrangement Hydro Tasmania was proposing to enter into under an Insurance Concession Deed with BPL were necessary, given the state of the international insurance market.

Draft letters to the Shareholder Ministers detailing Hydro Tasmania’s requests in relation to these issues were attached to the May 2002 business case considered at the June 2002 Board meeting.

Cabinet subsequently agreed to Hydro Tasmania’s requests at its 11 November 2002 meeting.

3.1. Independent advice obtained by Hydro Tasmania

In addition to the analysis undertaken within Hydro Tasmania, Hydro Tasmania’s Board obtained two third-party reviews of the May 2002 business case, one from the Investment Banking Group (IBG) and the other from the National Australia Bank (NAB). In addition, other specialist external advisers were engaged to review particular business case assumptions, such as the assumptions made about Victorian prices.

The advice of both IBG and NAB focused on the pass-through arrangements that had been agreed to by Hydro Tasmania in relation to the cost of subsea cable burial and insurance, and noted the risk to the project’s viability posed by increases in those (and other) costs. IBG also noted that the positive benefit of Basslink to Hydro Tasmania now relied on new or improved revenues from a number of sources, and that without these the May 2002 business case would show a negative result.

3.2. Independent advice obtained by the State Government

The Department of Treasury and Finance also obtained independent advice, from Price Waterhouse Coopers (PwC), regarding the impact of Basslink on returns to Government; the risk to the State should Basslink proceed (in both the ‘with gas’ and ‘without gas’ scenarios and whether the State should accede to the requests from Hydro Tasmania regarding the proposed insurance arrangements, the $50 million security deposit, the underwriting of BPL’s telecommunications revenue and the floating interest rate component of the facility fee.
The review by PwC was not the first time during the evolution of the project that the State Government had sought independent advice in relation to the risks to Government associated with energy reform options, including Basslink.30

The PwC report highlighted the need to consider the project from the perspective of its net present value, and to take into account the variability in financial outcomes on a year-by-year basis, which would be largely driven by hydrology. PwC cautioned that focusing on a single “APV” figure to justify proceeding with the project, as Hydro Tasmania’s business case did, disguised the variability that existed in some of the estimated benefits.

In particular, PwC noted the potential for the positive cash flows associated with the export of surplus energy in the first decade of Basslink’s operation to be reduced, or even reversed, if the hydrological inflows included in the assumptions underpinning Hydro Tasmania’s base case – which used a historic inflow sequence – were not achieved.31

The PwC report also considered the range of risks associated with the Basslink project from the State’s perspective. In light of the potential variability in Hydro Tasmania’s financial performance, highest amongst those risks was the risk to the State Government’s fiscal strategy, in terms of the returns to Government from Hydro Tasmania. The PwC report highlighted that the State Government was not in a strong position to influence or control the key financial risks arising from the project.

In relation to the risks faced by Hydro Tasmania, PwC’s opinion was that the key financial risks identified in earlier assessments of the business case for Basslink remained. The risk associated with Victorian price spread was rated by PwC as one of the highest risks, while the level of hydrological risk to the business case and Hydro Tasmania’s role as payer of the operational insurance costs for Basslink were considered key exposures.

PwC also noted that the annualised NPV calculation used by Hydro Tasmania as the basis for its decision to continue with the development of Basslink did not consider two cost elements in its assessment of the business case: the value of the security deposit ($50 million) and the foreign exchange and interest rate hedges that had been entered into by Hydro Tasmania in mid-2000, in an attempt to reduce the financial risks to the project ahead of financial close. PwC agreed with Hydro Tasmania’s treatment of the hedge positions as ‘sunk costs’ from a decision-making point of view.

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30 The review by PwC was led by Mr John Martin, a partner in PwC and former partner with Oakvale Capital Limited, which had previously been engaged by the State Government, through the Department of Treasury and Finance, to conduct reviews of earlier iterations of Hydro Tasmania’s Basslink business case, and provide advice regarding the impact on the financial returns to Government and risks for the State should the Basslink project proceed. The previous reviews had also examined NEM entry and the impacts that the introduction of natural gas in Tasmania would have. Prior to the re-examination of the business case for Basslink in May 2002, reviews were undertaken of the February 2000, August 2000 and March 2001 business cases.

31 As discussed above, this is, in fact, what ultimately transpired, with a series of below average inflow sequences in the years immediately prior to Basslink becoming operational impacting on Hydro Tasmania’s ability to capture the planned early cash flows.
The PwC report concluded that if these two cost elements were added back into the business case, to give the overall cost of Basslink to Hydro Tasmania, the estimated annualised NPV for Hydro Tasmania was reduced by $9.5 million.

Given that its brief was to consider the implications of Basslink for the State, and not just Hydro Tasmania, PwC contended that it was important to recognise that without Basslink, and in the face of new on-island generation fired with natural gas, the projected outlook was for a decline in Hydro Tasmania’s returns to Government over the following ten years. In addition, the report noted that the State Government had flagged Basslink as a strategically important project for Tasmania, given that it would facilitate further development of Tasmanian wind resources, reduce drought risk and introduce competition into the Tasmanian Electricity Supply Industry.

In conclusion, PwC’s advice was that a case could be made for the State Government to support Hydro Tasmania’s business case by endorsing Hydro Tasmania’s payment of the $50 million security deposit, providing the guarantees required by BPL and agreeing to act as payer of the Basslink operational insurance costs. The report noted, however, that in taking on these obligations the Government would be providing considerably more direct support for energy reform than had originally been envisaged.

3.3. Notice to proceed

A final update of the business case for Basslink was tabled at the September 2002 Hydro Tasmania Board meeting. The September 2002 business case included adjustments to the May 2002 business case arising from the fixing of the subsea burial costs and greater certainty regarding construction insurances. The Basslink revenue sources had also been reviewed, with the aid of ‘dynamic temperature’ modelling, which simulated the dynamic capability of Basslink and the impact that this would have on the daily bidding of Basslink.

The revised calculations based upon a more comprehensive study of the two key drivers of Basslink value, Victorian price volatility and inflow variability, resulted in a substantial increase in the estimated value of arbitrage opportunities, which in the May 2002 business case had represented over half of the revenue Hydro Tasmania expected to earn from Basslink.

As in previous business case updates, there were increases in the project’s cost, but again they were more than offset by increases in the estimated values of other Basslink revenue sources. The net result was a revised APV of $26 million per annum, an increase of $2 million per annum over the May 2002 business case.

Hydro Tasmania also undertook a final detailed risk assessment, which included identification of the risks to Hydro Tasmania if Basslink were not to go ahead, as well as the risks if Basslink proceeded.
It was noted in a presentation of the September 2002 business case to Hydro Tasmania’s Board that, once final legal advice on the amended project documents had been received, the Board should be in a position at its November meeting to issue a notice to proceed, as it was unlikely that there would be any further changes to the business case.

Accordingly, the Board resolved to accept the Basslink business case as a commercially sound basis for authorising the Corporation to enter into the 25 year BSA, subject to the satisfactory resolution of the outstanding issues in a manner that did not result in a significant adverse impact on the business case, and subject to formal approval of the final business case. Hydro Tasmania’s CEO was also given the authority to negotiate a further financial commitment to the project in order to obtain the required extension of the Engineering, Procurement & Construction (EPC) contract end date.32

The key tasks for the Hydro Tasmania Board at its November 2002 meeting were to receive an updated September 2002 business case and consent to the Corporation entering into the suite of amended project documents.

The updated business case showed that the link’s net value had increased to an APV of $29 million, $5 million higher than the figure included in the September 2002 business case.

The Board of Hydro Tasmania resolved that the Corporation would “take all necessary steps” to discharge its obligations under the amended project documentation tabled at the meeting, noting that “it is the commercial judgement of the board” that the Basslink project, as negotiated and presented to the Board, “will be advantageous to the conduct, promotion and attainment of the objects of the business of the Corporation”.33

In order for Hydro Tasmania and BPL to reach final agreement on the cost to complete Basslink – which still had not been resolved and by that time stood at around $850 million – the Board also authorised the CEO to negotiate a further increase to reach financial close.

A further special Board meeting was scheduled for 27 November 2002 to enable the CEO to report back to the Board on the final negotiations and the impact (if any) on the ‘final’ business case. At that meeting, the Board was advised that the negotiations to reach agreement on the final Cost to Complete, while close to resolution, would require the Board to authorise a further increase in negotiating limits, to allow for finalisation of construction insurances, and this was provided.

32 Hydro Tasmania’s final risk assessment identified that BPL had failed to conclude negotiations for an extension to the EPC contract with Pirelli and Siemens, giving rise to the possibility that the EPC contract could be terminated.
33 Minutes of a Meeting of Directors of Hydro Electric Corporation (ABN 48 072 377 158) (“Corporation”) at Hobart on the twentieth day of November 2002.
The final negotiations took place on 27 November 2002 and the Hydro Tasmania Board met again on the following day, where they were advised that agreement had been reached on the outstanding items, including the Cost to Complete.34

With the inclusion of foreign exchange and interest rate movements and the agreed final negotiated costs, the Board was advised that:

- the annual cost of Basslink to Hydro Tasmania would, on an APV basis, be $64 million, comprising a Basslink facility fee of $57 million, plus $7 million in hedging costs (in net terms) and Hydro Tasmania’s project related costs; and

- the estimated APV of Basslink to Hydro Tasmania now stood at $28 million, which represented a benefit/cost ratio of 1.44:1.

Based on confidential information provided by Hydro Tasmania, including details of the projected cash flows associated with Basslink over its first 20 years of operation and the discount rate used by Hydro Tasmania in calculating its APV measure of Basslink’s value, it is estimated that an APV of $28 million (2002$) equated to a NPV of approximately $260 million (2002$).

With the negotiated business case parameters being acceptable to the Board and legal advice having been received that confirmed the amended projects documents as suitable for execution, the project documents were duly executed and a Notice to Proceed issued to the State Government on 29 November 2002, resulting in the Basslink project becoming unconditional.

BPL also issued a Notice to Proceed on 29 November 2002 to its EPC contractors, the Tas-Vic Consortium (Siemens and Pirelli), to commence work on the project.

3.4. Project completion

BPL’s project plan had Basslink commencing commercial operation by late 2005. However, a number of major incidents occurred during construction, delaying the commissioning process.

While BPL requested an extension in the project’s due date, claiming that these events were beyond its reasonable control (i.e. force majeure), the claims were not accepted by the Project Inspector, with the result that BPL was required to pay $5 million in liquidated damages and there was no increase to the projected cost to complete the project from Hydro Tasmania’s perspective.

34 There would still be some pass-through of costs allowed, such as subsea burial costs, which were not fixed at that time.
The incidents, which included damage to transformers in transit from Germany (requiring replacements to be built and shipped to Australia) and several incidents during burial of the subsea cable, resulted in a five month delay in the project’s completion, with the result that Basslink did not commence commercial operation until midnight on 28 April 2006, some three years later than the originally proposed commencement date of April 2003. However, from the time of financial close, the project was delivered on schedule, except for the delay caused by the transformer damage during shipping.

The total cost to complete at the commencement of commercial operations in April 2006 was $874 million, including the agreed contribution towards the cost of subsea burial of the cable.
4. **Basslink’s performance - physical**

The operation of Basslink is governed by two main contracts, the Basslink Operations Agreement (BOA) and the BSA. Both agreements specify a range of operational requirements, some of which can be traced back to the technical requirements set out in the Project Brief used as part of the selection process to choose a developer for Basslink. The two agreements are, however, independent of each other and the performance obligations in both are different.

The BOA is the contractual mechanism between the State of Tasmania and the operators of Basslink, the primary focus of which is ensuring that an interconnector is available to the State for a period of 40 years. As such, the BOA has no financial incentives or penalties relating to the link’s performance.

The BSA, on the other hand, which is the agreement between Hydro Tasmania and BPL establishing the rights and obligations of both parties with respect to the operation of Basslink, includes a number of financial incentives relating to the link’s performance, in terms of its availability.

The requirements regarding the operational performance of Basslink set out in both agreements are summarised below.

**Basslink Operations Agreement**

The principal features of the BOA are:

- a minimum availability of 97 per cent, and a performance target of 97.5 per cent (excluding force majeure events), assessed on a rolling 12 month basis and taking into account unavailability due to both planned and unplanned outages;
- a cable failure frequency not exceeding once in ten years;
- a maximum of five unplanned interruptions to transfers across Basslink per annum (excluding interruptions that last for less than 500 milliseconds); and
- a maximum repair time per cable failure of two months (not including failures caused by force majeure events).

Under the BOA, sub-standard performance can also have potentially significant consequences for the operators of the link.

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35 The final business case for Basslink assumed availability of 97 per cent and allowed for 50 hours a year of unplanned outages.

36 Details of these arrangements have not been provided in this paper for reasons of commercial confidentiality.
**Basslink Services Agreement**

The principal features of the BSA are:

- a minimum availability of 97 per cent, assessed on a calendar year basis, along with financial penalties for BPL if the interconnector’s availability is below that level;

- a financial incentive to the operator of the link if the cable is 100 per cent available during the Victorian summer (see Incentive availability payments); and

- a commercial risk sharing mechanism that distributes the financial consequences of changes in the arbitrage opportunities made available through Basslink, which has the effect of incentivising the operator to ensure the link is 100 per cent available during times of high Victorian spot market volatility (see Commercial risk sharing payments).

### 4.1. Energy transfers

Figure 2 shows the flows of electricity to and from Tasmania via Basslink on a monthly basis since the cable began commercial operations in 2006, as well as the net balance of those north and south bound flows, which, until 2010-11, had consistently seen the net ‘importation’ of electricity into Tasmania.

**Figure 2 - Basslink energy flows (monthly)**

![Chart showing energy flows](image)

Source: Hydro Tasmania
Table 2 summarises the annual flows of electricity in each direction over Basslink since the cable was commissioned in late April 2006. Reflecting the below-average inflows into Hydro Tasmania’s water storages in the years immediately prior to and following Basslink commencing commercial operation, Basslink has thus far been used as a net supply option for Tasmania, rather than a means of selling electricity into Victoria. With the gradual return to more typical rainfall totals in recent years, 2010-11 was the first year in which north bound flows of electricity over Basslink exceeded southward flows (see Table 2, below).

**Table 2 - Annual Basslink flows**

<table>
<thead>
<tr>
<th>Direction of net flows</th>
<th>Flows to Tasmania (GWh)</th>
<th>Flows from Tasmania (GWh)</th>
<th>Net Flow (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>May - June 2006</td>
<td>144</td>
<td>125</td>
<td>19</td>
</tr>
<tr>
<td>2006-07</td>
<td>1 954</td>
<td>584</td>
<td>1 371</td>
</tr>
<tr>
<td>2007-08</td>
<td>2 506</td>
<td>227</td>
<td>2 279</td>
</tr>
<tr>
<td>2008-09</td>
<td>2 632</td>
<td>72</td>
<td>2 560</td>
</tr>
<tr>
<td>2009-10</td>
<td>1 785</td>
<td>669</td>
<td>1 116</td>
</tr>
<tr>
<td>2010-11</td>
<td>1 132</td>
<td>1 232</td>
<td>100</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>10 153</strong></td>
<td><strong>2 909</strong></td>
<td><strong>7 245</strong></td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania

The annual northward and southbound flows are detailed in Table 2 - Annual Basslink flows are presented graphically in Figure 3.
Low yields from Hydro Tasmania’s water catchments have meant that Basslink, to date, has not delivered the level of energy ‘exports’ expected in the business case. Interconnection was, however, proposed on the basis that it would be used both for the purpose of net supply in times of low inflows and net exports in times of high inflows. The net flow of energy over Basslink to date has, therefore, been consistent with its intended function, even if the overall direction of those flows has not resulted in the net ‘export’ of energy during the early years of the cable’s operational life that was factored into the final Basslink business case.

4.2. Availability

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 BOA and the BSA. Data provided by both Hydro Tasmania and BPL indicate that the link’s average availability has been around 97.5 per cent, noting that availability has been assessed on both a calendar year basis and a rolling 12-month basis, depending on the agreement against which performance is being measured.
It is useful to put the performance of Basslink in this regard into a wider context. The International Council on Large Electrical Systems (CIGRE) conducts an annual survey of the reliability of over 30 High Voltage Direct Current (HVDC) systems throughout the world, including Basslink. Figure 4 shows that, since Basslink was commissioned in 2006, its performance – in terms of its availability – has been above the average of the other interconnectors included in the survey and, with the exception of 2008 and to a lesser extent 2010, amongst the best performing HVDC systems.

**Figure 4 - Basslink availability**

There have, however, been periods when the availability of the link has been below the levels set out in the BOA and BSA, although only the link’s performance against the standard in the BSA has had financial ramifications in terms of the cost of the link to Hydro Tasmania.

This was particularly the case in calendar year 2008, when Basslink’s availability was below the 97 per cent required under the BSA, at 94.7 per cent (see Figure 5), resulting in a reduced Basslink Facility Fee (BFF). It is noted that despite the deterioration in availability that occurred in 2008, the total amount of energy transmitted in calendar year 2008 was higher than in either 2007 or 2009, even though availability in both those years was above the BSA standard.
Hydro Tasmania contends that the reduced capacity to ‘import’ electricity associated with the link’s diminished availability in 2008 also had significant operational and financial impacts for its business, outcomes which were exacerbated by drought conditions that saw Hydro Tasmania’s water storages drop to 16.5 per cent of capacity in June 2008.37

As with any interconnector, particularly monopole links (like Basslink) that lack the redundancy provided by a second HVDC cable, Basslink’s availability has been affected by planned and unplanned outages, although scheduled outages typically have less impact on the performance of the power system in question than unscheduled outages, because they are usually undertaken during periods of reduced system load or when a reduction in availability can be tolerated.

Figure 6 shows the unscheduled and scheduled outages that have occurred since Basslink was commissioned in 2006. The chart shows that there have been a small number of comparatively ‘major’ unplanned outages. To put those outages in context, the unplanned outage that began on 31 December 2007 lasted eight days and the unscheduled outage that occurred in July 2008 lasted nine days, as did the outage in April 2010.

The most significant planned outage occurred in October 2009, as part of a biennial preventative maintenance program, and lasted for four days.

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37 Source: Hydro Tasmania submission to the Panel. Measures were taken by Hydro Tasmania to address this fall in performance, resulting in the improvement seen in 2009.
Aside from the immediate impact that unscheduled outages have on Hydro Tasmania’s capacity to trade electricity, under the terms agreed to as part of the System Protection Scheme (SPS), unplanned interruptions that have occurred while electricity has been flowing southward into Tasmania and triggered the shedding of major industrial load under the SPS have, on a number of occasions, continued to constrain flows over Basslink into Tasmania – even after the operation of the link has been restored.

This is because the arrangements put in place with some of the major industrial customers which are willing to interrupt production in order to protect Tasmania’s electricity grid have, in the past, included provisions which prevented them being called upon to do so within a period after their most recent load shedding event. This arrangement meant that the level of load shedding available under the SPS could potentially be reduced, sometimes for weeks, following an outage of Basslink when ‘importing’ energy, constraining the link’s capacity to deliver energy into Tasmania and impacting on the value of Basslink to Hydro Tasmania. The impact of this constraint would be greatest when the restriction on southward flows coincided with periods of high demand in Tasmania and low prices in Victoria. The Panel understands that re-negotiation of the terms under which some industrial entities participate in the SPS has reduced the limitations on further load shedding following an SPS trigger.
4.3. Financial impacts of availability

As well as being crucial to the creation of value for Hydro Tasmania, the physical performance of Basslink impacts on the ongoing cost of Basslink to Hydro Tasmania and, consequently, the revenue earned by Basslink’s operator.

As noted earlier, the BFF paid by Hydro Tasmania is subject to risk sharing arrangements that reward BPL with an increased fee (via Commercial risk sharing payments) when the arbitrage value provided by the link is high, provided the interconnector is fully available during periods of high Victorian prices. Conversely, those same arrangements substantially reduce the BFF if the link is not fully available during these high priced periods, or if the arbitrage value is low. The potential impacts on the BFF are material to both Hydro Tasmania and BPL, in that the fee can be varied within a 40 per cent range under the risk sharing arrangements.

The commercial risk sharing arrangements have resulted in Hydro Tasmania paying an increased BFF in only one of the link’s first six years of operation (calendar year 2007). In that year, the price volatility in the Victorian spot market was such that Hydro Tasmania made additional payments equivalent to 25 per cent of the BFF for that year, the maximum amount payable under the terms of the BSA. This reflects that the arbitrage value available to Hydro Tasmania was high, providing it with the financial capacity to fund the additional payments.

Cumulatively, however, to the end of September 2011 Hydro Tasmania has been a net beneficiary from the risk sharing arrangements in the BSA since it commenced delivering energy in 2006.
5. Basslink’s performance - financial

There is considerable stakeholder interest in understanding how the Basslink commercial arrangements have impacted on Hydro Tasmania’s commercial performance. It should be recognised, however, that care needs to be exercised when evaluating the commercial viability of a long term infrastructure project early in its economic life.

Nonetheless, it is constructive to examine the extent to which the performance of the project to date conforms to the expectations set out in Hydro Tasmania’s final business case. Accordingly, this section of the paper presents an assessment of the outcomes which have been realised to date by Basslink from two perspectives:

(a) a comparison with the final business case for interconnection developed by Hydro Tasmania; and

(b) a comparison with a ‘counterfactual’ outcome – by considering what might have been the path of the Tasmanian energy sector had Basslink not gone ahead.

Consistent with the Panel’s Terms of Reference, which require it to focus on the implications of major infrastructure projects on customer prices, the Panel has not examined the wider economic impacts of Basslink for Tasmania, such as the effect that perceptions within the business community of lower hydrological risk and greater security of supply have had on business confidence and investment decisions.38

5.1. Basslink’s performance against the business case

For any commercial entity, the fundamental purpose of capital investment is to invest in projects that yield a positive net present value to the business, which is a function of the amount and timing of the future cash flows associated with the investment. Assessing the viability of a capital investment requires the variables which impact on those cash flows, as well as the cash flows themselves, to be forecast over the life of the project.

However, the process of forecasting, even in the short term, is inherently uncertain and the long-term nature of capital investment decisions introduces still greater levels of uncertainty.

38 The May 2002 Basslink Business Case identified a range of benefits for Tasmania that would be provided by Basslink, and noted that Basslink was consistent with Hydro Tasmania’s obligations to foster social and economic development under its Ministerial Charter. While the Hydro Tasmania Board was aware when it made its final commitment to Basslink of the broader considerations that made Basslink a project of State significance, those wider impacts were not part of the business case for interconnection and there is no evidence that these considerations were central to Hydro Tasmania’s commercial decision making.
In the case of Basslink, which required a minimum 25 year commitment by Hydro Tasmania, the business case incorporated assumptions about a range of variables, including long-term projections of the likely inflows into Hydro Tasmania’s water catchments (and their potential variability), the outlook for Victorian electricity prices and growth in the Tasmanian load, as well as the availability and capacity of the link itself.

The final business case endorsed by the Board of Hydro Tasmania in November 2002 took into account a range of costs (see Box 3) and benefits to Hydro Tasmania’s business that could be directly attributed to Basslink, in order to calculate the link’s net value to Hydro Tasmania.

That value was calculated on the basis of projected cash flows over a period of 20 years, which were then reduced to a single annual figure, representing the annuity that would return Hydro Tasmania the same Net Present Value (NPV) as the Basslink project. Hydro Tasmania referred to this figure as an APV. On this basis, in the final business case the link’s net value to Hydro Tasmania was estimated to be $28 million per annum, expressed in 2002 dollars.39

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39 About $36 million in 2011 dollars
What are Hydro Tasmania’s Basslink costs?

Observations that Hydro Tasmania has a ‘locked in’ facility fee of over $90 million per annum are not correct, although the overall cost of Basslink to Hydro Tasmania has, in some years, been in excess of $90 million since the link was commissioned. To better inform public discussion of the costs and benefits of Hydro Tasmania’s Basslink financial commitments, it is useful to clarify the costs that are involved and the nature and quantum of the payments made by Hydro Tasmania and Basslink Pty Ltd (BPL).

The following items make up the cost of Basslink to Hydro Tasmania:

**Basslink Facility Fee**

The BFF is paid by Hydro Tasmania to BPL in exchange for the rights to the variable inter-regional revenues accruing to Basslink through the NEM arrangements. While the BFF is indexed, the level of indexation is such that the fee declines in real terms over the life of the Basslink Services Agreement. It is the largest of Hydro Tasmania’s Basslink-related costs.

**Commercial risk sharing payments**

These payments are paid either by Hydro Tasmania to BPL or BPL to Hydro Tasmania, depending on the value of arbitrage opportunities presented by price volatility in the Victorian spot market. The risk sharing payments are highly variable and can have a material impact on the cost of Basslink to Hydro Tasmania, with the facility fee able to vary within a 40 per cent range.

**Incentive Availability payments**

Incentive availability payments are paid to BPL by Hydro Tasmania depending on the availability of Basslink at certain times of the year and at predefined Victorian spot market prices that may provide Hydro Tasmania with arbitrage opportunities. The amount of the payment made in any given year is variable, and is based on interconnector availability and spot market prices during the Victorian summer peak period. Incentive availability payments are relatively small compared to the facility fee (around 2 per cent).

**Insurance costs**

Hydro Tasmania funds the costs of marine insurance for Basslink. Owing to the particular features of the insurance market at the time of financial close, which was enduring a period of instability in the wake of the terrorist attacks on New York City in September 2001, it was agreed that operational insurance costs above those already factored into the BFF would be paid as an ongoing operational cost pass through. The costs of insurance are variable but relatively minor in the context of the BFF (in the order of 2-4 per cent).

**Financial costs**

Paid by Hydro Tasmania to financial institutions for products to cover aspects of the costs associated with Basslink that vary over time with movements in financial markets. These are highly variable and can be significant, relative to the BFF (e.g. in one year over the period 2005-06 to 2010-11, hedge costs were equivalent to around 43 per cent of the facility fee).
Figure 7 illustrates the relative contributions to Basslink’s net value, in real terms, by the various direct costs and direct revenue benefits on a similar basis to the business case for Basslink, based on the average outcomes that have been observed over the first five full years of the cable’s operational life. When compared with the sources of value factored into the final December 2002 business case it becomes clear that, on a number of fronts, Basslink’s financial performance is yet to fulfil the expectations contained in the final business case.

Figure 7 – Benefits of Basslink to Hydro Tasmania, 2006-07 to 2010-11 compared with business case, % of Basslink-related costs

Source: Hydro Tasmania
Notes: Quantums are not shown on the chart in monetary terms as the information is commercial-in-confidence. ‘Victorian Contract’ benefits have been captured in the arbitrage value, whereas these were separately identified in the business case (and in Figure 1). The benefits are expressed as a proportion of the Basslink-related costs in each case and, as such, are not directly comparable. For example, in the business case, arbitrage benefits coupled with Victorian contract value was expected to be broadly similar to the Basslink-related costs; whereas, in the first 5 years, these benefits were equivalent to around 60% of costs.
The benefits derived by Hydro Tasmania from Basslink have been heavily influenced by the prolonged period of below average rainfall that occurred during the past decade. Basslink has been used as a net supply option for Tasmania for most of its operational life to date – northward flows of electricity exceeded the flow of energy into Tasmania for the first time in 2010-11. The low level of inflows, particularly in the lead-up to Basslink commencing commercial operations and in the first three years of trading, had a number of impacts:

- the revenue contribution from net exports were substantially less than anticipated;
- the contributions from increased system yield and the accompanying creation of additional RECs were less than anticipated in the business case; and
- with Basslink heavily utilised as a supply option for Tasmania, the availability of the link to be used for arbitrage purposes was also diminished.40

Hydro Tasmania had anticipated that the outcomes in individual years from interconnection would be influenced by hydrological inflows. However, between the decision to proceed with Basslink and the commencement of commercial operations only three and a half years later, successive years of substantially below average rainfall meant that Hydro Tasmania’s expectations regarding the state of its water storages at the time Basslink would be commissioned turned out to be significantly higher than that realised.

As a result of the lower than expected ‘opening’ water storage levels, Hydro Tasmania was prevented from running down its inventory of water in the initial years following Basslink becoming operational in order to generate energy for ‘export’ and income. Hydro Tasmania estimates that the value forgone due to the difference between the opening inventory of water assumed in the business case and that which was observed is in the order of $115 million.

If only the realised costs and benefits directly attributable to Basslink and factored into the business case are taken into account41, then Basslink’s overall cost to Hydro Tasmania is approximately $134 million ($ nominal) higher than the realised direct financial benefits it has delivered since the interconnector was commissioned in April 2006.

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40 As discussed above, arbitrage refers to the use of Basslink on a balanced trade basis, where electricity is effectively purchased from Victoria at low prices (ie. water is conserved) and sent from Tasmania when prices are high (that conserved water used). If Basslink is used as a net supply option, purchases from Victoria are necessarily of a greater volume than sales to Victoria, and the arbitrage opportunity is reduced.

41 These financial benefits being arbitrage, net exports, the value of enhanced system yield and REC associated with the yield and increases in major customer prices.
Hydro Tasmania contends that the average financial performance of Basslink (leaving aside the avoided cost considerations discussed below) thus far understates Basslink’s future trading potential, and is essentially the result of consecutive years of extremely low inflows into Hydro Tasmania’s water storages, which coincided with a NEM wide drought. The Panel accepts that this view is reasonable.

It is also the case that Hydro Tasmania’s estimates of Basslink’s benefits, presented in Figure 7 above, make no allowance for the value of the increased inventory of energy now in storage, which to some extent has been enabled by the use of southward flows of energy across Basslink to support the recovery of Hydro Tasmania’s water storages. Further, no additional value is currently ascribed to any potential commercial gains associated with the introduction of a price on carbon emissions by the Australian Government. In this context, the financial snapshot provided above is conservative.

While the initially difficult trading conditions experienced in the years immediately following the link commencing operations did not feature in the base business case, the fact that those years have been followed by an ongoing improvement in both water inflows and the trading performance of Basslink is nonetheless consistent with Hydro Tasmania’s overarching expectations regarding the variability of Basslink’s performance over time, particularly in relation to hydrology.

Further, when Basslink’s average performance over the two most recent years of operation is examined, a different picture of the link’s value to Hydro Tasmania emerges, one that more closely resembles the expectations contained in the final business case for interconnection. In 2009-10 and 2010-11, Basslink generated financial returns in excess of costs for Hydro Tasmania approaching $30 million. This result lends support to Hydro Tasmania’s argument that the average performance of Basslink to date understates the link’s potential in the future, as does the fact that it was achieved with only a small contribution (in 2010-11) from net transfers of electricity to Victoria (‘net exports’), though with only two years of post-drought data to hand, it is too soon to make firm conclusions.

Figure 8 compares the financial benefits from Basslink to Hydro Tasmania with those included in the final business case. Figure 8 demonstrates that the return to more typical hydrological inflows in recent years has resulted in the performance of Basslink displaying a closer resemblance to the business case, with scope for further improvement with regard to the level of export income able to be realised in the future as a result of the rebuilding of water storages, as well as carbon pricing.

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42 As discussed above, Hydro Tasmania did conduct extensive sensitivity tests, which included hydrological scenarios with relatively dry early years. The base business case did contain a period of low inflows, but not in the immediate first few years.
5.2. Basslink’s contribution to supply reliability

Just as the financial performance of Basslink has been impacted negatively by low inflows into the Hydro Tasmania’s catchments, inversely, the benefits of interconnection have been demonstrated through the contribution of Basslink to meet Tasmania’s electricity needs.
This is a key consideration in examining the overall performance of the project, as the magnitude of any net avoided costs through Basslink represent material financial benefits to Tasmania.\(^{43}\)

While it is impossible to know exactly what might have transpired had Basslink not been developed, such an approach is consistent with the analysis undertaken by Hydro Tasmania when originally developing the business case for Basslink. In addition to the costs and benefits of Basslink, this approach also examined Hydro Tasmania’s likely future without interconnection.

### 5.2.1. Hydro Tasmania’s analysis

The central feature of Hydro Tasmania’s view of the Tasmanian energy market without Basslink is that Hydro Tasmania’s dams and hydro-electric power stations would have been unable to meet the demand for electricity in Tasmania, in terms of total consumption.

This assessment is based on the fact that Hydro Tasmania’s ability to generate electricity is constrained by the availability of water, rather than the capacity of its power stations. The yield from Hydro Tasmania’s water catchments between 2006-07 and 2010-11 was insufficient to meet the demand for electricity over the same period. The situation would also have been exacerbated by the fact that, by 2006, Hydro Tasmania’s long-term water storages had already been depleted by low inflows, particularly in 2004-05, to the point that there was limited capacity to draw down on those inter-year storages in order to make up for the lower yields being achieved from run-of-river and intermediate storages.\(^{44}\)

Based on the demand for electricity seen in Tasmania in the years since Basslink was commissioned, Hydro Tasmania estimates that between 2006-07 and 2009-10 there would have been a shortfall in the capacity of hydro-generation to meet on-island demand of just over 7,000 GWh. To put that shortfall into perspective, the total demand for electricity on mainland Tasmania is typically around 10,800 GWh per annum.\(^{45}\) In the absence of Basslink, this shortfall would have had to be met by other means.

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\(^{43}\) In practice, the distribution of these benefits is a function of how higher costs would have been distributed between Hydro Tasmania and customers.

\(^{44}\) Hydro Tasmania’s 32 power stations are fed by three types of water ‘storage’. ‘Run of river’ power stations generate electricity whenever water is available, as there is limited capacity to store water for later use. Intermediate storages cycle from full to empty over the course of a year and provide some scope for Hydro Tasmania to choose when to produce electricity (or retain water). Long-term storages (e.g. Lake Gordon and Great Lake) fill and empty over a long period and have storage capabilities substantially in excess of their annual inflows.

Hydro Tasmania has provided the Panel with a view on how that demand may have been met in the absence of Basslink. Hydro Tasmania’s scenario assumes that this would have required investment in gas-fired generation in Tasmania (by Hydro Tasmania) as well as, in times of extremely low inflows into Hydro Tasmania’s storages, negotiated load shedding by major industrial customers.46

Hydro Tasmania estimates that the combined cost of these two approaches to making up the shortfall in hydro-electric generation and balancing Tasmania’s supply and demand for electricity would have been in the order of $640 million over the period 2006-07 and 2010-11. Approximately 80 per cent of that expenditure reflected the costs (including fixed and variable costs) of generating 6 400 GWh of electricity using a combination of combined and open cycle gas generation, with the balance being the cost of load shedding by major industrial customers.

To determine the level of savings that could be attributed to Basslink, Hydro Tasmania offsets the cost of the energy actually sourced via Basslink (i.e. net southward flows) to supply Tasmania’s load during each year over the period against the estimated costs of new gas fired generation and industrial load buyback.

On this basis, Hydro Tasmania concludes that the avoided costs of additional generation plant and load interruption fees over the five years that Basslink has been in operation would have been in the order of $314 million, in nominal terms. Table 3 sets out the method used by Hydro Tasmania to calculate the costs to its business avoided by Basslink being in operation.

### Table 3  Hydro Tasmania’s estimates of Tasmanian energy supply costs avoided by Basslink, $ million nominal

<table>
<thead>
<tr>
<th>Description</th>
<th>$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hypothetical estimated cost of additional gas-fired energy (fixed and variable costs)</td>
<td>513</td>
</tr>
<tr>
<td>Hypothetical estimate of industrial load buyback</td>
<td>125</td>
</tr>
<tr>
<td>Total cost under ‘no Basslink’ scenario</td>
<td>638</td>
</tr>
<tr>
<td>Less</td>
<td></td>
</tr>
<tr>
<td>Actual cost of net inflows of energy to Tasmania via Basslink</td>
<td>324</td>
</tr>
<tr>
<td><strong>Avoided costs</strong></td>
<td><strong>314</strong></td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania

46 This is viewed as a credible outcome given that there is precedent for this response to low storage levels.
Noting the earlier assessment that the direct costs of Basslink were in excess of the realised revenue benefits up until 2009-10, if the avoided costs calculated in Table 3 are also considered a financial benefit, Hydro Tasmania contends that Basslink has been a source of substantial value to its business. Hydro Tasmania’s submission on the Issues Paper provides an estimate in excess of $40 million per annum ($nominal).\(^47\)

Taking that argument and accepting Hydro Tasmania’s estimates of the avoided costs, without Basslink, Hydro Tasmania’s net earnings would have been reduced by $180 million (see Table 4, below).

<table>
<thead>
<tr>
<th></th>
<th>$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct financial consequences of Basslink</td>
<td>(134)</td>
</tr>
<tr>
<td>Plus - Avoided costs (from Table 3)</td>
<td>314</td>
</tr>
<tr>
<td>Net benefit of Basslink</td>
<td>180</td>
</tr>
</tbody>
</table>

### 5.2.2. The Panel’s analysis

The Panel has undertaken its own analysis of the potential ‘avoided cost’ benefits of Basslink in order to test the reasonableness of Hydro Tasmania’s assessment, noting that it is not possible to be definitive about how the Tasmanian energy sector would have evolved in the absence of Basslink. The details of this analysis are in Appendix 1.

In brief, two potential scenarios were examined to develop a view as to the potential cost implications for Tasmania’s electricity sector had Basslink not been progressed, in order to compare this with the outcomes observed under the present Basslink arrangements. Those two scenarios were:

- electricity needs being met by new gas-fired generation; and
- electricity needs being met by the development of large-scale wind generation – the technical feasibility of which has not been tested.

In examining both cases, the Panel has assumed that observed electricity demand over the period was the level of demand that would have applied under the alternative scenarios.\(^48\)

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\(^47\) Hydro Tasmania’s estimate of $40m pa benefit is on a different basis to the Panel’s calculation of $180 million over the period owing to a difference in the estimated revenues and costs arising from the project.

\(^48\) This is a simplifying assumption. It is arguable that demand may have been at a lower or higher level, but the Panel considers this a reasonable basis for the analysis. It is the same assumption made by Hydro Tasmania in its analysis.
Gas-fired generation

The Panel’s gas thermal generation scenario assumes that two 200MW combined cycle gas facilities would have been built in Tasmania to meet emerging electricity needs, commissioned in 2003 and in 2010. The Panel considers that this would have delivered savings in capital expenditure that took place in Tasmania over this period, including the conversion of the Bell Bay Power Station to gas and the investment in the three Pratt and Whitney open-cycle units that were acquired by Hydro Tasmania in 2005 to provide drought support (see Table 5, below).

### Table 5 Panel estimates of Tasmanian energy supply costs avoided by Basslink - gas scenario, $nominal

<table>
<thead>
<tr>
<th></th>
<th>$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Panel estimated cost of additional gas-fired energy</td>
<td>604</td>
</tr>
<tr>
<td>less savings from avoided capital investment</td>
<td>75</td>
</tr>
<tr>
<td>plus estimate of industrial load buyback</td>
<td>Nil</td>
</tr>
<tr>
<td>Total cost under Panel’s gas-fired ‘no Basslink’ scenario</td>
<td>529</td>
</tr>
<tr>
<td>Less</td>
<td></td>
</tr>
<tr>
<td>Actual cost of net inflows of energy to Tasmania via Basslink</td>
<td>324</td>
</tr>
<tr>
<td><strong>Avoided costs from Basslink</strong></td>
<td><strong>205</strong></td>
</tr>
</tbody>
</table>

The Panel’s analysis leads to a conclusion similar to that reached by Hydro Tasmania, which is that Basslink has enabled Tasmanian demand to be met at a materially lower wholesale energy cost than would have been likely under a gas-based development of Tasmania’s electricity sector. The Panel concludes that Basslink has delivered avoided cost benefits to the Tasmanian energy sector of around $200 million over the period 2007 to 2011.

Wind-generation

The Panel’s wind-based scenario assumes that the State’s emerging electricity needs would have been met solely by the development of large-scale wind farms. It assumes the following developments:

- Woolnorth is developed as it was in reality - therefore the costs are not shown as they occur in both cases;
- a further 150 MW is commissioned in 2003-04 (potentially Mussleroe windfarm);
- a further 150 MW is commissioned in 2005-06 (potentially the proposed Cattle Hill or Robins Island windfarms); and

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49 The Panel’s estimates of avoided cost do not include the capital costs associated with the second CCGT unit, given that the TVPS was built in Tasmania and commissioned in 2009 - See Appendix 1.
a final 100 MW is developed, commencing operation 2009-10.

This would have amounted to an additional 400 MW of wind capacity in the Tasmanian system over this period, resulting in total on-island wind generation capacity of 540 MW, including the Woolnorth wind farm. Given the purpose of this analysis, the technical considerations and constraints relating to connection issues and system stability of such a level of wind development have not been examined. Advice from Hydro Tasmania, and confirmation from Transend suggests that it is likely that there would be significant technical limitations on wind development of this scale in Tasmania.

The cost analysis of this scenario is detailed in Appendix 1. A conservative estimate of $90/MWh has been assumed as the cost of wind-based electricity and the transmission costs associated with connecting wind generation into the system have been ignored. As with the gas scenario, there may have been some avoided costs with this scenario relating to the gas-fired capacity that was commissioned over this period. Specifically, it has been assumed that the Pratt and Whitney open-cycle units that were acquired by Hydro Tasmania in 2005 to provide drought support would not have been required, given the assumed development of wind, and the conversion of the Bell Bay Power Station would have occurred to provide thermal support to the combined hydro and wind system (see Table 6, below).

Table 6 - Panel estimates of Tasmanian energy supply costs avoided by Basslink, wind scenario, $nominal

<table>
<thead>
<tr>
<th></th>
<th>$ million</th>
</tr>
</thead>
<tbody>
<tr>
<td>Panel estimated cost of wind energy</td>
<td>725</td>
</tr>
<tr>
<td>less savings from avoided capital investment</td>
<td>50</td>
</tr>
<tr>
<td>plus estimate of industrial load buyback</td>
<td>Nil</td>
</tr>
<tr>
<td>Total cost under wind ‘no Basslink’ scenario</td>
<td>675</td>
</tr>
<tr>
<td>less Actual cost of net inflows of energy to Tasmania via Basslink</td>
<td>324</td>
</tr>
<tr>
<td><strong>Avoided costs from Basslink</strong></td>
<td><strong>351</strong></td>
</tr>
</tbody>
</table>

Given the location of wind developments relative to the transmission network, these costs can be significant.
The estimated net avoided cost to the Tasmanian energy sector from Basslink by comparison with the hypothetical wind scenario is considerably higher than that for the gas scenario, at around $350 million over the period 2006-07 to 2011. This reflects the higher operating costs of wind by comparison with gas. Despite the absence of fuel costs, wind powered generation is relatively more expensive on a per unit of energy basis than natural gas fired generation, largely because of the intermittent availability of wind generation. Some of that additional cost would have been offset by the value of RECs that would have been generated from that wind development. As discussed in Appendix 1, it is not possible to estimate the potential value of RECs for that volume of wind generation over the period.

While noting the widespread support in the community for renewable energy, the Panel, like Hydro Tasmania, considers that the use of natural gas fired generation to meet the shortfall in the capacity of hydro-generation would have been the most plausible alternative to Basslink.

In conclusion, analysis of the two potential alternative scenarios for the development of Tasmania’s energy sector in the absence of Basslink suggests that the costs associated with meeting Tasmania’s observed electricity needs would have been at least $200 million ($nominal) higher than those arising from Basslink over the period 2007 to 2011. These avoided costs of Basslink are in excess of the direct revenue shortfalls arising from Basslink over the same period by at least $70 million, based on the alternative gas scenario considered by the Panel.

5.3. Summary of the financial performance of Basslink

In summary, the analysis undertaken by the Panel of the performance of Basslink to date shows that:

- Hydro Tasmania’s trading performance utilising Basslink was substantially diminished by low rainfall in the years immediately prior to and immediately following Basslink becoming operational;

- the direct arbitrage revenue opportunities made available to Hydro Tasmania by Basslink have not, on their own, generated sufficient revenue to cover the overall cost of Basslink to Hydro Tasmania in any year since the link commenced commercial operation, although the business case was not predicated on them doing so;

- if only the range of benefits contemplated in the business case for Basslink approved by the Hydro Tasmania Board in 2002 are taken into account, the financial performance of Basslink over its first five years of operation – as realised by Hydro Tasmania – has fallen short of the net result forecast in the final business case – essentially as a result of the drought which occurred prior to and immediately after the commissioning of Basslink;
with inflows and storages returning to more sustainable levels in recent years, direct trading benefits have shown a corresponding and marked improvement, and the wider revenue benefits that Basslink has provided to Hydro Tasmania have more than offset its overall Basslink-related costs;

- Basslink has been an effective tool for managing hydrological risk; and

- if not for Basslink, the prolonged dry period experienced by Tasmania in the middle of the previous decade would have had far more severe negative financial consequences for Hydro Tasmania.
6. Are regulated customers paying for Basslink?

Under the BSA, Hydro Tasmania is responsible for meeting the cost of Basslink, which it does through a combination of payments, including the BFF paid to the owner and operator of the link. In return for the facility fee, Basslink presents Hydro Tasmania with a range of revenue-generating opportunities which, in turn, provide a source of funding for the cost of the link – as well as a source of profit.

None of those revenue streams draws on customers in the Tasmanian non-contestable electricity market.

The major source of revenue for Hydro Tasmania associated with Basslink is arbitrage, which involves bringing electricity into Tasmania from Victoria at times when Victorian prices are low, and then exporting a matching volume of electricity from Tasmania at times of high Victorian prices. On this basis, the value of arbitrage is derived from interstate customers and not on-island demand.

Similarly, net exports of energy into the NEM involve the earning of income by Hydro Tasmania from interstate customers.

While net imports do not generate additional revenue for Hydro Tasmania, the cost of imported energy since Basslink has been in place has, on the Panel’s estimation, been less than alternative on-island supply options.

The electricity prices and fixed charges paid by non-contestable customers through their regulated tariffs have no reference to Basslink in their derivation. The energy cost component built into Aurora Energy’s tariffs is based on the cost of a new entrant generator in Tasmania, and transmission and distribution costs are the subject of independent assessment by the Australian Energy Regulator that does not take into account the costs of Basslink.

The ongoing operational costs incurred by Transend in connection with Basslink and the SPS are either recovered directly from Hydro Tasmania, or indirectly from Hydro Tasmania via pass through arrangements with BPL, and the connection assets servicing Basslink are excluded from Transend’s regulated asset base, meaning that they are not factored into the transmission charges set by Transend for either direct connect customers, such as Tasmania’s major industrial users of electricity, or electricity retailers, including Aurora Energy.

Therefore, given that no upgrades of the transmission network were required to cater for the flow of energy over Basslink, Tasmanian customers, whether large or small, do not pay higher transmission costs as a result of Basslink, with the cost being recovered from the parties who are the beneficiaries of the trading opportunities the link provides (Hydro Tasmania and BPL).
For these reasons it is evident that Tasmania’s regulated customers are not paying for Basslink, either directly or indirectly. Moreover, as discussed in Chapter 5, interconnection has provided additional electricity supply to Tasmania over the period 2007 to 2011 at a lower cost than would otherwise have been achievable from on-island sources.

To the extent that the cost of Basslink to Hydro Tasmania has, thus far, exceeded the revenue generated directly as a result of interconnection, the shortfall is reflected in Hydro Tasmania’s profit and the dividends which have been paid to the Government in the years since the link was commissioned. In that sense, it could be argued that the financial consequences of Basslink for Hydro Tasmania thus far have been borne by the Tasmanian community, as the owners of Hydro Tasmania. However, if the recovery of hydrological inflows into Hydro Tasmania’s catchments which began in 2008 continues, the potential exists for the Tasmanian community to share in the benefits that Basslink will realise for Hydro Tasmania’s business.
7. Conclusion

The Basslink project had a lengthy gestation period, during which the business case for interconnection was examined and revised repeatedly.

The business case for Basslink was routinely updated for changes in costs and benefits between the in-principle commitment to the project by Hydro Tasmania in February 2000 and final binding commitment in December 2002. The business case continued to show Basslink to be a positive commercial proposition for Hydro Tasmania’s business during this evaluation period. Stress testing of the business case also showed it to be sufficiently robust under a range of sensitivity analyses that reflected the key risks to the business case.

The financial performance of Basslink thus far has not fulfilled the expectations contained in the business case on a number of fronts, which is largely a reflection of adverse hydrological factors. Hydrology was consistently recognised as one of the key risks to the Basslink business case.

With a return to more typical hydrological inflows in recent years, the financial performance of Basslink has been consistent with the expectations in the final business case.

Hydro Tasmania has presented the Panel with detailed information to support its conclusion that the net average benefits to its business are in excess of $40 million per annum. The gross benefits are, broadly, evenly split between direct revenue benefits to Hydro Tasmania and its estimates of the avoided costs of the thermal generation which it considers would have been required in the absence of Basslink to meet Tasmania’s demand for electricity.

Over the period 2007 to 2011, Basslink has cost Hydro Tasmania around $134 million more than the direct and realised revenue benefits it has achieved from Basslink. This reflects the prolonged period of below-average inflows into the hydro system. Over the period 2010 to 2011, Hydro Tasmania has generated around $30 million more in revenue from Basslink-related sources than Basslink cost it.

Basslink has delivered lower cost energy to Tasmania than otherwise would have been likely. The Panel estimates that the avoided costs over the period 2007 to 2011 are at least $200 million. Hydro Tasmania estimates the avoided costs to be more than $300 million.

Put simply, during periods of low inflows when Basslink has been needed to maintain supply reliability, the revenues available to Hydro Tasmania from the link have been less than its costs. During times of more ‘normal’ inflows, when the link is not needed for supply reliability, Hydro Tasmania has been able to earn revenues from Basslink above its costs. Moreover, the costs of meeting the shortfall in electricity from the hydro system from Basslink have been materially less than the on-island alternatives.

When the non-realised avoided-cost benefits associated with the investment in Basslink are added to the direct benefits from the trading performance of the link, the financial benefits of Basslink in the first five years of its operation have been positive.
Appendix 1: Basslink Counterfactuals

1. Gas counterfactual

As discussed above, it is not possible to be definitive about how the Tasmanian energy sector would have evolved in the absence of Basslink. Therefore, it is also not possible to develop a ‘black and white’ view about whether Tasmanians are better off than they otherwise would be without Basslink. Nonetheless, the Panel has examined two potential scenarios to develop an informed view of the potential cost implications for Tasmania’s electricity sector had Basslink not been progressed and to compare this to present arrangements.

By the late 1990s the total Tasmanian load was approximately the same as the then-assumed sustainable Hydro Tasmania output rating of 10,000 GWh. By 2001, the load had exceeded this rating indicating that additional generation was needed (see Figure 1). At the same time the system storages had reached a low-level plateau based on the commencement of oil-fired Bell Bay generation (Figure 2).

![Figure 1 - Actual system load, Hydro Tasmania system rating (ie inflows) and gas capability from 1996-2010](image-url)

Source: Panel analysis

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51 The Panel understands that this is a question that is sometimes posed.
52 As noted in other Panel papers, it was this situation that provided the impetus for the Tasmanian Government to pursue both Basslink and natural gas.
53 Bell Bay was used to support storages in low inflow periods by injecting thermal energy into the system to substitute for hydro generation, to reduce the rate at which storages empty. The operation of Bell Bay in this manner was defined as the thermal controls for Bell Bay and reflected storages levels at which more Bell Bay Power Station generation was called on. This operation was based on the cost of running Bell Bay and as storages declined further more Bell Bay generation, at a higher cost, was utilised.
The key question is, in the absence of Basslink, what would have been the alternative supply options, given that doing nothing to augment Tasmania’s capacity to generate electricity would have posed a risk to supply reliability? The Panel has developed two hypothetical energy development scenarios as possible alternatives to interconnection via Basslink, which involved adding to Tasmania’s on-island generation capacity through either:

- the development of new gas-fired generation; or
- the development of large-scale wind generation.

In examining both cases, the Panel has assumed that observed electricity demand over the period was the level of demand that would have applied under the alternative scenarios.\(^{54}\)

\(^{54}\) This is a simplifying assumption. It is arguable that demand may have been at a lower or higher level, but the Panel considers this a reasonable basis for the analysis.
Gas-based scenario

Over the period 2001 to 2006, before Basslink commenced commercial operation, Hydro Tasmania’s Bell Bay power station was run predominantly on gas, based on thermal controls related to the cost of generation. In the absence of Basslink, similar rules would have applied.

In the gas scenario, the thermal controls required would have likely seen more gas-fired electricity injected into the system to maintain storages at a higher level. This higher storage level would assist in maintaining an acceptable level of system reliability for the extreme low inflow case.

To meet the growing gap between supply and demand from 2001 onwards, it is likely a decision to use a thermal source would have been made. In the short term this would have been from Bell Bay (given it was in situ), with the key strategic decision for Hydro Tasmania being whether to:

- continue with oil as the fuel source;
- convert the units to gas-firing; or
- build a new larger gas-fired unit (i.e. CCGT).

---

55 The BBPS was built in the early 1970s and originally fired by heavy fuel oil. Its two 120 MW steam turbine generating units provided thermal generation back-up for Hydro Tasmania’s hydropower system, but were used sparingly. The power station was converted to gas firing in 2002 and 2003, after which it was used more frequently, to produce substantially more electricity.

56 The Bell Bay units were actually converted to gas in 2002 and 2003.
In the absence of Basslink and the need for Hydro Tasmania to maintain the security of the Tasmanian power system, it is likely that the judgement would have been made that it would have been too risky to rely on the old Bell Bay\textsuperscript{57} units to meet long term demand growth and provide drought support, whether converted to gas or not.

For the purposes of this analysis, it has been assumed that given the load growth, system capability and planned arrival of natural in the State, a decision in 1999-2000 to develop a new power station to support the future growth could have reasonably been made. A unit of around 200 MW is assumed to be appropriate, particularly given the growth in demand over the 1996-2001 periods. Such a unit would have been of a suitable size to meet the additional demand until 2010.\textsuperscript{58}

By 2008 it became apparent that the long term expectation for inflows had significantly changed. Hydrological analysis by Hydro Tasmania had shown that the expected inflows had reduced from 10 000 GWh to 8 700 GWh (Hydro Tasmania officially lowered the inflow expectation in 2008-2009). With the reduction in hydro system expected inflows, there would be a need for further development to meet load around the 2008-2009 period. At the time of the system derating, it is reasonable to assume that a decision to further develop/augment the generation system would have occurred.

For the purpose of this analysis, it has been assumed that a second CCGT unit of around 200 MW would have been constructed and commenced operations in 2009-10 (as the Aurora Energy Tamar Valley plant did). Given this plant was constructed in reality, and it is required under this scenario, its capital cost has not been included in the Panel's estimates of avoided costs.\textsuperscript{59}

In modelling the likely output from the CCGT plant, the following considerations were taken into account:

1. The CCGT would have produced the amount of energy actually injected by the Bell Bay Power Station over the period, as well as the additional energy needed to meet the demand observed during the period in excess of that supplied by the hydro system, (for a total of 7 013 GWh over the period); and

\textsuperscript{57} The Bell Bay units were not designed to be a long term energy supply option but more for storage support in low inflow periods. The age of the units, their intermittent operations and their reliability would be a significant risk if relied upon for long term energy supply.

\textsuperscript{58} A delayed cost option would have been to convert the units but then install CCGT later.

\textsuperscript{59} Moreover, the only variable costs that have been included in the analysis are the estimated costs of producing the 7000GWh of electricity that was supplied by Basslink over the period. In this context, the Panel is seeking to identify only those costs that were actually avoided by having Basslink in place.
2. Target end of year storages in the hydro system in the order of 45-50 per cent of capacity (i.e. reflective of the current year) were considered appropriate (i.e. not too high) and if storages levels fell below 20 per cent it was considered risky unless other generation was assumed.\(^{60}\)

The Panel has taken the fixed and variable costs estimates for CCGT plant used for regulatory purposes by the TER in setting prices for non-contestable customers in 2010, which were developed by IES.\(^{61}\)

With these general principles, the counterfactual was modelled and tables 1 and 2 show the cost and storage/energy implications of this counterfactual.

**Table 1: Outputs and costs under gas scenario\(^{62}\)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Bell Bay Actual (GWh)</th>
<th>Energy Required from CCGT (GWh)</th>
<th>Additional costs of Energy from CCGT ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002-03</td>
<td>460</td>
<td>911</td>
<td>54.2</td>
</tr>
<tr>
<td>2003-04</td>
<td>796</td>
<td>1 458</td>
<td>62.8</td>
</tr>
<tr>
<td>2004-05</td>
<td>934</td>
<td>1 640</td>
<td>64.6</td>
</tr>
<tr>
<td>2005-06</td>
<td>585</td>
<td>1 093</td>
<td>56.6</td>
</tr>
<tr>
<td>2006-07</td>
<td>936</td>
<td>1 731</td>
<td>68.2</td>
</tr>
<tr>
<td>2007-08</td>
<td>1 169</td>
<td>1 731</td>
<td>58.7</td>
</tr>
<tr>
<td>2008-09</td>
<td>608</td>
<td>1 731</td>
<td>81.5</td>
</tr>
<tr>
<td>2009-10</td>
<td>0</td>
<td>1 275</td>
<td>87.7</td>
</tr>
<tr>
<td>2010-11</td>
<td>0</td>
<td>820</td>
<td>69.2</td>
</tr>
<tr>
<td>Total</td>
<td>5 488</td>
<td>12 390</td>
<td>604</td>
</tr>
</tbody>
</table>

\(^{60}\) As an example of the adjustment made for high inflow, the July to December 2005 was the highest 6 months inflow period over the 1996-2010 period. In addition, the December 2005 inflows were nearly 200 per cent above the average inflow for December (for the 1996-2010 period). So for the July to December 2005 period, it is highly unlikely that significant CCGT input would have been achieved. For this reason the modelled generation from the CCGT was reduced to reflect this.

\(^{61}\) Review of wholesale energy price for period 2010-2013, 7 May 2010, IES.

\(^{62}\) The difference between the Bell Bay actual and energy required from the CCGT represents the additional energy required in the absence of Basslink to maintain system reliability.
### Table 2: Storage levels resulting from gas counterfactual

<table>
<thead>
<tr>
<th>FYE</th>
<th>Actual Storage Levels (%)</th>
<th>Predicted Storage Levels (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002-03</td>
<td>30.5</td>
<td>33.6</td>
</tr>
<tr>
<td>2003-04</td>
<td>38.2</td>
<td>45.9</td>
</tr>
<tr>
<td>2004-05</td>
<td>22.8</td>
<td>35.4</td>
</tr>
<tr>
<td>2005-06</td>
<td>30.5</td>
<td>46.7</td>
</tr>
<tr>
<td>2006-07</td>
<td>19.3</td>
<td>35.4</td>
</tr>
<tr>
<td>2007-08</td>
<td>19.1</td>
<td>22.6</td>
</tr>
<tr>
<td>2008-09</td>
<td>27.7</td>
<td>19.8</td>
</tr>
<tr>
<td>2009-10</td>
<td>36.3</td>
<td>29.8</td>
</tr>
<tr>
<td>2010-11</td>
<td>46.0</td>
<td>45.2</td>
</tr>
</tbody>
</table>

Source: Panel analysis

Note: Energy from AETV is included in both the actual and counterfactual cases and hence is in the storage projections but is not shown here (2700GWh).

The net gas input and subsequent change in storage trajectory is shown in Figure 3.

**Figure 3:** Additional gas production and storage variation of counterfactual compared to actual.

---

Table 2 indicates the additional storage build required in the gas counterfactual to ensure the storage level does not drop too low, significantly less than 20 per cent by the end of each financial year.
The Panel considered the storage profile and concluded that storages falling to below 20 per cent in 2008-09 would be perceived as a risky situation, but having the alternative support from the next CCGT plant starting in 2009-10 allows this to be a realistic scenario. It is also not dissimilar to what was actually observed with Basslink (see Figure 3).

Under the assumption of a CCGT plant being commissioned in 2002, the actual developments in Tasmanian’s generation sector over the period, i.e. Bell Bay conversion to gas and purchase of 120 MW of OCGT plant in 2005, the capital costs of these developments could have been avoided.

Development of more wind generation could also be an alternative around the 2008-2009 period. Although in the very dry periods, where capacity becomes the problem, it is not likely that wind would be a preferred option and it is unlikely it would have deferred the second CCGT development substantially.

Examination of a scenario that assumes gas-fired electricity was the next generation source to meet Tasmanian growing electricity needs in the absence of Basslink shows that:

- additional costs in the sector would have been in the order of $600 million over the period 2006-11;
- if the capital savings from avoiding BBPS conversion and the acquisition of the open cycle units in 2005-06 are taken into account, the avoided costs fall to around $525 million; and
- when the actual costs of meeting the demand through Basslink over the period are considered ($324 million), the net avoided cost from Basslink are around $200 million over the 2006-11 period.

2. A wind-based scenario

Under this scenario, it is assumed that, in the absence of Basslink, the energy deficit would have been made up by large-scale wind developments, rather than gas-fired electricity.

The decision to progress a wind development strategy would have been in response to the need for another energy source. While Bell Bay could still have been converted at a relatively low cost, under this scenario it has been assumed that it would be used as a limited back-up supply and, at most, provide the level of output it has historically. Therefore the decision to build additional wind would have occurred in the 2000 to 2001 period.
As with the gas scenario, the driver for the hydro system would be to build up storage levels and maintain them at higher levels over the period by comparison with that with Basslink, as this would assist in managing dry periods with the lower level of capacity support (i.e. converted Bell Bay) assumed in this scenario.

To balance the energy requirements, and to ensure storages do not drop too low, the analysis assumes that the following is a reasonable scenario for the roll-out of wind developments:

- Woolnorth is developed as it was in reality - therefore the costs are not shown as they occur in both cases;
- Develop 150 MW (i.e. Musselroe) in 2003-04;
- Develop another 150 MW by 2005-06 (potentially Cattle Hill or Robins Island); and
- Develop a final 100 MW commencing 2009-10.

This would amount to an additional 400 MW of wind capacity in the Tasmanian system over this period (including Woolnorth the total would be 540 MW). Given the purpose of this analysis, the technical considerations and constraints, relating to connection issues and system stability, of such a level of wind development, have not been examined.64

In relation to costs, an average cost of $2.5 million/MW of installed capacity has been assumed.65 Under these assumptions, a total investment of approximately $1 billion would have been required to meet the capacity development. On this basis, an annualised cost of wind generation of $90/MWh66 has been used.

As the amount of wind in the system increases, its effective capacity will decrease. This is due to the coincidence of wind availability, high storages and inflows and subsequently resulting in more spill from the combined system. In high inflow periods - winter and spring - a greater proportion of the hydro system becomes ‘must run’ due to the likelihood of spilling, and without interconnection to provide access to a larger market, opportunities are limited to Tasmanian demand. This is accounted for in the analysis by reducing the capacity factor assumed for wind as more wind is added to the system.

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64 Note there is also no strong correlation between when the wind blows and the demand for energy in Tasmania. This is why the synergy between wind and hydro generation/storage is so beneficial, i.e. using the wind generation when it blows and reducing the hydro generation and store more water when there is no wind that the stored energy in the hydro storages is used to meet demand.

65 The Panel is aware of a wide range of estimates of the cost of wind, particularly within the range of $2.2-$2.8 million/MW.

66 This is considered a low assumption. For example, based on the AEMO 2010 National Transmission Network Development Plan costs estimates for wind developments, 200 MW of wind from a medium scale wind development would be around $100/MWh on an annualised basis, and from a large scale wind development (500 MW) around $95/MWh. These estimates assume a capacity factor of 40 percent.
For modelling purposes, it is assumed that:

- for the first additional 150MW of additional wind capacity, the capacity factor of the wind generation was assumed to be 38 per cent;

- with additional wind capacity increasing to 300 MW, the overall capacity factor for wind was assumed to be 36 per cent; and

- with additional wind capacity increasing to 400 MW, the overall capacity factor was assumed to be 32 per cent.67

On this basis the modelling generated the outcomes shown in Table 3:

**Table 3: Wind scenario, estimated output and costs**

<table>
<thead>
<tr>
<th>FYE</th>
<th>Wind Capacity (MW)</th>
<th>Additional Wind Energy (GWh)1</th>
<th>Additional costs ($m)2</th>
<th>Actual Storages (%)</th>
<th>Predicted Storages (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002-03</td>
<td>150</td>
<td>499</td>
<td>47.3</td>
<td>30.5</td>
<td>33.9</td>
</tr>
<tr>
<td>2003-04</td>
<td>150</td>
<td>499</td>
<td>47.3</td>
<td>38.2</td>
<td>45.1</td>
</tr>
<tr>
<td>2004-05</td>
<td>150</td>
<td>499</td>
<td>47.3</td>
<td>22.8</td>
<td>33.2</td>
</tr>
<tr>
<td>2005-06</td>
<td>150</td>
<td>499</td>
<td>47.3</td>
<td>30.5</td>
<td>44.4</td>
</tr>
<tr>
<td>2006-07</td>
<td>300</td>
<td>946</td>
<td>94.6</td>
<td>19.3</td>
<td>34.1</td>
</tr>
<tr>
<td>2007-08</td>
<td>300</td>
<td>946</td>
<td>94.6</td>
<td>19.1</td>
<td>24.0</td>
</tr>
<tr>
<td>2008-09</td>
<td>300</td>
<td>946</td>
<td>94.6</td>
<td>27.7</td>
<td>20.0</td>
</tr>
<tr>
<td>2009-10</td>
<td>400</td>
<td>1 121</td>
<td>126.1</td>
<td>36.3</td>
<td>29.0</td>
</tr>
<tr>
<td>2010-11</td>
<td>400</td>
<td>1 121</td>
<td>126.1</td>
<td>46.0</td>
<td>46.5</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>7 078</td>
<td>725.2</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: Panel analysis

1 Assumes Woolnorth is operating in both cases and is the effective wind input,

2 Is the total cost of wind at $90/MWh (i.e. gross cost, not including REC revenue).

As can be seen the total cost is in the order of $725 million.

The energy production and storage estimates are shown in Figure 4.

---

67 Note with Woolnorth already assumed in the system, this scenario would see approximately 500MW of wind operating, potentially at times of system loads of less than 1 000 MW (and non-discretionary hydro generation of over 1 000 MW).
The above analysis assumes that all of the costs from wind generation are required to be funded from the Tasmanian market. However, under the Australian Government’s Renewable Energy Target scheme, the RECs generated by wind are nationally traded. A case can be made that a material proportion of the RECs generated by wind under this scenario would be acquired from markets outside Tasmania, reducing the overall cost burden that would be required to be met from Tasmania.

It is not possible to robustly estimate the revenue that may have been generated by the sale of RECs under this scenario. Given the volume of additional RECs assumed to be produced - close to 20 per cent of the original REC target of 9500 GWh - it is highly unlikely that the prices that did prevail for RECs would have been realised, given REC prices are responsive to supply and demand (and this scenario represents a large change in supply, with no change in demand).

Similarly to the gas scenario, there may have been some avoided costs with this scenario relating to gas-fired capacity that was commissioned over this period. Specifically, the Panel’s analysis assumes that the Pratt and Whitney open-cycle units that were acquired by Hydro Tasmania in 2005 to provide drought support would not be required, given the assumed development of wind, and the conversion of the Bell Bay Power Station would have occurred to provide thermal support to the combined hydro and wind system.

---

68 At the extreme, assuming there was no price response and that all of the RECs generated from the assumed wind put were sold at the then-prevailing market prices in the year in which they were produced, the Panel estimates that this would have generated around $260m over the analysis period. This is likely to materially overstate the REC revenues that could have been achieved.
This examination of a scenario that assumes wind-based electricity as the next generation source to meet Tasmanian growing electricity needs in the absence of Basslink shows that:

- additional costs in the sector would have been in the order of $725 million over the period 2007 to 2011;
- avoiding the capital costs of the Pratt and Whitney generators would save around $50 million;
- when the actual costs of meeting the demand through Basslink over the period are considered ($324 million), the net avoided cost from Basslink is around $350 million over the 2007 to 2011 period;
- the sale of RECs from wind would provide an ‘external’ source of revenue to meet some of these costs; and
- the practical feasibility of this hypothetical wind scenario has not been tested, although Hydro Tasmania’s view is that such a development would not have been technically feasible from a transmission and system security perspective.

**Conclusions**

- It is not possible to be definitive about how the Tasmanian energy sector would have evolved in the absence of Basslink.
- The Panel has examined two potential scenarios to develop a view as to the potential cost implications for Tasmania’s electricity sector had Basslink not been progressed and to compare this present arrangements.
- The analysis shows that Basslink has enabled Tasmanian demand to be met at a materially lower cost than under two hypothetical alternative scenarios: gas-fired electricity or a wind-based scenario, the technical feasibility of which has not been tested.
- The net avoided cost to the Tasmanian energy sector from Basslink by comparison with the gas scenario is estimated to be around $200 million over the period 2006-11.
- The net avoided cost to the Tasmanian energy sector from Basslink by comparison with the hypothetical wind scenario is considerably higher, at around $350 million over the period 2006-11, potentially offset by the value of RECs that could have been generated from that wind development.
- On the basis of this analysis, it is reasonable to conclude that Basslink has provided additional electricity supply to Tasmania over the period 2007 to 2011 at a lower cost than would otherwise be achievable from alternative on-island sources.
## Appendix 2: Sources of value from Basslink

<table>
<thead>
<tr>
<th>Source of value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arbitrage</td>
<td>The price differential associated with the simple matching of the highest priced ‘exports’ with equal volumes of the lowest priced ‘imports’ of energy – ie balanced flows across Basslink.</td>
</tr>
<tr>
<td>Lost Tasmanian sales</td>
<td>The decrease in sales attributable to Basslink as a result of existing hydro generation being displaced by new entrant wind and gas competitors.</td>
</tr>
<tr>
<td>Net exports</td>
<td>The balance of north and southbound energy flows across Basslink during any particular year, over and above the energy flows in each direction involved in arbitrage (which cancel each other out). Net exports reflect the energy able to be exported into Victoria during shoulder periods.</td>
</tr>
<tr>
<td>System yield</td>
<td>The increased system yield realised through better water management made possible as a consequence of Basslink. Additional energy is produced for the same level of hydrological inflows through better balancing of those inflows with export and import volumes across Basslink, reducing spill in times of high inflows as well as the level of water storages that need to be maintained as a buffer against hydrological risk.</td>
</tr>
<tr>
<td>Renewable Energy Certificates (RECs)</td>
<td>RECs are accumulated by Hydro Tasmania when generation at individual power stations exceeds their MRET baselines in an individual year. Increased system yield sees the creation of additional RECs, which are then sold to wholesale purchasers of electricity, such as electricity retailers, who then surrender the certificates to the Office of the Renewable Energy Regulator in order to discharge their liabilities to purchase a given percentage of their electricity needs from renewable energy power stations.</td>
</tr>
<tr>
<td>VIC contracts</td>
<td>Increased revenue associated with the sale of insurance products (i.e. price caps) in the Victorian region of the NEM.</td>
</tr>
<tr>
<td>Tas pricing effects</td>
<td>The additional revenue associated with an uplift in electricity prices for some customers with market based contracts as a result of periods of dry hydrological inflows.</td>
</tr>
</tbody>
</table>

Source: Panel analysis
Part B
Tamar Valley Power Station: Development, acquisition and operation
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Tamar Valley Power Station: Development, acquisition and operation
Executive summary

Securing a large gas-fired power station in the State to provide alternative supply and a source of competition in the wholesale energy market has been a key energy policy objective of successive Tasmanian Governments since the 1997 Directions Statement. The objective was closely linked to the introduction of natural gas to Tasmania, with a power station providing a foundation customer for the Tasmanian Natural Gas Pipeline (TNGP).69

The commissioning of the TVPS in October 2009 partly achieved this objective. However, ownership of the TVPS by Aurora Energy, and its use to back non-contestable customer load, does not deliver the original objective of effective competition in the Tasmanian wholesale market for new entrant retailers to back retail contracts with contestable customers.70

The TVPS’ entry has resulted in more available energy71 and capacity than is required to meet demand, at least until well into the next decade. Reflecting market conditions in Tasmania and the National Electricity Market (NEM) more broadly, Tasmanian spot prices have been low, relative to historic norms, since the TVPS came online. This has had a direct impact on the TVPS’ financial viability, as has the volatile nature of the wholesale market.

A key change with the Government’s decision to acquire the TVPS via Aurora Energy on the grounds of energy security is that the financial consequences of these risks are now borne by Tasmania’s public sector, rather than the private sector, as was anticipated early in the reform process.

Wholesale market revenue has not been sufficient to support the commercially sustainable operation the TVPS, which placed Aurora Energy in stressed financial circumstances during 2009-10.

The combination of the wholesale energy allowance that is provided to Aurora Energy for non-contestable customers, coupled with the contractual arrangements it has with Hydro Tasmania to partly back non-contestable customer load72, provide Aurora Energy with sufficient financial ‘headroom’ to cover the full costs of operating the TVPS to back the balance of its non-contestable customer load.

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69 Initially, this was achieved with the conversion of the Bell Bay Power Station to natural gas in 2003.
70 Arguably it does deliver this benefit to Aurora Energy, although the cost structure of the TVPS relative to prevailing market conditions means that it is not a commercially attractive option.
71 Noting that, in Tasmania, this is a function of hydrology.
72 Hydro Tasmania currently backs around half of the non-contestable customer load.
Having on-island thermal generation provides supply security for the market in light of the hydrological risk inherent in Hydro Tasmania’s generation system. It was on this basis that Government made the decision to acquire and complete the TVPS when the private sector developer, Babcock and Brown Power (BBP), indicated to the Government that it would not complete the project.

At the time that decision was taken, water storages were at near record lows, the existing aged on-island thermal generation plant was experiencing reliability difficulties, and Tasmania was effectively reliant on Basslink to meet electricity demand.

All Tasmanian customers benefit from having higher supply reliability through the TVPS being available for generation in the event of severe drought. The key issue is predicting the frequency and nature of those conditions, and the willingness of market participants to contract to manage those risks in periods of normal and above normal hydrology.

Currently, non-contestable customers and Hydro Tasmania are carrying the financial burden of the costs of having the TVPS available as ‘supply reliability insurance’. This is unlikely to be a sustainable approach under typical inflows and storages conditions (in terms of Hydro Tasmania’s willingness to contract with thermal generation to manage hydrological risk) and these arrangements will not be robust with a move to market-based arrangements for all customers. The financial position of the TVPS in the context of prevailing market conditions is a key issue that needs to be resolved as part of the Tasmanian Government’s future Energy Strategy.

The Panel’s key findings are summarised below.

**The development of gas-fired generation in Tasmania**

The acquisition, completion and operation of the TVPS by Aurora Energy were the outcomes of a chain of energy policy and market developments over the preceding decade. These included Tasmania's entry into the NEM, the Basslink and TNGP connections and the management of hydrological risk in order to ensure reliable electricity supplies during periods of low inflows and storage levels.

The Tasmanian Government’s early reform of the State’s energy market included the separation of the Bell Bay Power Station (BBPS) from Hydro Tasmania into an independent generating business. The TNGP development agreement provided for the establishment of a joint venture between Duke Energy and Hydro Tasmania to convert the existing units to gas and to repower the station to a 220 MW combined cycle gas turbine operating in competition with Hydro Tasmania in the wholesale market in Tasmania.
A commercial agreement for the development of the joint venture was not concluded. In April 2004, Alinta acquired Duke Energy’s assets, including the TNGP and interests in the BBPS. As an alternative to the joint venture, Alinta developed a proposal to construct a new power station, the TVPS, with a 203 MW combined cycle gas turbine on a site adjacent to the BBPS on a stand-alone basis.

The TVPS project was announced in October 2006 following agreement to a 25-year energy contract between Alinta and Aurora Energy. These arrangements were consistent with the ACCC’s requirement 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. The contractual arrangements with Alinta also provided Aurora Energy with options on the forms of contractual cover provided by the TVPS, which gave Aurora Energy broader scope to manage contract negotiations with Hydro Tasmania.

Alinta subsequently acquired from Hydro Tasmania the BBPS site and three 40 MW FT8 gas-fired turbines, which had been acquired by Hydro Tasmania as generation support during times of low inflows ahead of Basslink commissioning. Alinta granted a licence to Hydro Tasmania for it to continue to operate the Bell Bay 1 and 2 gas-fired units until the new combined cycle turbine was commissioned. A key component of the sale agreement was Hydro Tasmania’s release from its gas Pipeline Capacity Agreement liability with Alinta, which had been entered into by Hydro Tasmania and was valued by Hydro Tasmania at approximately $90 million.

In August 2007, Alinta began construction of the TVPS. Shortly after, the project was acquired by Babcock and Brown as an element of its acquisition of Alinta. As part of the broader distribution of Alinta’s assets, Babcock and Brown allocated the TVPS to Babcock and Brown Power (BBP), and the natural gas transmission assets to Babcock and Brown Infrastructure. This decoupled key financial value aspects of the TVPS development.

Due to a range of factors, in June 2008 BBP reached the point where it could no longer complete the project and elected to pursue a divestment strategy. BBP sought to sell the development to the market.

The Tasmanian Government initially attempted to facilitate BBP’s sale of the TVPS to a third party operator. The Government’s efforts focused on resolving technical issues relating to the connection of the station to the State’s transmission network. This was likely to impact on the successful divestment of the power station to another private operator in the short term.

However, BBP was unable to complete a market sale on terms acceptable to it and within its desired timeframes. BBP then approached the Government with a proposal for acquisition within an extremely compressed timeframe.

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73 Which was originally negotiated with Duke as a foundation for the Tasmanian Natural Gas Project.
74 The Agreement provided for the transport of gas for the BBPS power station in the first instance, and would have underpinned gas transport requirements for the proposed Joint Venture.
Acquisition and completion of the TVPS by the Tasmanian Government

Threats to timely completion of the TVPS came at the same time as near-record low hydrological inflows and storage levels, which in the event that the drought continued and both the Basslink and the Bell Bay Power Station were unavailable, had increased the risk of potential energy shortfalls in the autumn of 2009.

Based on its assessment of supply risk, the Government determined that it would direct Aurora Energy to purchase and complete the project.

The Government undertook a rapid due diligence process, which examined technical, legal and commercial aspects of the transaction.

The Government agreed to an acquisition price for the partially completed project of $100 million. Funding was made available to Aurora Energy through an equity contribution, with Aurora Energy assuming responsibility for what was estimated at the time to be $260 million in project completion costs, funded by debt. The transaction and equity funding were approved by the Tasmanian Parliament and the sale was completed on 15 September 2008.

A key aspect of the acquisition was the negotiation of gas supply (commodity and transportation) arrangements. At the time of the acquisition, there were no gas contracts in place for the TVPS. Aurora Energy and the Government were concerned that negotiating a gas supply contract with BBP after the completion of the acquisition would result in a materially worse negotiation position than putting those arrangements in place as a part of the acquisition.

Accordingly, BBP ‘carved out’ gas supply arrangements for the TVPS on terms consistent with a wider package of gas commodity and transport agreements that were in place in a related Babcock and Brown entity. The nature of the gas arrangements (volume and conditions) was consistent with the use of gas implied under BBP’s operating model for the TVPS.

Post-acquisition commercial and operational arrangements

Aurora Energy completed construction of the power station on time, and around $20 million under the anticipated budget. Given the complexity of the internal and external challenges Aurora Energy faced in delivering the project, this represents a highly successful outcome.
However, by October 2009 when the TVPS was commissioned, hydrological conditions had improved such that the risk of supply shortfalls was significantly reduced - although water storages remained just under 30 per cent.\(^{75}\) The operation of the TVPS enabled Hydro Tasmania to rebuild water storages at a faster rate than otherwise would have been the case.

The power station’s unsustainable financial position was realised in early 2009 (pre-commissioning) when Aurora Energy established a baseline budget for the subsidiary created to own and operate the TVPS, Aurora Energy Tamar Valley (AETV).

Aurora Energy’s modelling indicated that a fair market value of the TVPS was around $220 million and that without increases in expected revenue, and reductions in operating costs, the asset value of TVPS could face a large ‘write down’ in Aurora Energy’s accounts at the end of the 2008-09 financial year.

In response, Aurora Energy restructured its energy business to improve efficiency and implemented a tolling agreement\(^ {76}\) which replaced the BBP contract and provided the same value to AETV. The consequence of this restructuring was that value implications of changes in market conditions that relate to the operation of the TVPS would be observed in the parent Aurora Energy’s energy business, and AETV would be financially ‘whole’.

The initial tolling fee did not provide sufficient cash flow for AETV to operate the TVPS and manage the debt incurred in completing the power station. Aurora Energy’s Board approved an additional fixed tolling fee on the expectation that the 2010 regulated Pricing Determination would allow for an increase in the wholesale energy component of regulated tariffs paid by non-contestable customers over the period 1 July 2011 to 30 June 2013.

This was based on the assumption that the cost allowance methodology used in the 2007 Determination would again be used in 2010. In July 2009, the then Treasurer provided assurances to Aurora Energy consistent with this expectation, advising that the Tasmanian Energy Regulator (TER) would be instructed to apply a long-run marginal cost (LRMC) methodology to the wholesale energy allowance for non-contestable customers, which would set the allowance based on industry benchmark costs for ‘new entrant’ gas-fired generation.

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\(^{75}\) Hydro Tasmania’s preferred operating zone is a storage system level between 30 and 50 per cent of capacity. The lower level represents an ‘insurance level’ that can be used to generate electricity during some years of drought, while the higher level represents a reasonable buffer that can be used to provide flexibility in trading operations. (source: Hydro Tasmania 2010 annual report)

\(^{76}\) The tolling arrangement effectively transferred the rights and obligations associated with the pool income from the generation of TVPS from AETV to Aurora Energy in return for a tolling fee to effectively convert gas into electricity as directed by Aurora Energy. The tolling fee has fixed and per unit charges, to incentivise AETV to operate the TVPS efficiently.
Aurora Energy’s Board decided that impairment at the end of 2008-09 was not required, based in part on the increase to the tolling agreement paid by Aurora Energy to AETV and also because the station had not yet been fully commissioned and therefore had no actual substantive operating period in which to assess its cost and revenue base could be confirmed to inform that decision.

A number of issues during the 2009-10 financial year contributed to a worsening of the Aurora Energy energy business’ financial position:

- the cash flows from Aurora Energy to AETV under the tolling agreement were insufficient to meet the costs in operating the TVPS, resulting in AETV generating losses;

- early in the first half of year, Aurora Energy was using the TVPS as a physical hedge to back part of its non-contestable customer load, and had some exposure to the spot market for TVPS output, which impacted on the revenues available to Aurora Energy to fund the tolling fee;

- From January 2010, Aurora Energy became over contracted and faced larger wholesale market price risk from the TVPS. Tasmanian spot prices reflected Hydro Tasmania bidding to match its level of contract cover, and TVPS bidding to utilise its gas contracts, with consequential sustained reductions, relative to historic levels; and

- On a per unit basis, the 2009-10 wholesale energy allowance factored into non-contestable tariffs and, therefore, Aurora Energy’s revenues was below TVPS operating costs, requiring additional revenue to support its costs.

Aurora Energy’s energy business again faced significant write-down in value at the end of the 2010 financial year. Aurora Energy briefed its Shareholder Ministers in January 2010 and again (with detailed supporting figures) in April 2010, on its adverse financial position and requested significant and immediate assistance.

Amendments to the Price Control Regulations, passed by the Parliament in June 2010, had the effect of supporting AETV’s viability in two key respects.

77 In calendar 2008 and 2009, average annual Tasmanian spot prices were around $50/MWh, and 20 per cent or more above the average annual Victorian price. Coincident with the commissioning of the TVPS and a change in the non-contestable contract cover provided by Hydro Tasmania, annual average spot prices fell by around 40 per cent, and remained below Victorian annual average spot prices. Average quarterly Tasmanian spot prices showed substantial variation, which was also coincident with timing issues associated with the TVPS (commissioning and outages).

78 The key areas in which Aurora Energy sought Government assistance was in: rebalancing the debt levels within the Company; amendments in relation to the setting of non-contestable customer prices and in delivering pricing outcomes from Hydro Tasmania consistent with those determinations having regard to Aurora Energy’s overall costs; and pursuing reform of the wholesale market in Tasmania.
Firstly, the Regulations specified that the TER apply a LRMC methodology for determining the wholesale energy allowance for non-contestable customers, which had the effect of delivering an allowance at levels that were broadly consistent with the costs of the TVPS. This removed the risk that the TER would set an allowance that did not place a high weighting on benchmark costs of generation from the TVPS — for example, by placing a high weighting on prevailing market prices. Consequently, the ‘blanket’ five per cent cap for all non-contestable customers announced during the 2010 State Election campaign was not progressed, instead being replaced by a one-off increase to the electricity concession.

Secondly, the Regulations gave the Treasurer power to ensure that any commercial arrangements between Hydro Tasmanian and Aurora Energy in relation to non-contestable customers did not place Aurora Energy in a position of having overall higher energy costs (from all sources) than its revenue provided for under the regulatory allowance. These regulations empowered the Treasurer to impose a contract between the parties consistent with this outcome, in the event that a commercial agreement could not be reached. In the event, this power was not required to be exercised as the parties came to commercial arrangements that satisfied the overall cost test in the Regulations.

**Aurora Energy’s changing risk profile with TVPS ownership**

Aurora Energy’s risk position fundamentally changed once it became the owner of the TVPS, instead of the counterparty to a set of financial arrangements linked to the TVPS. Aurora Energy’s ownership of the TVPS involved it assuming a number of significant risks that would have been borne by BBP under the previous contractual arrangements. This has been a major driver of the financial implications of the TVPS for Aurora Energy. These are summarised in Table 1 and discussed in more detail below.

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79 Basing the wholesale energy allowance on LRMC is not the same as basing the allowance on actual costs of the TVPS, but by using relevant benchmarks, the costs do broadly align.
<table>
<thead>
<tr>
<th>Risk</th>
<th>With hedges for TVPS</th>
<th>As owner of TVPS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction Risk</strong></td>
<td>Nil – BBP risk</td>
<td>Aurora Energy risk - managed through construction contracts and owners engineer arrangements</td>
</tr>
<tr>
<td><strong>Operations and maintenance</strong></td>
<td>Ni – BBP risk</td>
<td>Aurora Energy risk - managed through internal resourcing</td>
</tr>
<tr>
<td><strong>Dispatch risk</strong></td>
<td>Ni – BBP risk</td>
<td>Aurora Energy risk - TVPS as a 'physical' hedge against spot prices requires gives rise to dispatch risk</td>
</tr>
<tr>
<td><strong>BBP contracts</strong></td>
<td>Contracts provide risk management for 203MW of generation to back contestable and non-contestable load</td>
<td>Contracts ineffective as on both sides of the transaction. TVPS becomes a merchant plant for Aurora Energy, highly exposed to the spot market</td>
</tr>
<tr>
<td><strong>Tas spot price firm</strong></td>
<td>BBP contract 'in the money', mark-to-market gain in Aurora Energy's accounts (unrealised)</td>
<td>Spot market revenues increase, improving TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Tas spot price softens</strong></td>
<td>BBP contract 'out of the money', mark-to-market gain in Aurora Energy's accounts (unrealised)</td>
<td>Spot market revenues decrease, weakening TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Spot market opportunities</strong></td>
<td>No exposure – BBP risk and return</td>
<td>Risk and return on Aurora Energy’s account</td>
</tr>
<tr>
<td><strong>Hydro Tasmania exercises options to vary load under its contract with Aurora Energy for non-contestable customers</strong></td>
<td>Aurora Energy has market risk, capped at the value of the BBP contract price</td>
<td>Aurora Energy has market risk, capped at value of TVPS operating costs (substantially higher than BBP contract price)</td>
</tr>
<tr>
<td><strong>Gas supply</strong></td>
<td>Ni – BBP risk</td>
<td>Aurora Energy risk - managed through gas contracts</td>
</tr>
<tr>
<td><strong>Gas volume</strong></td>
<td>Ni – BBP risk</td>
<td>Take-or-pay gas commitments result in large financial risk if required gas volumes change.</td>
</tr>
<tr>
<td><strong>Gas price increases</strong></td>
<td>Pass-through at time of price reset.</td>
<td>Direct financial exposure for TVPS</td>
</tr>
</tbody>
</table>

Source: Panel analysis

**BBP-Aurora Energy transaction**

BBP’s commercial arrangements with Aurora Energy provided some flexibility for Aurora Energy to change the balance of nominated contracts on an annual basis, after an initial five-year period. This would have enabled Aurora Energy to optimise its wholesale energy position in light of prevailing market dynamics.

Any change in Aurora Energy’s nominated hedge levels with BBP could change the operation of the TVPS and the level of gas it required. Under the BBP contract, this risk was BBP’s to manage and it would appear that, given its position in the national electricity and gas markets, BBP considered it was able to manage these risks.
While the Aurora Energy contract was a key underpinning source of revenue, BBP was proceeding on the basis of not being wholly reliant on the contract to cover the costs of TVPS. It expected that spot market revenues and wider gas trading arrangement would also provide key sources of revenues or risk mitigation.80

**What changed when Aurora Energy acquired the TVPS?**

The Government’s direction that Aurora Energy would acquire, complete and operate the TVPS fundamentally changed Aurora Energy’s risk profile. Aurora Energy also lost access to a hedge contract with a price below existing Hydro Tasmania contracts, and moved to a situation where it instead had all the costs of the TVPS, which turned out to be above its previous hedge costs.

Three key changes related to:

1) **The internalisation of the contractual arrangements that were in place between the TVPS and Aurora Energy**

With Aurora Energy’s acquisition of the TVPS, the value to Aurora Energy of the risk management advantages inherent in the previous contract arrangement were nullified, as Aurora Energy now ‘sat on both sides’ of the transaction.

In the absence of another third party being willing to take a longer-term position in contracting with the TVPS, this effectively turned the TVPS into a merchant plant, with its value being dependent on the outcomes in the Tasmanian spot market. This had consequential impacts on the value of the power station.

Based on financial due diligence undertaken for the Government during the acquisition process, the estimated value of the TVPS under separate ownership with the Aurora Energy contract in place was between $330 million and $415 million. By comparison, the estimated value with Aurora Energy owning and operating the TVPS as a merchant plant was around $200 million. At that time, the estimated cost to Aurora Energy to acquire and complete construction was $350 million.

Neither the valuation advice, nor work within Government on the acquisition, addressed the mechanisms through which the additional ‘hydrological risk premium’ could be raised and secured by Aurora Energy so that the value of the TVPS in its accounts could have corresponded to the combination of its merchant value and the assigned hydrological risk value.

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80 The Panel has reviewed the BBP’s financial model for the TVPS, which indicates that BBP was anticipating generating value over and above the commercial arrangement with Aurora Energy through the Tasmanian spot market.
2) The risks facing Aurora Energy arising from contractual arrangements that it had in place with Hydro Tasmania in relation to the non-contestable customer load

With the Alinta contract negotiated and expected to come into effect on 1 April 2009, Aurora Energy negotiated two fixed-volume profile hedges with Hydro Tasmania to back the non-contestable load for the periods 1 April 2009 (the expected commissioning date of the TVPS) to 31 December 2009 and from 1 January 2010 to 30 June 2010. Under each contract, Hydro Tasmania had the option to elect to reduce the notional quantity by either 75 MW or 150 MW.

The combined effect of the contractual arrangements with Hydro Tasmania and the BBP (formerly Alinta) contract exposed Aurora Energy to the risk that it would be over-contracted and therefore exposed to spot prices. Aurora Energy has explained to the Panel that it had an expectation that, given the terms contained in the BBP contract and its expectation of spot prices, it would be able to utilise the BBP contract to back contestable customer contracts.

However, when it became the owner of the TVPS, Aurora Energy took on higher costs than under the previous hedge arrangements and was now directly exposed to spot market prices to generate revenues to cover these costs. More importantly, the take-or-pay gas contracts reflected an expectation at the time of acquisition of the power station running at a high level of capacity. Aurora Energy was left exposed to spot market for the output of TVPS when Hydro Tasmania exercised its right to supply the full non-contestable load. Consequently, Aurora Energy was obliged to run the TVPS to minimise losses on its take-or-pay gas contract.

This risk was not proactively managed and the financial consequences were left to unfold as Hydro Tasmania exercised its commercial rights. This resulted in Aurora Energy being over-contracted and exposed to the prevailing spot market prices for output of the TVPS, particularly given its take-or-pay gas exposures – spot revenues were commercially superior to paying for unused gas and achieving no revenues.81

The financial consequences of the operation of the TVPS in the wholesale market in Tasmania were significant. At the end of the 2009-10 financial year, earnings before interest and tax (EBIT) for Aurora Energy’s energy business was some $50 million below budget, at minus $31 million.82 The financial impact on Aurora Energy during 2009-10 is discussed in more detail in Section 3 of this Paper.

The financial issues identified by Aurora Energy in the 2009-10 financial year, particularly its ability to meet its cash costs and service debt (and the implications for the book the value of the TVPS) have been addressed in the medium term through

81 Lower spot prices did not present an opportunity for improved margins in Aurora Energy’s retail business as given the risks of keeping a spot price exposure in Tasmania, very high levels of contract cover are maintained.
82 There were other contributors to this overall outcome, including the performance of Aurora Energy's national retailing activities.
the regulatory arrangements put in place by the Tasmanian Government in relation to the 2010 Price Determination for non-contestable customers and the contractual arrangements between Aurora Energy and Hydro Tasmania for the supply of the non-contestable load, as noted above.

These arrangements provide revenue certainty for the wholesale energy allowance which more closely reflects the cost of production from the TVPS and enable Aurora Energy to access contractual arrangements for the balance of the non-contestable load with Hydro Tasmania at a cost less than the wholesale energy allowance, such that its average contract costs are in line with the allowance. By utilising the TVPS to back non-contestable load and securing a lower price from Hydro Tasmania, Aurora Energy is able to cover the costs, and therefore preserve the value of, the TVPS. This arrangement is vulnerable to a change in regulatory arrangements at the end of the current Price Determination period.

3) **Aurora Energy’s financial exposure arising from all the operating costs of the TVPS, including gas contracts and the debt associated with the acquisition and completion of the power station.**

The gas commitments put in place at the time of acquisition were consistent with the operating regime anticipated for the TVPS in the BBP. While the Government and Aurora’s decision to ‘lock in’ a gas supply regime at the time of acquisition arguably optimised the timing of gas negotiations and removed the risk of a weak bargaining position, the strategy had two other material consequences:

- it placed Aurora Energy, in the position of having a long-term large take-or-pay gas exposure\(^{83}\), which has had significant implications for the financial consequences of the operation of the TVPS; and

- it provided a stronger underpinning of Babcock and Brown’s Tasmanian gas pipeline business.

Aurora Energy also had to manage the significant debt attached to the acquisition and completion of the TVPS, including the cost of servicing this debt and the impact on its credit rating.

**The future of the TVPS**

The financial performance of the TVPS is driven by a combination of:

- its costs, relative to prevailing market prices; and

- its inability to vary production due to take-or-pay gas supply contract arrangements.

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\(^{83}\) Noting that it is not uncommon for CCGT plants to have take-or-pay gas supply contracts.
The current regulatory arrangements provide Aurora Energy with access to a customer group that is required to pay a wholesale energy allowance more in line with the TVPS costs rather than in line with currently prevailing market prices, which reflect the current supply/demand balance, strong storage levels and modest Victorian (and wider NEM) wholesale prices. The financial difficulties currently facing the TVPS reflect contemporary market circumstances. If Tasmania’s wholesale prices increase, for example through a tightening of the supply/demand balance, the market value of the TVPS should rise. Changes in hydrological conditions will be a major driver of the Tasmanian spot market over time and the TVPS’ value as a hydrological risk management tool will be able to be captured by higher spot and contract prices at times of low storages.

The introduction of carbon pricing will have two opposing financial consequences for the TVPS:

- it will increase its costs of production, as it emits carbon dioxide; and
- Tasmanian market prices will increase as the Victorian price of electricity will rise with a price on carbon emissions.

Across the NEM, the commercial position of gas generators will improve relative to coal-fired electricity, given the former’s lower carbon intensity. The extent to which carbon pricing will provide a commercial benefit to the TVPS will depend on the degree to which Tasmanian market prices rise in parallel with Victorian market prices.

The second key influence on financial performance of the TVPS in the longer term is the renegotiation of gas supply arrangements, which remain in place until 2017. Unlike the situation at acquisition, Aurora Energy may consider the potential operating profile of the TVPS given the market settings that will exist in 2016-2017 and to secure gas supply arrangements that are consistent with that profile. This remains an issue for Aurora Energy’s future performance.

More immediately the Government needs to consider alternatives that more transparently manage the difference between the cost structure of the TVPS and its sources of revenue.
Introduction

The initial development of the TVPS project was a key component of Tasmania’s broader energy strategy, underpinned by the three core objectives of securing new sources of energy to meet load growth, mitigating the State’s exposure to energy supply risk by reducing reliance on hydro generation and increasing competition.84

The completion of the TVPS in October 2009 heralded significant changes to the Tasmanian electricity sector, in terms of providing a new source of generation and changing the State’s hydrological risk profile. However, by the time it was completed, the TVPS was operating under a very different set of arrangements than had been originally envisaged when it was proposed by Alinta Energy in 2006. Most significantly, instead of a new private sector entity competing in the generation sector, the State acquired the project and in doing so retained control of all of Tasmania’s significant on-island generation capacity.

The State’s acquisition of the TVPS has had a substantial financial impact on Aurora Energy as the acquiring entity. Subsequent actions taken by Government to support the viability of the TVPS, post-acquisition, have seen a number of changes to the power station’s commercial and operational arrangements.

This Paper is divided into two main sections, with analysis covering the key elements of TVPS development, acquisition and operation identified by the Panel.

The first section provides a factual chronology of the evolution of the project through its initial conception to commissioning and operation by AETV. It focuses on key events and associated commercial, policy and regulatory decisions across three time periods:

- the Initial Development of the TVPS Project;
- the Acquisition and Completion of the TVPS by the State; and
- post-Acquisition Commercial and Operational Decision-Making.

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84 The three ‘core energy objectives’ that have been pursued by successive governments in Tasmania since the Rundle Government’s 1997 Directions Statement are discussed in more detail in the Panel’s April Discussion Paper The Evolution of Tasmania’s Energy Sector.
Section 1 also includes a brief discussion of the acquisition decision from an energy supply risk perspective, including a summary of relevant information and advice provided to the Government at the time.

Section 2 considers in more detail the commercial aspects of the TVPS project. It compares initial expectations of the TVPS project with the outcomes that have been observed since its commissioning, and explains the apparent divergences. More specifically, it addresses the evolution of the TVPS operating model and explains how the power station’s fundamental value proposition changed from the initial commercial arrangement between Alinta and Aurora Energy to the model that was put in place following acquisition by Aurora Energy.
1. TVPS development, acquisition and operation: a chronology

1.1. Initial development of the TVPS project

The initial development of new gas-fired generation in the Tamar Valley was driven by three key factors:

- firstly, the TNGP delivering large-scale natural gas to Tasmania and the commercial desirability of developing a foundation customer for that project;

- secondly, the development provided the potential for competition in the wholesale generation market, as well as another significant source of on-island generation to provide energy diversity and a buffer against hydrological risk; and

- thirdly, the approval of some of the arrangements that formed part of Tasmania’s NEM entry required a commitment from the Government to separate the BBPS from Hydro Tasmania. Under its Vesting Contract for non-contestable customers, Aurora Energy was also required to source at least 10 per cent (and up to 25 per cent) of its energy from an alternative party to Hydro Tasmania. This opened up the possibility for private sector involvement, post separation, in redeveloping the BBPS and/or the development of new gas-fired generation, in the context of the Duke Energy TNGP project.

The TVPS project experienced a long gestation period from initial proposals in 2001 through to the commencement of construction in 2007, during which various commercial and operational models were considered. The evolution of the TVPS from initial concept to finalised project is briefly outlined below.

1.1.1. Original joint venture proposal between Hydro Tasmania and Duke Energy

In April 2001, as part of the Tasmanian Gas Pipeline Development Agreement, Hydro Tasmania signed a Joint Venture (JV) Heads of Agreement with Duke Energy International for the redevelopment of the BBPS to a 234MW combined cycle plant. The Agreement subsequently transferred to Alinta after its takeover of Duke Energy’s Australian and New Zealand assets in April 2004.

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85 Separation was scheduled to occur in April 2006 to coincide with the physical connection of Basslink.
86 Note that the Vesting Contract, and therefore the ACCC requirements in relation to it, terminated at the point Tranche 2 customers become contestable, or no later than 31 March 2007.
87 The Bell Bay Power Station was first commissioned in 1971 and was owned and operated by Hydro Tasmania. Initially comprising two oil-fired thermal units, Unit 1 was converted by Duke Energy to run on gas in March 2003 and Unit 2 was similarly converted by Hydro Tasmania in 2004. In 2006, three 35 MW gas turbines (Pratt & Whitney FT8 open cycle units) were installed in light of hydrological inflows and concerns about the State having access to sufficient capacity ahead of Basslink commissioning.
The Agreement provided for the establishment of a JV company between Hydro Tasmania and Duke Energy (later Alinta) to operate the BBPS Unit 2 from 1 January 2006. Under this arrangement, Bell Bay Unit 1 would continue to be owned and operated by the BBPS as a ‘stand by’ generator while Unit 2 would be repowered to a combined cycle gas turbine and operate competitively in the market.

Alongside the JV agreement, Hydro Tasmania was party to a Pipeline Capacity Agreement (PCA) with Alinta for an annual capacity of 10PJ of gas at an annual cost of $8.6 million (2007 dollars) until March 2017. In the event that the JV was to proceed, the PCA would have been transferred as part of that Agreement.

However, after extensive negotiations between the parties, no landing could be reached on the commercial basis for the development of the JV and these arrangements were not progressed.

### Initial Development of the TVPS - Key Events and Decisions

**April 2001** - Hydro Tasmania and Duke Energy enter into a Heads of Agreement as part of the TNGP Development Agreement for redevelopment of the BBPS

**14 November 2001** - The ACCC delivers its final decision regarding derogations and Vesting Contract arrangements for Tasmania’s entry to the NEM.

**23 April 2004** - Alinta acquires the Australian and New Zealand assets of Duke Energy, including the gas pipeline and interests in the Bell Bay Power Station (BBPS)

**26 April 2006** - Alinta publicly announces plans for the Greenfield development of TVPS near BBPS, following the collapse earlier in the year of joint venture negotiations with Hydro Tasmania.

**October 2006** - Alinta and Aurora Energy announce 203MW CCGT project with a target commissioning date of 31 March 2009

**7 March 2007** - Aurora Energy executes energy supply contracts with Alinta.

**19 April 2007** - The Tasmanian Parliament approves the sale of the Bell Bay Power Station. Alinta acquires the BBPS site and the three 35MW FT8 gas-fired turbines from Hydro Tasmania. As part of the deal, Alinta grants a licence to Hydro Tasmania for it to continue to operate the Bell Bay 1 and 2 thermal units until the later of 31 March 2009 or the commissioning of the new combined cycle gas turbine.

**August 2007** - Alinta commences TVPS construction.

**31 August 2007** - Babcock and Brown acquires Alinta, including the existing hedge contract with Aurora.
1.1.2. Development of alternative proposals

As an alternative to redeveloping the BBPS site, in 2005 Alinta (following its 2004 acquisition of Duke Energy’s Australian and New Zealand assets) had begun to develop a stand-alone proposal to construct a new power station on a site adjacent to the BBPS. Negotiations between Alinta and Aurora Energy continued through 2005 and into 2006 in relation to potential wholesale energy contracts that would underpin the viability of the development.

In March 2005, the Government also requested the management and independent directors of Bell Bay Power Pty Ltd\(^88\) to develop a commercially viable business plan for the BBPS under a state ownership model as an alternative to Alinta’s proposals to Aurora Energy. At a minimum, the Bell Bay Power business plan was intended to act as an ‘analytical benchmark’ against which the Alinta proposal could be assessed.\(^89\)

In response, Bell Bay Power submitted a proposal to the Minister for Energy and the Treasurer under which the subsidiary would be separated from Hydro Tasmania in the short term and the existing assets would be operated for profit ahead of re-powering Unit 2 to a combined cycle gas turbine.

In early 2006, Alinta re-approached Aurora Energy with regard to pursuing the Greenfield option and by August 2006 had negotiated a new commercial arrangement that, according to Aurora Energy, offered an attractive product mix that allowed for peak load management. Aurora Energy notes that the proposal was highly appealing as it provided the company with flexibility to change the nature of wholesale risk protection over time, which would broaden its scope in hedge contract negotiations with Hydro Tasmania over the long term. The commercial arrangements between Alinta and Aurora Energy are further discussed in Section 3 of the Paper.

The Aurora Energy Board approved the proposal on 24 August 2006.

In September 2006, the then Energy Policy Steering Committee made a number of recommendations to the Government regarding its assessment of the respective Bell Bay Power and Alinta proposals for generation at Bell Bay. The Steering Committee recommended that the Government support the Alinta Greenfield proposal, provided that the Aurora Energy Board was satisfied that it could enter into the necessary arrangements on a fully commercial basis without Government support or intervention and that Alinta did not seek any form of Government support for the development to proceed.\(^90\)

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\(^88\) Bell Bay Power was a subsidiary of Hydro Tasmania responsible for the operation of the BBPS.

\(^89\) Energy Policy Steering Committee, Assessment of Proposals for Power Generation in the Bell Bay Area, 26 September 2006 (Draft).

\(^90\) Energy Policy Steering Committee, Assessment of Proposals for Power Generation in the Bell Bay Area, 26 September 2006. While both project proposals were judged to have substantial merit, the Committee favoured the Alinta proposal “...on the basis that it provides a new entrant generator, is acceptable to the Board of Aurora Energy, will not threaten the commercial viability of Hydro Tasmania, and does not increase the State’s exposure to the highly volatile energy market”. 

Tamar Valley Power Station: Development, acquisition and operation
Alinta publicly announced its yet-to-be-finalised agreement with Aurora Energy on 26 October 2006. The relevant electricity supply contracts between Alinta and Aurora Energy were executed on 7 March 2007, with some minor adjustments in July 2007 following unexpected changes to Alinta’s gas supply arrangements. The final hedge arrangements with Alinta included provisions for regular gas price reviews and price increase ‘pass through’ to Aurora Energy. Aurora Energy considered the gas price risk to be commercially acceptable given the prices offered under the hedge and the linkages between gas costs and electricity prices in the NEM generally.

At this stage, Alinta was still proceeding on the basis that the new station would be built on an adjacent site in the Bell Bay industrial zone and not at the existing BPPS.

1.1.3. Sale of the Bell Bay power station

Following the public announcement of the TVPS project in October 2006, Alinta re-opened negotiations with Hydro Tasmania for the acquisition of the BBPS site. The BBPS site had value to Alinta for a range of reasons, including existing environmental permits, its proximity to the gas pipeline, electricity transmission lines and the node, access to cooling water and the existing of the turbines on site, providing some back-up plant.

Following Cabinet approval in March 2007, Hydro Tasmania agreed to sell the BBPS site to Alinta. Key features of the sale agreement included that:

- Hydro Tasmania would sell the site and the BB3 generating facilities, together with all licences, approvals and spare parts;
- Alinta would pay $30 million in full consideration for the assets;
- Alinta would grant a licence to Hydro Tasmania for it to continue to operate the thermal units until the later of 31 March 2009 or completion of construction (defined by receipt of certificate of completion);
- the PCA (negotiated by Hydro Tasmania and Duke Energy) would be terminated from 31 March 2009;
- the J V agreement would be terminated with neither party retaining any residual rights;
- Hydro Tasmania would complete the demolition of the Bell Bay thermal units and associated plant by 31 March 2017; and

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91 Cabinet approval was obtained prior to the tabling of a motion in the Tasmanian Parliament for the sale of the BBPS, which was required under section 7(4) of the Hydro-Electric Corporation Act 1995.

92 These were the 3 FT-8 gas-fired generators originally acquired by Hydro Tasmania in 2005 as back-up plant when the State was experiencing very low inflows.
Hydro Tasmania would provide Alinta with a zero premium option to execute a swap for up to 100MW electricity for the period 31 March 2009 to the earlier of the commercial operation of the new closed cycle units or 31 December 2009.93

The early release of Hydro Tasmania from the PCA was a key component of the sale agreement. The status of the PCA following the breakdown of JV negotiations between Hydro Tasmania and Alinta was legally unclear.94 Analysis at the time suggested that the sale had a positive net present value (NPV) of $22 million, as compared to an estimated negative NPV of minus $135 million if the deal had not been agreed to.95 Hydro Tasmania’s 2007 Annual Report stated that the release represented almost $90 million in savings (in addition to the $30 million direct cash benefit for the sale of the assets themselves).

The Tasmanian Parliament approved the sale of BBPS on 19 April 2007.96

1.1.4. Babcock and Brown’s acquisition of Alinta assets

On 31 August 2007, shortly after construction of the TVPS had commenced, BBP acquired Alinta, including AETV, the entity that owned the TVPS project.
Initial Development of the TVPS - Summary

- ACCC conditions placed on Tasmania’s entry to the NEM required the separation of the BBPS from Hydro Tasmania, which opened up commercial possibilities for new gas-fired generation at Bell Bay in the context of the TNGP project.

- The ACCC also required Aurora Energy, under its Vesting Contract for the non-contestable load, to source at least 10 per cent (and up to 25 per cent) of its wholesale energy from an alternative generator to Hydro Tasmania.

- The original JV proposal between Hydro Tasmania and Alinta (under the Gas Pipeline Development Agreement) for the redevelopment of the BBPS was set aside in 2006.

- Alinta was successful in developing an alternative Greenfield TVPS proposal, which was supported by electricity hedge contract arrangements with Aurora Energy. Aurora Energy notes that the proposal was highly appealing.

- This development was supported by Government over an alternative ‘benchmarking’ proposal under which Bell Bay Power would be separated from Hydro Tasmania in the short term (but continue under State ownership) and operate the existing assets for profit, ahead of re-powering Unit 2 to a combined cycle turbine.

- Alinta subsequently acquired the BBPS site and FT8 units from Hydro Tasmania. Alinta granted a licence to Hydro Tasmania for it to continue to operate the Bell Bay gas-fired 1 and 2 thermal units until the later of 31 March 2009 or completion of construction. A key component of the sale agreement was Hydro’s release from its PCA liability with Alinta, which was valued by Hydro Tasmania at around $90 million.

- Shortly after commencement of construction, on 31 August 2007 BBP acquired the TVPS project as part of its acquisition of Alinta.
1.2. Acquisition and completion of the TVPS by the State

Just under a year into the construction of the TVPS, new owners BBP began to experience financial difficulties. BBP’s financial position - and the resultant risks to project completion - would ultimately prompt the Government to take the decision to instruct Aurora Energy to acquire and complete the partially-built TVPS.

There were less than three months between the Government first becoming aware of the seriousness of BBP’s financial difficulties and the finalisation of a Sale and Purchase Agreement (SPA) between Aurora Energy and BBP for the TVPS. The key events during this period are described briefly below.

1.2.1. The Government’s initial response to BBP’s financial issues and threat to the TVPS sale process

The first public indication of BBP’s financial problems occurred when BBP announced to the Australian Stock Exchange (ASX) on 4 June 2008 that it was embarking on an asset sale program, which, it was subsequently revealed, included the TVPS project.

On 13 June 2008, BBP formally approached Hydro Tasmania as one of a number of selected parties to submit an expression of interest for the purchase of the TVPS. On 16 June 2008, Hydro Tasmania advised the Government of BBP’s approach and on 20 June 2008 the Government approved Hydro Tasmania making a non-binding offer “...as an interim step to preserve the State’s interest in any potential sale process”. By 23 June 2008, BBP had advised Hydro Tasmania that it had not been short-listed in the bid process.

The Government was aware of a number of outstanding issues that had the potential to jeopardise the sale of the TVPS to another private operator. Key amongst these was the uncertainty of the TVPS not having a connection agreement in place with Transend. The connection agreement was ultimately contingent on the results of a review by the Australian Energy Market Commission (AEMC) National Reliability Panel of Tasmania’s frequency standards. At the time, the prevailing frequency standard was too wide for TVPS’s turbines to meet the minimum access standard of the network.

While it was widely expected that the outcome of the Review would be a tightening of the standard allowing the TVPS to connect\(^9\), the uncertainty in the context of the sale process was considered likely to impact on the value of the station in the market, as well as affecting timely divestment and potentially delaying commissioning.\(^9\)

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\(^9\) It should be noted that the Frequency Standard Review was not instigated specifically in response to, or to accommodate, the development of the TVPS. Following Tasmania joining the NEM in May 2005, the Reliability Panel acquired responsibility for the Tasmanian frequency operating standards and was required to perform a review within one year. In its 2006 review, the Panel determined that the existing Tasmanian frequency operating standards should continue to apply until NEMMCO had gained sufficient experience operating Basslink. It was agreed that the Panel would again undertake a benefit/cost assessment of tightening the standards at a future time. In February 2008 the AEMC provided the Panel with terms of reference for this follow up review. The Panel commenced its review in April 2008. (See: AEMC Reliability Panel, Tasmanian Operating Frequency Standard Review: Final Report, December 2008).

\(^9\) Infrastructure Committee of Cabinet, Tamar Valley Power Station, 7 July 2008. Another key issue raised by BBP was that certain features of the Aurora hedge prevented the station from running at full capacity. Aurora disagreed with BBP’s assertions with regard to this matter but had offered to consider alterations to the contract to relieve these concerns.
The Government’s Electrical Technical Advisory Committee\textsuperscript{100} (ETAC) had been working through the range of TVPS connection issues, but had been largely adopting a monitoring function and “...had not reached any conclusions on a recommended way forward”.\textsuperscript{101}

On 7 July 2008, in the context of BBP’s financial position and timelines for divestment of the asset, the Government agreed to a strategy to facilitate the timely resolution of the TVPS connection issues, underpinned by a decision to task the CEO of Transend Networks with handling negotiations between the relevant parties, including BBP, Basslink, Transend, Aurora Energy, Hydro Tasmania and the AEMC National Reliability Panel. The Transend CEO agreed to take on the facilitation/negotiation role and report back to Government on the outcomes of negotiation by 31 August 2008.

In recommending its preferred option of a Government-facilitated solution to the TVPS connection issue, Treasury initially advised against any move for the State to acquire the asset and noted that “…from a strategic perspective, there is no inherent benefit in State participation in the TVPS sale process” in terms of the resolution of the connection issues.

However, it was noted that State ownership may need to be considered in the scenario that BBP “…fails to, or does not proceed to, sell the TVPS and subsequently does not advance construction rapidly enough to give the State confidence that the asset will be available to meet BB Power’s obligations under the Aurora contract as required in mid-2009”.\textsuperscript{102} By this time, Treasury had already commenced preliminary work to understand any potential issues or barriers in the event that a quick response to this situation was required.

\textbf{1.2.2. Discussions leading up to the Heads of Agreement}

Efforts to support and facilitate a sale of the TVPS to another private operator proved unsuccessful. Given its financial situation, its need to act swiftly in selling the TVPS and the frequency standard/connection issue, BBP had indicated that the TVPS was unattractive to third parties and would be difficult to divest.\textsuperscript{103}

\begin{flushright}
\textsuperscript{100} ETAC was a subcommittee of ECAC tasked with providing analysis and advice on technical matters.
\textsuperscript{101} Infrastructure Committee of Cabinet, Tamar Valley Power Station, 7 July 2008.
\textsuperscript{102} Infrastructure Committee of Cabinet, Tamar Valley Power Station, 7 July 2008.
\textsuperscript{103} Department of Treasury and Finance ‘Tamar Valley Power Station Acquisition Counterfactuals’, undated.
\end{flushright}
On 9 July 2008, the then Treasurer met with BBP representatives, on the Company’s initiation. At the meeting, BBP indicated that it was having difficulties in arranging finance to complete the project and that the outcome of the sale process was uncertain and that, in this context, there were risks to the timely commissioning of the TVPS. BBP suggested that, given energy security concerns related to the drought, the Government might have an interest in acquiring the TVPS. The Treasurer agreed that BBP would submit a range of purchase options for the Government’s consideration.104

On 11 July 2008 BBP submitted its written proposal to the Government. BBP advised that the only way for it to continue work on the project was if the State agreed to either enter into a purchase agreement or provide finance to BBP for both the uncompleted work and bridging finance of $100 million. BBP’s position appears to have been driven largely by timeframes to put in place project finance by 31 August 2008 and complete the sale of the TVPS as soon as possible.

The Government subsequently sought the views of Aurora Energy with regard to BBP’s proposal. Aurora Energy’s advice at that time, similar to Treasury’s initial position, was that “…energy security issues in the context of the TVPS are best facilitated through providing a clear ‘completion and connection pathway’ for potential purchasers”, rather than acquisition of the asset by the State.105

Treasury sought further advice from Aurora Energy on a proposed Government purchase in late July. In its 8 August reply, Aurora Energy’s preferred outcome was for BBP “…to negotiate project financing and then the commercial sale of the TVPS to a reputable and experienced energy market player, with Aurora Energy’s current contract remaining in place”, due to concerns about the financial impact of the acquisition on the Company. Aurora Energy indicated that it would support the State’s acquisition of the TVPS a new State-owned company took it on unattached to Hydro Tasmania and the existing BBP hedge deal remained on foot.106

104 Infrastructure Committee of Cabinet, Tamar Valley Power Station, 11 July 2008.
106 Letter from Aurora Chairman to Treasury Secretary, 8 August 2008. In the event of Government acquisition, Aurora Energy proposed two possible options. The first (and preferred) option was for the purchase by a new state-owned entity (unattached to Hydro Tasmania) and the retention of Aurora’s existing contract. The second option was that the Government could direct Aurora Energy to purchase the TVPS at its real market value - based on the Aurora off-take agreement and timing of connection, rather than construction cost, on the condition that the Government put in place ‘necessary strengthening’ of Aurora’s balance sheet to enable purchase while still retaining its investment grade credit rating.
On 8 August 2008, senior Treasury staff met with the Premier, the DPAC Secretary and the Minister for Energy’s senior adviser to discuss the TVPS situation. Treasury was authorised to enter into preliminary purchase negotiations with BBP, commencing with a meeting to be held the next day. It was noted at the meeting that legal, technical and financial consultancies had already been put in place to provide advice to the Crown: Worley Parsons to provide technical advice, Lazard Carnegie Wylie (LCW) to provide financial and valuation advice and Allens Arthur Robinson to assist with legal and contractual matters.

Treasury raised a range of issues and risks to Government associated with the proposed acquisition, including the outstanding connection/frequency standard issue, the ability to ‘reshape’ contractual arrangements post-acquisition to create a ‘workable, valuable entity’, the terms and nature of key contracts (including gas supply and transportation) and the potential impact on Tasmanian electricity entities, both in terms of their value and operations.

108 The Panel has viewed the substantial due diligence materials provided by the consultants.
Energy Security Risk and the TVPS Acquisition

The Government’s decision to acquire the TVPS took place against the backdrop of sustained, very low inflows to Tasmania’s hydro system.

Inflows for the period November 2007 to April 2008 were the lowest ever recorded. This followed on from ten years where inflows were well below the long-term average, which substantially depleted water in storage. At the end of January 2008, total system storage was at 23.2 per cent and by 11 June 2008 this figure had reached 16.5 per cent.

Low storages were exacerbated by the failures to both Basslink and the BBPS at the end of 2007. Basslink was out of service from 31 December 2007 to January 8 2008 due to a failed transformer at Loy Yang, while Bell Bay unit 2 was out of service for five weeks after it failed on 24 December 2007, also due to a transformer failure.

The Government was concerned about the maintenance of supply reliability through 2009 in the event that extremely low inflows in continued conjunction with a sustained outage of either Basslink or the BBPS.

The Government had a number of processes in place to monitor the storages situation and provide with regard to potential contingency options. The main forum for the discussion of hydro storages and energy security was the Electricity Coordination and Advisory Committee (ECAC), which was chaired by the Director of Energy Planning (the statutory officer with responsibility for providing advice to the Minister on energy supply and security issues).

Hydro Tasmania was the key source of advice on supply security risk during the period prior to the TVPS acquisition. Throughout 2007 and the first half of 2008, ECAC received regular presentations from Hydro Tasmania on the storages situation. In addition to participation at ECAC meetings during the first half of 2008, Hydro Tasmania was also preparing reports on storages and providing this advice to the Minister on a weekly basis. It was also participating in a weekly ‘Low Inflows Liaison Group’ meeting with the Director of Energy Planning, which in turn informed discussion of the inflows situation (among other issues) at regular fortnightly meetings between the Director of Energy Planning and the Minister.

Hydro Tasmania’s overall risk assessment remained consistent over the first half of 2008 - essentially that even in the face of ongoing low inflows, it believed energy security would be maintained through 2008 and 2009, barring the prolonged outages or failure of Basslink, the BBPS or any significant hydro generation.

ECAC did not directly advise Government on the risk to supply posed by the potential delay of the TVPS, nor was the Director of Energy Planning involved in the decision-making in relation to the power station’s eventual acquisition. Instead, interactions with BBP about the TVPS divestment process were coordinated and managed by Treasury, which coordinated supply risk information provided directly by the State Owned Energy Businesses (SOEBs).
Energy Security Risk and the TVPS Acquisition - Continued

Modelling provided by Hydro Tasmania to the Minister for Energy and the Treasurer showed that, in the scenario where the TVPS was delayed and Hydro Tasmania could not utilise any of its existing thermal generation beyond 31 March 2009, meeting Tasmanian electricity demand in the second year of a further two extreme low inflow years would be ‘difficult’.

However, this assessment was based on what Hydro Tasmania considered an ‘extremely unlikely’ inflow sequence - albeit the one that had just been experienced - suggesting that the risk of supply restrictions, even without any thermal support, were low.

Hydro Tasmania had concerns about its ability to continue to run the BBPS beyond the end of 2009 in the event that TVPS commissioning was delayed, due to both conditions contained in existing contractual relationships with BBP and the technical reliability of the plant. The existing thermal units were not considered a reliable source of generation, noting that one of the BBPS units had experienced a five-week outage at the end of 2007.

Given the BBPS was due to be de-commissioned when the TVPS came online in 2009, it was effectively being run without regard to longer-term reliability. This is reflected in its performance. For example, in 2008-9, the availability of Bell Bay Unit 1 was only 7 per cent, while the forced outage rate was 90 per cent. By way of comparison, the forced outage rate of the hydro system is approximately 2 per cent.

It should also be noted that the three FT8 units were not available at this time, as they were in the United States being refurbished and upgraded from 35MW to 40MW.

Therefore, the Government’s decision to acquire the TVPS was based on an unwillingness to accept a low probability, but high consequence risk of having insufficient energy to meet on-island demand, in the medium term, in the event that very low inflows continued, combined with the inability to source sufficient capacity from Basslink and thermal generation.

The Panel has not seen any evidence (including Cabinet materials) that any suggests that the acquisition was motivated by any factors other than ensuring the project’s timely completion in order to support energy security.
1.2.3. Heads of Agreement, Parliamentary Approval and Sale and Purchase Agreement

On 11 August 2008, Cabinet agreed that the Government would enter into negotiations with BBP for the acquisition of the TVPS. As part of its Decision, Cabinet authorised the Premier, Treasurer and Minister for Energy to approve the final transaction, approved the creation of either a new State-owned company or subsidiary to own and fund the purchase of the TVPS and authorised the Treasurer to enter into any necessary contracts on behalf of the Crown.

On 15 August 2008, following accelerated negotiations with BBP, the Government agreed to a binding Heads of Agreement (HoA) for the acquisition of the TVPS. The Government also endorsed the model that the TVPS would be owned and operated by a wholly owned subsidiary of Aurora Energy, AETV.

The AETV subsidiary model was selected on the basis that it was relatively simple to implement (i.e. not requiring the creation of a new State-owned company) and would be able to ‘draw on existing management capabilities and systems within Aurora’. The key consideration was that the model could be established within BBP’s timeframes for the TVPS sale.109

The HoA provided for the acquisition by the State of all shares and related assets of AETV for an agreed purchase price of $100 million, plus development costs between 8 August 2008 and completion of the sale, plus 50 per cent of the unused project contingency included in a works program agreed between the parties. As part of the transaction, the State would receive the three refurbished FT-8 gas turbines that were previously sold as part of Hydro Tasmania’s 2007 BBPS sale to Alinta. Total estimated project completion costs at the time were $360 million, which included the $100 million acquisition costs.

The HoA was subject to a number of Conditions Precedent (in addition to standard due diligence provisions) including:

- approval by the Tasmanian Parliament and the Australian Competition and Consumer Commission (ACCC);

- a draft ruling by the AEMC Reliability Panel that would indicate that the TVPS would be able to be connected to the network;

- the novation of gas supply and transportation contracts to Alinta Energy Tamar Valley prior to sale completion; and

- arrangements to ensure that AETV would have the benefit of key contracts required for the completion and subsequent operation of the TVPS.

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On 19 August 2008, the Premier made a Ministerial Statement to the Parliament announcing the Government’s HoA with BBP. On 21 August, the Minister for Energy introduced the Tamar Valley Power Station Bill 2008, which provided for the Shareholder Ministers to direct Aurora Energy to acquire from BBP shares and assets in AETV. The Bill was passed by the Parliament on 28 August 2008.

The Government indicated at the time of acquisition that it did not intend to be the long-term owner of the TVPS, with the intention that it would be sold to a private sector operator after an ‘appropriate’ period of operation (considered to be between three to five years).

At the same time that supporting legislation for the transaction was being considered by the Parliament, the Government was simultaneously progressing with legal, technical and financial due diligence and accelerated negotiations with BBP to finalise a SPA for the TVPS. The final SPA was based largely around the terms and conditions already laid out in the HoA and retained the same purchase price and conditions precedent to that agreement.

The Shareholder Ministers issued a formal direction to the Chairman of Aurora Energy on 27 August 2008 for the Company to acquire the shares and assets of Alinta Energy Tamar Valley. The SPA was subsequently executed by Aurora Energy on 1 September 2008.

The $100 million purchase price was funded by an equity injection from the Government to Aurora Energy under an appropriation from the Consolidated Fund, with the $260 million for estimated project completion costs debt funded through a finance facility with Tasmanian Government lender Tascorp, provided at ‘arms length’ from Aurora Energy’s existing finance facility. Because the development costs took Aurora Energy beyond its approved borrowing limit, Tascorp financing was provided on the condition that the Treasurer issue a ‘letter of comfort’ to essentially underwrite the TVPS borrowings.

1.2.4. Satisfaction of conditions precedent and completion of the SPA

Gas supply and transportation arrangements

At the time BBP had decided to include the TVPS in its asset sale program, there were no signed contracts with AETV for either gas supply or transportation to the power station. Instead, the supply and transportation arrangements were contained within a broader suite of agreements within the Babcock and Brown Group, which covered the supply of gas to other facilities in Tasmania and elsewhere in Australia.

The Bill also provided for the future sale of the TVPS (included to ensure that future sale was not prevented by the Electricity Companies Act 1997) and for the transfer of assets and liabilities between state-owned businesses and between the Crown and state-owned businesses.

Aurora Energy indicated to Treasury that a key issue that needed to be addressed in the negotiations by the Government for the purchase of the TVPS was for it to obtain certainty around gas prices, due to the material impact that changes in these prices could have on the cost base and broader financial viability of the power station.

Aurora Energy considered it essential that signed contracts for gas supply and transportation were on foot prior to the finalisation of the sale agreement. The stated rationale was that it considered that it would be in a weak commercial position in trying to negotiate for gas supply and transportation in the market having being directed to acquire a partly built power station with a clear requirement for gas.

Under the SPA, BBP was required to put in place gas supply arrangements for the TVPS on terms consistent with a wider package of gas commodity and transport agreements that were in place in a related Babcock and Brown entity. The nature of the gas arrangements (volume and conditions) was consistent with the use of gas implied under BBP’s operating model for the TVPS.

At the completion of the SPA for the acquisition of the TVPS, AETV (now owned by Aurora Energy) had in place:

- A Gas Supply Agreement (GSA) with Alinta Energy Australia Trading and Marketing (AEATM) (a subsidiary of Babcock and Brown), which was directly linked to a larger, aggregated GSA with Esso/BHP; and
- Gas Transport Agreements (GTA) with Babcock and Brown Infrastructure (for transport through the TNGP) and Jemena (for transport through the Eastern Gas Pipeline connecting with the TNGP).

The TVPS gas supply and transportation arrangements acquired under the SPA are outlined in Figure 1.
ACCC approval

Following the execution of the SPA, the ACCC raised significant concerns with regard to the potential competition impacts of the TVPS acquisition, including an indication that it may seek a Federal Court injunction to prevent the completion of the transaction. Treasury had earlier written to the ACCC outlining a range of principles that the Government was applying in relation to the acquisition, including a commitment to sell the TVPS within the short to medium term.\textsuperscript{112}

Initially, the ACCC’s position was that its approval of the transaction would be conditional upon the sale of the asset to another operator within a pre-determined timeframe. The Government considered the forced sale provision unacceptable as a sale under these circumstances could precipitate significant value loss on the asset.

Following further discussions, it was agreed that, subject to Aurora Energy preserving the asset, the ACCC would undertake a more rigorous assessment of the competition impacts of the transaction that would take into account the “public interest and specific circumstances of the acquisition” by early 2009.\textsuperscript{113}

Because ACCC approval was a condition precedent for the completion of the SPA, the Shareholder Ministers had to formally direct Aurora Energy to waive this
requirement to allow the sale to proceed, which they did in a Members’ Direction on 14 September 2008.

In its subsequent review, the ACCC concluded on 29 October 2008 that the acquisition was unlikely to result in a substantial lessening of competition in any of the relevant markets. The ACCC arrived at its conclusion based on a number of factors, including the nature and extent of the hedge contracts in place between AETV and Aurora Energy and its belief that the likely ‘counterfactual’ to Aurora Energy’s acquisition of the TVPS would have been that the station would have been delayed, or at worst terminated, based on its assessment that the sale to a private operator would have been unlikely in the circumstances.114

**Frequency standards review**

The condition precedent relating to the AEMC Reliability Panel’s review of Tasmanian frequency standards was satisfied on 28 August 2008, when the Panel handed down its draft report, which indicated that there should be no impediment to negotiating a connection agreement with the generator.115

With the satisfaction and/or waiver of all relevant conditions precedent, the SPA was completed on 15 September 2008.

1.2.5. **Project completion and commissioning**

Following completion of the SPA, AETV took on responsibility for project construction and completion. Under the SPA, all existing employees of BBP involved in the building of the TVPS transferred to AETV on equivalent terms and conditions.

The TVPS was commissioned over a six-month period, commencing in June 2009 with the testing of the Trent open cycle generator and the commissioning of the three FT-8 units. Delays to the implementation of the revised frequency standards approved by the AEMC Reliability Panel in December 2008 required AETV to seek a ‘non-controversial participant derogation’ in order to allow the connection of the TVPS for commissioning testing. The new frequency standards were implemented on 28 October 2009, following the official opening of the power station on 26 October 2009.

The project was delivered for around $20 million under the original $351 million dollar budget.

In considering project delivery issues, the Panel notes that at the time the Government made the decision to acquire the TVPS, Aurora Energy was a combined retailer/distribution business, with no experience in generation construction or operations. The complexity associated with this fundamental change in corporate direction required a step-change in Aurora Energy’s structure at the functional and at the corporate level. In the event, Aurora successfully executed the construction program while creating the internal capacity to ensure that the


power station was successfully commissioned into the Tasmanian electricity supply industry.

**Acquisition and Completion of the TVPS by the State - Summary**

- In June 2008, BBP embarked on a divestment program for a range of assets, which included the TVPS.
- Uncertainty regarding a connection agreement that would permit the station to connect to the Tasmanian system (or, less critically, delays caused by the Frequency Standards review process) was one issue impacting on the commercial attractiveness of the TVPS in the market.
- The Tasmanian Government initially attempted to act as facilitator to help BBP resolve the connection issue and assist with the sale to a third party operator.
- However, with no other likely buyers in the market and with pressure being applied by its financiers, BBP approached the Government and proposed acquisition within an extremely compressed timeframe.
- Threats to timely completion of the project came at the same time as near-record low hydrological inflows and storages and falling reliability of the BBPS, which had increased the risk of potential energy shortfalls in Autumn 2009.
- The Government determined that it would acquire and complete the TVPS project on energy security grounds.
- The Government paid $100 million to BBP and took on responsibility for what was estimated at the time to be $260 million in project completion costs. The transaction was approved by the Tasmanian Parliament.
- The acquisition was completed on 15 September 2008.
- TVPS construction and commissioning proceeded under the control of AETV, with project staff transferred from BBP. The station was officially opened on 26 October 2009. Project execution by Aurora Energy was very strong, with the TVPS being completed on time and $20 million under budget.
1.3. Post-acquisition commercial and operational arrangements

The period following the acquisition of the TVPS involved a number of key events and decisions that have shaped the commercial and operational arrangements that currently underpin the operation of the TVPS.

These included, most significantly:

- Aurora Energy’s acquisition of additional significant gas commodity and capacity contracts; and

- a range of actions taken by Aurora Energy and the Government to address AETV’s worsening financial position, including internal restructuring of Aurora Energy’s business groups, the establishment of revised commercial arrangements between AETV and Aurora Energy, and the passage of the Electricity Supply Industry (Price Control) Amendment Regulations 2010 (Price Control Regulations).

These matters are discussed in more detail below.

1.3.1. Aurora Energy’s purchase of AEATM assets/gas contracts

Following the completion of its sale of the TVPS to Aurora Energy, in November 2008 BBP approached the market to sell the full suite of AEATM assets/contracts, which included the GSA for the TVPS, as well as a larger aggregated GSA with Esso/BHP. The asset package also included the GTAs between AEATM and BBI and Jemena from which the TVPS GTA was ‘carved out’ and a Tolling Agreement over the output of the Bairnsdale Power Station in Victoria.

Aurora Energy was approached as one of a small number of participants to purchase the AEATM assets. BBP’s sale timetable was extremely compressed; with binding bids due by 10 December 2008 and financial close on 15 December.

Following a short due diligence process, the Aurora Energy Board approved the submission of a bid for the assets, which was based on a significant discount for risks associated with the quick sale process.117

In acquiring the AEATM gas assets, Aurora Energy was driven largely by a defensive, risk mitigation strategy that focused on securing control over its gas supply arrangements.118 Aurora Energy was concerned that the acquisition of the AEATM ‘head’ GSA by a competitor might see increases in gas prices. Aurora Energy saw value in being able to negotiate directly with Esso/BHP rather than relying on a third party with no obvious interest in securing a good gas price for AETV.
Commercial and Operational Arrangements: Key Events and Decisions

**December 2008** - Aurora Energy acquires BBP’s AEATM gas assets.

**February 2009** - Aurora Energy confirms that the TVPS’ fair market valuation is likely to be substantially lower than its completion costs or its replacement value.

**March 2009** - Aurora Energy approaches Government seeking assistance with regard to AETV solvency concerns. Treasury and Aurora Energy commence a joint work program to address identified financial issues.

**July 2009** - Aurora Energy implements a new integrated Energy Business structure and replaces the existing Aurora Energy/AETV hedge contract with a tolling agreement. The Treasurer advises Aurora Energy that the Government will be directing the Regulator to apply ‘long-run marginal cost’ to the 2010 Pricing Determination in order to provide a level of comfort to Aurora around future revenues for its retail business and its capacity to fund the tolling agreement for the TVPS.

**December 2009** - The Aurora Energy Chairman writes to the Shareholder Ministers on 11 December 2009, outlining a range of concerns regarding the financial position of the Company.

**January 2010** - The Aurora Energy Board tasks a special subcommittee to hold separate, extraordinary briefings with both Shareholder Ministers (the Minister for Energy on 12 January 2010 and the Treasurer on 18 January 2010) to further discuss the issues raised in the 11 December 2008 letter.

**February 2010** - The Government announces its election commitment of a ‘blanket’ five per cent electricity price cap for non-contestable customers for 2010-11, with the LRMC -based Pricing Determination to be delayed until 2011-12.

**April 2010** - Aurora Energy makes formal presentations to Government with regard to its worsening financial situation – including the likely impairment at the end of 2009/10 in the order of $340 million.

**June 2010** - The Government publicly announces that it will not be proceeding with its promise to cap electricity price increases to 5 per cent or all customers (instead committing to a $100 one-off increase in the electricity concession). The Parliament passes amendments to the energy Price Control Regulations, which have the effect of increasing revenues and revenue certainty for Aurora Energy.

**28 June 2010** - the amended Price Control Regulations take effect.

**1 July 2010** - Aurora Energy and Hydro Tasmania enter into new hedge arrangements for the non-contestable load, on terms consistent with those prescribed in the Price Control Regulations.
Aurora Energy was also concerned that, in the circumstances where BBP were to fail, AEATM’s GSA with Esso/BHP would be ‘disclaimed’, leaving AETV with no gas and finding itself in the situation where it would have to negotiate new supply arrangements from what Aurora Energy had determined would be a weak bargaining position. This was a similar rationale to that which drove the Government and Aurora Energy to secure of GSA/GTA arrangements as part of the SPA.

The AEATM acquisition increased the potential flexibility of the operating regime for the power station, as it removed a contractual ‘partition’ in the broader and larger take-or-pay arrangements between AEATM and Esso-BHP that applied to the TVPS.

Aurora Energy also saw some value in the acquisition in terms of growth potential in the supply of gas to major customers in Tasmania as well as retail customers. Aurora Energy created the option of reducing the gas obligations in relation to the TVPS if it could find alternative markets for the gas, either in Tasmania or elsewhere in Australia. However, the gas transport arrangements do not offer such flexibility – these have large fixed obligations, regardless of whether the gas is transported across the network to Tasmania or not.

1.3.2. Initial decisions and actions in response to AETV’s emerging financial difficulties

In September 2008, Aurora Energy wrote to the Treasurer raising concerns over the impact of the purchase and construction of TVPS on Aurora’s balance sheet and financial position.

By February 2009, Aurora Energy had developed a baseline budget for AETV’s ongoing operations and established the ‘fair market’ valuation of the TVPS. Based on modelling that it had commissioned, Aurora Energy found that the TVPS’ valuation, at $228 million, was substantially lower than its acquisition and completion costs or its replacement value. The valuation was based on a greater understanding of the BBP model, lower than expected market revenues available to the TVPS than assumed in that model and the recognition that the ongoing costs of TVPS were going to be higher than expected.119

Given the significant difference between Aurora Energy’s revised market valuation and the expected completion costs, Aurora Energy faced the prospect of having to significantly impair or ‘write down’ the value of the TVPS in its accounts. These concerns continued through 2009, with AETV internally concerned with potential impairment of the value of the TVPS of around $140 million in June 2009.

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119 This valuation assumed that the contractual arrangements that were in place for the TVPS with Aurora Energy remained in place.
The Aurora Energy Chairman subsequently wrote to the Shareholder Ministers on 27 February 2009 ‘as a matter of urgency’ with regard to the financial position of the TVPS. The Chairman advised that Aurora Energy would have to impair the asset and that, in the absence of other viable alternatives, would need to seek financial assistance from Government.

As a result of discussions with the Shareholder Ministers in March 2009, Aurora Energy and Treasury jointly agreed a work program in the first part of 2009 to address TVPS' financial difficulties. A key issue for the value of the TVPS was the value derived from the contractual arrangements between AETV and Aurora Energy, together with the ability of the TVPS to generate other sources of value from the market. Solutions were aimed at reducing the operating costs and enhancing both revenue and revenue certainty for the TVPS.

Aurora Energy pursued measures to maximise efficiencies and increase value in the TVPS, the key elements of which are summarised below.

**‘Functional integration’ of the Aurora Energy group structure**

In February 2009 the Aurora Energy Board approved a revised operating structure for the Group, based around the establishment of an integrated retailer/generation relationship and the creation of a new wholesale energy function to manage and optimise energy generation, wholesale supply and hedge contracts. This effectively integrated the commercial – distinct from the operational - functioning of TVPS within the Group so that it now operated as a ‘gen-tailer’.

AETV was maintained as a separate legal entity (as required under the operating model originally agreed by the Shareholder Ministers), responsible for the construction, commissioning and operation of the TVPS, while a Wholesale and Trading Division was established and have clear commercial relationships with TVPS and Aurora Energy’s Retail Business.

The new integrated Energy Business was subsequently approved by the Shareholder Ministers and established from 1 July 2009, comprising generation and wholesale energy, with the subsequent inclusion of Retail from 1 January 2010.

**Tolling fee arrangements**

As part of its revised Energy Business model, Aurora Energy also replaced the hedge contract between AETV and Aurora Energy with a new ‘tolling fee’ arrangement to govern the relationship between the Energy Business and AETV.

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120 Letter from the Chairman to the Treasurer, 27 February 2009.
121 At this time, this was the hedge that was in place between Aurora Energy and Babcock and Brown prior to the acquisition of the TVPS by Aurora Energy.
122 This was the hedge that was originally negotiated between Alinta and Aurora Energy, discussed in more detail in Section 3.
The new tolling agreement took effect from 1 July 2009. Under the arrangement, TVPS's rights and obligations associated with the pool income from generation are transferred from AETV to Aurora Energy, in return for a fee. The Energy Business owns the gas arrangements and makes the decision as to when TVPS will operate and at what level and provides the gas to it to produce at that level.

However, given that the new tolling agreement essentially replicated financial outcomes under the previous hedge contract, the new arrangement did not in and of itself make a material difference underlying commerciality of the TVPS or impact on its fair value.

Aurora Energy’s Board subsequently agreed to an increase in the effective hedge price/tolling fee revenue in July 2009123, following a request by the AETV Board. The revised tolling fee comprised two components:

- a base component that reflected the financial value inherent in the original financial contracts with Alinta/Babcock and Brown; and

- an additional payment based on Aurora Energy’s assessment of the market value of the TVPS to deliver additional value that would secure financial stability to AETV, valued at around $7 million per annum.

Approval of the increase was given on the understanding that Aurora Energy’s retail business could cover the increase in the short term but would likely be able to recover the additional cost of the price adjustment from future adjustments to regulated wholesale energy prices124, given that the Treasurer had advised Aurora Energy that the Regulator would be required to apply long-run margin cost (LRMC) for the 2010 Determination, which was expected to closely reflect the costs of the TVPS. The intention was that this would carry forward the existing basis for determining the wholesale energy allowance that was established in 2007.

While the tolling agreement was between AETV and Aurora Energy’s energy business, there was a subsequent transfer price agreement between the retail business and the energy business. At this time, however, there was no new net additional value created within Aurora Energy to underpin the tolling agreement – rather the arrangement concentrated the value implications of the TVPS’ function in the Tasmanian market with Aurora Energy’s energy business.

Aurora Energy’s Board ultimately decided that impairment at the end of 2008-09 was not required, based in part on the increase in the effective hedge price paid by Aurora Energy to AETV and also because the station had not yet been fully commissioned and so had no actual substantive operating period in which to assess its cost and revenue base to fully inform any change in the TVPS value.

123 The TVPS was yet to enter commercial service at this time.
1.3.3. Further decisions and actions relevant to AETV’s financial position

After the TVPS was commissioned in October 2009 and had been operating for a period of time, it became clear that its operating costs were still significantly higher than the revenues that were being delivered under the terms of the tolling agreement, leading to a loss on every MW of electricity produced.

In short, operational restructuring and an increase in the value contained within new tolling arrangements had not been enough to ensure that the TVPS could operate on a commercially sustainable basis. Moreover, wider changes in the energy market, coupled with the financial challenges facing the TVPS, gave rise to the potential significant impairment of the entire Aurora Energy, energy business at the end of 2009-10. This is because Aurora Energy had by this time developed a consolidated position on impairment. Under the new structure, for accounting purposes, the TVPS was considered to be part of the broader Energy Business Cash Generating Unit.

The Aurora Energy Chairman wrote to the Shareholder Ministers on 11 December 2009, outlining a range of concerns regarding the financial position of the Company, including:

- AETV’s unsustainable debt levels;
- a need to increase borrowing capacity; and
- wholesale energy arrangements that were preventing Energy business from generating enough revenue to cover operating costs.

The Aurora Energy Board also tasked a special subcommittee to hold separate, extraordinary briefings with both Shareholder Ministers (the Minister for Energy on 12 January 2010 and the Treasurer on 18 January 2010) to further discuss the issues raised in the 11 December 2008 letter. Aurora Energy was by now concerned that overall profitability was being impacted by large losses starting to appear in the Energy Division.\textsuperscript{125}

\textsuperscript{125} The presentation given to the Shareholders concluded with the comments that: “the Aurora Board is deeply concerned about Aurora’s projected financial position” and that the “Directors of Aurora are increasingly concerned about their future ability to properly discharge their responsibilities while these key issues remain unresolved”. Pricing decisions (including uncertainty around Hydro Tasmanian pricing for non-contestable customers after June 2010) were raised as one of the four key issues driving the current outlook.
Further detailed information about the extent of Aurora’s financial difficulties became evident when it submitted its draft Corporate Plan on 31 March 2010. Aurora Energy’s briefings to Government in March, April and May 2010 suggested that “...if action is not taken in the very short term most of the value of the Energy Business assets, including the TVPS will be impaired at 30 June 2010, and the business will be unsustainable in the medium to long term”.  

Aurora Energy’s main concerns related to uncertainty around a number of outstanding external issues of material impact on the performance of the Energy Business, including the revenue it could recover from non-contestable customers under the 2010 Pricing Determination and contractual arrangements with Hydro Tasmania for the supply of wholesale energy for the non-contestable market.

Aurora Energy’s poor financial situation was also being compounded by a significant annual finance charge arising from operating results for TVPS which, in the absence of sufficient cash flows, had to be further financed by debt.

Amendments to the Price Control Regulations passed by the Parliament in June 2010 were ultimately central to ensuring AETV’s viability in two key respects.

- firstly, the Regulations specified that the TER apply an LRMC methodology to the wholesale energy allowance for non-contestable customers, which would have the effect of delivering an allowance at levels that were broadly consistent with (but not the same as) the costs of generation from the TVPS; and

- secondly, the Regulations gave the Treasurer ultimate power to ensure that any commercial arrangements between Hydro Tasmanian and Aurora Energy in relation to non-contestable customers did not place Aurora Energy in a position of having overall higher energy costs (from all sources) than its revenue provided for under the regulatory allowance. These regulations empowered the Treasurer to impose a contract between the parties consistent with this outcome, if required.

The regulations were subsequently approved by the Tasmanian Parliament and became effective from 28 June 2010.

The outcomes delivered by the Regulations were critical to improving Aurora Energy’s financial position and facilitated a further increase in September 2010 of the tolling fee paid by Aurora Energy to AETV.

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126 Aurora briefing to Treasury, May 2010.
127 Aurora Briefing Note to the Expert Panel, 18 May 2011.
128 The effect of this regulation is that to the extent that Aurora Energy elects to utilise the TVPS to back non-contestable customer load, and those costs are in excess of the wholesale energy allowance, the value consequence is passed through to Hydro Tasmania.
129 The motion to pass the PCR amendments was carried with the support of the Tasmanian Greens. However, it should be noted that this support was contingent on the Government’s agreement to establish the independent inquiry into the Tasmanian electricity supply industry.
In its covering letter to its final 2010-13 Corporate Plan, Aurora Energy noted that “...profit before tax has changed from a negligible amount (or small loss in the later years) to levels not inconsistent with those achieved by Aurora Energy in the years prior to the Tamar Valley Power Station acquisition”.

The two key elements of the amended Price Control Regulations are briefly described below.

1) Wholesale energy allowance for non-contestable customers

Aurora Energy had been in discussions with Treasury since early 2009 regarding its position on the Regulator’s 2010 Pricing Determination for non-contestable customers, arguing that the methodology and principles applied by the Regulator needed to reflect costs that would be reasonably be expected to apply in Tasmania (essentially, the cost of generation at the TVPS).

The Treasurer wrote to the Aurora Energy Chairman in July 2009, confirming the Government’s intention to apply LRMC to the wholesale energy component under the 2010 Pricing Determination. It is noted that LRMC had also been applied in the 2007 Determination and in this sense its application in 2010 represented a continuation of the broad approach to setting the wholesale energy price. The Treasurer sought confirmation from Aurora Energy that certainty that LRMC would again be applied would provide sufficient comfort so that it would not be necessary to impair the TVPS. Aurora Energy subsequently confirmed that this was the case.

There was the potential for a departure from this approach in with the Labor Party’s announcement on 15 February 2010 (during the State Election campaign) that, if re-elected, it would cap 2010-11 price increases for non-contestable customers at five per cent and defer the next Pricing Determination by the TER for one year. This would have resulted in a delay in the implementation of the revised LRMC arrangements. However, the five per cent price cap commitment was subsequently changed to a $100 one-off in increase in the electricity concession for eligible customers. The passage of the amended Price Control Regulations saw the implementation of the original LRMC position with regard to the wholesale energy allowance.

2) Contractual arrangements between Aurora Energy and Hydro Tasmania for the non-contestable load

In addition to the outcomes of the 2010 Pricing Determination, the establishment from July 2010 of new contractual arrangements with Hydro Tasmania for the non-contestable load block was critical to the financial fortunes of AETV and avoiding the impairment of Aurora’s Energy Business, including the TVPS.

Aurora Energy noted in a 17 September 2010 letter to the Treasurer that “...the impacts of the Hydro agreement and energy price are by far the most material changes that have driven a significant positive turnaround in Aurora’s financial projections”.

Tamar Valley Power Station: Development, acquisition and operation
Aurora Energy’s key objectives in securing new arrangements from July 2010 were for “...an acceptable contract price that would ensure that Aurora Energy’s total costs of supplying wholesale energy to non-contestable customers did not exceed the revenues that customers would pay under regulated tariffs”,131 along with better utilisation of the TVPS.

To prevent the situation where Aurora Energy might face overall energy costs for non-contestable customers in excess of the revenues allowed by the Regulator, the amended Price Control Regulations contained a provision that, any contract between Hydro Tasmania had to be approved by the Treasurer, but only if he or she was satisfied “…that the effect of the terms and conditions of the relationship or arrangement is that Aurora Energy may expect that it will not cost Aurora Energy more, during the relevant period, to supply energy to non-contestable customers as a whole, than Aurora Energy is permitted, under any retail price determination in relation to the relevant period, to charge those customers as a whole for that supply”.132 If no commercial agreement could be reached, the Treasurer could mandate, by notification in the Gazette, a default contract arrangement for Hydro Tasmania to supply wholesale energy to Aurora Energy that satisfied this test.

Treasury had prepared a draft ‘fall-back’ contract for implementation under the Regulations, which would set the energy price paid to Hydro Tasmania for the non-contestable load at a level that did not exceed the energy allowance as determined by the Regulator.

However, before the terms and conditions of that contract were potentially required to be given effect, Aurora Energy confirmed that it had negotiated a suite of hedge contracts to back the non-contestable load with Hydro Tasmania on terms that were commercially acceptable to both parties, and which met the test under the Regulations, so a regulated contract was not required.

The revised hedging contracts for the non-contestable load addressed Aurora Energy’s previous issues with underutilisation of the TVPS and exposure to pool prices. As a consequence, Aurora Energy has since sought to utilise the capacity from the TVPS, (particularly from the CCGT) to back the higher-value non-contestable load.133

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133 Aurora Briefing Note, 28 Feb 2011.
**Reduced volatility of Frequency Control Ancillary Services (FCAS) costs**

The volatility of FCAS costs was also a major influence on the viability of the TVPS; prior to FCAS raise services being declared by the Tasmanian Regulator as a ‘prescribed service’.

On 1 April 2009, at the expiry of the previous load following hedge between Aurora Energy and Hydro Tasmania, FCAS raise contingency services increased from an average weekly cost of $45 000 to approximately $10 million per week and stayed at this level for a period of three weeks, up until the signing of a hedge contract between Aurora Energy and Hydro Tasmania, at which point they returned to ‘pre-spike’ levels.

The investigation by the ACCC and the Tasmanian Regulator into this event, and the subsequent prescription of raise FCAS services in late 2010, resulted in an obligation being placed on Hydro Tasmania to provide a new ‘safety net’ hedge contract in line with the Regulator’s pricing control arrangements. In essence, the safety net contract removes AETV’s (and other market participants’) exposure to FCAS market volatility and therefore provides a stable hedge cost (less than half that previously paid before FCAS was declared a prescribed service) that AETV is able to budget for.

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134 FCAS is used by AEMO to maintain the frequency of the transmission system. ‘Regulation’ FCAS constantly provides for the correction of minor deviations in load or generation output and is mainly supplied by generators. Generally, this involves a generator with fast response times either being started in order to correct a low frequency in the system, or generation plant being rapidly unloaded to correct a high frequency event. Less frequently used is ‘contingency’ FCAS, which is used to correct the large variations in system frequency that can result from events such as the tripping of a generator, an element of the transmission or distribution network (including Basslink) or the sudden loss of a significant customer load. Contingency FCAS is also generally supplied by generators. FCAS providers are paid by AEMO for being on standby, as well as when they are actually called upon. AEMO recoups these expenses from other generators (on a ‘causer pays’ basis) or customers (such as electricity retailers). The cost of lowering the network’s frequency is reflected in charges to customers while the cost of ‘raise’ services is met by generators and, ultimately, through energy prices.

135 In its 2009 determination on the matter, the Regulator found that Hydro Tasmania had been misusing its market power, extracting monopoly rents and bidding anti-competitively on FCAS at high prices – see the Tasmanian Energy Regulator’s FCAS Pricing Investigation – Final Report, 17 December 2010.
Post-Acquisition Commercial and Operational Arrangements - Summary

- The fair value of the TVPS and its relativity to book value was considered in early 2009 when Aurora Energy was going through the process of establishing a baseline budget for the new entity.

- Without increases in revenue, and reductions in gearing and operating costs, the TVPS faced significant impairment at the end of 2008-09.

- Aurora Energy pursued a number of strategies to address AETV’s financial circumstances, including a restructure to improve the efficiency of its energy business and the establishment of a tolling fee arrangement with AETV.

- Impairment was avoided in 2008-09, in part because of an increase in the effective hedge price under the new tolling fee arrangement funded by Aurora Energy’s retail business, and also on expectations regarding the 2010 Pricing Determination for non-contestable customers.

- A number of issues during 2009-10 contributed to a worsening of the Aurora Energy Business’ financial position, including a significant annual finance charge arising from operating results for TVPS which, in the absence of sufficient cash flows, had to be further financed by debt.

- A range of external issues were also impacting on Aurora Energy’s financial outlook, including its ability to negotiate a hedge contract with Hydro Tasmania for the non-contestable load at a price that did not result in its overall energy costs for non-contestable customers exceeding the Regulator’s allowance.

- Aurora’s Energy Business was facing significant impairment at the end of 2009-10. Aurora Energy briefed the Government in January 2010 and then again in April 2010 (by which time it had more detailed financial projections) on its financial position, requesting significant and immediate assistance.

- Government policy intervention was ultimately central to ensuring AETV’s viability in two key respects. Firstly, the Government set the parameters around the Regulator’s 2010 Pricing Determination for the wholesale energy allowance for non-contestable load which, in effect, broadly reflect the cost of generation at the TVPS. Secondly, it changed the regulatory framework within which Aurora Energy contracts with Hydro Tasmania for non-contestable load, which had the effect of providing Aurora Energy with the financial headroom to cover the TVPS’ costs.
2. Economic and commercial considerations

2.1 Core underpinnings of the Alinta-Aurora Energy transaction

The core commercial underpinnings that led to the development of the contractual arrangements between Aurora Energy and Alinta in respect to the TVPS were:

- Alinta owned the TNGP, and had a commercial driver to see the gas transmission pipe utilised – with the TVPS providing a key foundation load;136
- Alinta had experience in building, owning and operating gas-fired power stations in Australia – this was its core business;
- Alinta had a portfolio of gas arrangements, which it acquired from Duke Energy and experience in the wholesale gas sector;
- Aurora Energy had exposure to the Tasmanian spot market to back its contestable and non-contestable customers, and the ACCC authorisation of the vesting contract between it and Hydro Tasmania precluded the contract from covering between 25 and 10 percent of its vested load under that vesting contract; and
- Aurora Energy had a commercial interest in the development of an alternative generator in the Tasmanian region to provide competitive tension in its dealings with Hydro Tasmania.

Constructing and operating a long-term asset like the TVPS involves considerable risk – the longest-term of these (and a critical one in respect of financing such a development) is managing revenue risk. Securing a medium-long term arrangement in respect of the value of output is typically critical in moving a project from concept to reality. Like any off-take arrangement, this involves that producer transferring some or all of the value risk to the purchaser.

In the case of the TVPS development, Alinta took on the construction, operational, gas trading and some output value/trading risk and Aurora Energy took on the majority of the value/trading risk, along with retail market risk137 – see Table 2.

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136 This is a key consideration. In the event that a power station did not emerge in Tasmania, the gas pipeline would be heavily underutilised (in the absence of some other large-scale gas load).

137 That is that it would have ongoing contractual backing from the Alinta but a mismatch of customer contracts to “on-sell” that energy.
### Table 2 - Risk allocation under the Alinta-Aurora Energy arrangements

<table>
<thead>
<tr>
<th>Risk</th>
<th>Description</th>
<th>How managed</th>
<th>Responsibility</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction</strong></td>
<td>Risk of cost increases and not delivering to performance specifications (ie not fit for purpose)</td>
<td>Engage a developer with experience in gas development (ie Alinta)</td>
<td>Alinta - had that experience</td>
</tr>
<tr>
<td><strong>Operations</strong></td>
<td>Ensure plant operates to requirements and when required</td>
<td>Experienced operator of Gas plant with suitable incentives to operate at appropriate times</td>
<td>Alinta - had that experience</td>
</tr>
<tr>
<td><strong>Maintenance</strong></td>
<td>Plant is well maintained to ensure performance requirements are met</td>
<td>Experienced maintenance company as owner or engaged.</td>
<td>Alinta - had that experience</td>
</tr>
<tr>
<td><strong>Gas supply</strong></td>
<td>Gas supply quantities available and transported when required for power station to operate</td>
<td>Managed by a experienced Gas supplier ideally with a portfolio of gas contracts to manage volume risk</td>
<td>Alinta - had access to gas and owned the gas transmission pipe</td>
</tr>
<tr>
<td><strong>Electricity Trading</strong></td>
<td>Fluctuating future spot market energy prices impact on sustainable returns</td>
<td>Managed by a contract with a wholesale or retail counterparty to lock in a sustainable price for sufficient volume to achieve desired risk profile</td>
<td>Alinta had dispatch risk(^{138}) and Aurora had price risk associated with managing their retail requirements</td>
</tr>
</tbody>
</table>

Source: Panel analysis

In 2006, Aurora Energy and Alinta had agreed to a five-year suite of swap and cap arrangements that provided a further ten-year extension for either financial or physical options. These arrangements were subject to the finalisation of the gas supply arrangements, which subsequently were not completed, due to Beach Petroleum not proceeding with its Bass Strait gas developments.

By July 2007, Alinta had decided to use an existing gas supply agreement to back the TVPS operations with an increase in the both the swap and cap price and changes in the terms to 25 year deal (9+6+5+5 years), with a three-year review of gas prices.

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\(^{138}\) Dispatch risk is the risk that the power station does not achieve output levels consistent with contract levels and therefore creates spot market exposures for the generator (if prices are high and dispatch is not achieved, the generator has no spot market revenue to back its contract position with the retailer).
There was some flexibility provided to Aurora Energy under these arrangements, after five years, to change its nominations between the level of swap and caps on an annual basis. This was attractive from Aurora Energy’s perspective, as it enabled it to optimise its position in light of prevailing Tasmanian market dynamics. It allowed Aurora Energy to match potential changes in Hydro Tasmania’s contracting appetite and/or spot market behaviour, such that Aurora Energy could avoid being significantly over-contracted, and therefore reducing its exposure to the spot market and volatility in value that this creates.\textsuperscript{139}

A change in the mix of swaps and caps could significantly change the operating regime for the TVPS, and the level of gas it required. Under these arrangements, this was Alinta’s risk.\textsuperscript{140} It would appear that given its position in the national gas and electricity markets, Alinta considered it was able to manage these risks.\textsuperscript{141}

While the Aurora Energy contract was a key underpinning revenue source for the TVPS, Alinta was also relying on value extracted from their operation and management of their gas infrastructure, the spot market and the green products market.\textsuperscript{142} Therefore, Alinta was not wholly reliant on the contract to cover the costs of TVPS.

### 2.2 Babcock Brown Power purchase the Alinta assets

Babcock and Brown’s acquisition of the TVPS project as part of its nation-wide acquisition of Alinta led to an important change in the commercial framing of the transaction. Babcock and Brown effectively ‘partitioned’ the value arising from the project into separate (but related) entities – the TVPS was allocated to Babcock and Brown Power, and the gas pipeline was allocated to Babcock and Brown Infrastructure. This separation meant that the value attributable to each entity was not ‘seen’ by the other and eliminated any value Alinta had attributed to the joint management of the package of TVPS, gas commodity and gas transport arrangements.

\textsuperscript{139} It should be noted that this flexibility was limited by the option nominated by Aurora in the contract. In one option the flexibility was increased but needed 12 months’ notice, while the other was limited in flexibility but had a shorter notice period. If the first option was chosen the ability to change volumes at short notice would have been lost. The latter option was similar to a tolling agreement for higher volumes and favoured an expectation of high production from TVPS.

\textsuperscript{140} If the change in swap volume was substantial, there was financial compensation for Alinta from Aurora Energy. The Panel considers that this was likely to reflect the potential impacts in terms of generation and gas supply costs.

\textsuperscript{141} Discussions with Aurora Energy staff that were involved in the negotiations highlighted their view that the structure and pricing of the hedge arrangements were not built around capturing a value margin on a long-term gas (commodity) contract. Rather, the arrangements were more structured around securing value against the fixed costs associated with the TVPS and the gas transmission pipeline. The Aurora Energy staff view was that Alinta considered the risk it faced in securing alternative markets for gas relatively low by comparison with these other risks.

\textsuperscript{142} New South Wales Greenhouse Gas Abatement Certificates.
The Panel has reviewed the financial model BBP used for the TVPS. The model indicates that it was anticipating generating value over-and-above the direct swaps and caps with Aurora Energy. It expected to generate value from the Tasmanian spot market, through:

- arbitrage from the spot market when prices were lower than the costs of running the power station to support the hedge contract volumes;
- operating base load plant to its maximum capacity of 203 MW during peak priced hours and capturing additional value; and
- operating the peaking plant at high priced times, when base load plant is also operating, to capture the high prices.

In this context, the model indicates that Babcock and Brown Power proposed to take wholesale market risk in relation to the TVPS development. This aligns with the need to use gas in the order of 13PJ. The risk allocation between the parties under the BBP contract arrangements is summarised in Table 3.

**Table 3 - Market-related risk allocations under the Aurora Energy - Babcock and Brown contractual arrangements**

<table>
<thead>
<tr>
<th>Event</th>
<th>Aurora Energy</th>
<th>Babcock and Brown</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Tas spot prices soft</strong></td>
<td>BBP contract ‘out-of-the-money’ – mark-to-market loss in Aurora Energy’s financial accounts</td>
<td>BBP contract ‘in-the-money’ – mark-to-market gain in BBP financial accounts</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Spot market revenues fall, reducing profitability of TVPS.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Spot market revenues increase, improving profitability of TVPS.</td>
</tr>
<tr>
<td><strong>Aurora Energy decreases volume covered by swap and increases cover for caps</strong></td>
<td>Cost of cap cover increases. Aurora Energy can replace with Hydro Tasmania swaps or spot market exposure.</td>
<td>May reduce volumes of gas for TVPS and BBP may need to find alternative market for gas, depending on gas contracts.</td>
</tr>
<tr>
<td><strong>Gas price increases</strong></td>
<td>No impact within contract period. Gas price reset would increase hedge costs. Aurora Energy faces some gas price risk.</td>
<td>Higher costs passed through to Aurora Energy at price reset. Any price increase within period impacts on BBP profitability.</td>
</tr>
<tr>
<td><strong>Spot market revenue opportunities</strong></td>
<td>No exposure</td>
<td>Modelled value from spot market activities all BBP risk</td>
</tr>
</tbody>
</table>

Source: Panel analysis

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143 This was provided to Government as a part of the sale processes and obtained by the Panel from Treasury under the Panel’s information gathering powers.

144 Noting that the difference between the swap volume and the full output was effectively ‘at market’, unless the spot price was equal to or greater than the cap price.

145 With some additional gas required for the additional peaking plant operations.
2.3 What changed when Aurora Energy acquired the TVPS?

The Government’s direction that Aurora Energy would acquire, complete and operate the TVPS fundamentally changed Aurora Energy’s risk profile. Three key changes related to:

- The internalisation of the contractual arrangements that were in place between the TVPS and Aurora Energy;
- The risks facing Aurora Energy arising from contractual arrangements that were in place between it and Hydro Tasmania in relation to the non-contestable customer load; and
- Aurora Energy’s financial exposure arising from all the operating costs of the TVPS including the gas contracts that were put in place as a part of the acquisition of the TVPS and debt associated with the acquisition and completion of the power station.

2.3.1 Internalisation of the previous Aurora Energy - BBP contracts

With Aurora Energy’s acquisition of the TVPS, the value to the TVPS inherent in the hedge between Aurora Energy and BBP was nullified, as Aurora Energy ‘sat on both sides’ of the transaction.

In the absence of another third party being willing to take a longer-term position in terms of contracting with the TVPS, this effectively turned the TVPS into a ‘merchant’ plant, with its value being a function of the outcomes in the Tasmanian spot market.\textsuperscript{146}

As discussed in Section 1.2.1, the financial due diligence undertaken by LCW during the TVPS acquisition process identified the likely enterprise value of the TVPS under two scenarios - the Aurora Energy contracts remaining in place (effectively the value of the TVPS to any party other than Aurora Energy), and the enterprise value of the TVPS if it did not retain those contract (effectively the value of the TVPS if it were to be acquired by Aurora Energy).\textsuperscript{147}

\textsuperscript{146} As discussed above, with the contractual arrangements in place, Aurora Energy had already accepted a large share of this risk. A key difference is that changes in the Tasmanian spot price relative to the contract price would be shown as a non-realised mark-to-market movement in the value of its overall contract book. As owner of the TVPS however, the same change could potentially arise as a realised loss (or profit) in Aurora Energy’s accounts. Also, with acquisition, Aurora Energy was faced with all of the value risk, rather than a portion.

\textsuperscript{147} The valuation also examined the estimated replacement cost and the estimated actual cost to complete.
The valuation advice highlighted that the enterprise value of the TVPS under Aurora Energy ownership was around $200 million, having regard to the projected spot market outcomes for Tasmania over the period to 2034 (modelled by IES). By comparison, the enterprise value with the BBP contracts in place was estimated to be between $330 million and $415 million.\textsuperscript{148}

The market forecasts on which the valuation was based assumed that hydrological inflows at 90 per cent of long-term average.\textsuperscript{149} LCW highlighted that the merchant valuation of the TVPS contained no consideration of the potential security of supply benefits to Tasmania of having thermal plant located in Tasmania as the modelling assumed that there would be no availability constraints on Basslink or prolonged dry inflow sequences.

LCW considered how to quantify the security of supply benefits that the TVPS might bring to Tasmania and approached this task by estimating how long Tasmanian spot prices would be required to be at the market price cap (which was $10,000/MWh at the time) to enable the TVPS’ estimated merchant value to exceed the estimated cost to complete.

The analysis concluded that if Tasmania spot prices were at the market price cap for an average of 96 minutes per annum and the TVPS were able to generate from all of its capacity during those periods (which was assumed to include the Bell Bay thermal plant), the merchant valuation of the plant would be around $350 million. The valuation concluded:

“We consider an average of only 96 minutes per annum (when any Basslink outage could be for significantly longer) is at a level that electricity retailers (and consumers) in Tasmanian would be willing to enter contracts to avoid/reduce the risk, which should underpin a value of TVPS in excess of the estimated purchase price.”

The valuation advice did not address the mechanisms by which any ‘energy supply security premium’ could be raised and secured by Aurora Energy so that the ongoing revenue stream available to it would offset its operating and capital costs of owning and operating the TVPS. Were such arrangements in place, the value of the TVPS in Aurora Energy’s accounts would correspond with the combination of the merchant value and the energy supply security risk value.

\textsuperscript{148} The variation between $330 million and $415 million was a result of differences in assumed discount rates and the assumptions made about the utilisation of the OCGT units.
\textsuperscript{149} Another key assumption was that all output sold would be at spot market rates as it excluded any hedge cash flows and contract premia – the model assumed effectively assumed that Aurora Energy would own the TVPS throughout its operational life and that Aurora Energy would use the plant to back its long-term retail position in Tasmania.
The modelling also included a sensitivity analysis that concluded that if the real dispatch prices assumed were increased by 10 per cent in real terms over the whole period, the valuation of the TVPS would be around $400 million, which was around $50 million in excess of the cost of acquisition plus the costs to complete the power station.\footnote{In the event, since the TVPS was commissioned, spot prices have tended to be softer than historical norms.}

\subsection*{2.3.2. Hydro Tasmania contracts for the non-contestable customer load}

Until 31 March 2009, the non-contestable load in Tasmanian was backed by load-following hedge arrangements between Aurora Energy and Hydro Tasmania, with the hedge price directly linked to the regulated customer price set in the non-contestable tariffs.\footnote{As noted in other Panel documents, such as the ‘A review of the financial position of the State Owned Electricity Businesses’ and the Draft Report, ‘An Independent Assessment in to the Tasmanian Electricity Supply Industry’ prior to the finalisation of the current contracts to support Aurora Energy’s non-contestable load, all of the value available from the wholesale energy allowance determinations under the Tasmanian regulatory arrangements were captured by Hydro Tasmania – Aurora Energy’s retail business did not capture any additional premium through wholesale contracting.}

In anticipation of the commencement of the BBP contracts discussed above, Aurora Energy negotiated two fixed volume profile hedges with Hydro Tasmania to back the non-contestable load for the periods 1 April 2009 to 31 December 2009 and from 1 January 2010 to 30 June 2010.\footnote{The Panel has been advised that this optionality was implemented at Hydro Tasmania’s request, given its then-concerns regarding inflows and storage levels.} Aurora Energy considered that the combination of the Hydro Tasmania hedges, BBP hedges and some spot market exposure would maximise its commercial position.\footnote{Aurora Energy reached this conclusion after independent expert advice.}

The base notional quantity under these hedges was equal to the estimated average non-contestable customer load. Under each contract, Hydro Tasmania had the option to elect to reduce the notional quantity by either 75 MW or 150 MW. Aurora Energy has advised that when it entered into the hedges with Hydro Tasmania, it was effectively over-contracted and expected to use the BBP contract to back the contestable load as the Hydro Tasmania contracts ‘rolled off’. Aurora Energy expected the BBP contract to be ‘in the money’ compared to the spot market and other contracting options.

With Aurora Energy’s acquisition of the TVPS, it lost access to a hedge contract with a price below existing Hydro Tasmania contracts, and moved to a situation where it instead had all the costs of the TVPS, which turned out to be above its previous hedge costs, and higher than anticipated in the BBP financial model.
The Panel has not identified any evidence that shows Aurora Energy sought to address this very significant financial exposure through attempted renegotiations with Hydro Tasmania of the non-contestable customer contract or approaches to Government to facilitate a reopening of those arrangements, in light of the fact that it was the Government’s decision to instruct Aurora Energy to acquire the TVPS.\textsuperscript{154}

Rather, the financial consequences for Aurora Energy were left to unfold as the contracts came into effect (this is discussed below).\textsuperscript{155}

For the April-December 2009 period, Hydro Tasmania elected to reduce the volume under the non-contestable contract by 150MW. This meant that for this period, Aurora Energy was able to use output from the TVPS to cover its shortfall in non-contestable load requirements, as well as some of its contestable customer load requirements. This reduced the exposure of Aurora Energy’s energy business to the spot market.

For the January-June 2010 period, Hydro Tasmania elected not to reduce any of the volume covered by its contract, reflecting, amongst other things, a return to stronger inflows.\textsuperscript{156} With the relative attractiveness of the prices available under the non-contestable customer contract, Hydro Tasmania had a strong commercial driver to take up all of its volume entitlement under the contract that was in place.

This left Aurora Energy’s energy business exposed to the subsequent falls in spot market prices. The financial consequences of these events are discussed below.

\textbf{2.3.3. Gas supply}

The gas supply and transport agreement that were put in place at the time of Aurora Energy’s acquisition of the TVPS mirrored the arrangements that would have supported the anticipated production required to underpin the hedge with Aurora Energy.\textsuperscript{157} The gas supply agreement defined a 13PJ annual quantity with an 80 per cent take-or-pay requirement. Gas transport arrangements were also secured that supported the transfer of gas from Longford to the TVPS.

While this strategy arguably optimised the timing of gas negotiations and removed the risk of a weak bargaining position, having ‘locked in’ a gas supply regime at the time of acquisition had two other material consequences:

\textsuperscript{154} Aurora Energy has indicated that the risk was evident at the time, but the magnitude of its consequences were not foreseeable, as they were linked to spot market outcomes. It argues that it is debatable whether the Government would have supported any change on the basis that there could have been major financial exposures. In hindsight, the risk was large and ultimately required Government intervention to address its significant consequences.

\textsuperscript{155} This is unlike the arrangements that applied in relation to debt that Aurora Energy was obliged to incur to complete the TVPS, which were subject to direct support measures from Government in light of its direction.

\textsuperscript{156} Another key change from Hydro Tasmania’s perspective was that for part of the April-December 2009 contract period, it had a 100MW option contract that was negotiated with Alinta to provide Alinta cover for market prices in the event that the TVPS was not completed at the time the hedge with Aurora Energy commenced. That potential exposure was no longer current for the January-June 2010 period, increasing its contracting capability.

\textsuperscript{157} The Panel has examined how the costs of transport arrangements negotiated as a part of the TVPS acquisition compared with the previous arrangements between Hydro Tasmania and Duke Energy/Alinta under the Pipeline Capacity Agreement and found them to be broadly comparable on a cost per PJ basis.
- it placed the TVPS, and accordingly Aurora Energy, in the position of having a long-term large take-or-pay gas exposure\textsuperscript{158}, which has had significant implications for the financial consequences of the operation of the TVPS (see below); and

- it provided a stronger underpinning of Babcock and Brown’s Tasmanian gas pipeline business\textsuperscript{159}

2.3.4. Summary

The key changes in Aurora Energy’s risk position with it becoming the owner and operator of the TVPS are summarised in Table 4

\textsuperscript{158} Noting that it is not uncommon for CCGT plants to have take-or-pay gas supply contracts.

\textsuperscript{159} Without a foundation customer, the value of the Tasmanian gas pipeline would have been materially impacted. The costs under the PCA and those under the GTA are broadly comparable, which suggest that the negotiated neither a saving nor an uplift by comparison with then-existing gas transport costs.
Table 4 - Aurora Energy’s risk position pre and post TVPS acquisition

<table>
<thead>
<tr>
<th>Risk</th>
<th>With BBP contract</th>
<th>As owner of TVPS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Construction Risk</strong></td>
<td>Nil – Babcock and Brown risk</td>
<td>Aurora risk - managed through construction contracts and owners engineer arrangements</td>
</tr>
<tr>
<td><strong>Operations and maintenance</strong></td>
<td>Ni – Babcock and Brown risk</td>
<td>Aurora risk - managed through internal resourceing</td>
</tr>
<tr>
<td><strong>Dispatch risk</strong></td>
<td>Nil – Babcock and Brown risk</td>
<td>Aurora risk – TVPS as a ‘physical’ hedge against spot prices requires gives rise to dispatch risk</td>
</tr>
<tr>
<td><strong>BBP hedge contracts</strong></td>
<td>Contracts provide risk management for 203MW of generation to back contestable and non-contestable load</td>
<td>Contracts ineffective as on both sides of the transaction. TVPS becomes a merchant plant for Aurora Energy, highly exposed to the spot market</td>
</tr>
<tr>
<td><strong>Tas spot price firm</strong></td>
<td>BBP contract ‘in the money’, mark-to-market gain in Aurora Energy’s accounts (unrealised)</td>
<td>Spot market revenues increase, improving TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Tas spot price softens</strong></td>
<td>BBP contract ‘out of the money’, mark-to-market gain in Aurora Energy’s accounts (unrealised)</td>
<td>Spot market revenues decrease, weakening TVPS profitability (realised)</td>
</tr>
<tr>
<td><strong>Spot market opportunities</strong></td>
<td>No exposure – Babcock and Brown risk and return</td>
<td>Risk and return on Aurora Energy’s account</td>
</tr>
<tr>
<td><strong>Hydro Tasmania exercises options to vary load under its contract with Aurora Energy for non-contestable customers</strong></td>
<td>Aurora Energy has market risk, capped at the value of the BBP contract price</td>
<td>Aurora Energy has market risk, capped at value of TVPS operating costs (substantially higher than BBP contract price)</td>
</tr>
<tr>
<td><strong>Gas supply</strong></td>
<td>Nil – Babcock and Brown risk</td>
<td>Aurora risk – managed through gas contracts</td>
</tr>
<tr>
<td><strong>Gas volume</strong></td>
<td>Nil – Babcock and Brown risk</td>
<td>Take-or-pay gas commitments result in large financial risk if required gas volumes change.</td>
</tr>
<tr>
<td><strong>Gas price increases</strong></td>
<td>Pass through at time of price reset.</td>
<td>Direct financial exposure for TVPS</td>
</tr>
</tbody>
</table>

Source: Panel analysis

In short, Aurora Energy’s risk position increased significantly with the Government’s direction to acquire and complete the TVPS, particularly given:

- it had no gas power station development management capability and experience;
- it had no gas station operational or maintenance experience;
- it had a large gas supply commitment on a take-or-pay basis; and
- the internalisation of the Alinta contract meaning the TVPS was now exposed to the spot market and effectively a merchant plant.
2.4 Aurora Energy’s energy business financial outcomes for 2009-10

With Hydro Tasmania electing to reduce the volume under its non-contestable customer contract with Aurora Energy by 150MW for the April 2009 to December 2009 period, Aurora Energy was able to utilise a reasonable proposition of the output of the TVPS to meet that reduction in non-contestable customer load. The cost structure of the TVPS was higher than the wholesale energy allowance, and the value impacts of the differential were absorbed by Aurora Energy.

The 2009-10 budget forecast for the Energy business is shown in Figure 2, and demonstrates that the original budget for the Energy business was an EBIT outcome of around $18 million for 2009-10.

Figure 2 - Aurora Energy’s energy business 2009-10 budget cumulative EBIT

Based on the arrangements with Hydro Tasmania and the tolling agreement with the TVPS, EBIT for the energy business was tracking close to Budget in October 2009. Aurora Energy revised down its forecast EBIT by 50 per cent to around $9 million for that year, with most of the fall expected in the second half of the financial year. This forecast fall in financial performance reflected a change in expectations by Aurora Energy of the financial performance of the TVPS, given Hydro Tasmania’s election to not reduce the volume under its non-contestable customer contract with Aurora Energy, which had the effect of exposing a greater proportion of the TVPS output to the spot market.

The revised EBIT forecast for Aurora Energy’s Energy business is shown in Figure 3.

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160 This had a negative effect on the financial outcomes between the TVPS and Aurora Energy’s Energy business, as the tolling fees paid by Aurora Energy were in excess of the revenues achieved through production. Production remained driven by the take-or-pay nature of the gas contracts for the TVPS - spot market revenues offered income to offset gas costs that would have been incurred regardless of the output of the TVPS.
The performance of the Energy business deteriorated during the period November-December 2009. Low spot prices in Victoria led to a loss on the Bairnsdale tolling agreement (acquired as a part of the AEATM asset purchase) due to lower running, and high volatility in NSW and SA in November saw Aurora Energy’s interstate retail exposures lead to an EBIT shortfall in the order of $11 million relative to Budget. During this period, Aurora Energy continued to utilise the TVPS to back its non-contestable load.

As a result, Aurora Energy’s December 2009 forecast was for a further $12 million reduction in expected 2009-10 EBIT, with the expectation at this time for a loss of $3 million, compared to the original budget of a profit of $18 million.

With Hydro Tasmania’s election to not reduce the load covered by its non-contestable customer contract with Aurora Energy coming into effect in January 2010, the Energy business became substantially exposed to the Tasmanian spot market in relation to revenues generated by the TVPS.

Figure 4 shows the significant change in Tasmanian spot prices over this period, reflecting a number of outcomes:

- low spot market prices in Victoria, which coupled with relatively fewer Basslink constraints, resulted in a softening of Tasmanian prices;
- more water availability in Tasmania, reducing the opportunity value of hydro electricity, reflected in Hydro Tasmania bidding also delivering softer spot prices; and
- substantial excess capacity in Tasmania, with Hydro Tasmania bidding to back the full non-contestable customer contract with Aurora Energy, and the TVPS bidding for dispatch reflecting its gas contracts.
In calendar 2008 and 2009, average annual Tasmanian spot prices were around $50/MWh, and 20 per cent or more above the average annual Victorian price. Coincident with the commissioning of the TVPS and a change in the non-contestable contract cover provided by Hydro Tasmania, annual average spot prices fell by around 40 per cent, and remained below Victorian average annual spot prices. Average quarterly Tasmanian spot prices showed substantial variation, which was also coincident with timing issues associated with the TVPS (commissioning and outages).

The falling Tasmanian spot price had a significant impact on the financial performance of the Energy business, with January EBIT falling short of revised budget expectation by around $7 million.

The February - April 2010 period saw continued exposure to low spot market prices lead to further erosion in the expected end of year EBIT outcome. The March 2010 forecast was for a loss of $20 million, a fall of $38 million from the original 2009-10 Budget.
There was an outage of the TVPS’s CCGT plant in May 2010, and Aurora Energy took a partial hedge to cover its exposure to the spot market. This resulted in some spot market exposures for Aurora Energy - and corresponding spot revenue opportunities for Hydro Tasmania, which it successfully captured - which led to prices above $1700/MWh for eight half hour periods (this is evident in the monthly average spot price shown in Figure 4). Due to the CCGT plant outage, Aurora Energy was exposed to the high spot prices.

This, and the subsequent lower prices for the remainder of the month on the return of the TVPS CCGT plant, resulted in further reductions in EBIT relative to Budget of around $6 million.\footnote{This highlights the vulnerability of Aurora Energy in the wholesale market with the current architecture. When the TVPS was available, Aurora Energy was effectively over-contracted (given the TVPS’ gas contracts) and is therefore exposed to the spot price. Aurora Energy was unable to earn sufficient revenue from the spot market to cover the tolling fee, and incurred losses as a result. With the CCGT TVPS unit out of service, Aurora Energy became under-contracted and again exposed to the spot market. Hydro Tasmania’s strategic bidding drove up spot prices, which again had a negative financial impact on Aurora Energy’s energy business.}

The final cumulative EBIT outcome for June 2010 saw EBIT some $50 million below the original Budget, recording a loss of $31 million.

These outcomes are summarised in Figure 5, which shows actual cumulative EBIT by month for 2009-10 for Aurora Energy’s Energy business.

**Figure 5 - Aurora Energy’s energy business actual cumulative EBIT, 2009-10**

- Actuals
- Budget
- Sep FC
- Dec FC
- Mar FC

Source: Aurora Energy

### 2.5. Key differences between the Babcock and Brown model and Aurora Energy’s outcomes

It is clear that the sustained and large falls in the financial performance of Aurora Energy’s Energy business that coincided with the acquisition of the TVPS were not fully anticipated by it, given the number of ongoing revisions to expected earnings throughout 2009-10.

The emerging performance of the TVPS did not correspond with the expectations contained in the Babcock & Brown financial model, which anticipated positive spot market opportunities for the TVPS and much firmer prices.
The Panel has identified other key differences between ‘expectations’, as documented in the Babcock and Brown model and observed outcomes, which included:

- the anticipated value of NGAC revenue dropped by around 50 per cent from the time of the original agreements being put in place – in the BBP model, these revenues were expected to be in the order of $8 million - $9 million per annum.

- the operating costs of the plant have increased from the provisions made in the Babcock and Brown model, particularly in relation to operating and maintenance costs, rather than the gas supply and transport contracts, which are broadly in line with the model assumptions. Aurora Energy advises that there were a number of other items that were not included in the BBP model, including FCAS and interruptible load costs. In reviewing the actual operating and maintenance costs for the 2010-2011 financial year, there is approximately $10 million in additional costs compared to the assumptions in the BBP model.

Taking the change in revenue and costs, the new tolling arrangement has provided the necessary revenue to keep AETV profitable and in many respects provides the cash flow to match the original expectations under the BBP model. For example, in 2010-2011 the tolling fee is approximately $119 million versus expected revenue in the BBP model of $116.6 million.

2.6. AETV’s current position

In summary, the fundamental drivers of the TVPS’ negative financial position prior to 30 June 2010 was that:

- Aurora Energy was effectively ‘over-contracted’ with the combination of the non-contestable customer contract it had with Hydro Tasmania and the commercial driver to produce electricity from the TVPS, given the gas contracts that were finalised as a part of the acquisition process;

- with the substantial softening in the Tasmanian spot market prices coinciding with the TVPS coming online, the revenues available to Aurora Energy to fund output from the TVPS were insufficient to cover its costs; and

- a number of market events where spot market opportunities were available to, and captured by, Hydro Tasmania further compounded the poor financial position.

From Aurora Energy’s perspective, these financial issues have been addressed in the medium term through the arrangements that apply until June 2013, which:

- provide revenue certainty for the wholesale energy allowance for non-contestable customers, with the allowance broadly reflecting (but not equal to) the costs of production from the TVPS; and
enable it to access contractual cover for non-contestable customers with Hydro Tasmania at a cost less than the wholesale energy allowance.

The combination of these two factors provides the financial ‘headroom’ for Aurora Energy to be able to contract with the TVPS through its tolling agreement to fund TVPS’ full costs, including debt retirement over the economic life of the plant and a level of profitability. However, these arrangements are potentially vulnerable to change at the next retail pricing determination and/or once the current contract with Hydro Tasmania expires.

By providing Aurora Energy the financial headroom to utilise the TVPS to part back its non-contestable load requirements, the TVPS no longer appears as a merchant plant to Aurora Energy, and its financial outcomes do not reflect the underlying circumstances in the Tasmanian region.

In short, depending on inflows into the hydro system, Tasmania currently faces an overcapacity in generation in relation to its ability to meet peak demands, as illustrated in Transend’s Annual Planning Report - see Figure 6.162

Figure 6 - Projected excess generator capacity, MW

With storages currently at high levels by long-term historic standards, Basslink remaining available and prevailing Victorian spot prices, the underlying market value opportunities for gas-fired electricity in Tasmania are substantially limited. The revenues available are not sufficient to cover the gas, operating and capital costs of the TVPS.

162 The methodology assumes that excess capacity represents the total capacity of all current hydro and thermal generators in Tasmania, wind generation is assumed to be out of service unless otherwise specified, and the excess capacity is determined by deducting the 10 per cent POE medium forecast for winter MD from generator capacity.
Were circumstances to change – for example were the types of low probability scenarios contemplated by the Government at the time of its decision to acquire the TVPS to emerge (critically low water storages and a sustained outage of Basslink over several months), the market prices would rise very significantly, providing a funding mechanism to support the production and capital costs of the TVPS.

Over time, as the supply/demand balance changes, the financial position of the TVPS will similarly change. Outcomes that tighten the supply/demand balance, such as growth in Tasmanian load will see an increased need for base-load, on-island capacity and the underlying economics of the TVPS will improve. The timing of this is uncertain – a large industrial development that requires energy will bring this forward, and similarly, the loss of one of Tasmania’s current large industrial customers would push this back. Large-scale development of renewable energy, stimulated by the Australian Government’s renewables target, will similarly push back the need for additional capacity.

Reforms to the wholesale market architecture in Tasmania may reduce some of these risks, which could improve the TVPS’ financial performance.

The Government’s decision to acquire and complete the TVPS as a hydrological risk mitigation strategy saw the public sector take on the direct financial consequences of this ‘bring forward’ of capacity that is in excess of the State’s current requirements. If the development had progressed as anticipated, many of these risks would have been borne by the private sector.

At the same time, the additional capacity has had a positive impact for contestable customers that are exposed to market-determined wholesale energy costs – these are lower than they would otherwise be if TVPS was not operating as it currently is.

A key matter for the future is, in the absence of a structural shift in the Tasmanian supply/demand balance that would improve the economic opportunities for the TVPS, how will the financial consequence of the ‘bring forward’ of base load capacity be funded and/or the cost structure of the TVPS be reduced?

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163 In recent times, residential electricity demand has been relatively static, and it is difficult to see this sector having a major structural impact on Tasmania’s supply demand balance.
Part C
A review of the efficiency and effectiveness of the State Owned Electricity Businesses
Executive summary

Why efficiency matters

As noted in the Issues Paper, the Panel is of the view that the Tasmanian electricity supply industry (TESI) will make the best contribution to the growth and development of Tasmania, and to the economic welfare of Tasmanians, if it is operated on the most economically efficient basis possible.

Viewed from a customer perspective, the efficiency of the SOEBs is a key driver of electricity prices.

This is particularly the case for the regulated sectors, such as the network businesses, where regulatory frameworks can be effective in protecting customers from the worst aspects of the absence of market forces. However, they are generally less effective in actively driving high levels of productivity.

Once regulatory parameters are set (for example, in the case of network entities, regulated operating cost allowances are set for a five-year period), the actual performance of the network businesses does not have a bearing on prices to customers, at least in the short term. In this context, customers arguably should be at least as focused on the effectiveness of the regulatory process in ‘allowing’ efficient costs as they are on the performance of the regulated businesses in meeting those allowances.

For those aspects of the TESI that are subject to competitive forces, prices are set independent of an individual business’ costs. However, where competitive forces are relatively weak or the market is illiquid, there is real possibility of customers facing higher costs through inefficiencies.

In Tasmania, customers have seen relatively low levels of competition in the market and, as such, Tasmanian customers could be expected to have greater interest in business efficiency than would be the case if high levels of competition existed.

From a Shareholder perspective, the efficiency of a business is critical regardless of whether it is regulated or market based, as efficiency drives the financial performance of the business and the ability of the business to provide shareholder returns and enhance business value.

In the Tasmanian context, where electricity supply businesses are State-owned, Government, Parliament and taxpayers all have an interest in seeing the businesses perform well from both an efficiency and effectiveness point of view.

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Noting that the Tasmanian community are the ultimate owners of the SOEBs.
The key point is that efficiency is of prime importance from two perspectives:

- it can influence the price setting framework depending on the effectiveness of the regulatory framework or the effectiveness of market mechanisms; and
- it contributes to the financial stability of the SOEBs and drives shareholder value, which can be returned to the Tasmanian community through dividends.

The extent to which high levels of productivity are achieved remains one of the predominant tasks of management, overseen by the Boards of the SOEBs. Therefore, it remains a priority for Boards to ensure that policies are in place that focus business culture and performance on productivity issues. This Paper explores the extent to which this has been evident in the SOEBs.

There is also a role for shareholders, in the case of the SOEBs, the responsible/shareholding Ministers (the Treasurer and the Minister for Energy) on behalf of the community, to ensure that Boards are clearly focused on achieving high levels of productivity to achieve sustainable financial returns. Through a focus on driving Boards to achieve efficiencies, governments are best placed to achieve other policy objectives, such as minimising pricing pressures on electricity users. The Panel has investigated how the Tasmanian Government, as shareholder, has sought to influence the SOEBs to drive efficiency and effectiveness.

**The Panel’s approach**

In this Paper, the term ‘efficiency’ is related to all aspects of the business that impact on costs and is a measure of the extent to which activities are carried out at least cost.

The Panel has taken as a given the outcomes of previous assessments undertaken by expert regulators on efficient costs - and has not sought to reconsider or remake these judgements. The Panel’s focus has been the extent to which the SOEBs have operated within these regulatory determinations as a primary indicator of efficiency. Where efficient benchmarks through regulatory approaches are absent, the Panel has examined cost trends within the SOEBs, and where practicable, peer comparisons, to examine efficiency.

The Panel has defined the ‘effectiveness’ to be the extent to which SOEBs are contributing towards the continuity and quality of electricity supply - or in other words its technical performance. The various functions of the electricity supply chain; generation, transmission, distribution and retail services have specific measures to assess the extent to which individual contributions meet standards necessary to achieve overall performance. The Panel has observed how performance has tracked over time, and how it compares with peers, in order to examine effectiveness.

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165This is important given the broader economic importance of SOEBs beyond dividend payments to the Budget.
Findings in relation to effectiveness

In general terms, the Panel has concluded that the effectiveness, or technical performance, of the electricity supply industry in Tasmania is good and generally comparable to the average effectiveness of the industry in other states. In particular the Panel has concluded that:

- the technical performance of Hydro Tasmania’s generating plant currently meets the requirements of its participation in the NEM, particularly from a risk management perspective (being able to physically back its market positions). Any ongoing significant deterioration of performance could be an indicator that the current asset management strategy was risking long-term asset value. In its annual review and update of its Ten-Year Asset Management Plan, Hydro Tasmania should ensure that performance of its assets are maintained and improved;

- the transmission network operated by Transend is performing satisfactorily and improving by comparison with peer entities. There remains scope for further improvement, although this is an economic question of the cost of further capital investment required to increase reliability levels;

- Aurora Energy’s distribution network effectiveness is currently adequate and, while community based targets for improvements are in place it remains to be seen if this approach results in average performance improvements. The declining trend in service levels for urban areas is a matter that should be addressed to ensure that improvements in rural performance are not delivered at the cost of effectiveness for the majority of customers; and

- Aurora Energy’s retail’s performance in terms of customer service measures appears to be relatively stable, and may require additional focus in the event that full retail contestability is introduced.

Findings in relation to efficiency

The Panel’s assessment of efficiency is less clear cut. The benchmarking of operating expenditure, and particularly capital expenditure, is more problematic than benchmarking technical performance, due to the differences in scale, operating environment and industry structure.

In relation to Hydro Tasmania, there has been a sustained focus on reducing operating costs, with three efficiency programs implemented over the past eight years, the latest of which aims to reduce operating expenses to around 80 per cent of current levels.
A primary driver for improvements in efficiency within Hydro Tasmania has been the scarcity of capital to fund capital investment and growth strategies, which was compounded by the drought in 2007 and 2008. Capital constraints have also incentivised Hydro Tasmania to achieve more efficient delivery of major capital projects.

Transend’s operating costs are higher than its peers (in part reflecting scale dis-economies) and have grown at a higher rate over the period 2004-05 to 2008-09. Transend made a considered decision to spend above the regulatory allowances, based on its view that the regulatory determination was unsustainable. Over that period, Transend’s operating costs were $28 million, or 16 per cent higher than its allowance.

Transend’s performance relative to its operating allowances has improved with its 2009 regulatory determination, which saw a 40 per cent increase in its operating cost allowance. Transend has operated within the allowance for the past two years.

In relation to capital spending, Transend’s capital program exceeded its regulatory capital allowance by around 10 per cent over the period 2004-05 to 2008-09. The AER subsequently undertook a detailed ex-post review of capital projects over that period and found that the capital expenditure was prudent.

Aurora Energy’s distribution business has also had a history of overspending regulatory allowances, but to a smaller degree than Transend. Over the period 2004 to 2009-10, the distribution business overspent its operating allowances by $14 million (in nominal terms), which represents four per cent of total allowed expenditure, with a key driver of this being emergency repair and response costs. Aurora Energy’s regulatory proposal that is currently being considered by the AER indicates that the business is seeking to deliver real operating cost decreases over the period 2012-13 to 2016-17 period. Significant changes are emerging within the distribution business that indicates there is a commitment to deliver on the productivity savings that underpin the regulatory proposal. The AER’s draft determination was released in November 2011, and the AER has proposed to reduce the proposed level of operating expenditure by $36.5 million (nominal) over the forthcoming regulatory period.

In relation to capital spending, Aurora Energy’s distribution business has consistently exceeded its regulated allowance, spending $208 million above its total allowance of $535 million over the period 2004-2010. Around half of the additional spending was a result of customer-driven capacity developments.

Aurora Energy’s retail business has been unable to operate within its regulatory operating allowance with respect to the non-contestable customer base. The Panel understands that in the competitive contestable market, there have been strong pressures on retail margins to maintain market share. Aurora Energy has developed a strategy to reduced costs in line with regulated cost to serve levels, and the first phases of that strategy have been implemented.
The major capital expenditure program related to the retail business over the review period was the customer information and billing system project. This project was highly complex, under-scoped and poorly managed, particularly in the period before January 2010. Because of the large differences between the eventual costs of the system and allowance permitted under the regulatory arrangements and as a result of capitalisation tests under the accounting standards, the project has had a large negative financial consequence for the business, with around $32 million in project costs being written off.

Overall, if previous detailed regulatory determinations are taken as the benchmark for efficiency (and there is some contention about the extent to which this is the case), the Panel concludes that regulated aspects of the SOEBs have not been operating efficiently consistently over the review period.

The financial consequences of this have primarily been borne by taxpayers as owners of the businesses through lower returns, rather than by electricity customers through higher prices. This is further discussed in the Panel’s Information Paper on the Financial Position of the SOEBs. Where subsequent regulatory determinations have been undertaken to reconsider efficient costs and allowances ‘reset’ at higher levels, there have been price impacts on electricity customers, but only to the extent that regulators have determined costs to be efficient.

The approach taken within the SOEBs towards efficiency and effectiveness is, in the Panel’s view, the fundamental driver of performance. It shapes the way in which the regulated businesses approach and operate within the regulatory framework and, together with competitive forces, drives performance for the market-facing SOEBs.

There has been a mix of approaches across the portfolio in relation to driving efficiency over the past decade, and the focus on efficiency has varied within parts of the businesses.

The apparent willingness of the regulated businesses to regularly overspend regulatory allowances and the preparedness by Boards and the Shareholders to accept the financial consequences of this through poor financial performance and lower returns to the Budget has created an environment where there is not a consistent focus on driving business performance.

The Panel notes that more recent changes in regulatory incentives and governance arrangements have sought to address this to some extent.
The nature of the cultural change currently evident within Aurora Energy provides an indication of the preferred approach to business management with a strong focus on efficiency. While that approach has arguably been available across the portfolio, until recently it has not been a strong focus, at least not uniformly. It is notable that in Aurora Energy’s case, the economic regulatory framework has not been the driver of improved efficiencies. Rather these efficiencies have been prompted by a combination of personnel change, technological change and a change in the strategic direction of the company.

The Panel has sought to determine why such initiatives haven’t been a consistent and prominent feature of business activity in the past. The Panel has concluded that:

- The process by which businesses are licensed by the TER, and which is aimed in part to promote efficiency in the electricity supply industry, does not of itself require efficiency improvement programs to be implemented or provide a particular focus for Boards or management to drive business performance.

- Revisions to the regulatory framework in 2008 and 2009 provide more comfort that regulatory allowances permit network businesses to recover their efficient costs, and provide stronger incentives to outperform expenditure and service targets.

- While Ministerial Charters and Letters of Expectation have contained broad expectations that SOEB Boards will conduct their businesses efficiently, they are pitched sufficiently broadly that specific expectations are not established.

- Annual Shareholder letters associated with the development of corporate plans have required businesses to operate efficiently and, more recently, formalised expectations for the businesses to instigate and report on specific programs.

- Although businesses have tended to respond positively to these specific requests, there does not appear to have been a process developed for reporting the details of the program, or programs, so developed or of the success or otherwise of the programs.

- The extent to which Boards have taken responsibility for initiating efficiency or productivity improvements, rather than executive management, is difficult to determine given the generally cooperative approach to strategic planning undertaken by the businesses. The Panel is of the view that Boards should be taking a predominant role in ensuring an efficiency focus is initiated and appropriately measured.

Of particular importance in driving business technical and financial performance is the establishment of accountability and incentive frameworks that provide a ‘clear line of sight’ between Shareholder expectations and the regulatory framework on the one hand, and Board, management and staff performance on the other.
The Panel has not reviewed in detail the effectiveness of the performance monitoring frameworks employed in the different parts of each of the SOEBs, but notes that these do variously exist. The Panel’s view is that it is important that these frameworks are regularly independently (of management) reviewed by either Boards or Shareholders to ensure that there remains strong alignment between the incentives faced by individual employees, management and the Board in driving outcomes that are consistent with regulatory requirements and Shareholder expectations.

The Panel considers that Shareholders could have been more active in driving accountability for efficiency and effectiveness over the past decade. The Panel has been left with the impression that until recently, there has been a relatively low level of engagement between Shareholders and the businesses in efficiency-related matters and that Shareholders have taken the view that the economic regulatory environment and independent regulators will provide the dominant drivers for SOEBs efficiency and effectiveness.

The regulatory framework can, at best, provide a level of assurance that businesses not exposed to competitive disciplines are not able to routinely operate at generally inefficient levels.

Optimising business performance within the broad parameters established by the economic regulatory environments remains the domain of management and Boards, with Shareholders providing the ultimate incentives and sanctions for efficiency and effectiveness. Developing and maintaining a focus on maximising efficiency and continual improvement in reducing costs is critical and has not been consistently evident across the portfolio over the review period.

The Panel notes that in relatively recent times, this has become more of a focus in the broad corporate governance arrangements between Boards and Shareholders in the SOEBs, and highlights this as a key area of governance reform for the SOEBs.

Finally, in any business, an important challenge for management is resolving the tension between meeting performance standards on the one-hand and managing costs and the consequences for prices. Similarly, there are tensions between investment in asset replacement and renewal and higher maintenance costs. The tension is evident in the SOEBs.

In the case of Hydro Tasmania, decisions have been made within the business to defer capital expenditure on maintaining core hydro generation assets to provide financial ‘headroom’ for other investment activities. A key judgement is that the proceeds from the reinvestment of these funds into other activities will offset the short-term negative impacts from this strategy, and that expected improved financial outcomes will enable Hydro Tasmania to ‘catch-up’ the deferred expenditure. Hydro Tasmania considers this strategy to be prudent, particularly given the strategy is reviewed annually, with the potential to increase investment if funds are available (as has occurred).
Closely examining the risks and returns from capital spending and the appropriateness of potential maintenance expenditure are characteristics of a well performing businesses - they are consistent with an approach focused on efficiency and effectiveness. A key issue that arises from Hydro Tasmania’s asset management strategy is that its success is dependent on growth in future revenue streams that have accompanying risks. Those future revenue streams also have alternative uses, both within the business and from a Shareholder perspective.

Decisions around capital expenditure, particularly where the relate to core assets versus diversification and growth strategies, are one of the inherent reconciliations that need to be made in providing scope to SOEBs in planning business strategy and performance. Having a very clear understanding of the purpose of the SOEBs and what government is seeking to achieve through its ownership of them is a key foundation in resolving these tensions. This is addressed further in the Panel’s Final Report.
Objectives and structure

The purpose of this Paper is to address the Panel’s Term of Reference number one, being ‘the current efficiency and effectiveness of the Tasmanian energy industry with particular reference to the existing regulatory framework and the cost and operation of the energy industry elsewhere in Australia’.

The Panel has interpreted this Term of Reference as relating to the core Tasmanian operations of the SOEBs, being hydro-generation, transmission and distribution networks and retail functions, and in particular to technical and cost-related performance issues.

The Panel’s investigation excludes matters related to Hydro Tasmania’s retail business Momentum, wind farm developments through Roaring 40s, consulting services through Entura and Aurora Energy’s telecommunication business and operation of the Tamar Valley Power Station. These activities are addressed elsewhere in the Panel’s work program. The financial performance of the SOEBs, including capital structure, investment and returns to Shareholders are addressed in a separate Information Paper. This paper is structured as follows:

- Chapter 2 outlines the Panel’s approach to the investigation, its interpretation of the terms efficiency and effectiveness; and discusses how efficiency and effectiveness are influenced in both regulated and market based businesses models;
- Chapter 3 discusses the key elements of the Panel’s investigation and the methodology for collecting and analysing information related to the task;
- Chapters 4 to 7 present the findings of the investigation for each of the businesses; Hydro Tasmania, Transend, and Aurora Energy - Distribution and Retail; and
- Chapter 8 contains a summary of conclusions and reports on issues which impact on each of the businesses or influence relationships between them.

Unless otherwise noted, all dollar figures in this chapter are expressed on a nominal basis and dates represent the associated financial year.
Definition of terms and approach

The importance of efficiency

As noted in the Issues Paper, the Panel is of the view that the electricity industry will make the best contribution to the growth and development of Tasmania and to the economic welfare of Tasmanians if it is operated on the most economically efficient basis possible.

Viewed from a customer perspective, the importance of the efficiency of an individual business is linked to the effectiveness of the markets in which the business operates. A strongly competitive market, where prices are set independent of an individual business’ costs, will mean that customers do not bear the consequences of poor performance. Where competitive forces are relatively weak or the market is illiquid, as is the case in Tasmania, there is a real possibility of customers facing higher costs through inefficiencies being passed through in prices.

In relation to the regulated sectors, customers should consider efficiency to be important for a regulated business because of the absence of external forces, other than the regulatory framework, for driving efficiency. Regulatory frameworks can be effective in protecting customers from the worst aspects of the absence of market forces, but they are generally less effective in actively driving high levels of productivity in the regulated businesses.

Once regulatory parameters are set (for example, in the case of network entities, regulated operating cost allowances are set for a five-year period), the actual performance of the regulated entities does not have a bearing on the prices paid by customers, at least in the short term. In this context, for the regulated sector, customers arguably should be at least as focussed on the effectiveness of the regulatory process in ‘allowing’ efficient costs as they are on the performance of the regulated businesses in meeting those allowances.

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166 Economic efficiency can be considered from three dimensions: technical/productive efficiency (producing at least cost); allocative efficiency (that resources are used in the highest value activity); and dynamic efficiency (the ability of a business/sector to respond and adapt over time). The aspect of efficiency that this paper is primarily focused on is technical efficiency.

167 There remains a very real risk that inefficiencies prevalent within a regulatory cycle can be built into subsequent determinations.
In Tasmania, customers have seen relatively low levels of competition in the market and have experienced the situation where rising expenditures in regulated businesses have been reflected in higher prices. As such Tasmanian customers could be expected to have greater interest in business efficiency than would be the case if high levels of competition existed or if the regulatory apparatus had a strong weighting on industry-wide best practice performance and was better able to drive productivity improvements. Any consideration of industry-wide best practice performance must still be able to adjust for the specific operating environment of a business, including the different jurisdictional obligations network businesses in the NEM face.

From a Shareholder perspective, the efficiency of a business is critical regardless of whether it is regulated or market-based, as efficiency drives the financial performance of the business and the ability of the business to provide Shareholder returns and enhance business value.

In the Tasmanian context, where electricity supply businesses are State-owned, Government, Parliament and taxpayers all have an interest in seeing the businesses perform well from both an efficiency and effectiveness point of view.

The key point is that efficiency is of prime importance from two perspectives:

- it can influence the price setting framework depending on the effectiveness of the regulatory framework or the effectiveness of market mechanisms; and
- it contributes to the financial stability of the SOEB and drives shareholder value which can be returned to the Tasmanian community through dividends.

Electricity supply business efficiency is highly dependent on labour and other resource productivity. In both regulated and market based business models, the extent to which high productivity is achieved remains one of the predominant tasks of management. Therefore, it remains a priority for Boards to ensure that policies are in place that focus business culture and performance on productivity issues.

There is also a role for Shareholders, and in the case of State-owned businesses, the responsible/shareholding Ministers (the Treasurer and the Minister for Energy) on behalf of the community, to ensure that Boards are clearly focused on achieving high levels of productivity to achieve sustainable financial returns. Through a focus on driving Boards to achieve efficiencies, governments are best placed to achieve other policy objectives, such as minimising pricing pressures on electricity users.

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168 It is noted that the AER is required to take into account industry benchmarking when undertaking a determination.
169 For example, the national network pricing arrangements impose an assumed capital structure for network businesses when the AER is required to determine the weighted average cost of capital. This may weaken the incentive for network businesses to shape capital structures to achieve entity-specific rates of return.
170 Noting that the Tasmanian community are the ultimate owners of the SOEBs.
171 This is important given the broader economic importance of SOEBs beyond dividend payments to the Budget.
Moreover, two considerations must not be overlooked:

- the proper functioning of the regulatory framework to provide strong incentives for efficient service delivery and avoiding the worst elements of the absence of competitive forces; and

- ensuring that the underlying architecture in the market-related aspects of the energy supply industry contain effective competitive pressures to drive efficiency and productivity.

These are important considerations, and are matters that the Panel addresses in its Final Report.

The Panel has defined the ‘effectiveness’ of the SOEBs as a measure of the extent to which it contributes towards the continuity and quality of electricity supply - or in other words their technical performance. The various functions of the electricity supply chain; generation, transmission, distribution and retail services have specific measures to assess the extent to which individual contributions meet standards necessary to achieve overall performance.

In this Paper, the term ‘efficiency’ is related to all aspects of the business that impact on costs and is a measure of the extent to which activities are carried out at least cost.

As highlighted in the Panel’s Statement of Approach\(^{172}\), the Panel has taken as a given the outcomes of previous assessments undertaken by expert regulators on efficient costs - and has not sought to reconsider or remake these judgements.

The Panel’s focus has been the extent to which the SOEBs have operated within these regulatory determinations as a primary indicator of efficiency. Where efficient benchmarks through regulatory approaches are absent, the Panel has examined cost trends within the SOEBs, and where practicable, peer comparisons, to examine efficiency outcomes.

Establishing the comparative performance of the SOEBs with Australian contemporaries may be problematic given differences in industry nature, size, and structure in Tasmania. It is, therefore, useful to complement such comparative analyses with observations of historical trends within each of the SOEBs to identify changes in their performance over time and the drivers of those changes.

\(^{172}\) The Statement of Approach was released on 17 December 2010 and is available on the Panel’s website www.electricity.tas.gov.au/publications.
The approach adopted by the Panel was to assess the performance of the SOEBs from two perspectives:

- a ‘top down’ internal investigation into the historical and current effectiveness and efficiency, including the influence of regulatory arrangements; and
- an assessment of the roles of executive management, Boards and Shareholders in driving improved performance, including by setting targets for effectiveness and efficiency, and initiating appropriate monitoring, reporting and evaluation mechanisms.

The Panel’s approach has also recognised that the regulation of electricity supply businesses in Tasmania is evolving with the Australian Energy Regulator (AER) in the process of assuming the responsibilities of the Tasmanian Energy Regulator (TER) in the assessment of revenue allowance for Aurora Energy’s distribution business. This change will take effect from July 2012. The AER assumed responsibility for the economic regulation of Transend from the Australian Competition and Consumer Commission (ACCC) in 2009.

In framing the overall assessment approach it has been necessary to recognise that the incentives for Tasmania’s SOEBs to continue to supply reliable and cost-efficient services are provided in combination by two key influences:

- the different (regulated and competitive) market models that apply to the businesses; and
- by the governance framework and obligations imposed on them by the Government as Shareholder.

To drive efficiency and effectiveness, both are essential and need to work in a complementary manner.

These market and governance arrangements and the incentives and obligations they provide are outlined in the proceeding sections.

**Regulated businesses**

In the broad, the function of the economic regulatory framework is to provide a proxy for a competitive market. There are several key features of the regulatory framework:

- removing the scope for regulated entities to control prices;
- ensuring that regulated businesses are able to recover their efficient costs and earn an appropriate rate of return, thereby economic rents are not generated; and
- providing incentives and drivers for improved business performance, and for these to be passed through to customers over time.
Through the implementation of revenue/price caps for regulated services, which are based on the independent assessment of efficient costs (both operating costs and required capital investment), there is an incentive for profit-maximising entities to perform at least to the assessed level of efficiency in order to earn the rate of return that forms part of the regulatory assessment.

Some regulatory arrangements provide specific mechanisms to incentivise the businesses to ‘outperform’ the regulatory allowances. For example, in the case of transmission pricing arrangements, the ‘Efficiency Benefit Sharing Scheme’ acknowledges additional savings in operating costs in each year of the regulatory period and effectively allows savings to be retained for a period of five years, even if this extends into the next regulatory period. There is also a Capital Expenditure Incentive which rewards transmission businesses for minimising or deferring capital expenditure.

While regulatory frameworks and regulatory entities seek to press for improvements in efficiency, it is generally beyond the scope of economic regulatory arrangements to establish and seek to impose the most efficient means of delivering outcomes on a business-by-business basis – this is legitimately the domain of management.

This is where the complementary influence of Shareholders and the Board brings pressure to bear on driving business performance on regulated businesses. Ensuring that performance is at least consistent with, and where possible and sustainable, better than, requirements imposed through the economic regulatory frameworks is central. Well-designed regulatory arrangements will, over time, capture these improvements in efficiency and pass the benefits back to customers.

The economic and the technical performance/standards frameworks need to operate together and reconcile changes in required technical performance with the cost implications. Importantly, the relationship is not linear - at some point marginal improvement in performance can only be achieved at the expense of significant additional cost. An effective interface between these regimes is important in balancing the tensions between the two.

The detailed regulatory process for network pricing was reviewed extensively to deliver the National Electricity Law and supporting national transmission and distribution rules implemented in 2008 and 2009 respectively. The revenue-setting arrangements are currently the subject of further review at a national level with the discussion focusing on the effectiveness of the regulatory arrangements in balancing incentives for cost efficiency and service reliability with the delivery of efficient prices to consumers.
A review of the efficiency and effectiveness of the State Owned Electricity Businesses

Figure 1 - Regulated and market based business models

**Regulated Business**
- Regulator or jurisdiction sets performance requirements
- Regulator sets revenue allowance based on estimated cost plus profit allowance to achieve performance
- Prices determined on basis of revenue allowance
- Quality/effectiveness delivered by regulatory functions
- Efficiency determines actual costs
- Profit revenue less costs

**Market Business**
- Business sets performance parameters to meet market requirements
- Business controls costs to "meet the market"
- Market determines price
- Market determines perception of quality/effectiveness
- Efficiency determines costs
- Profit revenue less costs

If market is not competitive, individual business costs can impact on market prices

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\* In the case of the Tasmanian SOEBs, the Tasmanian taxpayer also receives the financial benefit of the income tax payments.

Source: Panel analysis
Market-based businesses

For market-based businesses, standards of technical performance tend to be more driven by market requirements and the need for the business to maintain a competitive position, or are set by the business to improve market share or take advantage of a perceived opportunity. Nonetheless, regulatory influence on technical performance remains, and the competitive sectors in the NEM are influenced by a range of technical and price related regulatory\textsuperscript{173} obligations.

Prices in the competitive sectors of the electricity industry (generation and retail in the contestable market) are set on the basis of supply and demand.

In the case of generation, the competitive dispatch process provides a discipline on generators to operate efficiently to minimise their bids to ensure that they are dispatched\textsuperscript{174} by the market operator, AEMO. Competition provides the incentive to drive technical performance as well. A generator that may have low production costs but poor availability levels will achieve lower levels of dispatch and fewer revenue opportunities. It will also face higher risks in contracting capacity and find it difficult to compete with similar cost, but higher reliability generators, as that risk premium would need to be factored into its contract price.

Similarly, in the wholesale energy contract market, competitive tensions between generators to secure contracts with retailers to provide longer-term revenue certainty provides incentives for these to be priced on a cost-reflective basis. The interplay between an effective spot market and contract market will enable retailers and large customers to vary their spot exposure in light of excessive contract pricing.

In relation to electricity retailing in the contestable market, securing customers requires a combination of appropriate price-setting and service standards. If a retailer has a higher cost to serve than a competitor, or seeks to charge a higher retail margin, it will face a greater challenge in attracting and retaining customers, and its financial performance may deteriorate as a result.

In the market-based model, there is a strong incentive for participants to minimise costs, as these savings can be retained by the business through higher profits and returned to shareholders by way of dividends, used for reinvestment, or passed through to customers to increase market share, and thereby increase future profitability. Moreover, the competitive dynamic typically means that participants cannot afford to not pursue improved efficiencies, given rivals are likely to be doing the same.

\textsuperscript{173} For example, the National Energy Customer Framework sets out a range of obligations on retailers in relation to retail customer protection. There is a wide variety of technical performance standards required of generators in the competitive wholesale market.

\textsuperscript{174} Noting that the level of competition is not uniform across the merit order or across NEM regions, so that depending on supply and demand conditions, competitive forces vary.
The importance of governance

As discussed above, strong discipline from either a competitive market or a regulatory framework is a necessary but insufficient condition for the delivery of efficiency and effectiveness by businesses. Pressures for cost-efficiency will be maximised with complementary governance arrangements between shareholders and boards/management that have a strong performance focus.

The principal-agent problem is common to most businesses and arises where business owners are not in direct control of the business, and is well documented in the literature.¹⁷⁵

If shareholders are not particularly focused on financial performance, the incentives within the regulatory framework will provide a relatively weak discipline for efficiency and effectiveness. This is particularly the case for the network businesses, where around two-thirds of allowed costs (and therefore revenues) are derived from the regulated return on assets. Without a strong focus on financial performance, this provides ‘headroom’ for inefficiencies in operating expenditure, as overspending operating expenditure allowances are somewhat masked by the return on assets in terms of ‘bottom line’ performance.

 Appropriately incentivising performance is a central issue for governance for all businesses, and particularly publicly owned entities that lack the visibility of a share price and the threat of takeover in the financial market.

This issue is further addressed in the Panel’s Final Report.

¹⁷⁵ When ownership and control are separated, there is a need to align the interests of the managers and the shareholders. In the absence of such alignment, the self-interest of managers may lead them to act other than in the interest of the shareholders. This can manifest in many different ways, including financial underperformance, diversification and a loss of focus on core business. The principal-agent theory is about designing monitoring and/or incentive systems that will make managers act in the best interest of the shareholders.
Methodology

The Panel has identified the following six parameters in undertaking this investigation:

1. Identification of the pertinent operational and reliability performance measures and the comparison of same over time and with other Australian utilities.

2. An assessment of the process of identifying the need for infrastructure additions or system enhancements (i.e. the technical need), the corporate approval process, the method of acquisition, and capital project management, including the comparison of actual cost to approved budget.

3. The examination of the SOEBs’ asset management philosophy and/or maintenance practices, including the acquisition of services.

4. An examination of the major cost drivers for each core function, including cost performance measures, historical cost trends and the comparison of these costs where possible with other Australian utilities.

5. An assessment of the cost of a range of resources (e.g. labour, materials) and operational and/or maintenance activities that are intrinsic to Tasmania.

6. The extent to which the current regulatory arrangements for each SOEB have been driving technical performance and the efficiency of operational activity or maintenance practices, and the impact on the costs incurred.

To facilitate this investigation, the Panel engaged consultants Wilson Cook to assist with the information review and comparative performance analysis.

In parallel with Wilson Cook’s work, the Panel also sought advice from the SOEBs and relevant parts of Government to identify the extent to which the underlying drivers of efficiency improvement programs were instigated by the businesses instruments generated by Boards, Shareholders or Government more generally.

In seeking this advice the Panel has sought to determine the extent to which management has concentrated on cost control and overall productivity as a means of maximising profit and potential shareholder returns including the development of a ‘cost minimisation’ business culture. The Panel also sought to determine how the Shareholders have communicated with Boards on these issues, the extent to which Boards have established policies to focus management on productivity issues and the extent to which they have been regularly assessed against established targets.
The Panel has not examined the efficiency of the operations of the Tamar Valley Power Station (TVPS), which is owned by Aurora Energy, through Aurora Energy (Tamar Valley) Pty Ltd. This is for three primary reasons:

- the Panel focused on the core operations of the SOEBs, and not examined the efficiency and effectiveness of other diversified activities undertaken by the SOEBs. For example, in this review the Panel has not examined Hydro Tasmania’s retail activities through Momentum Energy, or the provision of consulting services through Entura, or in relation to Aurora Energy, the efficiency and effectiveness of its telecommunications business;

- the TVPS business has been operating for a relatively short period of time and, unlike the other core business activities of the SOEBs, there is no trend by which comparisons can be made; and

- the Panel has undertaken a review of the market effectiveness and function of the TVPS in examining the performance of the Tasmanian wholesale market and in relation to Government decision making and is of the view that the level of technical efficiency of the TVPS is of second-order importance relative to those issues.

Similarly, the Panel has not undertaken a review of the effectiveness of the wholesale trading functions of Hydro Tasmania or Aurora Energy per se. These are recognised as key value drivers for both businesses and the outcomes of the trading functions are reflected in the financial performance of the businesses, which is examined in section D of this volume. The outcomes of Aurora Energy’s energy business are also discussed in section B of this volume.
1. Presentation of findings - Hydro Tasmania

1.1. Generating asset base

The hydro-generation assets owned and operated by Hydro Tasmania are unique in Australia. They were developed progressively to meet the growing needs of Tasmania’s electricity demand until the cessation of the hydro-electricity construction period in the 1980s. Hydro generation plant elsewhere in Australia has largely been developed in conjunction with irrigation or water management projects and has supplemented the generating capacity and electrical energy requirements of systems primarily supplied from thermal generating facilities. Hydro Tasmania’s plant remains the principal source of electricity generating capacity and electrical energy in Tasmania.

The technical details of Hydro Tasmania’s generating facilities have been presented in other papers prepared by the Panel but in essence they consist of a number of hydro generation schemes associated with long, medium and short-term water collection and storage infrastructure.

The schemes contain some 60 generating units of varying age and technology located at 30 sites around the State. The generating plant is dependent on supporting infrastructure which includes a large number of dams, storage facilities, tunnels and canals as well as buildings, bridges and over 600km of access roads. The combined capacity of the generating plant is 2 271 MW and is capable of sustainably supplying an average of 8 700 GWh of electrical energy per annum.

Hydro Tasmania’s asset base is therefore significantly different to that of generators located in other states and other countries where a single power station can exceed the combined generating capacity and energy output of all Hydro Tasmania’s plant. For example, Bayswater Power Station in NSW has four generating units; a combined capacity of 2 640 MW and in recent years has contributed some 16 000 GWh per annum to the NEM.

Hydro Tasmania operates the various schemes and individual units of its facilities in a manner which optimises seasonal energy inflow, system demand and market opportunities.

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176 The capability of the system is constrained by the amount of water held in storage and that which flows into the system on a year-by-year basis.
1.2. Performance

The principal measures of generating plant performance are **availability** and **forced outage rate**. Plant availability is a measure of the time a plant is fully available for service expressed as a percentage and may be reduced by both planned and unplanned (or forced) outages.

In systems which are constrained by limited capacity, availability is of prime importance. In systems that are not as constrained by limited capacity, forced outage rate tends to become more important as a measure of non-availability during a period when the plant was required to be in service. Achieving the balance between planned maintenance outages and forced outages is one of the key challenges of generating plant asset management.

**Table 1 - Hydro Tasmania plant performance**

<table>
<thead>
<tr>
<th>Performance Measure</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equivalent Availability Factor</td>
<td>87.87</td>
<td>90.35</td>
<td>89.25</td>
<td>90.16</td>
<td>89.30</td>
<td>88.09</td>
</tr>
<tr>
<td>Equivalent Forced Outage Factor</td>
<td>1.14</td>
<td>0.82</td>
<td>2.62</td>
<td>1.22</td>
<td>1.65</td>
<td>0.51</td>
</tr>
<tr>
<td>Planned outage factor</td>
<td>10.99</td>
<td>8.82</td>
<td>8.13</td>
<td>8.62</td>
<td>9.05</td>
<td>11.40</td>
</tr>
</tbody>
</table>

Equivalent Availability Factor + Equivalent Forced Outage Factor + Planned Outage Factor = 100%

Source: Wilson Cook

Figure 2 illustrates that the combined availability of Hydro Tasmania’s hydro-generating plant from 2004 to 2011 has remained constantly around 90 per cent during the period.

**Figure 2 - Availability factor**

Source: Hydro Tasmania
Figures 3 and 4, below, show the planned outage and forced outage rates of the same plant over the same period.

**Figure 3 - Planned outage**

**Figure 4 - Forced outage**

Both planned and forced outages have been reasonably constant over the period, although the forced outage rate showed an upward excursion associated with a poor result, relative to other years, in 2008.177

Although Hydro Tasmania’s planned outage rate has remained relatively constant over recent years, the measure may not reflect the level or extent of maintenance actually carried out during the scheduled periods. The extent to which planned outage periods were utilised to maximise the opportunity to carry out maintenance was not examined in detail by the Panel, although Hydro Tasmania has provided anecdotal evidence of particular projects for which this has been a specific priority (e.g. in relation to recent works undertaken at the Poatina power station).

In general, increasing planned maintenance, and possibly the planned outage rate, tends to reduce forced outages and the forced outage rate. Reconciling the increased costs of additional planned maintenance with the benefits of reduced forced outage rate is one of the key challenges of generating plant management. The balance is influenced by the amount of generating capacity available relative to the peak load to be generated and the seasonal characteristics of the electricity demand.

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177 The high level of forced outage in 2008 was largely due to a single event - the Poatina 3 isolation valve failure from 27 July 2007 to 12 March 2008.
In normal hydrological conditions, Hydro Tasmania has generating plant capacity well in excess of Tasmanian demand. Nonetheless, at certain times of the year, Hydro Tasmania may require most of its generating plant to be available in order to maximise its ability to bid capacity to capture trading opportunities or back contract positions, such as during periods of high Victorian pool price, particularly during the peak summer demand in mainland states. This is a key source of value to the business.

Figures 5 and 6 compare plant availability and forced outage rate of Hydro Tasmania with the combined performance of generation businesses in other Australian States and two New Zealand hydro-electric based generation businesses, Meridian Energy and Mighty River Power. The New Zealand businesses, like Hydro Tasmania, have multiple plants and are more like Hydro Tasmania than Australian businesses with predominantly thermal plant.

**Figure 5 - Comparison plant availability**

**Figure 6 - Comparison forced outage rate**

These figures show that Hydro Tasmania’s plant availability is as good as or better than the thermal-dominated Australian businesses but that its New Zealand peers are achieving a slightly higher rate. Hydro Tasmania has superior forced outage factors to its Australian peers and a similar rate to Mighty River Power. Meridian exhibits superior performance, with an average forced outage rate below half a percent over the five-year period. Meridian’s plant is, however, generally newer and bigger than Hydro Tasmania’s and its higher levels of performance could be reasonably expected.

It should be noted that conventional thermal plant utilising boilers and steam turbines of the type most common on mainland Australia have inherently lower availability and higher forced outage rates than hydro plant due to the complexities of the fuel handing and steam raising components of thermal plant.
As part of its performance reporting, the TER has also benchmarked Hydro Tasmania against hydro-electric generation businesses in North America and has found that Hydro Tasmania compares favourably in terms of plant performance with those businesses.

Wilson Cook concluded “Overall, we are satisfied that Hydro Tasmania’s hydro-electric plant has exhibited good performance to date, although a small deterioration in relation to forced outages is evident and we would be concerned if the trend continued.” The Panel shares this view, noting, however, that Wilson Cook did not have before it the most recent data for 2011 showing a reduction in forced outages.

Embedded within the performance data considered above is Hydro Tasmania’s maintenance of supply through the drought of 2007 and 2008. This period required the careful management of fuel (water and gas), plant (some of which was required to operate in sub-optimal conditions) and trading (particularly Basslink and load buybacks). It is notable that, although conditions were such that interruption to supply was a very real threat, continuity of supply was achieved, unlike during Tasmania’s 1966 drought.

1.3. Application of capital

Within Hydro Tasmania, the responsibility for assessing potential capital investment requirements or opportunities is allocated to the Capital Investment Allocation Team (CIAT). This executive-level team, and the process which it uses, have been in operation since 2007. CIAT is responsible for reviewing capital update reports, assessing business case studies, and managing the pipeline of potential projects with a value in excess of $0.5 million. The CIAT applies a three-stage approval process from concept with indicative financial estimates, through to detailed business case development and Board recommendations.

In assessing Hydro Tasmania’s capital expenditure assessment and implementation processes, Wilson Cook reviewed projects of greater than $5 million which had been undertaken over the last five years. Wilson Cook noted that collectively, actual expenditure was less than the approved level, most projects were completed on time, and all projects were considered to have met the objectives that were set for them. Wilson Cook also examined a sample of businesses cases and post-implementation reviews and observed that the associated documentation appeared to be thorough and contain the level of detail that it would expect for projects of that type and magnitude.

Wilson Cook concluded that “overall, we were satisfied that the business follows good practice for selecting, approving and controlling capital expenditure.”
1.4. Asset management philosophy

Hydro Tasmania’s current asset management philosophy has been substantially developed since 2006 with the decision to change the focus from ‘asset maintenance’ to ‘asset management’. Asset maintenance is characterised by maintaining assets in accordance with original manufacturer’s recommendations irrespective of the duty or expected future life of the asset, or the asset’s influence on overall business performance.

Current asset management practices take each of these issues into account and balance the business risks with maintenance activity and cost.

The process involves making a detailed assessment of the condition of the majority of some 7,500 asset items. This assessment enables the development of an objective risk-based evaluation across 50 key production lines.\(^{178}\)

Hydro Tasmania’s asset management strategy was established on the basis of this assessment and risk evaluation to set priorities to:

1. Address all safety, compliance, duty of care and legislative obligations.
2. Maintain, on a prioritised risk basis, the full productive ability of the asset portfolio.
3. a. Develop a core group of strong and reliable production lines.
   b. Manage the balance of supporting productions lines on the basis of less capital investment and more maintenance.

The philosophy led, in early 2008, to a five-year capital improvement program supported by a continuous improvement maintenance program.

In response to corporate initiatives to provide financial headroom for the business and to optimise investment timing, a new Ten Year Asset Management was developed in 2010 (the 2010 Ten Year Asset Management Plan). The Plan constrains capital expenditure on Tasmanian-based generation assets in the near term (the first five years of the plan) followed by increased expenditure in the medium term to compensate.

The plan acknowledges that the forced outage rate is likely to rise to about double the present rate\(^ {179}\) and that ongoing maintenance requirements would also rise and result in a small increase in the planned outage rate. The Plan assesses that the cost of the increased maintenance requirements would be covered by ongoing productivity improvements.

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\(^{178}\) A production line is defined as including all assets leading to and from a particular generating unit and includes inlet water delivery systems and valves, the generating plant and control systems and dedicated electrical interconnection items.

\(^{179}\) Hydro Tasmania has indicated that as a result of more recent capital investment decisions, this is no longer the case.
Hydro Tasmania has indicated that the Plan reflects a drive for greater productivity in its capital investment program in light of the capital constraints it faces. By way of example, Hydro Tasmania was able to revise the approach to recent works at Tungatinah to deliver the project outcome for a cost reduction of greater than $10 million against the original business case.

In summary, the 2010 Asset Management Plan acknowledges that the reduction in capital expenditure “reduces investments in the asset portfolio to the minimum sustainable level”. In detailed discussions with Wilson Cook, and through dialogue with the Panel, Hydro Tasmania reaffirmed its view that the deferment of capital spending on Tasmanian hydro-generation assets was a prudent business decision. In support of its view, Hydro Tasmania has provided the Panel with reports from independent experts commissioned both by Hydro Tasmania and by OTTER, who have undertaken assessments of the Plan.

Wilson Cook reviewed Hydro Tasmania’s asset management philosophies and practices, including the 2010 Asset Management Plan, and in its summation to the Panel emphasised that it considered the proposed deferral of expenditure on hydro-generation plant involves significant risk.

Wilson Cook highlighted that there could be longer-term ramifications for asset performance and/or funding issues arising from the strategy of deferring funding for capital maintenance activities in the short term and ‘catching up’ that expenditure later.

Hydro Tasmania argues that from a risk management perspective, the asset portfolio is in a better position than at any time during the past decade. Hydro Tasmania provided the Panel with information relating to the risk rating of its asset base that suggests there has been a strong and sustained reduction in the proportion of assets that represent a high revenue or duty of care risk (falling by around 70 per cent from 2007 to 2011), while the proportion of assets that represent a medium revenue or duty of care risk have been relatively constant.

The 2010 Asset Management Plan highlights that there are material negative enterprise value implications from its implementation. The key business decision taken by Hydro Tasmania in implementing the Plan is that the negative impact on enterprise value will be offset by even greater returns from the redeployment of the freed-up capital in a range of activities, including diversification activities. The Plan highlights the importance of how the financial headroom created by the strategy is utilised:

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180 The quantum of the loss in enterprise value has not been disclosed for confidentiality reason.
The 10 year asset management plan developed will accomplish the Business Objective of creating ‘head room’ by ‘sweating the assets’. If frees up $Xm over the next 5 years against the $Ym baseline investment profile... This money, when invested wisely (emphasis added), will offset the enterprise value erosion of approximately $Zm created by the diversion of investment from the hydro portfolio. The plan has the ability to transform Hydro Tasmania and result in us being a credible and significant NEM participant; we see this as an imperative for long-term business success and sustainability. ($m omitted for confidentiality reasons).

It is important to note that in making the decision to implement the 2010 Asset Management Plan, Hydro Tasmania recognised that its success was dependent on growth in future revenue streams that have accompanying risks. Those future revenue streams also have alternative uses, both within the business and from a shareholder perspective. The Plan established a strategy that effectively draws down on future earnings from the hydro generation assets, particularly any upside in value arising from carbon pricing, in order to fund wider commercial objectives.

Hydro Tasmania contends that the decisions associated with this balance will be made progressively over the life of the 2010 Asset Management Plan and may influence the flow of capital from Hydro Tasmania to the shareholder. In its first review of the 2010 Asset Management Plan, Hydro Tasmania has increased its planned level of capital expenditure included in the Plan by some $54 million over the period 2010-11 to 2014-15. Hydro Tasmania argues that this has significantly redressed the reduction in enterprise value described in the original plan.

Decisions about capital expenditure, particularly where they relate to non-core and diversification and growth strategies, is one of the inherent reconciliations that need to be made in providing scope to SOEBs in planning business strategy and performance. Having a very clear understanding of the purpose of the SOEBs and what government is seeking to achieve through its ownership of them is a key foundation in resolving these tensions. This is addressed further in the Panel’s Final Report.
In this context, the Panel notes relatively recent changes in the expectations communicated by the Government to all State-owned business which places a priority on core business operations and a reduced emphasis on business diversification. These changes may have an impact on the future direction of Hydro Tasmania’s Asset Management Plan and consequently on Hydro Tasmania’s opportunities to seek enhanced returns from the business.

1.5. Operating expenditure

The key drivers of Hydro Tasmania’s generation business are the operation and maintenance requirements of its power stations and ancillary works, the cost of operational and commercial interfacing with the NEM and the corporate and overhead costs allocated to the business, which is in part a function of decisions regarding the allocation of overheads to activities other than generation, including diversification strategies.

Figure 7 shows actual operating expenditure for the core generation business for the period 2008 to 2010 and projected expenditure for the subsequent six years. Trading costs, depreciation charges, financing costs, costs relating to Basslink and costs relating to Momentum, Entura, Roaring 40s and Bass Strait Islands are not included. Recent expenditure has averaged approximately $120 million per annum ($real 2011) terms, with expenditure projected to reduce progressively to $107 million ($real 2011) per annum by 2016.

Figure 7 - Hydro Tasmania operating expenditures

Source: Wilson Cook

Note: Real values are calculated using ABS CPI data for Hobart for 2008-2011 and assume CPI of 3 per cent in out years
The projected reduction in real operating expenditure trend is being driven by a corporate initiative to reduce core business operating expenditure to $100 million in 2011 dollars. These expenditure savings will be targeted as part of the annual budgeting process, and Hydro Tasmania has provided confidential information to the Panel that highlights the likely areas of focus in the short-medium term.

Figure 8 shows the operating expenditure directly attributable to the operation and management of the generation assets between 2006 and 2011. These costs include labour, materials, professional services and internal charges. Figure 8 shows a reducing trend in operating costs for generation. Hydro Tasmania has advised that there have been structural and internal cost allocation changes over the period, such that the underlying trend of cost reductions illustrated in Figure 8 is indicative of performance, but a detailed comparison between years needs to be made with caution.

Wilson Cook noted that these direct costs account for only about one third of the total core business operating expenditure. Other core business costs not related to the operation and management of generating assets include non-direct labour and business overheads.

The primary drivers of the decline in direct generation costs include risk reduction strategies and maintenance improvement initiatives yielding results; a substantial reduction in work undertaken by Entura for the generation business (in 2011, this was around one third of the level that was incurred in 2006) together with tight management of other labour costs, which fell by some 15 per cent in nominal terms over the period.
Wilson Cook also reviewed a summary provided by Hydro Tasmania of previous benchmarking work undertaken in comparison with Snowy Hydro in 2006 and 2009. The analysis shows that Hydro Tasmania compared well in terms of staff numbers per unit of capacity and per unit of output, noting that there are differences between the two systems in terms of installations, geographic spread of assets and operating regimes.

In terms of overall staffing levels, Hydro Tasmania has demonstrated a broad reduction in staffing levels in the primary business (i.e. excluding Entura, Momentum and subsidiaries). Staffing levels have decreased from 523 FTEs in 2007 to around 483 in 2011. Executive positions over that period remain relatively constant, indicating that the labour savings were achieved in the general workforce. Average labour costs exhibited modest growth across all categories, with executive salary costs rising by an average of 4.25 percent per annum, and wages in the general workforce increasing by 5.7 percent per annum in nominal terms. Following an organisational review, Hydro Tasmania implemented a new organisation structure in April 2011, which it argues better reflects the nature of its business operations now and into the future, aligned with its strategic business objectives and imperatives.

Separate to the investigation of the effectiveness and efficiency, which is the primary focus of this report, the Panel has conducted detailed investigations into the Hydro Tasmania business model and its internal mechanism for setting its competitive dispatch bids into the NEM and in setting contract prices. In brief, Hydro Tasmania’s approach is to price on an opportunity value basis, with the key factors being the Victorian wholesale energy price and the timing of the use of its water that is in its inter-annual storages. Pricing decisions are not based on a “cost plus” approach as it relates to operating expenditure.

While Hydro Tasmania has had three major programs to drive down its operating expenditure, this has not been with a view of lowering costs to enable it to bid and contract at slightly improved rates in the competitive market. Rather, the focus has been to lower costs to improve cash flow, to fund capital expenditure, both for reinvestment, and for business expansion in interstate markets and to improve returns to shareholders over the period.

1.6. Regulatory impacts

As a NEM-based generator, Hydro Tasmania is not subject to an economic regulatory process. It is, however, required to report annually to the TER on the performance of its generating plant, and compliance with its management plans, as a requirement of its generation licence. The report is entitled Generation Performance and Compliance Performance Report. The TER requires that the compliance performance is reviewed regularly and reported upon by an independent assessor.
The particular requirements of Hydro Tasmania’s generation licence have been set by the TER to be consistent with the TER’s functions and objectives set out in the Electricity Supply Industry Act 1995.

While this TER process undoubtedly focuses Hydro Tasmania’s management attention on these performance issues, the TER’s objective is to ensure that plans and performance targets are reasonable and consistent with good practice, rather than set specific efficiency or effectiveness targets.

In a submission to the Panel, Hydro Tasmania expressed the view that:

“OTTER is required to ensure the reliability of the electricity supply even though this requirement has been superseded by national processes. While OTTER’s approach has been pragmatic, there is a need to amend the legislation to remove this requirement from OTTER’s mandate. The process does not provide any value to the industry.”

1.7. Governance and Shareholder oversight issues

Hydro Tasmania is incorporated under the Hydro-Electric Corporation Act 1995 and governed by the Government Business Enterprise Act 1995 and, as such, is required to prepare and submit a corporate plan annually to the Treasurer and Portfolio Minister for approval.

The corporate plan is developed with the guidance of a letter from the Ministers to Hydro Tasmania’s Board that conveys their strategic priorities and broad expectations for the business, and raises specific issues to be considered in the plan. The letter traditionally provides guidance on the desire of the Ministers to have a well performing business, but does not request information on efficiency and effectiveness targets to enable monitoring.

The Panel has not been able to identify evidence of there being a strong and sustained focus by the responsible Ministers in the corporate planning process on efficiency measures over the past decade, although this has changed in more recent times.

- For example, the expectation letters for 2008 and 2009 Corporate Plans do not refer to efficiency and effectiveness per se, although there are more specific expectations established in relation to financial performance, such as highlighting key targets that Hydro Tasmania is to report on - although specific targets were not established.

- In the 2010 expectation letter, explicit reference to efficiency and effectiveness is noted, and an ‘expectation in relation to financial discipline’ is stated. Again, no specific targets were set out.
In the 2011 expectation letter, more definitive language is use “...we expect the business to operate in an efficient and cost effective manner in regard to both capital and operating expenditure, subject to safety and reliability standards, to minimise overall costs and ensure that customer pricing is consistent with market dynamics”. The letter also required “details of operational efficiencies and productivity measures to enhance financial performance”.

In response, the 2011 Plan stated that amongst other strategic initiatives “the Least Cost Producer Strategy had resulted in the identification of cost savings additional to those identified in the 2010 plan and reach a total of $11 million per annum by 2013”. The Plan provides no further details on the Least Cost Producer Strategy. Hydro Tasmania indicates that these cost savings are incorporated in Hydro Tasmania’s financial benchmarks.

It remains unclear to the Panel how the responsible Ministers can hold the Board accountable for the delivery of a ‘Least Cost Producer Strategy’ if the primary strategy document does not establish clear targets for cost reductions that can be tracked overtime.

Performance against overall financial benchmarks is important, but it does not provide a high degree of transparency about how successfully efficiency measures are being implemented, and whether they are achieving the intended outcomes.

1.8. Summary of investigation

The Panel considers Hydro Tasmania’s current effectiveness to be good, with both planned outages and forced outages being reasonably constant over the review period. The most recent data for 2011 shows a reduction in forced outages.

The Panel has noted that initiatives to improve efficiency and productivity continue to provide benefits to Hydro Tasmania, and to shareholders through the ability to deliver financial returns and reinvest in the business, in both core areas and in diversifications/growth areas.

The rescheduling of asset refurbishment programs to free up capital for other activities is noteworthy because:

1. It requires significant increases in capital expenditure after five years to accelerate the asset renewal program and the availability of that capital depends, in part, on the success of unrelated programs to provide those funds;

2. The additional operating expenses associated with the capital deferment are assumed to be sourced from productivity improvements, as there are no increases in operating expenditure in real terms provided for in Hydro Tasmania’s corporate plans;
3. The capital deferment is, by Hydro Tasmania estimation, the maximum allowable although Hydro Tasmania advises that it retains borrowing capacity to manage contingencies;

4. Individually or in combination these factors constitute a risk that funds may not be available for the future requirement for higher capital expenditure on Tasmanian hydro generation assets. There is a related risk that this will lead to a further trade-off between retaining funds in the business to address growing risks of asset under performance on the one hand, and the level of dividends being returned to the community on the other; and

5. Hydro Tasmania has advised the Panel that, with the prospect of increased future revenues associated with MI customers moving off historical contracts onto market-based terms and the benefits arising from a carbon price, it is confident that funds will be available as required. In the meantime, Hydro Tasmania believes that its risk monitoring and portfolio management effectively supports asset performance. The Panel observes that it will be important for Hydro Tasmania to monitor both asset performance, and its effect on financial performance, as part of its asset management program.
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<td>The principal measures of <strong>generating plant performance</strong> are availability and forced outage rate.</td>
<td>Availability has remained constant at around 90 per cent. Forced outage rates have fluctuated between one and two and half per cent.</td>
<td>Hydro Tasmania performs well against its peers.</td>
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<tr>
<td>The measures of <strong>application of capital</strong> are capital expenditure assessment and implementation processes.</td>
<td>In relation to sampled projects reviewed by Wilson Cook, actual expenditure was less than approved levels, most projects completed on time and all projects considered to have met objectives. Business case and post implementation review documentation considered thorough and at sufficient level of detail.</td>
<td>Hydro Tasmania appears to follow good practice for selecting, approving and controlling capital expenditure.</td>
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<td>Asset management philosophy has evolved from 'asset maintenance' to 'asset management'.</td>
<td>Asset management seeks to balance business risk with maintenance activity and cost. Asset management strategy includes risk evaluation priorities. Asset management plan constrains expenditure in the near term followed by increased expenditure in medium term to compensate. Asset management strategy driven by corporate priority on business savings to fund business diversification.</td>
<td>An asset management approach is more consistent with an efficient and effective focus by the business. Deferred maintenance expenditure may compromise plant efficiency and impact financial performance in the longer term. Hydro Tasmania considers the asset maintenance plan to be prudent.</td>
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<td>Operating expenditure.</td>
<td>Hydro Tasmania has implemented three major efficiency/cost management programs over recent years. The current program is seeking to limit operating expenditures to around $100 million per annum in 2011.</td>
<td>Trend to reduce operating expenditure driven by corporate initiative to improve cash flow to fund capital investment in core and non-core activities.</td>
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<tr>
<td>Governance – regulatory and shareholder.</td>
<td>Hydro Tasmania is required to report to the TER on plant performance as part of its generation licence. TER’s focus is to ensure plans and performance targets are reasonable and consistent with good practice, rather than set specific efficiency or effectiveness targets. Information provided to shareholders does not detail efficiency and effectiveness targets or strategies.</td>
<td>No evidence of strong and consistent shareholder focus on efficiency or effectiveness over the past decade, although this has changed in more recent times. It is unclear how the Shareholder drives accountability for efficiency outcomes if specific actions and targets are not detailed in the Corporate Plan.</td>
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2. Presentation of Findings - Transend

2.1. Services provided

The majority (approximately 90 per cent) of services provided by Transend are prescribed services, covered by a revenue cap established by the AER. The balance of services are negotiated services, covered by the AER-approved negotiating framework, or non-regulated services which are not subject to regulation. The following analysis deals only with the prescribed transmission services provided by Transend.

2.2. Network characteristics

The capital development of a transmission network, the costs necessary to maintain it, and technical performance of the network are dependent on its size, the load and generation characteristics of the electricity it is required to transmit, the characteristics of the terrain through which it is required to pass, and the location of its principal switching elements.

The performance of each connection to the transmission network or from the network to the distribution system, or directly to a customer, is also influenced by whether or not alternate transmission system elements are available. Connections which have alternative supply options are considered to be firm while connections which have a single source of supply are termed non-firm.

The Tasmanian transmission network tends to be characterised by relatively long transmission lines, through often difficult terrain, with limited meshing\textsuperscript{181} or alternative supply elements. While each transmission network in Australia is unique, comparisons between networks can be useful. Overall the South Australian transmission network operated by Electranet provides a more relevant comparison to the Tasmanian system than those of other states.\textsuperscript{182}

2.3. Performance

Transend reports annually on the following range of performance measures to satisfy the requirements of the AER, the AEMO and the TER:

- Transmission line circuit availability for critical circuits.
- Transmission line circuit availability for non-critical circuits.
- Transformer circuit availability.

\textsuperscript{181} Meshing refers to the availability of multiple paths to connection points. A highly meshed network work would exhibit several alternative paths to connect two points on the network. This provides for levels of redundancy - if one element of the network is unavailable, there are alternative paths to reconnection.

\textsuperscript{182} For example, both the Tasmanian and South Australian systems have similar load profiles and connect relatively remote areas with radial feeders. Nonetheless, there are key differences, such as the South Australian transmission network has fewer generator connections, does not service predominantly hydro-based generation where generation patterns vary depending on hydrological conditions, and services a demand with a significantly lower capacity factor.
- Loss of supply system events (for events > 0.1 system minutes).
- Loss of supply system events (for events > 1.0 system minutes).
- Average outage duration - transmission lines.
- Average outage duration - transformers.
- Percentage of unserved energy.
- System minutes off supply.
- Capacitor bank availability.

These performance measures are typical of those used to measure transmission network performance in Australia and elsewhere. However, Transend, in response to a request from the AER, further classifies its transmission line circuits into critical and non-critical categories. Critical circuits are those under direct AEMO oversight while non-critical circuits are those which have indirect AEMO oversight.

The first five of the measures listed above are incorporated into the Service Target Performance Incentive Scheme (STPIS) administered by the AER. Each of the measures is weighted with an emphasis on critical circuit availability and loss of supply events. The STPIS provides that Transend may receive up to one per cent additional revenue for achieving better-than-target performance or lose up to one per cent of revenue for falling short of target.

Figure 9 shows Transend has achieved additional revenue on the basis of above average performance over the five years to 2009. For example in 2009 the additional revenue received was about $1 million or some 16 per cent of net profit after tax. This demonstrates the materiality of the incentives provided under the regime and its potential to achieve performance outcomes.

**Figure 9 - Transend’s ‘S’ factor, percentage of annual prescribed revenue**

Source: Wilson Cook

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183 This reflects that the market impact of transmission congestion (MITC) element of the service target performance incentive scheme (STPIS) is yet to apply to Transend, as there has been insufficient historic data to date from operating in the NEM.
Transend’s annual transmission circuit availability, combining both critical and non-critical categories and annual system minutes off supply are shown in Figures 10 and 11. These figures show an upward trend in transmission circuit availability and a relatively steady trend in system minutes off supply.

**Figure 10 - Circuit availability**

![Figure 10 - Circuit availability](source)

**Figure 11 - System minutes lost**

![Figure 11 - System minutes lost](source)

Figure 12 shows average circuit availability and average system minutes off supply for years 2005 to 2009 compared with other Australian State averages and Transpower of New Zealand.

A review of the efficiency and effectiveness of the State Owned Electricity Businesses
This comparison shows that Transend has similar circuit availability to comparable Australian transmission network service providers (TNSP) and better availability than Transpower (NZ). However, Transend has shown higher minutes off supply than Australian TNSPs, although significantly lower than Transpower. The technical performance of Electranet outperforms that of Transend.

It should be recognised that the design of the transmission network over time, together with customer load characteristics, affects the impact of plant failure and outages on loss of supply. A more strongly meshed network with fewer point load connections will be likely to have lower system minutes losses than a weakly meshed network with some very large point load customers.

This reflects that a meshed network has more redundancy to continue supply in the event of failure of a particular element, and that failure that affects a large point load or loads may quickly contribute to large system minute events. Decisions regarding increased redundancy within the network are economic ones, where the benefits of increased reliability must be traded off against the costs to achieve this increase.

Wilson Cook noted that:

“In summary, these performance indicators show that Transend performs well in relation to its supply, with an improving trend. They also show that its results are in broad alignment with its peers, after taking into account the characteristic of its network.”

Transend also measures and reports on the reliability of customer connections to determine underlying drivers of reliability and availability. Average connection site reliability for firm and non-firm connections to distribution and direct customer

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184 These measures are established for use internally and are not specified in agreements with consumers or imposed by regulators, but Transend is required to report performance to TER. The number and duration of faults on which these measures are based are accounted for in the broader overall availability performance measures discussed above.
connections are measured for both number of fault outages, and fault duration. Transend also sets targets for individual connection sites and measures the impact on connection site reliability for both planned maintenance and fault situations.

### 2.4. Application of capital

Transend’s prescribed capital expenditure includes two main categories\(^{185}\): capital required for system augmentation; and capital required for the replacement and/or upgrade of aging assets. Augmentation projects are required by the NER to meet a regulatory investment test which involves demonstrating a market benefit and/or a requirement to meet a jurisdictional reliability requirement. Forecast expenditure needs to be approved by the AER in order to generate a revenue allowance. At the end of each regulatory period actual prescribed expenditure is rolled into the asset base.

In the current regulatory period (2009 - 2014) the augmentation category of the revenue decision amounts to $222 million (nominal dollars), and accounts for about 35 per cent of total forecast capital expenditure of $643 million (nominal dollars). Some 50 per cent of that augmentation expenditure is associated with the recently completed Waddamana to Lindisfame 220 kV transmission line.

Transend’s asset replacement program has been ongoing over the last ten years and Transend has noted that over this period the average age of its assets has reduced, but only to the average of those of its peers.\(^{186}\)

In comparing the age of its assets with others Transend considers both transmission lines and substation facilities and breaks down both groups into component elements. Transmission line elements tend to be older than those of its peers. For example some 20 per cent of transmission line support structures are over 60 years old. Transend’s transformers and circuit breakers on the other hand are of comparable ages to those of other networks. The average age of 220 kV and 110 kV circuit breakers are 12 and 22 years respectively.

Figure 14 shows Transend’s historical capital expenditure and approved capital expenditure through regulatory determinations.

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\(^{185}\) Connections for load are another significant category.

\(^{186}\) Age is an important, but not sole, driver for asset replacement. Performance and condition are also important considerations that Transend takes into account in considering its asset renewals program.
Figure 14 - Transend’s capital expenditure, regulatory allowance and actual, $ million nominal

![Graph showing Transend’s capital expenditure, regulatory allowance and actual, $ million nominal]

Source: Transend

Annual differences between the regulatory-determined capital expenditure and that incurred by Transend partly reflect timing differences in the delivery of capital projects. During the 2004-09 period, the regulatory arrangements assessed capital spending when projects were commissioned, not when expenditures were incurred.\(^\text{187}\) This has changed under the current regulatory period.

A more accurate perspective on the effectiveness of Transend’s capital project delivery is to examine the cumulative level of capital expenditure during a regulatory period. This is shown in Figure 15.

\(^\text{187}\) Thus, a project scheduled to be commissioned in, say, May 2006, which was actually commissioned in July 2006 would be included in the determination for 2005-06, but appear as an actual in 2006-07. There may have been no difference in the overall project costs, yet the data would suggest that Transend ‘underspent’ in 2005-06 and ‘overspent’ in 2006-07.
Figure 15 - Transend’s cumulative capital expenditure, regulatory allowance and actual, $ million nominal

Figure 15 shows that over the 2004-09, regulatory period Transend’s capital program totalled around ten per cent more than the regulated capital spending allowance. Capital spending was below the determined levels in the early part of the period, particularly in 2005, and over the period, Transend’s actual spending of $373 million was $37 million higher than the regulated determination of $336 million.

In explaining the variance of capital expenditure relative to that allowed over the 2005 to 2009 period, Transend noted that the AER, in its 2009 to 2014 revenue decision, included a detailed ex-post review of capital projects for the period. The AER noted that Transend had re-ordered its capital project priorities in the face of delays for the Waddamana-Lindisfame project, prioritising asset replacement programs, that input costs had escalated at a greater rate than that assumed and that the actual capital expenditure was prudent.

Wilson Cook examined the documentation that is regularly prepared by Transend to identify capital requirements and manage capital project execution and found them to be consistent with good industry practice.

Transend’s major capital expenditure projects over the last five years were reviewed by Wilson Cook and reported as being generally below budget and on time, with the overall capital program in excess of that forecast under the 2004-09 regulatory determination, and expenditure in the first two years of the present 2009-14 determination tracking under the allowance.
Wilson Cook also examined a sample of Transend’s post implementation reviews and noted that they contained a level of detail that would be expected for projects of the magnitude undertaken. Wilson Cook noted that Transend’s post implementation report for a particular project requiring funding in excess of the initial business case, and which was completed some three years after the original forecast completion date, made a number of recommendations for improvements. They noted improved budget and timeline performance on subsequent projects.

2.5. Asset management philosophy and maintenance practices

Transend prepares a suite of plans that incorporate aspects of its asset maintenance philosophy and maintenance plans. The most prominent of these are:

- an Annual Planning Report for the Tasmanian network. This plan includes a 20 year demand forecast, a technical review of system security and a rolling five year investment plan; and

- a biannual Transmission System Management Plan. The plan describes life cycle management of the various asset classes with maintenance and replacement based on asset condition and risk assessment. The current plan notes the continued existence of aged assets in service despite recent replacement programs. Asset management systems are said to be modelled on the International Infrastructure Management Manual.

The above plans are supported by an asset management information system, an environmental management system, a risk management system, a plant restriction and plant outage management system, an operational information system, a land information system and a document and standards system. Wilson Cook noted that “these are conventional systems for businesses of this type” and also noted that the AER considered Transend’s network planning framework and processes consistent with good industry practice.

2.6. Operating expenditure

Transend’s operating expenditure has increased significantly since it was established in 1998. Figure 16 shows regulatory-determined operating expenditure allowances and compares them with actual operating expenditure over the period 2004-10.
Significant increases in operating expenditure, particularly during the period 2005 - 2009, are apparent and substantially exceed the allowance set by the ACCC in its regulatory reset for the 2004 - 2009 period. In making its determination, the ACCC allowance provided for containment of operating cost growth and imposed a cumulative two percent per annum efficiency requirement. By contrast, Transend’s performance demonstrated two step changes in operating costs - a 26 percent nominal increase between 2005 and 2006, and an increase of a similar proportion in 2008. Over the 2004 - 2009 period, Transend’s expenditure exceeded the regulatory allowance by around $28 million in nominal terms, which equates to around 16 percent of the regulatory-determined total operating expenditure over the period.

The Transend Board made a considered decision to spend above the regulatory allowances, based on its view that the ACCC determination had made unsustainably low expenditure allowances. Transend advised its Shareholding Ministers of this strategy through successive Corporate Plans, noting that “Transend considers that the long-term interest of Transend’s customers and Shareholders is unlikely to be best served by trying to beat the ACCC’s operating allowance. It is not considered prudent to make arbitrary cuts to the operational budget and set unrealistically low expectations for the future”.

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188 Transend Strategic Plan 2007. Similar statements were contained in other Corporate Plans over the regulatory period.
In correspondence on the Corporate Plan, Shareholders noted that the Board had made that judgement and requested that written justifications be provided supporting the need for expenditures to be maintained at levels higher than the regulated allowances.

Subsequent Corporate Plans did not provide detailed information on efficiency targets, measures or outcomes in relation to maintaining costs, rather there were references to ‘organisational efficiency and effectiveness’ objectives, which included “a focus on reducing internal operating expenditure” and an “increased focus on annual expenditure targets”.

The Panel’s review of the Corporate Planning documents indicates that Transend was focused on meeting the budgeted expenditures it put forward through the regulatory process, and that the ACCC determination on allowances and productivity improvements appeared to have minimal impact on performance targets.\textsuperscript{189}

In its investigation, Wilson Cook reviewed Transend’s regulatory proposal to the AER for the 2010 to 2014 regulatory period and also a report by Worley Parsons who were appointed by the AER to review Transend’s regulatory proposal in detail. Wilson Cook noted that from 2005 - 2009

“expenditure had risen in real terms in all cost categories, with significant increases in transmission services, transmission operation, asset management, corporate costs and network support. The lowest increase in percentage terms was in field operations and maintenance. Preparation for, and entry into, the NEM were said to have contributed to cost increases in a number of categories. Planning and implementation of a wider-ranging and more complex works programme than in the preceding years was also said to have required an increase in works management capability and in asset management capability.”

The increases in operating expenditure for the 2004 to 2009 period are graphically presented in Figure 17.

\textsuperscript{189} In this context, it appears that the performance hurdle established through the regulatory framework was considered so high that it was effectively set aside by the business. For example, there is no evidence that Transend sought to achieve a performance pathway towards the allowances established by the ACCC noting that Transend was unable to challenge the appropriateness of the cost allowances, owing to the absence of a merits review.
Of particular interest is the fact that field operations and maintenance had the lowest increase in percentage terms. Transend has advised that since its establishment it has outsourced all field operation and maintenance activities to capable service providers the majority of whom are party to performance based contracts with some having financial incentives. Transend has benchmarked some of these contracts to ensure that pricing and levels of service are consistent with industry best practice.

Figure 16 illustrates that the AER made an operating expenditure allowance significantly higher than that approved by the ACCC.

Transend considers that this recognises that the ACCC allowances were not sustainable and given the similarity between the AER determined operating cost allowance for 2009-10 and its actual costs in 2008-09, that it was operating efficiently during the previous regulatory period, regardless of the ACCC determined allowances.

Wilson Cook also noted that Transend’s operating expenditure in the present period was expected to increase annually in real terms but at a slower rate, and that Worley Parsons, working on behalf of the AER, considered the expenditure reasonable and the supporting documentation the best they had seen in contemporary Australian entities.

Using data from the AER’s annual electricity transmission business performance reports, Wilson Cook compared Transend’s operating costs with those of other Australian TNSPs. Figures 18, 19 and 20 show Transend’s performance compared to their peers in terms of cost per kilometre of circuit length, cost per MW of peak demand and on the basis of a composite of capacity and circuit length respectively.
Figure 18 - Operating expenditure per km, $ nominal per km

Source: Wilson Cook

Figure 19 - Operating expenditure per MW, $nominal per MW

Source: Wilson Cook

A review of the efficiency and effectiveness of the State Owned Electricity Businesses
The data shows that for all measures, Transend’s 2009 operating costs in relative terms were higher than their NEM peers. This reflects among other things underlying scale issues for Transend, relative to other NSPs. Regulatory determinations, such as that undertaken by the AER, reflect that a number of cost benchmarks are affected by scale economies.

What is more revealing is the rate of growth in Transend’s cost relative to its peers. A comparison of the businesses on a total operating cost basis is given in Figure 21, starting from a level of 100 in 2004 and shows Transend’s operating expenditure rising 72 per cent over the period. The average rate of growth in operating expenditure across Transend’s Australian peers was 43 per cent.

Wilson Cook acknowledged the increasing expenditure and commented that the costs:

“were accepted by the AER after detailed review” and “the results of detailed analyses take precedence over high level benchmarking of the type presented above”.

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190 Other things include age of assets, terrain, the dispersed nature of generation and local labour/input costs.
Figure 21 – Operating expenditure growth 2005-2009

Source: Wilson Cook

Wilson Cook also considered data from the 2009 International Transmission Operation and Maintenance Study (ITOMS) provided by Transend. ITOMS compares performance indicators based on operation and maintenance data from transmission businesses internationally. Figure 22 presents an extract from the report.

Figure 22 - Extract from 2009 ITOMS operating and maintenance report

Source: Wilson Cook

The international benchmarked averages of cost and service are at the point where the lines intersect and regional averages are shown as triangles. The figure shows that, according to the ITOMS methodology, Transend’s relative operating and maintenance performance has improved in terms of cost and performance over the last five studies, is now in the optimum quadrant, and has outperformed the ASP (Australia South Pacific) regional average in the most recent study.
Wilson Cook noted that:

“the AER, in its determination did not accept the ITOMS findings as sufficient to indicate efficiency of expenditure and we concur with that view”

The Panel sought to reconcile the apparent inconsistency between the ITOMS report and the AER data, which shows that Transend’s costs were increasing at a higher rate than its Australian contemporaries. Transend has advised that the ITOMS study only considers transmission assets operating at 110 KV and above and does not include overheads including business support services and regulatory functions which, tend to be higher than other transmission entities because of Transend’s smaller size.

Although Wilson Cook accepts that Transend’s costs are reasonable, and Transend has over the last two years contained costs within its regulatory allowance, the Panel notes that Transend’s costs are increasing at a greater rate than its contemporaries and maintenance increases are not consistent with the improving age of assets. Improving asset age is only one of the drivers of maintenance costs. In Transend’s case, increases in labour charges by contractors retained to provide O&M services has increased at a rate greater than CPI accounting for the majority of increased maintenance costs. The expanded scope of maintenance activities due to an expanded asset base, as in Transend’s case, also contributes to increased costs, while in some areas costs have fallen as new equipment has been installed.

2.7. Regulatory impacts

Apart from the STPIS referred to earlier in this chapter the AER provides an incentive for Transend to manage its operating expenditure within its allowance by the application of an Efficiency Benefit Sharing Scheme (EBSS). The scheme acknowledges additional savings in each year of the regulatory period and effectively allows savings to be retained for a period of five years even if this extends into the next regulatory period. The arrangement has enabled Transend to retain savings of $1.7 million in 2009 and a further $3 million in 2010. Transend’s current financial projections assume that future efficiency gains will amount to $2.5 million per annum.

The regulatory framework is designed to provide incentives for TNSPs to minimise or defer capital expenditure.
Transend commits a part of the gains achieved from the combined incentive schemes to an Employee Regulatory Incentive Scheme, to incentivise its staff to deliver operating and capital efficiencies, whilst still maintaining service levels. Under the scheme eligible employees are able to earn a bonus of up to $3,000.\textsuperscript{191} This scheme is self-funding through a combination of cost savings made and STPIS incentive payments earned.

In addition to the AER’s reporting requirements, Transend is also required to report to the TER annually as a requirement of its operating licence. The report is required to include details of Transend’s technical performance and compliance with management plans in a similar manner to that required of Hydro Tasmania and detailed above.

The Panel is of the view that some rationalisation of the reporting, or at least alignment of the requirements, of both the AER and TER may be beneficial in providing a single performance focus for Transend and minimise the cost and effort required to produce the reports.

The need for Transend to meet a regulatory investment test for augmentation projects has been noted earlier in this paper. The jurisdictional network reliability requirements that Transend must plan to in undertaking the regulatory investment test analysis are set out in the Electricity Supply Industry (Network Performance Requirements) Regulations 2007. These standards were developed in 2006 by a TER advisory panel. Although Transend advised at the time that the regulations were promulgated that the correction of many of the identified deficiencies had already been provided for in the approved capital development program of the day, a number of new projects were identified with an estimated cost of some $31 million to $38 million.

Transend’s annual planning report identifies those parts of the transmission system where Transend does not presently meet the network performance requirements, or is forecast not to meet the requirements based on demand forecasts. The annual planning report consultation process provides an opportunity for parties to come forward with non-network solutions to address the identified issues over the planning horizon. The regulations containing the reliability requirements are due for review in 2012.

**2.8. Governance and Shareholder oversight**

Transend is incorporated under the Corporations Act (2001). The Shareholders require the company to prepare and present an annual corporate plan the details of which are described in Chapter 4.

\textsuperscript{191} Inclusive of business on-costs. However the scheme does not provide for a negative impact on employee earnings.
The Panel has noted that the Shareholder’s corporate plan expectation letters have progressively become more specific as to their expectations over time, but that corporate plans have yet to include the details, or targets, of efficiency or productivity improvement measures in response to these expectations.

For example, the 2011 Shareholder’s corporate plan expectations letter to Transend’s Board required as a specific matter to be included in the plan

“details of operational efficiencies and productivity measures that would enhance financial performance without detracting from the quality and reliability of service”.

Transend’s 2011 Corporate Plan noted that “we are focused on achieving operational efficiencies and improved productivity that does not detract from the quality and reliability of supply” and included financial targets for operating and capital expenditure and returns to shareholders associated with this focus. The plan also included service performance targets, to ensure financial savings are not delivered at the detriment of customer service. Management efforts to achieve efficiencies relative to the regulated allowance appear to be meeting with some success, given recent trends that have reversed the situation from overspending operational expenditure compared to regulatory allowances to underspending.

2.9. Summary of investigation

Wilson Cook concluded

“Overall, we conclude that Transend is operating with an appropriate balance of prudence and efficiency and we are satisfied that there is detailed, independent scrutiny of its capital expenditure to ensure that works undertaken are efficient and effective.”

The Panel has noted Wilson Cook’s conclusion and agrees that Transend’s technical performance, or effectiveness, is satisfactory and trends towards improvement. The Panel also notes the improving trend with respect to meeting regulatory operating expenditure allowances but remains concerned about the apparent inconsistency of rising maintenance costs with improving asset age and condition. A majority portion of this increase can be attributed to the increase in labour costs over and above CPI during the period.

The Panel also is of the view that there is an opportunity for increased involvement of Shareholders to influence Boards in the pursuit of improved efficiency through the corporate planning process and other avenues. The Panel notes that this would require a more detailed level of reporting than is currently the case.
<table>
<thead>
<tr>
<th>Measure</th>
<th>Commentary</th>
<th>Conclusion</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Principal measures of transmission network performance</strong> focus on availability and loss of supply.</td>
<td>Transend reports annually on a broad range of performance measures to the AER, AEMO and the TER. Transend also reports to TER the reliability of customer connections, measured by number of fault outages and fault duration.</td>
<td>Upward trend in transmission circuit availability and steady trend in system minutes off supply. Transend performs well against industry peers in relation to circuit availability but has higher system minutes off supply. The usefulness of peer comparison is limited by differences across transmission networks.</td>
</tr>
<tr>
<td>The measures of application of capital are capital expenditure assessment and implementation processes. Capital expenditure required for system augmentation is required to meet a regulatory investment test.</td>
<td>In the 2004-09 regulatory period Transend overspent its approved capital allowance. It is presently spending under the 2009-14 allowance. 10 year asset replacement program has reduced the average age of assets but only to the average of industry peers. Transmission line elements older than average of peers. Transformers and circuit breakers are of comparable age to peers.</td>
<td>Documentation identifying capital requirements and capital project execution consistent with good industry practice. Post implementation reviews at a level of detail and made recommendations for improvements that were implemented and noted in subsequent projects.</td>
</tr>
<tr>
<td><strong>Asset management</strong> philosophy and maintenance practices.</td>
<td>Key plans include annual planning report for the Tasmanian network and biannually updated transmission system management plan. Plans supported by industry consistent information, planning and risk management systems.</td>
<td>Network planning framework and processes consistent with good industry practice.</td>
</tr>
<tr>
<td>Operating expenditure.</td>
<td>Trend to increase operating expenditure. In the 2004-09 regulatory period Transend overspent its approved operating allowance. It is presently spending under the 2009-14 allowance.</td>
<td>Across a range of measures, Transend’s operating expenditure is higher than industry peers and increasing at a faster rate. The usefulness of peer comparison is limited by differences across transmission networks.</td>
</tr>
<tr>
<td>Measure</td>
<td>Commentary</td>
<td>Conclusion</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Governance - regulatory and shareholder.</td>
<td>Transend is required to report to the TER on technical performance and compliance with management plans as part of its operating licence. Information provided to shareholders does not detail efficiency and effectiveness targets or strategies. Transend has implemented an internal efficiency initiative to drive reduced or deferred capital expenditure.</td>
<td>No evidence of consistent shareholder focus on efficiency or effectiveness, although this has become a more recent focus.</td>
</tr>
</tbody>
</table>
3. **Aurora Energy - Distribution**

3.1. **Network characteristics**

The characteristics of a distribution network depend primarily on the distribution and load characteristics of its customer connections. Figures 23 and 24 provide comparative information on network connection density and load density for Aurora Energy - Distribution and other distribution networks in the NEM.

**Figure 23 - Industry comparison - customer density**

![Graph showing comparison of customer density across different companies.](source: Wilson Cook)

**Figure 24 - Industry comparison - load density**

![Graph showing comparison of load density across different companies.](source: Wilson Cook)

A review of the efficiency and effectiveness of the State Owned Electricity Businesses
Aurora Energy - Distribution’s load and connection density characteristics are similar to those of the South Australian distribution business ETSA and not substantially different to the combined characteristics of New South Wales and Queensland, noting that there is substantial variation among the businesses within those states. Aurora Energy - Distribution, however, is one of the smallest distribution businesses in Australia and with only 275 000 customer connections. By way of comparison, the ETSA has nearly three times the number of customer connections of Aurora Energy - Distribution.

3.2. Performance

Aurora Energy - Distribution reports annually on a suite of reliability performance measures to satisfy the requirements of the TER and AER. The primary measures of performance are based on an assessment of the average number of interruptions to consumer supply (SAIFI) and the average duration of interruptions (SAIDI). The measures can be applied on a system basis or for particular groups or categories of consumers.

Aurora Energy - Distribution’s performance in terms of overall network reliability is shown in Figures 25 and 26 below.

**Figure 25 - Overall SAIDI**

![Graph showing overall SAIDI from 2001 to 2010](source: Wilson Cook)
The figures show a small downward trend in underlying SAIDI (i.e. after exclusion of major event days) and a more significant declining trend in SAIFI. This indicates that, on average, Aurora Energy - Distribution customers are experiencing fewer interruptions and the average duration of interruptions has also decreased slightly in trend terms over the last ten years.

Reliability targets for Aurora Energy - Distribution are set out in the Tasmanian Electricity Code (TEC) and, as such, are a function of decisions made at the state level.

Prior to December 2007, reliability targets were based on three customer categories; CBD, Urban, and Rural. Average reliability targets were set for number and duration of outages in each category and Aurora Energy had a ‘reasonable endeavours’ obligation to ensure that no more than five per cent of feeders in each category fell below a lower bound of performance in each category.

From January 2008, the TEC was changed to set an overall number and duration of outage targets for five categories detailed in the table below. The change also identified within the five categories 101 communities with defined geographical boundaries and also set number and duration of outage targets on a community basis. These reliability targets are shown in Table 2.
Table 2 - Reliability targets

<table>
<thead>
<tr>
<th>Customer Category</th>
<th>Communities Per Category</th>
<th>Overall</th>
<th>Each Community</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>SAIDI</td>
<td>SAIFI</td>
</tr>
<tr>
<td>Critical Infrastructure</td>
<td>1</td>
<td>30</td>
<td>0.2</td>
</tr>
<tr>
<td>High Density Commercial</td>
<td>8</td>
<td>60</td>
<td>1</td>
</tr>
<tr>
<td>Urban and Regional Centres</td>
<td>32</td>
<td>120</td>
<td>2</td>
</tr>
<tr>
<td>High Density Rural</td>
<td>33</td>
<td>480</td>
<td>4</td>
</tr>
<tr>
<td>Low Density Rural</td>
<td>27</td>
<td>600</td>
<td>6</td>
</tr>
</tbody>
</table>

Source: Tasmanian Electricity Code, Office of the Tasmanian Economic Regulator

Aurora Energy - Distribution is required to use reasonable endeavours to meet these targets by the end of the current regulatory period 2012. It is generally considered that a reduction in the number of interruptions, or a reduction in SAIFI, requires a stronger and better-meshed system, principally requiring the application of additional capital spending. On the other hand, to achieve a reduction in duration of interruption, or a reduction in SAIDI, requires a faster repair response and may have the consequence of an increase in maintenance capability and operating expenditure. In its 2008 regulatory reset Aurora Energy - Distribution was allowed significant increases in both capital and operating allowances, which reflected, amongst other things, higher costs associated with reliability.

Since the introduction of the new categories and associated targets, Aurora Energy - Distribution has performed better in achieving the SAIFI targets than it has in achieving the SAIDI targets. It met the SAIFI targets in all five categories in the last two years but exceeded its SAIDI targets in all five categories in 2009 and in all but one in 2010.

On a community basis, in 2009 Aurora Energy - Distribution failed to meet the SAIFI target in 13 communities and the SAIDI target in 37 communities. In 2010, it failed to meet the SAIFI targets in four of the 101 communities and failed to meet the SAIDI targets in 33 communities. While there is some apparent improvement, the results show a degree of volatility and in the Panel’s view are not extensive enough to show any long term trend.192

Results on the basis of the pre 2008 categories are shown in Figures 27, 28 and 29.

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192 These results include the impact of major event days, as specified and reported by the Tasmanian Economic Regulator.
Figure 27 - CBD SAIDI

Figure 28 - Urban SAIDI

Figure 29 - Rural SAIDI

Sources: Wilson Cook

A review of the efficiency and effectiveness of the State Owned Electricity Businesses
The trends show a marked deteriorating performance in the CBD and urban categories but generally improving performance in the rural category. This trend means that areas of high customer density have experienced declining performance in terms of outage duration, while the smaller share of the population that live in rural areas have experienced improved performance.

Distribution network businesses in the NEM are also required to report supply reliability statistics to the AER. The statistics are reported in four categories, CBD, Urban, Short Rural and Long Rural. Wilson Cook calculated the average SAIDI over the period 2004 to 2010 in order to compare Aurora Energy - Distribution's performance with other NEM distribution businesses. These comparisons are shown in Figures 30 to 33. Because the data used in these comparisons is fairly broad, the comparisons may be considered as only indicative.

**Figure 30 - Industry comparison - CBD SAIDI (2006-2010 Average)**

![Graph showing CBD SAIDI comparison for Energex, ETSA Utilities, EnergyAustralia, Aurora Energy, CitiPower. Source: Wilson Cook](source)

**Figure 31 - Industry comparison - urban SAIDI (2006-2010 Average)**

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**Figure 32 - Industry comparison - short rural SAIDI (2006-2010 Average)**

![Bar graph showing industry comparison - short rural SAIDI (2006-2010 Average)](source: Wilson Cook)

**Figure 33 - Industry comparison - long rural SAIDI (2006-2010)**

![Bar graph showing industry comparison - long rural SAIDI (2006-2010)](source: Wilson Cook)

Aurora Energy - Distribution falls in the mid to high range in all four categories and is outperformed by ETSA in each category.

Wilson Cook noted that:

“In summary, Aurora has improved its supply reliability over the last ten years through reducing the number of interruptions but there has been little overall improvement in the average duration of interruptions. Comparison with the targets set out in the Code and with national statistics that show Aurora in the mid-to-high range of average SAIDI in all categories and suggests that there is scope for further improvement.”

The Panel is inclined to share this view and notes that improvements in rural areas may be at the expense of the deterioration in performance in urban areas.
3.3. Application of capital

Figure 34 shows Aurora Energy - Distribution’s capital expenditure from 2004 to 2010 together with the regulatory allowance.

**Figure 34 - Aurora Energy-Distribution’s capital expenditure trend ($ million nominal)**

Aurora Energy - Distribution classes its capital expenditure into two categories; augmentation and replacement. Wilson Cook reviewed the individual expenditure categories and advised that Aurora Energy - Distribution has increased its replacement expenditure since 2008, with expenditure increasing by around 40 per cent from $22.3 million in 2009 to $31.1 million in 2011.\(^{193}\)

Wilson Cook noted that Aurora Energy - Distribution has undertaken several significant system augmentation projects over recent years, particularly in the Hobart area. Aurora Energy advised Wilson Cook that it has experienced significant growth in connection expenditure prior to the global financial crisis that commenced in 2007 and that it has had to accelerate a number of targeted reliability programs. Aurora Energy has noted that it has started to see a reduction in customer generated work this calendar year.

Capital expenditure in the next regulatory period is projected to continue at a fairly constant level, averaging around $135 million per annum ($2009-10), and at a lower level than the present.

Wilson Cook acted for the TER in 2006 to review Aurora Energy - Distribution’s proposed operating and capital expenditure for the period 2007 - 2012 and advised that at the time that it was of the view:

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\(^{193}\) This is broadly in line with the regulatory determination, which was a 34 per cent increase over this period.

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“that the capital expenditure proposals put forward by the business at that time were reasonable, subject to three relatively minor adjustments.”

In relation to replacement expenditure, Wilson Cook commented that:

“although the level of expenditure is much higher than historical levels of expenditure under this category, we consider that the historical levels are not sustainable if the network is to continue to meet acceptable service and safety targets.”

The Panel notes that total capital expenditure in excess of the regulatory allowance for the period 2004 to 2010 was a nominal $208 million, representing an increase of around 40 per cent on the regulatory determination of an aggregate capital spend of $535 million over that period.

A breakdown of the $208 million is show in Figure 35, which demonstrates that around half of the overspend was a result of customer-driven capacity augmentations.

**Figure 35 - Spending in excess of regulatory allowances 2004-2009-10, shares**

![Figure 35](image)

While the additional financing and depreciation charges associated with this excess capital expenditure has no immediate impact on customers through price adjustments, there is a current regulatory period impact on Aurora Energy’s financial performance through additional financing costs, which impacts on Shareholder returns. However, at the next regulatory reset, provided the regulator allows the excess capital expenditure to be rolled into the regulatory asset base, these financial impacts will be reversed. A regulated return will be earned on the higher regulatory asset base, increasing customer prices and potentially Shareholder returns.
Aurora Energy appointed Parsons Brinckerhoff (PB) to review its proposed capital expenditure and unit costs for the next regulatory period (2012 – 2017). PB concluded that the proposed expenditure was aligned with or below industry levels and the unit costs it reviewed were generally aligned with industry expectations.

In its current work for the Panel, Wilson Cook identified a possible risk of under-investment in replacement expenditure proposed for the forthcoming regulatory period in Aurora Energy’s submission to the AER. Under-investment in replacement expenditure may result in an ageing infrastructure and may require an increase in future expenditure, with accompanying increases in pricing structure, in the event of escalating asset failure rates.

Aurora Energy observed that its distribution strategy aims to deploy smart grid technology to monitor the network and more efficiently utilise assets over their life, and that this will assist in addressing this risk.

The Panel has noted the possible risk identified by Wilson Cook and acknowledges that the situation is a further example of the reconciliation that needs to be made between the maintenance of a reliable system on the one hand, and cost to electricity users on the other. It emphasises the critical importance of the regulatory process in driving appropriate behaviour over time.194

The Panel is also cognisant of the fact that Aurora Energy - Distribution’s asset condition monitoring approach, as the basis for asset replacement, will tend to identify areas where asset failures may become more pronounced and provides a basis for greater levels of investment to address falling performance should that be required.

### 3.4. Asset management

In considering Aurora Energy - Distribution’s asset management philosophy and processes, Wilson Cook noted that it had advised the TER in a 2005 mid-term review of Aurora Energy - Distribution’s capital expenditure and had reviewed asset management planning, organisation and asset database, and work implementation documentation as part of that assignment. Wilson Cook considered that, at that time, Aurora Energy - Distribution had been slow to recognise the need for asset database and process improvements focused on better network performance.

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194 In periods of sharp rises in electricity prices, there can be pressure brought to bear on electricity entities and Governments to find short-term ‘wins’ to decreased price pressures. These are not always in the long-term interests of electricity customers and independent regulation provides a sound mechanism to protect the longer term interests of electricity customers from potential under or over investment in the networks.
In its investigation for the Panel, Wilson Cook reviewed Aurora Energy - Distribution’s current 2011 asset management plan, which describes Aurora Energy - Distribution’s present asset management strategy and the policies and processes through which it is to be implemented. Wilson Cook noted a number of improvements in the policies including those for asset replacement and concluded;

“Overall, we consider that Aurora continues to have reasonable processes for planning and executing its asset management functions and for undertaking new capital works but that it also continues to exhibit some of the symptoms that we observed in 2005 – essentially, a stronger focus on ‘process’ than on action.”

3.5. Operating expenditure

Figure 36 illustrates Aurora Energy - Distribution’s actual operating expenditure compared to the regulated operating expenditure allowance for the period 2004 - 2010.

Overspending of operating allowances is common across the 2004 - 2010 period, particularly 2005-2007. Across the whole period, Aurora Energy - Distribution overspent its operating allowances by a nominal $14 million, which represents four per cent of total allowed expenditure. Figure 37 details the sources of over and under-spending over the period 2004 - 2010. It shows that the major sources of overspending were in relation to emergency response and repairs, NEM and contestability-related costs and system operations. By comparison, overall network management related operating expenditure was at or below the regulated allowances. These account for around half of the total operating expenditures for the distribution business.
In its 2011 Corporate Plan, Aurora Energy reported that its current strategy is to ensure that the business is more strongly focused on customer outcomes and to respond appropriately to capital constraints. Aurora Energy - Distribution has commenced a number of initiatives to improve overall efficiency and productivity, including a new approach to network management and a restructuring to improve works delivery efficiencies. This is illustrated in Figure 38, which shows Aurora Energy – Distribution’s actual and forecast operating expenditure over the forthcoming regulatory period. It shows that it is forecasting a steady decline in real operating costs, from a high of $80 million in 2009-10 to $65 million in 2017.
In preparing its proposal to the AER, Aurora Energy commissioned PB to benchmark both capital and operating expenditure with industry contemporaries. In their review of the study Wilson Cook observed:

“PB considered that the proposed expenditure in total was in alignment with industry averages. It benchmarked costs for the larger programmes and found that emergency maintenance and meter maintenance costs were above industry averages but within the range exhibited by other businesses. It found that vegetation costs were well below the industry average and that asset inspection costs were much lower than the industry average. Unit costs for pole replacement, conductor replacement, transformer installation and meter installation were found to be below their industry averages.”

Wilson Cook also compared Aurora Energy - Distribution’s operating expenditure with the combined values of the distribution businesses in the other NEM states in terms of cost per kilometre of circuit length, cost per connection and cost per kilowatt of peak demand. It should be noted that these comparisons represent broad indicators of effectiveness only. The operating expenditure data was sourced from the latest regulatory decisions and is shown for 2009, the latest complete year for which most data was available, together with the regulatory allowances for 2013. Figures 39, 40 and 41 show these comparisons.

**Figure 39 - Operating expenditure per km, $/km**
The analysis shows that in relation to these very broad expenditure comparisons, Aurora Energy - Distribution is in the lower-to-middle part of the range for all measures. In its current revenue proposal to the AER for the 2012-13 to 2016-17 period Aurora Energy - Distribution is forecasting that its operating expenditure will be at a similar level in 2013 to that in 2009, whereas, in all other states, it is forecast to increase over that period. The extent to which Aurora Energy - Distribution can deliver the efficiency improvements underpinning the AER regulatory proposal will be critical in determining if this outcome is delivered.\footnote{The Panel notes the labour saving measures announced by Aurora Energy during 2011 provide some evidence that changes within the business are being implemented that will assist in achieving these outcomes. These include the announcement of more than 50 positions in the Network Division in late 2010, and the announcement of up to 40 voluntary redundancies from the Network Division in October 2011.}
In considering Aurora Energy - Distribution’s overall operating expenditure, Wilson Cook concluded:

“Whilst Aurora’s operating expenditure has risen in recent years, the business has taken steps to improve the efficiency of its operations and is proposing lower expenditure over the next regulatory period. A comparative study of expenditure indicators with other states shows that Aurora compare favourable on all operating cost indicators.

Overall, therefore, we conclude that Aurora is operating with a reasonable degree of efficiency and commend it for the initiatives it is taking to improve operating efficiency further.”

While Aurora Energy has advised the Panel that it is confident that it is able to reduce operating expenditure and operate within regulatory allowances in the future on the basis of improved technology and processes, the Panel is of the view that such a step change in financial performance will require very significant attention from all levels of management, and strong and consistent accountability for performance driven by the Board and the Shareholders. Recent reductions in staffing levels implemented by the Company in its distribution business indicate that this challenge is being actively managed.

One of the issues raised in submissions to the Panel and at the April 2011 Community Hearings was the appropriateness of the current business boundary between Transend and Aurora Energy - Distribution. The view expressed was that inefficiencies because Transend owned and operated the circuit breakers on Aurora Energy - Distribution’s distribution feeders. The matter was referred to Wilson Cook as part of its assignment.

Wilson Cook advised that they were familiar with the situation since it had parallels in New Zealand prior to industry rationalisation in that country. It noted that the problem was overcome by first allowing the distribution lines businesses in New Zealand to operate the circuit breakers with their SCADA systems, then by selling the circuit breakers to them, giving them complete control. Wilson Cook suggested that the latter course of action is appropriate in Tasmania.

Transend considers that there are no material benefits to customers from a change in the asset ownership boundaries between Transend and Aurora. Rather, continued cooperation between the two entities, including the current program of establishing new operational arrangements is the preferred approach. A key reason for this is that it is not practical to split ownership responsibilities within HV switchboards, which are integrated units.

The Panel has noted Wilson Cook’s advice on this matter and that of Transend and is of the view that it is a matter that should be resolved by Aurora Energy and Transend.
3.6. Governance and Shareholder oversight Issues

Like Transend, Aurora Energy is incorporated under the Electricity Companies Act 1997 and is subject to similar requirements for the development and presentation of an annual corporate plan to Shareholders.

The Panel has noted that Shareholder’s expectation letters have progressively become more specific as to their expectations in recent years in relation to the efficiency and effectiveness of Aurora Energy’s distribution business. For example:

- the expectation letter for the 2008 plan contained no references to efficiency and effectiveness and there was a focus on the plan explaining the impacts of the 2007 distribution pricing determination, and a requirement for clear business segment reporting;

- For the 2009 plan, direction was provided in relation to the establishment, monitoring and reporting on key financial performance indicators and business segment reporting; and

- For the 2010 plan, the Shareholders requested that the plan identify “strategies to actively pursue cost reductions and efficiency gains throughout the business...” and “benchmarking expected performance in the regulated areas of the business against the Regulator’s determinations”.

For the 2011 plan, the expectation letter noted that Aurora Energy:

“needs to manage operating costs in regulated areas to within its regulated revenue allowances over the planning period. In this regard, we would appreciate details of specific operational efficiencies and productivity measures that are being implemented to enhance financial performance without detracting from the quality and reliability of services, particularly within the individual business segments that comprise the core energy and distribution businesses. In addition, we note that it is important for Aurora Energy to review its capital expenditure program, in light of the capital constraints and impact on customer prices...” The expectation letter also highlighted that the corporate plan should, amongst other things, provide “a review of forecast operating and capital costs against regulatory allowances for the distribution business.”

Reviewing the Shareholder expectation letters in relation to Aurora Energy, it is clear that the growing diversification of the business has had an impact on framing Shareholder expectations. Until recently, Shareholder expectations tended to broaden as Aurora Energy took on new business activities and to lack a more detailed focus on specific matters within the core functions. The 2011 expectation letter contained a higher degree of focus on core functions.
Reviewing the corporate plans in relation to the distribution business, Aurora Energy has been slow to respond to the increasing desires for a focus on efficiency. Prior to the 2011-12 to 2015-16 Corporate Plan, the plans made reference to improving efficiency but did not highlight specific strategies and targets by which this objective would be met. For example, the 2010 Corporate Plan identifies ‘materially improve the efficiency of the Distribution Business’ as a key strategic direction and highlights several broad strategies, but provides no indicators or targets by which performance could be judged.

The 2011 corporate plan goes further in describing the strategies that are planned to be implemented to improve the efficiency of the distribution business and highlights projected aggregate savings that are anticipated over the planning period.

The Panel recognises that Aurora Energy’s corporate plans are already large documents (in excess of 100 pages) and contain a significant amount of detailed information. The Panel also recognises that specific efficiency programs will be incorporated into other strategic and operational documents within Aurora Energy, and in relation to performance monitoring arrangements for management. Nonetheless, accountability for improvements in efficiency and effectiveness will be stronger if the key strategic document between the Shareholder and the Company addresses these matters in greater detail.

3.7. Summary of investigation

- Aurora Energy - Distribution’s technical performance, or effectiveness, has shown marginal improvement in terms of the number of interruptions but the average length of interruptions has not materially reduced in the last ten years. The Panel is of the view that while Aurora Energy - Distribution’s performance is currently better than that of some distribution utilities in Australia, any deterioration would be inconsistent with the substantial resources provided to the company to deliver services under the regulatory process.

- The Panel has also noted that Aurora Energy - Distribution’s focus on performance is based on improving reliability in individual communities, many of which are underperforming against the targets, but is of the view that this should not be at the expense of an overall decline in performance in areas of higher population density. It is notable that despite increases in capital spending regulatory allowances for improved reliability, and Aurora Energy overspending these allowances by some 15 percent, there has not been a marked improvement in reliability.
A review of the efficiency and effectiveness of the State Owned Electricity Businesses

- Aurora Energy - Distribution’s historical performance has demonstrated mixed results in meeting regulatory allowances. Over the past four years, operating expenditure regulatory allowances increased by an average of 9.5 per cent per annum, and Aurora Energy’s actual operating expenditure grew by an average of around 11.4 per cent per annum. Achieving the projected savings targets Aurora Energy has set for itself, which are forecast to deliver year on year real savings in operating expenditure, will require a considerably different approach by the management and Board of the company. Recent changes announced within the distribution business indicate the process of change is underway.

- The Panel has noted the significant real reduction in operating costs and reduced capital expenditure requirements advanced by Aurora Energy in the current regulatory proposal. The Panel notes potential risks of underinvestment in asset replacement and Aurora Energy’s strategies to manage this risk.

- As with Transend, the Panel is of the view that there is an opportunity for increased involvement by the Shareholders in influencing Boards in the pursuit of improved efficiency and the maintenance of appropriate technical performance. In Aurora Energy’s case, it appears from its regulatory proposal and changes already announced within business, that the challenge of improving efficiency has been embraced.
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<td><strong>Principal measures of distribution network performance</strong> are average number of interruptions to customer supply (SAIFI) and average duration of interruptions (SAIDI).</td>
<td>Excluding major event days, there is a small downward trend in underlying SAIDI and a more significant declining trend in SAIFI. Based on the 101 communities’ reliability targets, Aurora Energy met SAIFI targets in all five community categories in the last two years but exceeded its SAIDI targets in all five communities in 2009 and all but one community in 2010.</td>
<td>Achievement of performance targets is variable. Deteriorating performance in CBD and urban community categories but generally improving performance in the rural category.</td>
</tr>
<tr>
<td>The measures of <strong>application of capital</strong> are capital expenditure assessment and implementation processes. Capital expenditure required for system augmentation is required to meet a regulatory investment test.</td>
<td>Asset replacement expenditure has increased since 2008, approximately doubling between 2008 and 2010. Several significant augmentation projects have been undertaken in the recent period and there has been similar growth in customer connections.</td>
<td>Historically, Aurora Energy has consistently overspent its overall regulatory capital allowance. Forecast reduced capital expenditure is considered by Aurora Energy to be aligned with industry levels.</td>
</tr>
<tr>
<td><strong>Asset management</strong> philosophy and maintenance practices.</td>
<td>A mid-term review of asset management philosophy and processes in 2005 considered that Aurora Energy had been slow to recognise the need for asset database and process improvements focused on better network performance. A review of Aurora Energy’s current asset management plan noted a number of improvements.</td>
<td>Considered to have reasonable processes for planning and executing asset management functions and for undertaking new work. Stronger focus on process than action.</td>
</tr>
<tr>
<td>Operating expenditure.</td>
<td>Trend to increase operating expenditure and expenditure growth above the growth in regulatory allowances. Forward projections to reduce operating expenditure in real terms on a year-on-year basis.</td>
<td>Across a range of measures, Aurora Energy’s operating expenditure is in the mid range of industry peers. Step change in efficiency is required to meet forward expenditure projections. This process has commenced within the Company.</td>
</tr>
<tr>
<td>Governance – regulatory and shareholder.</td>
<td>Aurora Energy is required to report to the TER on technical performance and compliance with management plans as part of its operating licence. Corporate plan does not detail efficiency and effectiveness targets and provide an overview of strategies.</td>
<td>More recently Shareholders have demonstrated stronger interest in efficiency and effectiveness through formalised expectations. Improvements in reporting to shareholders on efficiency and effectiveness could improve accountability for change.</td>
</tr>
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</table>
4. Aurora Energy - Retail

4.1. Business parameters

Until 2006, when Tasmania commenced the introduction of retail contestability, Aurora Energy was the sole electricity retailer. While Aurora Energy has retained a prominent position in the market, retail licences have been issued to ERM Power Retail Pty Ltd, Country Energy TRUenergy Pty Ltd, and AGL Sales Pty Ltd. Aurora Energy estimates that it has retained a market share of around 85 per cent of the contestable customer market.

Aurora Energy retains a statutory monopoly for all non-contestable customers. From July 2011 this sector comprises all small business and residential customers with an energy demand in less than 50 MWh per annum.

4.2. Performance

The technical performance of an electricity retail business is traditionally assessed by the extent to which it meets customer service expectations. Aurora Energy reports to the TER on three customer service measures: customer calls answered within 30 seconds, percentage of customer calls abandoned, and disconnections for non-payment. Figures 42 to 45 below show Aurora Energy's recent past performance and indicates relatively consistent performance.

Figure 42 - Number of incoming calls

![Number of incoming calls](source: Aurora Energy)
The decline in performance for 2009 reflects a sharp increase in calls to the call centre in that year arising from a number of major storm events. These calls are highly concentrated in a small period of time and the call centre capacity to answer calls can be rapidly overtaken by demand. The call centre is not staffed to meet these unpredictable short-term peaks. Aurora Energy has recently introduced changes in call systems to automatically divert calls to pre-recorded information services to both reduce the number of calls taken by the call centre in the case of major events, and to assist customers efficiently access information.
The sharp decline in disconnections in 2007 is notable, and reflects changes in credit management processes implemented by Aurora Energy in that year and its work with community groups and welfare agencies to assist customers facing payment difficulties. The trend since 2007 has been year-on-year growth in disconnections, which, in part, reflect electricity costs that have increased well above the rate of inflation and wages growth in Tasmania. In 2007, Aurora Energy provided $88,119 through its hardship payment program, which assisted 930 customers. In 2010, it provided $270,000 through the same program, assisting 226 customers.

The Panel understands that in other jurisdictions, retailers are required to report on indicators relating to the timeliness and accuracy of customer billing, and that this is not the case under the current Tasmanian regulatory requirements. Given the importance of these issues to customers, this is a notable omission from the regulatory framework. However, data on complaints relating to billing is captured under the current arrangements – which will continue in the new National Energy Customer Framework.

Figure 46 shows trends in customer complaints in relation to Aurora Energy’s retail business (i.e. it excludes complaints related to network faults). It demonstrates that the retail business has experienced a significant downward trend in complaints, both in terms of absolute numbers and as a proportion of its retail customer base. Across the period, complaints about billing-related matters (including billing accuracy, prices, debt recovery and disconnections) were consistently around 11 per cent of all retail complaints, but in 2010 this jumped to 28 per cent.
Wilson Cook was able to obtain only limited comparative information on the retailing sector due to it being a competitive activity and was unable to benchmark Aurora Energy's customer service performance against its peers.

The Panel sought advice from the Office of the Tasmanian Ombudsman, which has staff dedicated to energy issues, on trends of complaints about contact with Aurora Energy's Customer Service Centre (CSC).\textsuperscript{196} The Ombudsman has advised that complaints to it made specifically about contact with the CSC increased from 40 in 2010 to 54 in 2011.\textsuperscript{197}

The Ombudsman noted that additional complaints about poor CSC service also tended to be made as an aside to complaints about other more substantive issues, including pricing and credit issues, but were not generally recorded on their system.

\textsuperscript{196} Given the focus of the study, the Panel has not investigated other sources of complaint in relation to the energy sector through the Ombudsman, e.g. complaints about electricity prices.

\textsuperscript{197} To put these figures into context, total complaints for 2009-10 (retail and supply) were around 3500, and Aurora Energy had a total of around 270 000 retail customers in that year.
As a comparison with CSC service complaints the Ombudsman noted that complaints about tariff issues had also risen in the last financial year from 14 to 22 and that complaints about not being able to access pension concessions has risen from nine to 29 (although most of these related to a one off cash payment to eligible concession holders).

The Ombudsman also noted an increase in the number of complaints which were resolved by referring the complainant to a higher level within Aurora Energy. In the Ombudsman’s opinion the CSC was often unable to address customer concerns and had limited scope to escalate the issue within the Aurora Energy organisation.

4.3. Application of capital

The predominant capital requirement for retail businesses is for IT systems. Aurora Energy recently replaced its customer information and billing system, reflecting that its existing system, Frontline, was no longer supported by its vendors and did not provide suitable capability for a competitive retail environment.

The project was originally approved by the Aurora Energy Board to proceed in February 2007 at an estimated cost of $15 million. Aurora Energy opted to purchase an “off the shelf” system from SPL, recognising that some customisation would be necessary. The complexity of the customisation process was not anticipated by Aurora Energy and resulted in unsatisfactory project progress. Following a number of internal reviews, which resulted in restructuring of the project management arrangements and program modifications, the project proceeded. Project expenditure to the end of 2009 was some $33 million.

In January 2010, Aurora Energy was restructured and the retail division became part of the new Energy Business under a Chief Operations Officer. A further two formal reviews of the project were undertaken, one internal and an external review by Deloitte. Following these reviews a new project director was appointed and Deloitte engaged as a project quality assurance provider. At this time a revised budget of $63 million was established. The project was delivered for $60.3 million and went live in February 2011 with no major implementation issues.

Aurora Energy noted in comments to the Panel that major cost and time blow-outs were common in recent Australian utility billing system projects and noted the relative immaturity of its IT processes, the change of vendors, limited experience of the start-up project team, and clash of priorities across the business contributed to the problems encountered with the project.

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198 Following SPL’s appointment by Aurora Energy it was purchased by Oracle who Aurora Energy considered to have a different business culture and operational framework.
Wilson Cook noted that Aurora Energy was yet to complete a post implementation review of the project but suggested “that independent peer review of the project should be included in the business case for future major information system projects”. The Panel supports this conclusion, and notes that Aurora Energy has advised that a review is currently underway under the oversight of the CFO. Given that around 45 per cent of Aurora Energy’s forecast capital spending outside the distribution business is on IT systems, identifying past mistakes and areas for future improvement are particularly important.

The financial implications of this project have also been significant for Aurora Energy. The Company has written off around $32 million of the expenditure between 2009-10 and 2010-11, which has had a corresponding impact on profitability (and shareholder returns through dividends).

**4.4. Operating expenditure**

Aurora Energy’s retail operating costs include costs associated with billing and revenue collection, marketing expenditures, costs of providing a customer interface (predominantly call centre costs, but also some IT costs) regulatory compliance costs and an appropriate allocation of corporate overheads. Collectively, these are referred to as ‘costs to serve’.

An allowance for the cost to serve that can be recovered from non-contestable customers is subject to regulation by the TER. In its most recent retail price determination, Aurora Energy applied for a cost to serve allowance of around $105 per customer per annum for 2011, falling to around $99 per customer per annum in the following two years. The TER agreed to an allowance of around $95 for 2011, falling to around $89 per customer per annum in the following two years.

In setting the allowance the TER considered:

- its own assessment of operating costs attributable to the non-contestable customer base (noting that Aurora Energy’s retail business provides services to contestable customers);
- Aurora Energy’s proposed cost to serve allowance;
- interstate benchmarks; and
- matters raised in submissions on its draft findings.

Consistent with its Statement of Approach, the Panel has not sought to review the appropriateness or otherwise of regulatory decisions, including the cost to serve decision. The Panel is not in a position to judge the extent to which the determination accurately reflects the efficient cost to serve in Aurora Energy’s context. The Panel notes, however, that in reaching it decision, the TER undertook a comprehensive and consultative approach and explained the reasons for its findings.
Figure 47 provides comparative cost to serve provisions in other states.

**Figure 47 - Cost to serve regulatory allowances**

![Bar chart showing cost to serve regulatory allowances for different states.]

Source: Wilson Cook

Aurora Energy provided a breakdown by cost centre for its retail and energy businesses for the period 2007 to 2011 as part of the information provided to Wilson Cook. Aurora Energy noted that its retail cost allocation model has changed over time and that care needed to be taken in reaching any conclusion on the data that it provided. On that basis, the Panel has not included this data in this report.

In other regions of the NEM where full retail contestability has been introduced, in setting fall-back contract arrangements, some regulators explicitly include an additional allowance in retail costs to cover customer acquisition costs, when determining the efficient cost to serve for an incumbent retailer. In the absence of full retail contestability in Tasmania, there is no such allowance factored into the TER's calculation of Aurora Energy's cost to serve.

From time to time, there is debate in the media regarding the consequences of Aurora Energy's marketing expenditures on retail customer bills. The marketing expenditure that the TER has allowed Aurora Energy retail business to recover from its customers includes only those marketing costs that the Regulator considered relevant to non-contestable customers, who are not able to choose their retailer. For example, costs associated with brand recognition or sponsorship were removed from the cost base and costs associated with customers becoming contestable were also excluded.
Depending on the effectiveness of competition in the contestable retail market, Aurora Energy may be able to recoup its marketing costs\(^{199}\) (e.g. Aurora Energy’s sponsorship of Aurora Stadium in Launceston and the costs associated with the media promotion of energy efficiency issues) from contestable customers through the retail margin. From discussions with market participants, it appears that there is effective competition on retail margins between Aurora Energy and ERM for those customers that are targeted by both companies, and, therefore, a limited opportunity for Aurora Energy to recoup higher costs from the contestable customers.

In its current corporate plan Aurora Energy forecasts a cost to serve for non-contestable customers materially higher\(^{200}\) than the regulatory allowance, indicating that it is having difficulty in meeting the cost performance expectations of the TER. Higher than ‘allowed’ retail costs are effectively funded by the Shareholders of Aurora Energy through a reduction in profits and are not experienced as higher prices to non-contestable customers.\(^{201}\)

A central issue in considering the efficiency of Aurora Energy’s retail business is the consideration of scale economies. Energy retail businesses enjoy economies of scale as a large proportion of the costs of retailing do not vary materially with changes in customer numbers (e.g. core IT platforms such billing system, trading functions, some marketing costs)\(^{202}\), so that incremental additions to the customer base deliver relatively large marginal revenues. Conversely, relatively small customer numbers can produce relatively high costs to serve per customer. There are around 270,000 residential and business customers in Tasmania, and in light of retail competition in Tasmania, Aurora Energy has diversified its retail activities to other NEM jurisdictions to assist in defraying its fixed retail costs over a wider customer base. Nonetheless, with a total of 140 retail customers across 1,167 sites outside of Tasmania, Aurora Energy is a small retailer in the national context.

\(^{199}\) The effectiveness of such marketing initiatives for Aurora Energy’s position in the contestable market is a key determinant for management and the Board in considering these expenditures, and is not a matter that the Panel has investigated. It is noted that throughout the Review period, Aurora Energy’s retail business has progressively been exposed to retail competition and has needed to position itself.

\(^{200}\) The quantum of the difference has not been disclosed for confidentiality reasons. The difference between Aurora’s proposed cost to serve and the regulatory determination for 2010-11 was around ten percent. The Corporate Plan projects a difference larger than this.

\(^{201}\) The Panel notes that the energy business is implementing a major cost reduction program that has expectations of delivering greater savings than those incorporated into the Corporate Plan. The successful implementation of that plan and the achievement of the anticipated savings would, on Aurora Energy’s estimation, result in the business achieving the regulated cost to serve allowance.

\(^{202}\) There are recognized ‘tiers’ in energy retailing. Once customer numbers reach certain thresholds, there can be step changes in some of the largest costs associated with retailing, particularly billing systems. Accordingly, there are returns to scale across bands of customer numbers. The generally accepted ‘minimum scale’ for electricity retailers has increased significantly over the past decade. Data from the Energy Retailers Association of Australia shows that in the markets of Victoria, NSW, Queensland and South Australia Origin Energy has around 3.3m customers, TRU Energy has around 2m customers, AGL has around 1.9m customers and all other retailers combined have around 1.5m customers – see: [www.eraa.com.au/db_uploads/IPART - Changes in regulated electricity retail prices from 1 July 2011 - Draft Report.pdf](http://www.eraa.com.au/db_uploads/IPART - Changes in regulated electricity retail prices from 1 July 2011 - Draft Report.pdf)
The Panel notes that planned changes to Aurora Energy’s energy business were announced in August 2011 that propose around 40 positions to be cut, some of which will relate to the retail business. Aurora Energy has established targets for material reductions in operating costs over the Corporate Planning period and for a target return on investment from the energy business, which it argues is on-track to achieve.

4.5. Summary of investigation

- The evidence gathered by the Panel indicates that Aurora Energy’s retail business has been relatively effective in relation to service delivery over the review period. It has implemented strategies to deal with emerging increases in credit issues, although disconnections are showing an upward trend, and the number of complaints received in relation to the retail function has shown a downward trend.

- In relation to efficiency, Aurora Energy’s retail business has been unable to operate within the regulatory operating allowance. To the extent that the regulatory determination by the TER provides an indication of efficient costs for Aurora Energy having regard to its relative scale, this suggests that this part of the business is currently not efficient. Aurora Energy has developed a strategy to reduced costs in line with regulated cost to serve levels.

- The customer information and billing system project was complex, under-scoped and poorly managed, particularly in the period before January 2010. Because of the large differences between the eventual costs of the system and allowance permitted under the regulatory arrangements and as a result of capitalisation tests under the accounting standards, the project has resulted in large negative financial consequences for the business, with around $32 million in project costs being written off.

- In relation to the contestable market, the Corporate Plan highlights that it has been necessary to reduce margins in order to retain market share, indicating that there remains pressure within this part of the retail business on cost performance, given the pricing of competitor offerings.

- The Corporate Plan highlights strategies that aim to more closely align Aurora Energy’s cost to serve with regulatory allowances. Recently announced efficiency measures within the energy business provide an indication that some of the planned changes are being implemented, which will improve the efficiency in both the contestable and non-contestable markets. Aurora Energy also intends to continue to defray its fixed retail operating costs by retailing in other parts of the NEM.

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203 These targets have been communicated to the Panel but not published in this report to preserve commercial confidentiality.
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<td><strong>Principal measure of retail performance</strong> is the extent to which customer expectations are met.</td>
<td>Calls answered within 30 seconds remained relatively consistent at between 75 and 80 per cent.</td>
<td>The retail business is operating relatively effectively in relation to service delivery.</td>
</tr>
<tr>
<td>Aurora reports to the TER on three measures: 1. Customer calls answered within 30 seconds. 2. The percentage of customer calls abandoned. 3. Disconnections for non-payment.</td>
<td>Calls abandoned, excepting 2009, trended downward, as did the number of disconnections. Complaints to the Ombudsman around tariff issues was trending upwards in the last financial year, but represent a very small proportion of complaints and an extremely small proportion of customer numbers. The Ombudsman questions the effectiveness of the Call Centre to effectively address complaints.</td>
<td>Performance measures relating to timeliness and accuracy of billing would be useful.</td>
</tr>
<tr>
<td><strong>The measures of application of capital are capital expenditure assessment and implementation processes.</strong></td>
<td>The predominant capital application in the retail business is IT systems. Aurora Energy recently replaced its customer information and billing system at a final cost four times higher than the original estimate.</td>
<td>Given the focus on IT developments over the Corporate Planning period, lessons learned from the customer information and billing system will be very important.</td>
</tr>
<tr>
<td>Operating expenditure.</td>
<td>Aurora Energy’s cost to serve allowance is significantly higher than the TER allowance for non-contestable customers. Aurora Energy’s cost to serve regulatory allow ance is higher than that allowed in other jurisdictions.</td>
<td>Aurora Energy continues to have difficulty in meeting its cost to serve allowance and Aurora Energy has put in place strategies aimed to address these efficiency requirements.</td>
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5. Costs intrinsic to Tasmania

One of the six elements the Panel identified as being relevant to the investigation into the efficiency and effectiveness of the SOEBs was the assessment of the cost of a range of resources, including labour and materials, and operational or maintenance activities that are intrinsic to Tasmania. The objective was to establish whether it is inherently more or less costly to operate a utility in Tasmania than in other Australian states.

In considering this issue, Wilson Cook noted that significant cost increases over the last decade had been widespread across the industry. It observed from reviews in New South Wales, New Zealand and Western Australia that the cost of manufacture and installation of electrical transmission and distribution equipment rose more rapidly over the period 2003 to 2007 than did consumer price indices and considered that there is no reason to assume that the Tasmanian industry was not affected similarly. Wilson Cook also noted that there had been significant increases in the cost of electrical materials and equipment over the period, driven in the main by high metal prices, and that that the high rate of price increases was stemmed by the global financial downturn in 2007 and has not so far resumed.204

Wilson Cook also noted from earlier reviews of Aurora Energy’s expenditure that costs tended to be higher in Tasmania than in the more populous eastern states, suggesting that the cost of operating electricity transmission and distribution businesses in Tasmania is inherently greater than it is in other states. They were not able at the time to quantify the difference.

As part of the investigation, each of the businesses was requested to identify areas of cost that they considered intrinsic to Tasmania.

Hydro Tasmania identified the size and geographical spread of its assets, the need to maintain roads, bridges, jetties and boat ramps in remote areas for public use, the maintenance of remote employee accommodation, and the requirement to operate a large vehicle fleet.

Technical factors identified by Transend that it considered led to higher costs relative to its mainland peers included:

- Network topology – long transmission lines across difficult terrain with limited meshing of the network;
- Generation and load characteristics – geographically dispersed hydro and wind generation and large load in different parts of the island;
- A relatively high number of directly connected customers;

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204 The impact of the resources sector growth on the back of strong economic development in place like China and India is well recognised – for example, BIS Shrapnel presentations by Adrian Hart, see www.bis.com.au.
- A wide range of supply voltages from 6.6 kV to 220 kV - it is unusual for a transmission business to have so many sub-transmission assets;
- A system that is operating near its maximum capacity, requiring significant operating management; and
- The complexity created by Basslink, which has a high level of capacity relative to the size of the network.

Other factors identified by Wilson Cook included the extent to which Aurora Energy’s distribution activities in particular, could be competitively priced and routinely subject to competitive price tension through the market and the more limited extent to which competitive market forces could be brought to bear in Tasmania. Wilson Cook noted that such competitive forces would be further affected by the isolation of parts of the network and the high set-up costs that would be faced by a potential outside contractor. Transend concurred with this view and cited geographical isolation, the small population, limited access to skilled labour, limited access to contractors and a greater remoteness from manufacturers as reasons for intrinsically higher costs in the State.
Part D
A review of the financial position of the State Owned Electricity Businesses
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PART 1

A review of the financial position of the State Owned Electricity Businesses
Purpose and approach

The Panel’s review of the financial position of the SOEBs is focused on business activities directly related to the supply of electricity to Tasmanian customers – hydro-generation, transmission, distribution and retail in Tasmania. For the purposes of this Paper these activities are termed functional business activities.

Consistent with its Terms of Reference, the Panel’s review is limited to the financial sustainability of the SOEBs and does not look at wider value considerations of business activities, such as contribution to broader economic or community benefits (beyond direct returns through dividends).

The Panel selected the period 2004 to 2010 for its review as this period spans the key events in the development of the Tasmanian Electricity Supply Industry (TESI), - physical interconnection via Basslink, adoption of National Electricity Market (NEM) arrangements and the phased rollout of retail contestability to Tasmanian electricity customers. The SOEB entities have commented to the Panel that a historical review of financial performance is not an indicator of future financial performance, citing improved financial outcomes in 2011 resulting from productivity and efficiency measures and new strategic business directions. However at the time of writing, complete actual 2011 data was not available and therefore has not been included.

For Hydro Tasmania and Aurora Energy, competition and customer choice for energy gave rise to changes in business risk. Tasmania’s participation in the NEM also provided the stimulus for the pursuit of business opportunities and activities outside Tasmania. As a result, there has been a clear diversification of business activities by Hydro Tasmania and Aurora Energy. The Panel has observed that the primary motivation behind this trend appears to be the mitigation of risk in functional business activities. However, some diversification activities have been pursued as value creating strategies in their own right and are more remotely related to existing functional business activities.

Tasmania’s entry into the NEM has also seen changes to the regulatory framework applying to the transmission and distribution network businesses as it has transitioned from Tasmanian based regulation to the national regulatory framework under the Australian Economic Regulator (AER). Evolution of the regulatory framework has also seen changes in the methodologies applied across regulatory determinations.

In addition to market changes, the review period included a period of extreme hydrological significance, described by Hydro Tasmania as a “1:1 000 year event” of low inflows. Water storage levels fell to historic lows of 19 per cent across 2007 and 2008, significantly below Hydro Tasmania’s preferred operating zone of a storage system level between 30 and 50 per cent.

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As opposed to estimated or forecast data for the 2011 financial year.
During this time Hydro Tasmania was required by its Shareholders to ensure supply. This expectation, coupled with its contract position, required Hydro Tasmania to operate the gas fired Bell Bay Power Station (BBPS) and purchase electricity from the NEM, via Basslink. Both of these options incurred higher costs than Hydro Tasmania’s existing contract arrangements.

The Panel has approached its investigation from both a ‘whole-of-portfolio’ basis (Part 1 of this Paper) and on an individual entity basis (Part 2 of this Paper).

Part 1 of this Paper:

- Provides an overview of the structure of the TESI and describes how the proceeds from electricity sales flow through the SOEB portfolio;
- Identifies the primary sources of underlying profitability – or direct financial value – within the SOEB portfolio, where value is realised and what influences value outcomes (financial performance measured by EBIDTA206);
- Identifies the major inter-SOEB financial flows and the major intra-SOEB financial flows; and describes how these have been influenced by energy sector reform and diversification of business operations;
- Describes how value translates into ‘free cash’ (measured by cash available from operations) and how this cash is utilised by SOEB entities; and
- Identifies key risks and opportunities to future financial performance.

Part 2 of this Paper:

- Looks at key influences on financial performance for each of the SOEBs in greater detail. In this regard it provides further information underpinning the analysis in Part 1 of the Paper.

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206 Earnings Before Interest, Depreciation, Tax and Amortisation (EBIDTA).
Qualification

The complexity of the Tasmanian electricity market, and the SOEBs themselves, has increased since 2004. As a consequence, methods of recording and reporting financial information within each business have changed over time. Further, new activities and transactions have commenced and some activities and transactions have ceased. This creates difficulties in analysing changes in financial performance on a consistent basis over time.

The financial information presented in this paper has been obtained from a variety of sources including the audited accounts and other financial information held by the SOEBs, such as management accounts. In developing this Paper, the Panel has requested some information from the SOEBs in forms that are different from the way in which they typically record and review their own information. In some cases, estimates have been required to be established (prepared with the assistance of Ernst & Young). The information in this a paper has been reviewed by the SOEBs where appropriate for factual accuracy. The analysis and conclusions drawn by this Paper are those of the Panel and do not represent the views of the SOEBs.

As such, readers of this Paper should interpret the financial information as illustrative of broad trends, rather than precise and detailed financial results that will always reconcile with published annual report information or information from other sources.

For the purposes of this Paper, Aurora Energy’s principal activities of retail, distribution and energy are discussed as separate business components to enable the reader to gain an understanding of their respective financial performance. This is different to the way in which Aurora Energy structures its business operations, whereby it incorporates retail and energy (including gas) in its Energy Division, while retaining distribution and network services separately in its Distribution Division.

Unless otherwise indicated, all dollar figures in this Paper are expressed on a nominal basis and dates represent the financial year.
**Executive summary**

In the simplest terms, the financial performance of the SOEBs is a measure of how much is earned through revenue for services provided offset by how much is spent on the cost of providing those services (operating expenses and capital). The financial position of the SOEBs reflects how what is being earned is utilised by the businesses, including the payment of dividends to Shareholders.

In terms of financial position, from a Shareholder perspective, there is a tension between sustainable capital structures, approving major capital investment (particularly where it relates to business diversification or expansion for growth) and the provision of dividend returns to the community.

From the historical review we can observe how this tension has been resolved through the choices that have been made by the Shareholders and the financial consequences of those choices. This can provide guidance on future choices around the same inherent tensions.

**How the proceeds from electricity sources flow through the SOEB portfolio**

Changes in the total revenue earned by the SOEBs over the review period are partly a function of increases in electricity prices paid by Tasmanian customers as well as load growth. It is important to understand that Aurora Energy’s revenue from Tasmanian customers includes pass through costs of supply, such as Renewable Energy Certificates (RECs) and charges applying to distribution and transmission network services, which is revenue earned by its distribution business and Transend. A large portion of Aurora Energy’s cost of supply is the cost of energy, which historically has been reflected as revenue by Hydro Tasmania and now also includes Aurora Energy’s tolling fee for the Tamar Valley Power Station (TVPS). In this sense, prices paid by Tasmanian electricity customers ‘filter through’ the vertical chain of supply as revenue.

Unlike the situation pre-NEM entry, revenue earned from Tasmanian electricity customers is no longer the only source of revenue within the SOEB portfolio. For example, both Hydro Tasmania and Aurora Energy trade wholesale energy in the NEM and have retail customers outside Tasmania. Aurora Energy is also a gas wholesaler and retailer in Tasmania and a gas wholesaler Victoria, and has a tolling arrangement with the Bairnsdale power station for electricity the station produces.

**2010 An illustration of revenue flows and cash utilisation**

Figure 1 illustrates the two primary financial flows within the SOEB portfolio:

1. How revenue paid by Tasmanian customers to Aurora Energy flows through the SOEB portfolio and is attributed to the components of electricity supply - generation, transmission, distribution and retail; and
2. How total revenue received by SOEB entities, including all revenues arising from the Tasmanian customers (not just those that originate through Aurora Energy’s retail business) and revenues derived from other business activities in Tasmania and elsewhere, is attributed within the business or returned to Shareholders as a dividend.

The internal complexity of Hydro Tasmania and Aurora Energy, and the general complexity of the electricity market, presents challenges in undertaking this type of analysis. Therefore, the Panel reiterates that dollar figures shown in Figure 1 are approximates only and, as all transactions are not represented, will not necessarily be ‘additive’. The intent is to illustrate the broad quantum of financial flows within the SEOB portfolio and between total revenues earned by the SOEB portfolio and uses of cash, including dividend returns to the Tasmanian community.
Figure 1

2010 Revenue to Returns

SOEB Tasmanian Customer Revenue

Aurora Energy - retail business
- Tasmanian customer revenue total: $865M
  - Non-contestable: $542M
  - Contestable: $323M

Aurora Energy - distribution business
- DUOS/TUOS Total: $223M
  - DUOS $231M
  - TUOS $89M

Aurora Energy - energy business
- Energy costs total: $518M
  - TVPS Tolling Fee: $82M
  - Hydro Tasmania: $416

Transend Networks
- Non-direct connect customers: $93M

Hydro Tasmania (Energy)
- Total energy revenue: $416M

Other Revenue

- Retail gas: $46M
- Mainland electricity: $165M

Total Revenue

- DUOS non-Aurora customers: $10M
- Wholesale gas sales: $32M
- TUOS Direct connect customers: $67M
- Other Income: $26M
- Settlements: $7M
- Mainland energy: $36M
- Other NEM products: $2M
- Momentum: $114M
- Entura: $49M
- Roaring 40s JV: $-6M

EBITDA

- Energy Business: $-10.5M
- Distribution: $165M

Net Cash

- $49M

Uses of Cash in 2010

- Aurora Energy
  - Capex: $294M
  - Interest: $55M
  - Dividend Paid: $10M

- Transend Networks
  - Capex: $168M
  - Investment: $66M
  - Interest: $23M
  - Dividend Paid: $4M

- Hydro Tasmania
  - Capex: $36M
  - Investment: $30M
  - Interest: $63M
  - Dividend Paid: $5M

Aurora Energy Tasmanian Customer Revenue: $865M

Total EBITDA: $522M

Total Dividends: $19M

*This is not an exhaustive account of cash usage. For example, it does not show change in working capital, borrowings, and changes in cash balances between years.

**Dividends relate to payments made in FY10, based on financial performance for FY09.

#Combined retail and energy business.
**Revenue flows from Aurora Energy’s Tasmanian customers**

The first column of Figure 1 should be read downward, as it illustrates how revenue from Aurora Energy’s Tasmanian customers flows through the SOEB portfolio.

In 2010, Aurora Energy’s Tasmanian customer revenue was approximately $865 million. Of this $542 million was derived from non-contestable customers and $323 million from contestable customers.

Some $323 million of customer revenue flowed through to Aurora Energy’s distribution business for transmission and distribution costs. Transmission use of system (TUOS) charges of $93 million were a direct pass-through to Transend and distribution use of system charges (DUOS) of $231 million were retained by Aurora Energy’s distribution business.

Aurora Energy’s energy business costs totalled $518 million, of which $82 million was paid to its subsidiary, Aurora Energy Tamar Valley (AETV) under the tolling arrangements for the TVPS. The balance, approximately $416 million, flowed through to Hydro Tasmania for energy purchases.

Figure 2 below illustrates the share of Tasmanian customer revenue attributable to each component of the supply chain, noting that retail will include some pass-through costs, such as RECs, that will flow to third parties.

**Figure 2 - Allocation of Aurora Energy’s Tasmanian customer revenue 2010**

Source: Panel analysis
Note: This does not reflect the break-up of costs incorporated into non-contestable customer tariffs as show in Panel publications, as it relates to contestable and non-contestable customer revenue.
**SOEB revenue generation to cash utilisation**

Returning to Figure 1, reading across the page illustrates how total revenue derived from all sources by each SOEB entity translates to earnings after operating expenses (represented by EBITDA), which is then utilised by the business for capital investment, financing costs and dividends paid.

On a cash basis, direct operating costs (payments to suppliers and employees) as a proportion of cash received from customers varied across the SOEB entities, with Aurora Energy 92 per cent, Hydro Tasmania 70 per cent and Transend 33 per cent. These outcomes reflect each entity’s ability to fund capital investment (or business diversification), repayment of borrowings and dividends from cash from operations – or is reflective of need to borrow for these activities. In summary; in 2010:

- Aurora Energy’s net cash after operating activities, including payment of finance charges and Income Tax Equivalents (ITEs), was $49 million. Capital investment of $234 million and dividends paid of $10 million were funded from increased debt and retained cash from 2009;
- Hydro Tasmania’s net cash after operating activities was $178 million. From this, Hydro Tasmania funded a $95 million capital investment program and completed the acquisition of Momentum Energy Pty Ltd (Momentum) for $35 million. Hydro Tasmania also prepaid $69 million of debt, improving its capital structure; and
- Transend’s net cash after operating activities was $101 million. This was utilised to fund capital investment of $147 million, increasing debt by $30 million.

**Key sources of financial value within the SOEB portfolio**

Across the SOEB portfolio, key sources of financial value relate to hydro-generation, transmission and distribution business activities. By comparison, gas-fired generation, electricity retailing and diversification activities have contributed only marginally to financial returns.

Energy generation and energy trading is Hydro Tasmania’s main value driver. It generates hydro-electricity in Tasmania which it uses to back contract positions with wholesale customers, and retailers in Tasmania and to retail customers, through its subsidiary Momentum in other NEM regions. It also generates value via Basslink arbitrage opportunities and through trading in spot market and contract markets.

**A particular source of value from to Hydro Tasmania is the value from its contracting arrangements with Aurora Energy for supply to non-contestable customer sector.**

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207 Hydro Tasmania sells electricity to its retail business - Momentum Energy Pty Ltd - which operates on the mainland.

A review of the financial position of the State Owned Electricity Businesses
In both the 2007 and 2010 price determinations, the regulated wholesale energy allowance has been higher than the market cost estimate. The contract arrangements struck between Hydro Tasmania and Aurora Energy for the period of the 2007 price determination saw the full value of the wholesale energy allowance captured by Hydro Tasmania.

The latest arrangements for energy to supply non-contestable customers results in a shift in value available under the Electricity Supply Industry (Price Control) Regulations 2003 (Price Control Regulations) away from Hydro Tasmania (which with its higher than market value would have been reflected as profit) and to Aurora Energy where it was used to fund the large fixed costs (gas commodity and transport and debt) associated with operating the TVPS. As these fixed costs are paid to third parties, part of the value available under the Price Control Regulations has been transferred to the private sector and is therefore not available to be returned to the Tasmanian community as a dividend.

During the drought period, Hydro Tasmania’s financial performance was assisted by the price methodology set in the 2007 Price Determination (effective 1 January 2008 to 30 June 2010), which required non-contestable customers to pay a ‘drought premium’ of slightly less than $3/MWh - amounting to $28 million in total.

For contestable customers in the position of renegotiating contracts with Hydro Tasmania during the drought period, market prices reflected the prevailing conditions, meaning that the cost of alternate generation would have been passed through to these customers.

The value of hydro-generation has also been positively influenced by the Basslink arbitrage opportunity. This is derived from Hydro Tasmania holding back production of electricity at times of low prices in Victoria, allowing electricity to flow southward as a substitute for on-island generation, and then later producing that same volume and selling it into Victoria at higher value.

For the regulated network businesses, the largest single driver of value is the return on capital invested in network assets. Return on capital is determined under the revenue cap regulation process by applying the Weighted Average Cost of Capital (WACC) to the Regulatory Asset Base (RAB).

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208 The RAB represents the capital investment used to undertake the prescribed network services and is derived from the initial value of the assets plus additional capital expenditure (if approved by the Regulator) after allowing for depreciation.
Over the review period, there has been considerable capital investment by network businesses to replace and refurbish aged assets and to meet customer-driven demand. The opening RAB for Aurora Energy’s distribution network increased by $541 million or 70 per cent from $726 million in 2004 to $1.267 billion in 2010, with WACC increasing from 6.61 per cent to 6.64 per cent between the 2003 and 2007 Price Determinations. By comparison, the WACC included in Aurora Energy’s proposal for the 2011 price determination is 10.33 per cent which will be applied to the opening RAB for each year of the determination.\footnote{In its Draft Determination, the AER has not accepted Aurora Energy’s proposed WACC – rather the AER had determined an indicative WACC of 8.08 per cent.} The opening RAB for the 2011 Price Determination is estimated by Aurora Energy to be $1.485 billion, $759 million higher than the opening RAB for the previous determination of $726 million.

Similarly, the opening RAB for Transend’s transmission network increased by $524 million or 92 per cent from $570 million in 2004 to $1.094 billion in 2010, with WACC increasing from 8.80 per cent to 10.0 per cent between the 2003 and 2009 price determinations.

This historical expenditure will have ongoing consequences for Tasmanian transmission and distribution prices in the future as the WACC is applied to the RAB (after allowing for depreciation) in future regulatory periods.

Offsetting increases in revenue, operating expenses have also increased over the review period. The Panel observes that there has been a progressive focus by SOEB entities on efficiency gains, in response to a more clearly articulated direction by Shareholders in recent years. While this may improve future financial performance, historical overspending of regulatory allowances by Transend and Aurora Energy’s retail and distribution businesses has contributed to operating expenses over and above those determined through the regulatory process. These have had a direct impact on profit. Recently the SOEBs have adopted a range of measures to improve the efficiency of their operations.

**Summary of efficiency measures/programs:**

- Hydro Tasmania has had an internal efficiency focus for some time, illustrated by its management of cash through the drought period 2007 to 2009 where it incurred additional costs to source supply from gas fired generation and from the NEM. Hydro Tasmania’s current efficiency strategy is to reduce capital and operating expenditure to generate cash to repay debt to reduce financing costs and achieve a credit rating of BBB+ by 2014; and to finance other investment initiatives. Reflecting the efficiency measures, over the last three years Hydro Tasmania has repaid $69 million in debt and funded the Momentum acquisition of $52 million from internally generated funds.
Transend has recently implemented an Employee Regulatory Incentive Scheme to incentivise its staff to deliver operating and capital efficiencies, while maintaining service levels. This scheme is funded through the AER’s Capital Expenditure Incentive Scheme which rewards Transend for minimising or deferring capital expenditure. For the first year of the current regulatory period, 2010, Transend’s actual capital expenditure was $28 million below forecast and actual operating expenditure was $3 million below forecast. In part this reflects an increase in the regulatory allowance allowed by the AER compared to Transend’s previous determination. By comparison, during the previous regulatory period, Transend overspent its capital expenditure allowance by $37 million or 11 per cent and overspent its operating expenditure allowance by $28 million or 15 per cent.

Aurora Energy is in the progress of implementing efficiency measures to reduce upward pressure on distribution service prices and to position itself competitively in the retail market. Evidence of the effectiveness of these measures will be in future years rather than in data analysed for the review.

Aurora Energy considers that the reductions in its current regulatory proposal for prescribed distribution services are achievable due to the significant investment in the distribution network that has been made in the past. For the first two years of the current regulatory period (2009 and 2010), Aurora Energy overspent its capital expenditure allowance by $29 million or 9 per cent and underspent its operating allowance by $2 million. This compares to the previous regulatory period where Aurora Energy overspent its capital expenditure allowance by $170 million or 80 per cent (noting that $95 million related to customer connections) and overspent its operating expenditure allowance by $16 million or nine per cent.

There is evidence of historical overspending by Aurora Energy in other parts of its business operations. The development of a new customer billing system, originally budgeted to cost $15 million was completed for $60 million. Of this, $32 million will be directly expensed impacting financial performance (of which $21 million was expensed in 2010 and $11 million was expensed in 2011).

The Tasmanian Economic Regulator (TER) has allowed Aurora Energy an industry benchmarked cost to serve of $95 per customer per annum, compared to Aurora Energy’s submission of $105 per customer per annum. Aurora Energy’s retail cost to serve per customer is impacted by economies of scale and its move into mainland retail sales was driven in part by an effort to spread fixed costs across a larger customer base. This cost is a focus of Aurora Energy’s current efficiency and productivity measures and will need to be reduced if Aurora Energy is to position itself competitively in an open retail market in Tasmania.

The renewed focus on efficiency is expected to improve financial performance. However, this will require ongoing focus by management and Shareholders if it is to be achieved and maintained.
The Tasmanian Government, on behalf of the Tasmanian community, has a direct interest in the financial sustainability of the SOEB portfolio in three key regards:

- The SOEB entities sustain a financial position to continue the delivery of electricity to Tasmanian customers, including sustainably re-investing in those activities;

- The SOEB entities maintain appropriate capital structures and debt levels. In 2010 the SOEB combined debt comprised 88 per cent of the Tasmanian Government's total non-financial business debt portfolio. This debt forms part of the total public sector balance sheet which is considered for credit rating purposes and therefore influences the cost of debt to the Tasmanian Government as well as investor confidence in the State; and

- The Tasmanian community benefits from its investment in the SOEBs by way of dividends that should reflect a commercial return on its equity investment. These dividends contribute to funding a broad range of policy objectives and this return is core to the public ownership of SOEB entities.

The Panel’s approach to its review of the financial position of the SOEBs was to analyse how net cash from operations (free cash) has been used for capital expenditure and diversification investment, repay debt and return a dividend to Shareholders.

Figure 3 illustrates net cash from operations for each of the SOEBs over the review period.

**Figure 3 - SOEB Net cash from operations 2004 to 2010**

Source: SOEB annual reports
The extent to which efficiency has been a focus of management and Shareholders will determine whether cash from operations is consistent with that which should be expected given regulatory outcomes or prevailing market conditions.

Each of the SOEB entities has generated sufficient cash to fund operating activities and to have available an amount of ‘free cash’ to utilise for capital investment in functional assets or diversification and growth activities, repay debt or return to Shareholders as equity. Following capital investment for the refurbishment and replacement of assets related to functional business activities, the actual allocation of free cash over the review period indicates a preference by Shareholders for investment in diversified business activities, particularly by Hydro Tasmania, rather than the return of capital to the community by way of dividends (for example through the payment of special dividends).

**Sustainable delivery of core business functions**

The SOEBs generate sufficient cash to continue the delivery of electricity to Tasmanian customers and to sustainably re-invest in those activities.

There has been an increase in the scope and magnitude of financial liabilities which must be met from cash from operations. In 2010, the financial liabilities of the SOEB portfolio included gross debt of $2.5 billion, including an unfunded defined benefits superannuation liability of $450 million. Additionally, the major infrastructure investment decisions of Basslink and the TVPS, together with the commercial decision by Aurora Energy to become a wholesale gas operator, have created fixed financial obligations in the order of $90 million per annum on Hydro Tasmania and Aurora Energy respectively. However, the source of revenue available to service these commitments, and therefore the risk of not being able to do so, is different.

Basslink enables Hydro Tasmania to trade electricity between Tasmania and other NEM jurisdictions to capture the highest value for its water resources. Hydro Tasmania’s ability to generate this value is a function of water availability and the temporal changes in electricity prices that provide arbitrage opportunities.

The Panel’s detailed review of Basslink highlighted that when water is available, Basslink has provided revenues to Hydro Tasmania in excess of the additional costs that it brings to the business. In low inflow periods, Basslink has not provided revenues in excess of its costs, but it has enabled electricity supplies at a lower cost than alternate on-island generation.
A review of the financial position of the State Owned Electricity Businesses

Aurora Energy utilises output from the TVPS, by tolling arrangements with its subsidiary AETV, to back approximately one half of its non-contestable customer load. Aurora Energy’s ability to fund the tolling arrangement is based on the current regulatory arrangements for the energy allowance for non-contestable customers and its commercial arrangements with Hydro Tasmania for the balance of energy required for the non-contestable load. These arrangements expire on 30 June 2013. Should different arrangements be applied after that date, this could impact on Aurora Energy’s ability to service these commitments.

**Capital expenditure and investment**

Between 2004 and 2010, capital expenditure and equity investment across the SOEB entities totalled $2.6 billion, including $491 million invested in diversification activities. $100 million was invested in business activities outside Tasmania.

Sources of funds for capital expenditure and diversification investment include free cash, debt or equity contributions from Shareholders.

Table 1 shows SOEB capital expenditure on functional business assets and investment in diversification activities between 2004 and 2010.

<table>
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<th>2005</th>
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<td>244</td>
<td>276</td>
<td>698</td>
<td>503</td>
<td>2 632</td>
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</table>

Source: Panel analysis
Hydro Tasmania’s primary area of capital expenditure has been on hydro-generation assets, with $407 million spend between 2004 and 2007. In addition to equity contributions to the Roaring 40s joint venture (of which $48 million was provided by the Government) between 2004 and 2006, Hydro Tasmania spent $103 million on renewable developments including wind farm assets, primarily sourced from debt. Hydro Tasmania’s $52 million acquisition of its retail business, Momentum, was made from free cash.

Aurora Energy’s primary area of capital expenditure has been its distribution network, with a total of around $753 million in investment. The second largest spend was $116 million in corporate and shared services – which represented whole-of-entity investment in activities such as IT and the development of its new billing system. Aurora Energy’s capital investment is funded through cash from operations and debt. In 2008, Aurora Energy received an equity contribution of $100 million from its Shareholders to acquire the TVPS.

Transend’s principal area of capital expenditure has been on the transmission network, with $252 million on expended on system augmentation and $274 million on asset renewal. Transend utilises free cash from operations to fund network investment with the balance sourced through increased debt.

**Maintenance of appropriate capital structures and debt levels**

The total SOEB debt position increased by $938 million or 63 per cent from $1.482 billion in 2004 to $2.420 billion in 2010. In general terms, the borrowing capacity of the SOEB portfolio is constrained. Debt levels also impact on credit ratings and consequently the cost of debt through interest charges.

Hydro Tasmania increased its debt in 2005 by $131 million principally for the construction of Woolnorth Studland Bay and Cathedral Rock wind farms. A further increase of $115 million in 2007 provided working capital during the drought period. Repayment of debt is an emerging trend in Hydro Tasmania’s free cash allocation, with debt reduced by $106 million from 2008 to 2010. Hydro Tasmania is targeting a BBB+ credit rating that will require debt to be held at current levels.

Historically, Aurora Energy and Transend’s debt related to capital investment in their respective network businesses. More recently, directions from Shareholders have increased the debt position of both companies.
In 2009, Aurora Energy was required to borrow $260 million to complete the construction of the TVPS. Borrowing to fund the TVPS required the Treasurer to provide a letter of comfort to the TASCORP on that portion of Aurora Energy’s debt. The TVPS has a highly geared capital structure, impacting on Aurora Energy’s overall credit rating and consequently its cost of debt, including to its distribution business. Any changes in the regulatory framework for non-contestable customers from 30 June 2013 may impact on the ability of Aurora Energy to service this debt. Aurora Energy is currently BBB rated but is targeting BBB+ within a five to ten year time period. A BBB+ rating is consistent with the assumed rating used by the regulator as part of the network pricing determination process. This means that Aurora Energy’s cost of debt relating to its distribution business is higher than the financing costs it receives under its regulatory allowance.

Transend’s debt has increased as a result of the Tasmanian Government’s decision to rebalance equity across the SOEB portfolio via a ‘debt swap’ between Hydro Tasmania and Transend ($220 million) and to withdraw equity ($50 million) in 2008 which was also provided to Hydro Tasmania. Transend is currently ‘A’ rated and has some balance sheet capacity, although this will be reduced if Transend needs to fund from debt the Tasmanian Government’s equity commitment to TasRail of $100 million over the next five years.

**Benefit the Tasmanian community by providing commercial returns on their invested capital**

The Tasmanian community benefits from its investment in the SOEBs through dividends which should reflect a return on its equity investment. These dividends contribute to funding a broad range of government policy objectives and are core to the rationale of ongoing public ownership of the SOEBs.

The payment of dividends to shareholders, and therefore the return to the Tasmanian community from business activities, totalled $309 million over the period 2004 to 2010. This represents, in aggregate, 18 per cent of cash from operations. Of total dividends paid, $52 million, or 17 per cent comprised the Shareholder’s special dividend requirement from Hydro Tasmania. During the first three years of the analysis period, Hydro Tasmania was required to supplement ordinary dividends with special dividends to pay a total dividend of $40 million per annum.

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210 ‘Equity investment in a government business carries an opportunity cost, being the benefit the Government forgoes from an alternative use of the equity. Accordingly, the Government expects its businesses to achieve returns that are comparable to alternative investments of similar risk, and for dividends to be at an appropriate level to reflect these returns’ (Department of Treasury and Finance (2010) - Guidelines for Tasmanian Government Businesses – Dividends – November 2010).
Other than Hydro Tasmania’s special dividend arrangement, the Panel has seen no evidence that successive Tasmanian governments have utilised the SOEBs as quasi tax-raising entities through the extraction of dividends. On the contrary, dividend returns have been continuously low and below the cost of capital for investment of the kind undertaken by the SOEBs. However, in the 2011-12 Budget, the Government announced a preference for improved returns across the SOEB portfolio by increasing the rate of underlying profit to be returned as a dividend from 2011.

**Business diversification activities**

There has been a clear diversification of business activities by Hydro Tasmania and Aurora Energy, away from their respective functional business activities of hydro-generation and distribution and retailing in the Tasmanian market.

The primary motivation for business diversification appears to be mitigating risk in functional business activities — arising in part from the nature of the native Tasmanian market and in part from implications of energy reform. Some diversification activities have been pursued by the entities as value-creating strategies in their own right and in some cases the strategic basis for an activity has shifted from a risk mitigating measure to a value creating opportunity over time.

Hydro Tasmania’s initial basis for building wind farms in Tasmania was to secure additional on-island capacity following the end of dam construction. Subsequently, Hydro Tasmania developed wind assets in the national and international markets, as a value strategy not related to energy supply in Tasmania. Hydro Tasmania’s current wind strategy is to secure RECs to support its retail business growth.

Hydro Tasmania’s capital investment in wind assets through the Roaring 40s joint venture is $98 million, which to date has returned a cumulative loss of $11.2 million. In 2010 Hydro Tasmania’s equity share in the Roaring 40s joint venture was $121 million, noting that the joint venture has since been dissolved and Hydro Tasmania has sold a 75 per cent equity stake in the Woolnorth wind farm assets for $88.6 million. The proceeds from the sale will be invested in the Musselroe wind farm development.

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211 Unlike private shareholders in traded companies, Government shareholders cannot sell shares to access their capital (unless the business is privatised). For Government owned businesses, dividends are the only way in which shareholders can get a return. As such, a Government which is getting little or no dividends is accepting all of the risk and no gain.

212 For example, Hydro Tasmania’s current retail strategy is to provide a path to market for excess generating capacity in Tasmania.
Similarly, following the end of dam construction, Hydro Tasmania’s consulting business, Entura, was retained to provide operation and maintenance services to the existing hydro-generation assets and provide services to the other SOEBs. There has been an ongoing strategy to diversify Entura’s revenue base away from Hydro Tasmania. Entura’s share of revenue sourced from Hydro Tasmania has declined from 68 per cent in 2004 to 39 per cent in 2010, offset by services to external clients, increasingly in the national and international markets. Since 2002, Entura has made an EBITDA contribution of between $1 and $4 million per annum, with a loss of $4 million in 2010 associated with the Global Financial Crisis.

Hydro Tasmania’s purchase of its retail business, Momentum, is to capture the wholesale and retail value of excess generation capacity in Tasmania following the commissioning of the TVPS and to mitigate against the loss of a large customer. The analysis period reflects the acquisition phase of Momentum. As such, the longer-term outcome of this strategy will be reflected in future year’s performance. Hydro Tasmania’s capital investment in Momentum is $52 million, which to date, has returned a cumulative loss of $15.1 million during its start-up phase. Hydro Tasmania believes that Momentum will deliver strong profit growth in the coming years.

In a similar manner, in response to the introduction of customer contestability, Aurora Energy expanded its retail base into other NEM jurisdictions to spread its largely fixed cost-to-serve expense across a larger customer base. Between 2005 and 2010 Aurora Energy’s cumulative return from mainland electricity retail trading was $3.3 million.

At the direction of its Shareholders, on the basis of energy security, Aurora Energy acquired and completed construction of the gas fired TVPS. This required Aurora Energy to borrow $260 million, which has influenced the overall cost of debt across the business. The Panel has estimated the negative impact on Aurora Energy’s net profit after tax from the operation of the TVPS in 2010 to be $29 million when compared with an assumed situation where it could have sourced its energy requirements from Hydro Tasmania at a price equivalent to the regulated wholesale energy allowance. As noted above, the viability of the TVPS for the period 2011 to 2013 is underpinned by the value of the wholesale energy allowance and Aurora Energy’s contractual arrangements with Hydro Tasmania for the balance of the non-contestable customer load.

Shortly after its sale of the TVPS, Babcock and Brown Power also put up for sale the assets of its business AEATM, which included the gas supply arrangements (commodity and transport) for the TVPS. Aurora Energy made a commercial decision to acquire the AEATM assets for $15 million in order to mitigate gas price risks and to obtain synergies with its NEM retailing operations.
The gas assets acquired through the AEATM purchase included gas commodity and transport arrangements, in addition to those related to the TVPS and tolling arrangements with the Bairnsdale power station in Victoria. The gas arrangements provide Aurora Energy with a growth opportunity in wholesaling gas to major customers in Tasmania and on the mainland and in retailing gas to customers in Tasmania. Aurora Energy returned a $1.8 million loss on wholesale gas trading in 2010.

On a smaller financial scale, Aurora Energy has developed the electrical safety WireAlert product and is the Tasmanian Government’s strategic partner in telecommunications, which includes the rollout of the Australian Government’s National Broadband Network (NBN) project. While these activities are less capital intensive (for example, $8.8 million has been invested in the WireAlert product with a cumulative loss of $0.6 million), they consume a significant amount of management and board time that reduces time available to focus on functional business activities.

The Panel has not considered in detail the nature and extent of the risks being mitigated through each of these various diversification activities, whether the activity has been the best way of managing risk, nor whether it has resulted in an overall lower risk position.

These matters are for the Shareholders and the businesses as owners and managers of the businesses respectively. However, irrespective of how these kinds of investments are funded, it is important to remember that the capital has opportunity cost in terms of its ability to support General Government Sector service delivery. In this context, the Panel has questioned whether such investments and activities are appropriate investments for government at all, given that, in making them the Government has also accepted that General Government Services will need to be adjusted in the event that they are not commercially successful.

The Panel has observed the outcomes of these diversification activities and concluded that:

- Diversifications have provided a major focus for (limited) board and senior management resources.
- The Panel has found little evidence in support of the proposition that these business activities have or will generate sufficient improvements in Shareholder value to justify them. Further, there is little evidence that the Tasmanian community, as owner of the businesses, has realised direct value, from these investments though dividends paid.214

213 Aurora Energy’s WireAlert product (marketed in Tasmania as Cable PI) is a safety sensor provided to Tasmanian households in 2009.
214 The Panel believes that this is a key consideration given the difficulties in crystallising the value of capital growth from government-owned businesses.
Through a series of incremental decisions, SOEB business activities have moved away from the primary activity of electricity supply to Tasmanian customers. The extent to which these diversification strategies have changed the risk/return profile in particular of Hydro Tasmania and Aurora Energy is a matter for the Government, as Shareholder, to be aware of and to be satisfied that the resulting risk profiles are consistent with its objectives and expectations for the SOEBs.

There appears to be a lack of clarity around when and how the financial returns from some diversification strategies will be realised by the community. In this regard, a key consideration is whether the financial outcomes of diversification activities reflect the opportunity cost of this capital invested, for example, through higher dividends or the repayment of debt to strengthen the SOEB balance sheet position.

Generally, a consequence of a growth strategy is the medium-term need by the business for capital. This can be in discord with the short-term, year-on-year Shareholder need to withdraw equity through dividends. There is a risk that this tension can compromise the delivery and/or value of the growth strategy.

**Future risks and opportunities**

Although not analysed as part of the Panel’s review, results for the 2011 financial year indicate financial performance across the SOEB portfolio is stronger than it has been during the review period. This is due to a number of reasons. Higher than average water inflows means that Hydro Tasmania has inventory to sell rather than using Basslink to back its contract position; the TVPS is underpinned by regulatory arrangements and Aurora Energy’s contract arrangements with Hydro Tasmania; and Transend has benefitted from a materially better outcome under its current price determination that under previous determinations. The 2011 results also reflect the renewed focus on efficiency.

Nonetheless, the energy market is dynamic and there will always be transitory drivers of value up or down in particular years. Similarly, circumstances reflected in the 2011 results may not continue into the future.

In this sense a historical review of longitudinal financial performance is valuable in that it illustrates what decisions have been made and how choices have affected outcomes.
The SOEBs have generated sufficient cash from operations to ensure that the supply of electricity to Tasmanian customers is maintained and reliability improved. In addition, there has been ‘free cash’ generated that has been applied primarily to capital investment and diversification activities. At the same time, returns to Shareholders have been poor. There is a tension between growth (earnings over time) and return of capital now for the benefit of the community. The community has seen limited tangible financial value from diversification initiatives, notwithstanding the considerable investment they have required.

A common theme throughout the Panel’s broader review, and its investigation into the financial position of the SOEBs, is the lack of a clear view on what the Government is seeking to achieve through its ownership of the SOEBs – for example the extent to which it is for the supply of electricity to Tasmanian customers, or it is to pursue Shareholder value through business operations in other NEM jurisdictions and internationally. A key consideration is whether the risk profile of these wider opportunities is consistent with the risk appetite of government and the Tasmanian community relative to its investment in them and the opportunity cost of that investment and, indeed, whether the anticipated returns eventuate.

Value creating strategies require capital investment. As the Panel has observed, in a general sense the SOEB portfolio is currently debt constrained and Hydro Tasmania and Aurora Energy are targeting credit ratings that will require debt to be reduced or maintained. At the same time, the Tasmanian Government has implemented a dividend strategy that delivers better returns to enable provision of key public services. While the Tasmanian Budget is constrained this is likely to remain in place.

A key risk in pursuing non-core value creating strategies is that the associated capital needs exceed SOEB capacity, either through internally generated funds or debt. For example of Hydro Tasmania’s venture into wind asset development could not keep pace with capital requirements and needed to secure an equity contribution from its Shareholders of $50 million.

A key question then is if additional capital is required where is this capital going to be sourced? Or will growth opportunities be forgone due to the lack of available capital, despite the expectation that may have been built around them?

From a Shareholder perspective, there are several key financial risks confronting the SOEB portfolio.

- Aurora Energy’s retail business is financially vulnerable to a loss of market share arising from further retail competition; and the cost of operation of the TVPS, in terms of average cost per megawatt hour of output is higher than both the prevailing market prices in Tasmania and the regulated wholesale energy allowance. This leaves Aurora Energy’s energy business highly vulnerable to changes in the regulatory arrangements and re-negotiation of contract arrangements with Hydro Tasmania for the non-contestable load beyond 30 June 2013; and to the introduction of further retail competition.
Hydro Tasmania remains vulnerable to hydrological risk, although the nature of this risk has changed over time. Both Hydro Tasmania and Transend are vulnerable to a large industrial load leaving Tasmania, in terms of the opportunity value of stranded energy and stranded network assets respectively.

The financial performance of Aurora Energy and Transend’s network businesses is determined by how aligned actual expenditure compares to determined revenue. The regulatory risk to these businesses arises from changes in the regulatory framework or that the regulatory framework does not deliver revenue outcomes that are consistent with board and management’s expectations of expenditure requirements.215

The principal financial opportunity for the SOEB portfolio is the potential increase in value available to Hydro Tasmania from its hydro-generation in light of carbon pricing.216 The application of any increase in value remains a key consideration for the Tasmanian Government. A key question for the Tasmanian community is how much of the additional value from hydro-generation resulting from a price on carbon will be allocated to growth strategies or returned to the Tasmanian community in recognition of its historic investment in those assets.

There is a fundamental tension here between certainty and risk which ultimately fall on Government to resolve. Value returned to the community now can be spent on the provision of public services. Value re-invested in growth opportunities with the SOEBs may return greater value to the community at some time in the future, but neither the quantum nor the time frames for that return are certain.

215 Note the AER’s Draft Determination for Aurora Energy’s distribution business proposes WACC of 8.08 per cent compared to Aurora Energy’s proposed 10.03 per cent; capital expenditure of $536 million compared to Aurora Energy’s proposed $675 million; and operating expenditure of $311 million compared to Aurora Energy’s proposed $340 million.

216 This environment will further increase the generation costs of the TVPS relative to hydro-generation, but will also result in higher energy prices overall, which will improve TVPS’s financial position relative to the market.
1. Structure of the Tasmanian energy market

Since disaggregation of the Hydro-Electric Corporation (HEC) in 1998, the TESI has experienced major structural, regulatory and investment changes. The Panel’s Discussion Paper ‘The Evolution of Tasmania’s Energy Sector’ provides a detailed discussion of energy sector reform undertaken in Tasmania since 1995. In addition to that paper, the Panel has also previously released the Discussion Paper ‘Tasmania’s Energy Sector – an Overview’ which provides a detailed discussion on the physical structure of, and main participants in, the TESI.

The Tasmanian Government owns the three primary entities in the TESI, Hydro Tasmania, Transend and Aurora Energy, collectively referred to as the SOEBs.

Figure 4 below illustrates the corporate structure of the TESI and summarises the various relationships across the portfolio.

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217 These papers are available on the Panel’s website at www.electricity.tas.gov.au.
218 Including subsidiary companies and activities undertaken through joint venture arrangements.
2. Financial flows through the SOEB portfolio

There are a number of inter-relationships which govern the functioning of the TESI. These relationships reflect the complexity of financial flows within each SOEB and between the SOEBs.

The diagram below presents a high-level summary of the primary financial flows between the three SOEBs, as well as the intra-entity financial flows among the various business segments within each of the SOEBs.

**Figure 5 - 2010 Inter and intra entity financial flows within the SOEB portfolio**

Note: Some of the key financial flows have been omitted to preserve commercial confidentiality.

There are two major inter-entity financial flows within the SOEB portfolio, namely:

- wholesale energy contracts between Hydro Tasmania and Aurora Energy for both contestable and non-contestable customers; and
- the pass-through of transmission charges from Transend to Aurora Energy.

Energy sector reform has influenced the complexity of intra-entity financial flows within both Hydro Tasmania and Aurora Energy, as each business has diversified business operations resulting in more vertically integrated entities than those that were anticipated at disaggregation.
2.1. The two major inter-SOEB financial flows relate to energy and transmission

2.1.1. Wholesale energy

Given Hydro Tasmania’s dominant position in the Tasmanian wholesale energy market, and Aurora Energy’s dominant position as the incumbent retailer, coupled with its direct participation in the wholesale energy market through the TVPS, there are several financial interrelationships between the two SOEBs through the wholesale energy market.

The contractual arrangements between the two entities under which Aurora Energy contracts for wholesale energy to service its contestable and non-contestable load are the primary form of financial interrelationship. The foundations on which these financial relationships are based differ, which is explained below.

Wholesale contracting for non-contestable customers

Prior to the commissioning of the TVPS in 2009, Hydro Tasmania provided Aurora Energy’s wholesale energy contracts for its non-contestable customer base. The total value of this relationship was based on the wholesale energy allowance provided to Aurora Energy under the Price Control Regulations. Typically, the contract arrangements struck between Hydro Tasmania and Aurora Energy for these customers saw the full value of the allowance captured by Hydro Tasmania. Aurora Energy did not secure any ‘additional margin’ in excess of the allowed retail margin through ‘savings’ on the wholesale energy cost.

The nature of these arrangements has changed materially. The first significant change was that, following the negotiation of its hedge arrangement with Alinta backed by the TVPS, Aurora Energy no longer sought to contract for the full non-contestable load exclusively with Hydro Tasmania. Following acquisition and completion of the TVPS, Aurora Energy has subsequently has utilised the output of the TVPS, to cover around half of the non-contestable customer load.
The second major change is that Hydro Tasmania is no longer capturing all of the ‘value’ inherent in the wholesale energy allowance for the volume under its contract. Some of this value has been captured by Aurora Energy, which assists it with the financial consequences of owning and operating the TVPS and results in a substantial transfer in value available under the regulatory arrangements from Hydro Tasmania to Aurora Energy, by comparison with earlier arrangements.\textsuperscript{219}

**Contracting for contestable customers**

With Aurora Energy’s commercial decision to utilise the TVPS capacity to part-back its non-contestable customer load requirements, Aurora Energy, like other retailers operating in the Tasmanian market, seeks wholesale contracts with Hydro Tasmania to back offerings to contestable retail customers. Contestable retail contracts will typically reflect the underlying wholesale cost of electricity (i.e. are usually ‘cost plus’). All retailers, including Aurora Energy, may choose to take differing levels of spot market exposure or use different risk mitigation products (e.g. combinations of hedges and caps) to back retail positions. These strategies have differing costs and risk profiles, and could result in a different wholesale energy cost estimate on which retailers could price retail contracts, even if all retailers are faced with a common wholesale energy contract offering from Hydro Tasmania.

The Panel understands that where its retail position is not backed by generation, Aurora Energy seeks to minimise its spot market exposure due to market volatility in Tasmania, so that there is a large degree of financial interconnectedness between Aurora Energy and Hydro Tasmania in relation to contestable customers through wholesale energy contracts for contestable customers.

**Spot Market**

All retailers and generators face a degree of spot market exposure, even in light of a high level of contracting, as end customer loads are variable and difficult to predict. This also applies to the availability of generating plant.\textsuperscript{220}.

\textsuperscript{219} The wholesale energy allowance for regulated customers is determined through the Tasmanian Economic Regulator’s price determination. To the extent that the wholesale energy allowance is greater than the prevailing market price for electricity ‘value’ is created. How this value is allocated depends on the contracting arrangements between Aurora Energy and its supplier. Prior to July 2010, the contractual arrangements between Aurora Energy and Hydro Tasmania for backing the regulated customer base consistently allocated all of the value to Hydro Tasmania (i.e. the contract ‘price’ reflected the wholesale energy allowance). Aurora Energy received no additional margin on its retail business for any ‘savings, on the cost of wholesale energy. From July 2010 to July 2012, the contractual arrangements between Aurora Energy and Hydro Tasmania for the cost of wholesale energy supplied to meet the regulated customer load (52 per cent of load) is lower that the wholesale energy allowance, transferring this value to Aurora Energy. Aurora Energy applies this ‘value’ to offset the cost of energy supplied by the TVPS through its tolling arrangements (48 per cent of load) which is higher than the wholesale energy allowance. The changes to the Price Control Regulations in 2010 were made to enable the Treasurer to determine the arrangement between Hydro Tasmania and Aurora Energy should they not be able to reach a commercial arrangement. This regulatory intervention was not utilised as the parties reached a commercial decision.

\textsuperscript{220} A load following or whole-of-meter swap will provide full cover for a retailer against the spot price, but these are not typically used for the majority of load.
As Hydro Tasmania’s generation business and Aurora Energy’s retail business are on the opposite sides of the buy/sell transaction in the spot market, there can be material value shifts between the businesses arising from spot market outcomes on a half-hourly basis. In circumstances where Aurora Energy has fixed-price supply obligations to retail customers and an exposure to the spot market, spot prices above the assumed rate within the retail contract will shift value away from Aurora Energy and to Hydro Tasmania (assuming it has a similar spot market exposure). Generally, to the extent that Hydro Tasmania is able to capture additional value from spot market activities this will generally see a value shift from wholesale market buyers, including Aurora Energy\textsuperscript{221}, to Hydro Tasmania.

From an overall SOEB portfolio perspective, improving returns from one part of the portfolio derived through the spot market can be offset by directly poorer returns from another part of the portfolio, noting that respective businesses may have different exposure to the spot market and therefore different risk profiles.\textsuperscript{222}

**TVPS**

With the commissioning of the TVPS, there is now an additional financial interconnection between Aurora Energy and Hydro Tasmania. Depending on the contracting and operating profile of the TVPS, Aurora Energy has simultaneous financial interests in both the sell and buy side of the Tasmanian spot market. In some circumstances, this can act as a ‘natural hedge’ by effectively insulating part of Aurora Energy’s exposure to the market by being on the ‘opposite side’. For example, if Hydro Tasmania is able to take advantage of commercial opportunities in the spot market (for example, owing to unexpected demand by customers pushing volumes higher than contracted volumes) to the extent that it is under-contracted, Aurora Energy could be exposed to the spot market. If the TVPS is also operating at that time and is also under-contracted, it would benefit from the higher spot price – offsetting some of the negative impact on the retail business.\textsuperscript{223} Similarly, if Aurora Energy is over contracted and spot prices were low it would have a negative impact on its energy business.

\textsuperscript{221} And also includes other retailers and large customers with spot market exposure. 
\textsuperscript{222} Some value can be lost from the SOEB portfolio to customers from this spot market activity. 
\textsuperscript{223} The impacts are not always neutralising.
2.1.2. Transmission use of system charges

The second major inter-SOEB financial flow relates to Transend’s TUOS charges. TUOS charges are derived from the following sources:

1. TUOS charges paid by Aurora Energy (and potentially other retailers) to Transend for non-direct connect customers (predominantly residential and business customers). These TUOS charges are passed through to users in the electricity retail price;

2. TUOS charges paid by Aurora Energy (and potentially other retailers) to Transend for direct connect customers (primarily large businesses). These TUOS charges are passed through to users as a separate component of their electricity bill; and

3. Direct connect charges paid by major industrials and generators (Hydro Tasmania and the TVPS) directly to Transend.

The transmission component of electricity charges to customers represents a pass-through cost to Aurora Energy – both its revenues and costs incorporate transmission costs and it receives no value from that proportion of revenue that corresponds to the transmission charges.

2.2. Significant intra-SOEB financial flows are a consequence of the increasing complexity of Hydro Tasmania’s and Aurora Energy’s business activities

The current complexity of the financial flows within the SOEBs has been influenced by energy sector reform, particularly Tasmania’s entry into the NEM and more recently, the commissioning of the TVPS.

2.2.1. Aurora Energy

Among the SOEBs, Aurora Energy has the most complex intra-entity financial flows. These are mainly attributable to:

- The pass-through of network charges, (TUOS and DUOS) from its distribution business to its retail business; and

- The acquisition of the TVPS and associated gas supply contracts which have led to the establishment of AETV and the creation of Aurora Energy’s integrated energy business.
**Distribution business:**
The distribution business, while generating approximately 40 per cent of Aurora Energy’s total revenue, contributes approximately 90 per cent of total earnings margin (EBITDA). The distribution business passes through the regulated charges for both the distribution and transmission networks to Aurora Energy’s retail business (and other retailers) for on-charging to customers. The network component (distribution and transmission) of the regulated electricity price has increased significantly during the last decade driven mainly by capital investment and the consequential increase in the value of both the distribution and transmission regulated asset bases.

The balance sheet strength of the distribution business, and the cash flows that it generates, support Aurora Energy’s energy business and its retail business (in a financial, rather than a regulatory sense) and non-core activities. Aurora Energy’s energy business and retail business also benefit from a stronger credit rating than would be achieved on stand-alone basis. Conversely, Aurora Energy’s distribution business is exposed to higher debt costs as a result of the energy business than would be the case on a stand-alone basis.

**Wholesale energy business:**
The primary function of the energy business is the wholesale purchase of electricity on behalf of the retail business; and the wholesale purchase and trading of gas for the TVPS operation, the Bainsdale power station and for resale to large gas customers.

Aurora Energy has implemented two tolling arrangements between the energy business and AETV, the entity which owns the TVPS. These tolling arrangements effectively transfer the rights and obligations associated with the pool income from the generation of TVPS from AETV to the energy business in return for tolling fees to produce and dispatch electricity from the gas provided by the energy business at the discretion of the energy business.

With the Government-directed purchase of the TVPS, Aurora Energy acquired a suite of gas supply contracts to ensure the security of supply of gas to operate the TVPS. Aurora Energy subsequently entered into a separate commercial transaction to acquire a portfolio of gas supply, transport and sales arrangements (including the contracts for the supply of gas to the TVPS) from Babcock and Brown Power (AEATM). With these arrangements Aurora Energy is the principal supplier of gas for industrial and retail purposes in Tasmania (including its own retail gas business and to supply the TVPS). Aurora Energy also wholesales gas in other jurisdictions and has a tolling arrangement with the Bainsdale power station, including the supply of gas.
2.2.2. Hydro Tasmania

Hydro Tasmania’s significant intra-entity flows relate to diversification of business activities on the back of hydro-electricity generation.

Over 2009 and 2010, Hydro Tasmania acquired the retail business, Momentum. Momentum is located in Melbourne with customers in Victoria, New South Wales, Queensland, the ACT and South Australia. Wholesale energy pricing arrangements between Hydro Tasmania and Momentum provide opportunities for Hydro Tasmania to allocate margins and risks between itself and Momentum in relation to electricity and RECs. Hydro Tasmania has advised the Panel that pricing arrangements between its energy business and Momentum are at market rates and consequently do not involve a margin shift from generation to retail. The extent to which these arrangements allocate risk between the two entities is less clear.

Hydro Tasmania’s consulting business, Entura, provides services to Hydro Tasmania and external entities. The value of internal revenue has been a significant proportion of Entura’s historical revenue, notwithstanding a longstanding objective to increase external revenue.

Over the past decade, there have been substantial flows of funds and physical assets from Hydro Tasmania to the Roaring 40s subsidiary, and the subsequent joint venture with China Light and Power (CLP). Hydro Tasmania has an off-take agreement for energy and RECs with Roaring 40s for the Waterloo wind farm as this comprised part of Hydro Tasmania’s broader portfolio prior to disaggregation of the joint venture.

To illustrate how the financial inter-relationships have changed over time, Table 2 below illustrates a comparison of some of the financial flows within and among the SOEBs in 2004 (pre significant reform in the TESI) and 2010.

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224 Hydro Tasmania is unable to retail electricity in Tasmania (other than the Bass Strait Islands) due to legislative constraints, which means that Momentum is unable to offer its products to Tasmanian customers.

225 Following the end of development of new major hydro-generation capacity, Hydro Tasmania retained a large engineering workforce formerly referred to as Hydro Consulting and now trading as Entura. Hydro Tasmania does not require the full consulting capacity of Entura to maintain its hydro-generation assets – consulting services between Entura and Hydro Tasmania is projected to decrease.
Table 2 - Inter and Intra SOEB financial relationships 2004 and 2010

<table>
<thead>
<tr>
<th>Relationships relating to the supply of energy in Tasmania (functional business activities)</th>
<th>2004</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity sources in Tasmania</strong></td>
<td>92% (9834 GWh) of total TESI load requirement met by Hydro Tasmania’s dam assets.</td>
<td>76% (8184 GWh) of total TESI load requirement met by Hydro Tasmania’s dam assets.</td>
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<tr>
<td></td>
<td>7% (796 GWh) of total TESI load requirement met by the BBPS.</td>
<td>10% (1114 GWh) of total TESI load requirements met by the TVPS.</td>
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<tr>
<td></td>
<td>1% (95 GWh) of total TESI load requirement met by wind.</td>
<td>10% (1056 GWh) of total TESI load requirement met by Basslink imports.</td>
</tr>
</tbody>
</table>

| **Annual value (cost) of energy supplied by Hydro Tasmania to Aurora Energy** | $354 million | $416 million |
| **New cost of energy for Hydro Tasmania - Basslink-related costs** | Nil | $84 million |

| **Substantial value growth is in the distribution business. Distribution EBIDTA ($ value, % of Aurora’s total EBIDTA and RAB value). Note: 2004 RAB includes metering assets whereas the 2010 RAB excludes metering assets.** | $115 million 91% | $165 million 105% |
| **Substantial value growth is in the transmission business. Transmission revenue ($ value, % total retail electricity price and RAB value)** | $107 million¹ 15% | $166 million 15%² |
| **Falling returns to the Government - dividends paid** | $66 million | $34 million |

<p>| <strong>New financial relationships relating to diversification business activities</strong> | 2004 | 2010 |
| Hydro Tasmania’s investment in wind assets - Roaring 40s investment | $48 million (FY07 to FY10 - investment in joint venture) | ($11.2 million) (FY06 to FY10) |
| Hydro Tasmania’s cumulative returns (loss) from Roaring 40s investment | $48 million (FY04 to FY06 - investment in subsidiary) | ($15.7 million) (FY09 (10 months) and FY10) |
| Hydro Tasmania’s investment in retail - Momentum acquisition costs | $52 million (FY09 and FY10) |
| Hydro Tasmania’s cumulative returns (loss) from Momentum investment | | |
| Entura’s share of revenue from Hydro Tasmania | 68% | 39% |</p>
<table>
<thead>
<tr>
<th>Aurora Energy</th>
<th>2004</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aurora Energy’s investment in the TVPS</td>
<td>$360 million (FY09 and FY10)</td>
<td></td>
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<tr>
<td>Aurora Energy’s impact on NPAT from the TVPS</td>
<td>$29.1 million lower³ (FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s investment in AEATM (wholesale gas contracts and dispatch rights)</td>
<td>$15 million (FY09)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s returns (loss) from wholesale gas trading</td>
<td>($1.8 million) (FY10)</td>
<td></td>
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<tr>
<td>Aurora Energy’s cumulative return from mainland electricity retail trading</td>
<td>$3.3 million (FY05 to FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s telecommunications business capital investment</td>
<td>$13.7 million (offset by customer contributions of $3.2 million)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s cumulate return (loss) from telecommunications⁴</td>
<td>($4.3 million) (FY07 to FY10)</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s investment in Cable PI/WireAlert devices⁵</td>
<td>$8.8 million FY10</td>
<td></td>
</tr>
<tr>
<td>Aurora Energy’s return (loss) from Cable PI/WireAlert⁶</td>
<td>($0.6 million) (FY10)</td>
<td></td>
</tr>
</tbody>
</table>

Notes:
1. 2005 data used as 2004 a half year per the regulatory determination.
3. Estimate based on reversal of tolling fee and AETV net loss before tax, reductions in interest expenses – offset by the purchase of load valued at the wholesale energy allowance.
4. Note that losses in Aurora Energy’s telecommunications business arise from the accounting treatment of the Tasmanian Government’s support of Aurora Energy as its telecommunications strategic partner, which is provided as an equity contribution. Aurora Energy has received equity contributions totalling $7.8 million between 2009 and 2010.
5. $8.8m relating to the cost of supply of WireAlert devices was capitalised into the distribution business in 2010.
6. Segmented data not available for FY09 and operating results to not include an allocation of corporate and shared costs as this information was not provided.
3. Cash generation and allocation - changes over time

The purpose of this section of the Paper is to highlight how cash generated within the SOEB entities is used, whether it is for capital investment in assets used to derive income (increasing the equity of the business), to manage debt (capital structures) or returned to Shareholders as dividends.

Two perspectives are considered:

- Section 3.1 - Cash generation and allocation within each SOEB entity. This section considers the broad nature of revenue generated and associated expenditure and how this has trended over time; and how cash derived from operating activities has been used. Net cash from operating activities can be used to invest in existing assets or new business activities, repay debt, or pay dividends.

- Section 3.2 - A portfolio perspective on how capital expenditure and investment expenditure, debt and dividends over time reflect the cash allocation decisions discussed in section 3.1.

The period 2004 to 2010 represents a period of significant change within the TESI and expansion of activities within Hydro Tasmania and Aurora Energy in particular. In addition, Tasmania experienced a major drought event between 2007 and 2009.

It is worth highlighting some of the different circumstances confronting each of the SOEBs over the analysis period, as it provides important context for financial performance and cash utilisation.

- For Hydro Tasmania, the analysis period includes a major drought between 2007 and 2009 combined with high contract cover, which together created very difficult financial circumstances. It also represents a phase of business diversification, particularly outside the Tasmanian market, through investment in wind assets and acquisition of a retail business.

- For Aurora Energy, the analysis period represents a period of significant investment in the distribution network, the phased introduction of retail contestability and the acquisition and operation of the TVPS.

- For Transend, the analysis period represents a period of continued investment in the transmission network, the facilitation of Tasmania’s adoption of NEM arrangements and Basslink connection.
3.1. SOEB perspective - cash generation and utilisation

3.1.1. Hydro Tasmania

Up until 2005, Hydro Tasmania operated as a hydro-generation business with a focus on sales to Tasmanian customers. With the commissioning of Basslink in 2006, Hydro Tasmania became a trading entity in the NEM, seeking to maximise the value of its energy in the wholesale electricity market. In 2009 and 2010 a change in strategic focus saw Hydro Tasmania acquire Momentum. Hydro Tasmania is now an integrated generator-retailer (‘gentailer’) with its generation and retail activities split between Tasmania and other NEM jurisdictions (i.e. hydro-electricity is generated in Tasmania and sold to wholesale customers in Tasmania and retail customers in other NEM regions).226

Energy generation and trading is Hydro Tasmania’s main value driver. Historically, Hydro Tasmania provided all of Tasmania’s electricity needs. Over the period 2004 to 2010, Hydro Tasmania’s negotiated contractual arrangements relating to the non-contestable load has captured the strongest margins of all customer groups.

**Hydro Tasmania’s financial performance 2004 to 2010**

Figure 6 illustrates Hydro Tasmania’s financial performance between 2004 and 2010.227

Total revenues remained fairly consistent between 2004 and 2008 at between $440 million to $490 million, with significant growth in 2009 (33 per cent) and 2010 (15 per cent). In 2009, electricity revenue, excluding Momentum, increased by $87 million, or 21 per cent from 2008, notwithstanding hydro station output remaining at just over 7,000 GWh (7,100 GWh in 2008 and 7,203 GWh in 2009). Expenses grew on average at a rate of around 18 per cent per annum since 2006, with a decline to around 14 per cent in 2010. This rate of change reflects the change in Hydro Tasmania’s operating environment including the need to purchase gas to supplement hydro storages, the commencement of the Basslink facility fee and the inclusion of network costs associated with Momentum customers (refer Figure 8).

Over the same period EBIDTA declined until 2009 but has not returned to 2004 and 2005 levels.

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226 Due to Hydro Tasmania’s dominant position in the Tasmanian generation sector, it is precluded by legislation from retailing electricity in Tasmania.
227 Analysis excludes financing and depreciation revenues and costs.
A review of the financial position of the State Owned Electricity Businesses

Figure 6 - Hydro Tasmania’s financial performance 2004 to 2010

Source: Hydro Tasmania annual reports
Note: Total revenue and total expenses from 2008 include Momentum.

As Figure 7 illustrates, electricity generation and trading is Hydro Tasmania’s primary revenue source. Revenue from electricity is a function of contracted load, actual physical generation and price. The drivers of revenue growth over the analysis period are discussed in Section 5, Part 2 of this Paper. ‘Subsidiary revenue’ in 2009 and 2010 is revenue earned by Momentum.

Figure 7 - Primary contributors to revenue 2004 to 2010

Source: Hydro Tasmania annual reports
As illustrated in Figure 8, there was a significant and steady growth in Hydro Tasmania’s expenses from $203 million in 2004 to $491 million in 2010. The purpose of Figure 8, in addition to illustrating the quantum changes in operating expenses, is to show the changes in types of operating expenditure as the market has changed over time. For example, from 2006 Hydro Tasmania had an operating expense associated with Basslink and gas and gas transport costs peaked through the drought period as the BBPS was utilised to maintain supply. The growth in generation, transmission and retail costs in 2010 can be partially attributed to Momentum.

Figure 8 - Primary contributors to operating expenses 2004 to 2010

Source: Hydro Tasmania annual reports
Hydro Tasmania’s cash generation and utilisation 2004 to 2010

Figure 9 illustrates Hydro Tasmania’s cash from operations over the period 2004 to 2010.

Figure 9 - Hydro Tasmania’s cash from operations 2004 to 2010

Source: Hydro Tasmania’s annual reports

In 2004, net cash provided by operating activities was $105 million, which increased over the period to 2006. Reflecting the impact of the drought on Hydro Tasmania’s financial position, net cash provided by operating activities fell by just over $100 million between 2006 and 2007, from $140 million to $37 million. With improved water inflows and storage levels, net cash provided by operating activities increased by $134 million between 2009 and 2010, from $44 million to $178 million.

Between 2004 and 2009, cash receipts from customers ranged between $400 million and $550 million per annum. There is a marked increase in cash receipts in 2010 to $788 million (an increase of $297 million or 60 per cent from 2009), reflecting improved water inflows, storage levels and retail trading. From 2007, cash payments to suppliers and employees increased as a percentage of cash receipts from an historical average of around 55 per cent to between 70 and 80 per cent. There was a step increase in 2008 of $148 million from $305 million in 2007 to $453 million in 2008, reflecting in part Hydro Tasmania’s higher cost of RECs, gas purchases to operate the BBPS through the drought and financial commitments to Basslink.

After operating costs, the two key uses of cash are 1) investing activities, including capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities; and 2) financing activities, including the repayment of debt and returns to Shareholders by way of dividends.
Figure 10 illustrates cash utilised in investing activities over the period 2004 to 2010.

Figure 10 - Cash utilised in investing activities 2004 to 2010

Source: Hydro Tasmania’s annual reports

Over the analysis period, total capital investment was $613 million, or 83 per cent of cash used in investing activities. A more detailed discussion of Hydro Tasmania’s capital investment profile is included at section 3.2.1. Total investment in new business activities (wind and Momentum) was $125 million, or 17 per cent of cash used in investing activities. Hydro Tasmania’s investment in wind activities since 2007, $48 million, was funded by an equity contribution from its Shareholders. Its investment in the acquisition of Momentum, $52 million, was funded from internally generated funds.

Proceeds from other investing activities include proceeds from the sale of property, plant and equipment of $33 million in 2008 which related to the sale of the BBPS to Alinta.

Figure 11 illustrates cash used in financing activities over the period 2004 to 2010.
Excepting 2006, between 2004 and 2007 Hydro Tasmania increased its borrowings, most significantly in 2005 ($131 million, used principally for the construction of the Woolnorth Studland Bay and Cathedral Rock wind farms) and 2007 ($115 million used to provide working capital during the drought). However, Hydro Tasmania has repaid debt in each of the subsequent years. In 2010 this amounted to $69 million. Over the period, Hydro Tasmania decreased its borrowings from $1081 million in 2004 to $893 million in 2010. This was assisted by an equity contribution from Shareholders of $220 million in 2008 by way of transfer of Tascorp loans from Hydro Tasmania to Transend. Other sources of financing included a Shareholder equity contribution of $50 million in 2008 to fund Hydro Tasmania’s ongoing investment in Roaring 40s joint venture (shown in Figure 8 as other operating expenses).

**Summary of Hydro Tasmania cash generation and utilisation**

Hydro Tasmania has maintained a positive cash from operations position throughout the analysis period, including the years in which drought had a significant impact on financial performance where Hydro Tasmania absorbed much of the additional cost of alternate supply (BBPS and from the NEM via Basslink). In this period, Hydro Tasmania adjusted its investment activities by reducing its capital investment program - thereby avoiding additional pressure on debt levels. Hydro Tasmania was also provided dividend relief through changes in its dividend policy agreed to by the Government.

From 2008 to 2010, Hydro Tasmania reduced borrowings by $106 million and funded the acquisition of Momentum, $52 million, from its cash from operations. However, dividends have been nil or minimal during this time, representing only three per cent of cash from operations.
3.1.2. Aurora Energy

Up until 2008, Aurora Energy operated primarily as a retailer (in Tasmania and elsewhere in the NEM) and distribution business. Subsequent to the acquisition and operation of the TVPS, Aurora Energy is now an integrated generator-retailer (‘gentailer’) and distribution business, as well as a wholesale gas trader.

The regulated part of the distribution business has been Aurora Energy’s main value driver, generating on average 40 per cent of total revenue, but contributing 90 per cent of EBITDA.

Typically, electricity retailing is a high volume/low margin business and is subject to economies of scale. Aurora Energy has the financial challenge of spreading its fixed costs across a small (predominantly Tasmanian) customer base.

The introduction of retail competition has resulted in a transfer of load from Aurora Energy to new entrant retailers, which has put downward pressure on Aurora Energy’s retail margins as fixed costs are spread across fewer customers. Aurora Energy’s retail business is vulnerable to the loss of further market share, particularly if it is unable to materially reduce retail costs in line with losses in volume.

While energy revenue has increased due to average price increases across all customer types, particularly non-contestable customers, this higher revenue reflects the pass-through of higher costs rather than material improvements in retail margins.

Increases in retail electricity prices that are experienced by customers are not fully captured by Aurora Energy’s retail business. This is because:

- The transmission component, the highest proportional increase over time, represents a pass-through cost to Transend;
- The distribution component represents a pass-through cost to Aurora Energy’s distribution business; and
- Traditionally, the wholesale energy allowance set the financial parameters for the contract between Hydro Tasmania and Aurora Energy for the non-contestable customer load. The 2010 contract arrangements have seen value flow from Hydro Tasmania to Aurora Energy, which has effectively been used by Aurora Energy to fund the tolling arrangements between its energy business and AETV.

228 Aurora Energy also had relatively small business activities in telecommunications and gas retailing.
229 The cost of billing and other systems required by electricity retailers are relatively fixed within large bands of customers, although significant step changes can be incurred once certain customer levels are reached (hence the demarcation of TIER 1 and TIER 2 retailers).
230 Aurora Energy estimates that it has around 85 per cent share of contestable customers in Tasmania.
231 Changes to Aurora Energy’s energy business announced in October 2011 indicate that the company is actively addressing these pressures.
232 Hydro Tasmania and Aurora Energy have two contract arrangements, a contract for energy and a drought security option, that combined have the effect of Hydro Tasmania receiving a lower price than the regulated energy allowance, for energy to supply Aurora Energy’s non-contestable load.
In relation to Aurora Energy’s energy business, the average cost of generation (per $/MWh) from the TVPS exceeds the wholesale energy allowance. The viability of the AETV entity which owns the TVPS is sustained by two tolling agreements with Aurora Energy’s energy business. The value provided by the tolling agreements is sufficient to cover the cost of electricity production from the TVPS, pay down debt over the life of the plant and provide a modest rate of return. In 2010, gas commodity and transport costs represented approximately half of the tolling fee revenue.233

Figure 12 illustrates contribution to EBIDTA by Aurora Energy’s business activities.

**Figure 12 - Aurora Energy’s EBIDTA contribution by activity**

![Graph showing Aurora Energy’s EBIDTA contribution by activity](image)

Source: Aurora Energy
Note: Wholesale includes electricity and gas trading; and AETV EBIDTA is a function of the tolling arrangements between Aurora Energy and AETV.

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233 The TVPS cost structure is not competitive in the NEM and while the tolling arrangements cover the power station’s costs, they would not be sustainable at competitive prices in the NEM wholesale market.

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A review of the financial position of the State Owned Electricity Businesses
**Aurora Energy’s financial performance 2004 to 2010**

Figure 13 illustrates Aurora Energy’s financial performance between 2004 and 2010.

Over this period, revenues increased from $643 million in 2004 to $1.173 billion in 2010, an increase of $530 million or 82 per cent. Revenue growth was at a continuous, albeit escalating rate, with a high point in 2010 of 18 per cent from 2009. Expenses increased consistent with revenues from $525 million in 2004 to $1.044 billion in 2010, an increase of $519 million or 99 per cent. The annual rate of increase has also been escalating with a high point in 2010 of 20 per cent.\(^\text{234}\)

Over the same period, EBITDA has remained consistent at, on average, 16 per cent of revenue. The exception was 2010 when EBITDA fell to 11 per cent of revenue as a result of poor performance of the energy business.

*Figure 13 - Aurora Energy’s financial performance 2004 to 2010*

Aurora Energy’s revenue comprises revenue from electricity sales from its customers in Tasmania and other NEM jurisdictions; distribution network services, gas wholesale and retail and energy trading from the output of its Tamar Valley and Bairnsdale power stations. A portion of revenue earned from electricity sales includes the pass-through of transmission and distribution costs.

\(^234\) Aurora Energy has advised the Panel that the 2010 year was not on trend, primarily due to losses in the energy business relating to issues within the Tasmanian wholesale energy market. Losses attributable to the cost of energy account for half of the energy business loss, the other half being attributable to the expensing of $21 million of billing system costs. Improved results for the energy business in 2011 are based on the outcomes of the regulatory process and contracting arrangements with Hydro Tasmania for the non-contestable customer load, which are in place until 30 June 2013. If these arrangements do not continue it is anticipated that energy business results will deteriorate.
For revenue from Tasmanian electricity customers, the pass-through of distribution costs to the distribution business reflects the revenue earned by the distribution business. In addition, the distribution business earns revenue from other Tasmanian retailers. For example, in 2010 the distribution business earned revenue of around $231 million from Aurora Energy and around $10 million from other retail service providers.

**Figure 14 - Primary contributors to functional expenses 2004 to 2010**

![Bar chart showing primary contributors to functional expenses from 2004 to 2010.](source)

Source: Aurora Energy annual reports

Figure 14 illustrates the primary contributors to functional expenses 2004 to 2010 and Figure 15 provides a further breakdown of energy and transmission costs.

As shown in Figure 14, there was a significant and steady growth in Aurora Energy’s functional expenses from $525 million in 2004 to $1.044 billion in 2010. Some of these cost increases, such as transmission purchases and RECs are pass-through costs and outside Aurora Energy’s control. For those costs within Aurora Energy’s control, labour costs have increased by $41 million or some 75 per cent between 2004 and 2010. Direct expensing of billing system charges, $21 million, contributed to increased expenses in 2010.

As illustrated in Figure 15 transmission purchases have increased, particularly from 2008, as have energy purchases with energy purchase costs in 2010 reflecting outcomes of operating the TVPS.
A review of the financial position of the State Owned Electricity Businesses

**Figure 15 - Breakdown of energy and transmission purchases 2004 to 2010**

![Bar chart showing energy and transmission purchases from 2004 to 2010.](image)

Source: Panel’s analysis

**Aurora Energy’s cash generation and utilisation 2004 to 2010**

Figure 16 shows Aurora Energy’s cash from operations over the period 2004 to 2010.

**Figure 16 - Aurora Energy’s cash from operations 2004 to 2010**

![Line graph showing cash from operations from 2004 to 2010.](image)

Source: Aurora Energy’s annual reports

Cash from operations show year-on-year variability and does not ‘track’ the EBITDA profile over the same period. The decline in cash from operations in 2010 reflects the impact of negative returns from the energy business associated with Aurora Energy’s contract position and subsequent fluctuations in the Tasmanian spot market price.
After operating costs, the two key uses of cash are 1) investing activities, capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities; and 2) financing activities, the repayment of debt and returns to Shareholders by way of dividends.

Figure 17 illustrates cash utilised in investing activities over the period 2004 to 2010.

**Figure 17 - Cash utilised in investing activities 2004 to 2010**

![Chart showing cash utilised in investing activities 2004 to 2010](chart.png)

Source: Aurora Energy annual reports

Over the analysis period, Aurora Energy’s primary use of cash for investing activities was capital investment in its distribution network and the acquisition and construction of the TVPS in 2009 and 2010. In addition, in 2009, Aurora Energy acquired a suite of gas contracts and dispatch rights from Babcock and Brown. More detailed discussion on Aurora Energy’s capital investment is included at section 7.2.1.

A review of the financial position of the State Owned Electricity Businesses
Figure 18 illustrates cash utilised in financing activities over the period 2004 to 2010.

**Figure 18 - Cash utilised in financing activities 2004 to 2010**

Source: Aurora Energy's annual reports

Analysis of cash utilised in financing activities indicates that Aurora Energy increased its borrowings in each year between 2004 and 2010. The significant increase in borrowings in 2009 relates in part to additional borrowings of $260 million to construct the TVPS. Aurora Energy’s borrowings are also impacted by the timing of AEMO prudential requirements ($100 million in 2009), that required Aurora Energy to deposit cash in a standby facility to ensure sufficient liquidity reserves existed for a potential call on spot market purchases. Cash used for this facility was subsequently used to retire the associated debt in 2010.

Equity issued in 2009 and 2010 reflect the $100 million equity contribution from the Tasmanian Government to acquire the TVPS and contributions to support Aurora Energy as the Government’s telecommunications strategic partner.

**Summary of Aurora Energy’s cash generation and utilisation**

In 2004, Aurora Energy was the sole retailer of electricity in Tasmania and, as it remains in 2010, the monopoly distribution services provider. In 2009, as a result of a direction from its Shareholders, Aurora Energy’s business operations further diversified with the ownership and operation of the TVPS. Aurora Energy also made a commercial decision to enter into the wholesale purchase and sale of gas (including the gas supplied to the TVPS) through its acquisition of Babcock and Brown Power’s wholesale gas business. As such, the analysis period, particularly in the latter years, has seen a significant additional complexity in Aurora Energy’s business operations.

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235 This does not mean that Aurora Energy has not repaid borrowings; rather that drawdown on loans has exceeded repayment of loans in each of the years of the review.
Aurora Energy has maintained positive cash from operations position throughout the analysis period, including 2010 where it saw significant issues in its energy business. However, ‘free cash’ has been variable year-on-year.

Aurora Energy’s capital investment program in its distribution business is driven by the need to upgrade the network and customer generated connections. This capital investment has subsequently driven the distribution business’ regulatory revenue allowance. Throughout the review period Aurora Energy increased borrowings on an annual basis to contribute to its capital investment program. In addition, Aurora Energy was required to borrow an additional $260 million to fund the construction of the TVPS.

Dividend payments have averaged around $10 million per annum – although this has been variable across years, representing, again on average, 15 per cent of cash from operations.

3.1.3. Transend

Over the review period, Transend’s business operations have remained primarily focused on the operation of Tasmania’s transmission network. However, the period has seen the transfer of the system controller function to AEMO in 2006. In addition, at the direction of its Shareholders, Transend resolved a number of complex technical issues to prepare Tasmania for NEM entry and the connection of Basslink. The cost of this work was effectively internally funded\textsuperscript{236}, impacting on financial performance in the early years of this analysis.

Revenue from prescribed transmission services is Transend’s main value driver, contributing on average 90 per cent of revenue. Investment in the transmission network has been funded from cash from operations and increased borrowings. Borrowings have also increased as a result of the Government’s decision to rebalance equity across the portfolio via a debt swap between Hydro Tasmania and Transend ($220 million) and to withdraw equity ($50 million) in 2008 which was also provided to Hydro Tasmania.

Higher incurred operational and capital expenditure spending relative to regulatory allowances has impacted on profitability and contributed to lower returns to Government than would be expected from the return on equity allowance provided for under the regulatory framework.\textsuperscript{237}

\textsuperscript{236} These costs were not provided for in the regulatory determination and therefore not recouped from customers.

\textsuperscript{237} Differences in the businesses asset valuation for regulatory and accounting purposes also provides a key driver for this outcome. See Section 2 Part 2 of this Paper.
Transend has advised the Panel that its board made an active decision to spend above the regulatory allowances based on its view of long term benefits to customers and that its Shareholders were informed of this approach. Transend considers that the ACCC’s 2003 pricing determination made unsustainably low expenditure allowances. This issue is discussed in more detail in the Panel’s Paper ‘A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses’.

**Transend’s financial performance 2004 to 2010**

Figure 19 illustrates Transend’s financial performance between 2004 and 2010. Total revenue in 2004 and 2005 includes the system controller function which was subsequently transferred to AEMO, and is not included in revenue (or expenses) in later years. On average across the analysis period, prescribed revenue accounts for approximately 90 per cent of total revenue and has increased from $86 million in 2004 to $166 million in 2010, an increase of 93 per cent. The total expenses trend has mirrored the total revenue trend across each year. Over the same period, EBIDTA has, with the exception of 2006, improved in each year and has remained fairly constant at between 65 per cent and 70 per cent of total revenue.

*Figure 19 - Transend’s financial performance 2004 to 2010*

As Figure 19 illustrates, revenue from prescribed transmission services is Transend’s key revenue source. Primary drivers of prescribed transmission revenue over the analysis period are discussed in Section 7 Part 2 of this Paper.
As illustrated in Figure 20, there has been a steady growth in operating and maintenance expenses relating to the transmission network over the review period. In 2004 and 2005 Transend’s expenses included costs of the system controller function – as noted above this function transferred to AEMO and is now included in network costs.

Between 2004 and 2006 Transend incurred costs associated with Tasmania’s NEM entry.

Source: Transend’s annual reports

Figure 20 - Primary contributors to revenue 2004 to 2010

Figure 21 - Primary contributors to operating expenses 2004 to 2010

Source: Transend’s annual reports
Transend’s cash generation and utilisation 2004 to 2010

Figure 22 illustrates Transend’s cash from operations over the period 2004 to 2010.

Figure 22 - Transend’s cash from operations 2004 by 2010

Source: Transend’s annual reports

Cash from operations shows year on year variability, but overall tracks EBITDA. Following a decline in cash from operations of $61 million in 2009, there has been a significant increase in 2010 of $40 million to $101 million.\(^{238}\) 2010 is the first year of Transend’s current regulatory period that saw an opening RAB of $951 million, $123 million higher than the 2009 RAB and an uplift in WACC from 8.8 per cent to 10 per cent.

After operating costs, the two key uses of cash are 1) investing activities, capital investment in the refurbishment and replacement of primary assets and investment in diversified business activities, which in Transend’s case has been very modest; and 2) financing activities, the repayment of debt and returns to Shareholders by way of dividends.

\(^{238}\) Revenue recovered in 2009 was based on the AER’s original decision and prior to the Australian Competition Tribunal’s amended decision released in November 2009. Therefore, 2009 results were based on the AER’s original decision of 8.8 per cent WACC. The Tribunal subsequently amended WACC to 10.0 per cent.
Figure 23 illustrates cash utilised in investing activities over the period 2004 to 2010.

**Figure 23 - Cash utilised in investing activities 2004 to 2010**

![Graph showing cash utilised in investing activities 2004 to 2010]

Over the analysis period, Transend's total capital investment was $637 million, or 98 per cent of cash used in investing activities. A more detailed discussion of Transend's capital investment profile is included at section 3.2.1. Transend’s only investment in new business activities was its purchase of the telecommunications business from Hydro Tasmania in 2009 for $15 million.239

Figure 24 illustrates cash utilised in financing activities over the period 2004 to 2010. Over this period, on a net basis, Transend has drawn on borrowings in each year. In 2008, return on Shareholder equity represents Transend’s $50 million equity return that was subsequently transferred to Hydro Tasmania for wind asset investment.

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239 On 1 November 2008, Transend acquired the Communication Services business from Hydro Tasmania to bring-in house communication services required to operate the transmission system. Transend’s telecommunications business also provides services to customers in the TESI, providing the high levels of reliability used for operational purposes such as power station protection, monitoring and control, voice communications and asset management functions. (Transend Annual Report 2009).
Figure 24 - Cash utilised in financing activities 2004 to 2010

Source: Transend’s annual reports

Summary of Transend’s cash generation and utilisation

Unlike Hydro Tasmania and Aurora Energy, the scope of Transend’s business operation has remained focused on its functional business activity of owning and operating the transmission network. Notwithstanding this, Transend has managed considerable changes arising from Tasmania’s participation in the NEM and the connection of Basslink.

On an annual basis, cash from operations has been positive with a significant improvement in 2010 - the first year of the AER’s current regulatory determination.

Transend’s capital investment program is driven by the augmentation, renewal and strengthening of the State’s transmission network, which in turn, drives up its regulatory allowances. The capital investment program included a large one-off project in 2009/10, the Waddamana to Lindisfame 220kv line. Throughout the review period Transend has increased borrowings on an annual basis to contribute to its capital investment program. In addition, Transend made a direct return of Shareholder equity of $50 million and an indirect return, of $220 million, by way of a debt swap with Hydro Tasmania in 2008.

Dividends payments have averaged around $15 million per annum, although this has been variable across years, representing, again on average, 22 per cent of cash from operations.

3.1.4. Summary of SOEB portfolio cash generation and utilisation 2004 to 2010

Table 3 illustrates how cash generated has been utilised by the SOEBs over the 2004 to 2010 review period.
<table>
<thead>
<tr>
<th>SOEB Entity</th>
<th>Cash Generation</th>
<th>Cash Generation Notes</th>
<th>Investing Activities</th>
<th>Cash Utilisation</th>
<th>Dividend Returns</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hydro Tasmania</strong></td>
<td>Variable - reflecting drought conditions between 2007 and 2009.</td>
<td></td>
<td>Total capital expenditure $613 million or 83 per cent of total expenditure.</td>
<td>Substantial increase in debt in 2005 ($131 million) and 2006 ($115 million).</td>
<td>Special dividend arrangements between 2004 and 2006 (reflecting and equity withdrawal by Shareholders) - $52 million.</td>
</tr>
<tr>
<td></td>
<td>Significant improvement in 2010.</td>
<td></td>
<td>Total investment (wind and Momentum) expenditure $125 million or 17 per cent of total expenditure.</td>
<td>Trend from 2008 to 2010 to improve capital structure through debt reduction totalling $106 million.</td>
<td>Dividend returns between 2004 and 2010 - $98 million.</td>
</tr>
<tr>
<td></td>
<td>High of $178 million in 2010.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Aurora Energy</strong></td>
<td>Variable.</td>
<td></td>
<td>Total capital expenditure $876 million or 78 per cent of total expenditure.</td>
<td>Substantial increase in debt in 2009 ($337 million) primarily as a result of $260 million borrowings for the construction of the TVPS and $100 million relating to AEMO prudential requirements.</td>
<td>Dividend returns between 2004 and 2010 $81 million.</td>
</tr>
<tr>
<td></td>
<td>Low of $49 million in 2010.</td>
<td></td>
<td>Total investment (TVPS and gas) expenditure $244 million or 22 per cent of total expenditure.</td>
<td>Trend through the review period to drawdown on debt.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>High of $126 million in 2009.</td>
<td></td>
<td>$100 million TVPS investment funded by Shareholder equity.</td>
<td>Increase in borrowings from $336 million in 2004 to $1029 million in 2010.</td>
<td></td>
</tr>
<tr>
<td><strong>Transend</strong></td>
<td>Variable - trend to increased cash returns.</td>
<td></td>
<td>Total capital expenditure $637 million or 98 per cent of total expenditure.</td>
<td>Substantial increase in debt in 2008 ($71 million) and 2009 ($91 million) relating to Shareholder’s equity withdrawal, assumption of debt from Hydro Tasmania and ongoing capex.</td>
<td>Dividend returns between 2004 and 2010 $79 million.</td>
</tr>
<tr>
<td></td>
<td>Low of $56 million in 2004.</td>
<td></td>
<td>Total investment (telecommunications) $15 million or 2 per cent of total expenditure.</td>
<td>Drawdown on borrowings variable through the review period reflecting cash available from operations.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>High of $101 million in 2010.</td>
<td></td>
<td></td>
<td>Increased borrowings from $35 million in 2004 to $518 million in 2010 reflecting establishment with nil debt and subsequent equity withdrawals ($50 million) and debt transfer to Hydro Tasmania ($220 million) in 2008.</td>
<td></td>
</tr>
</tbody>
</table>

1 Note Hydro Tasmania invested a total of $73m in wind between 2004 and 2008, $48m of which was into the Roaring 40's JV.
3.2. Portfolio perspective of financing activities

3.2.1. Investment - functional and diversified business activities

Capital expenditure on functional business activities

Over the review period, annual capital expenditure on functional business activities across the SOEB portfolio increased by $118 million from $279 million in 2004 to $397 million in 2010, an increase of 25 per cent. The composition across the businesses is shown in Figure 25.

Figure 25 - Total capital expenditure SOEB portfolio 2004 to 2010

Aurora Energy was the largest contributor to capital expenditure over the review period with a total of $915 million. On an average basis, Aurora Energy spent $131 million per annum, Hydro Tasmania spent $93 million per annum and Transend spent $82 million per annum. A breakdown of each entity's capital expenditure is discussed further below.

Investment in diversified business activities

In addition to capital expenditure on functional business activities, across the SOEB entities, between 2004 and 2010, investment in diversified business activities amounted to $475 million, of which $360 million was invested by Aurora Energy on the TVPS at the direction of its Shareholders, Hydro Tasmania invested around $100 million in business activities outside Tasmania; including $48 million wind assets and $52 million on its retail business.
SOEB investment in diversified business activities is illustrated in Figure 26 below.

**Figure 26 - Total investment in diversified business activities SOEB portfolio 2004 to 2010**

The breakdown of each entity’s capital expenditure is discussed further below.

**Figure 27 - Aurora Energy’s capital expenditure 2004 to 2010**

Source: Panel analysis

Note: Aurora Energy’s capital expenditure profile does not include capital investment in the TVPS of $360 million.
Historically, Aurora Energy’s primary area of capital expenditure has been in its distribution business, with a total of around $753 million invested. Capital expenditure in corporate and shared services shown in 2009 and 2010 includes investment attributable to the development of the new billing system, which is a whole-of-business investment.

The capital invested in the regulated distribution business is relatively low risk, and will earn a regulated rate of return over its economic life. Other capital expenditure has a materially higher risk profile. In the case of the billing system, considerable value has already been written off as an expense.240

**Figure 28 - Hydro Tasmania’s capital expenditure 2004 to 2010**

![Graph showing hydro generation, renewable developments, Bass Strait islands, corporate and shared services, and other assets from 2004 to 2010]

Source: Panel analysis

Note: Hydro Tasmania’s capital expenditure does not include capital investment in the Roaring 40s joint venture from 2007 (previously investment in wind development has been included in renewables developments) or the capital investment of Momentum.

Historically, Hydro Tasmania’s primary area of capital expenditure has been hydro-generation assets, with $407 million expended between 2004 and 2007. Capital expenditure was reduced between 2007 and 2009 due to the financial impact on Hydro Tasmania from the drought, which reduced free cash flows (see Figure 28).

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240 Of the $60 million expended on the billing system, $32 million has not been capitalised, but has been written off as an expense having a direct impact on the company’s financial performance.
Between 2004 and 2006, $103 million was expended on renewable developments, including wind farm assets. From 2006, following the Roaring 40s joint venture arrangement, investment in wind asset development is recorded as equity to the joint venture. Between 2007 and 2010, Hydro Tasmania contributed $48 million equity to the joint venture.

Figure 29 - Transend's capital expenditure FY04 to FY10

Source: Panel analysis

Transend’s primary area of capital expenditure is the transmission network. As Figure 29 illustrates, in 2004 capital expenditure was predominantly on renewal of assets. However, by 2010 the focus of investment is on development assets. Expenditure in 2009 and 2010 included the Waddamana-Lindisfame 220kV transmission line to secure transmission to Hobart and southern Tasmania, with that project costing approximately $130 million.

Summary of capital expenditure and investment in business diversification

Table 4 below sets out the capital expenditure and investment in business diversification activities by each entity over the 2004 to 2010 period. Over this period, a total of $2.6 billion has been invested within the SOEB portfolio, including around $491 million in equity investments to fund business diversification activities.

Hydro Tasmania contributed $48 million of equity to the Roaring 40s JV to fund wind farm development, funded by its Shareholders, sourced from an equity withdrawal from Transend. Hydro Tasmania acquired 100 per cent ownership of Momentum for $52 million from internal funds.

Aurora Energy acquired 100 per cent ownership of the TVPS for $100 million, funded by a direct equity contribution from its Shareholders. Completion of the TVPS cost $260 million and was debt-funded by Aurora Energy with the assistance of a Treasurer’s letter of comfort on borrowings. Aurora Energy purchased gas contracts and dispatch rights from Babcock and Brown for $15 million.
Transend acquired Hydro Tasmania’s telecommunications business for $15.8 million.

By comparison, as discussed in the sections below, over the same period net SOEB debt has increased by $938 million and returns to Government through dividends totalled $309 million.

Table 4 - SOEB portfolio capital and investment expenditure 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro Tasmania Capex</td>
<td>135</td>
<td>105</td>
<td>128</td>
<td>54</td>
<td>55</td>
<td>81</td>
<td>96</td>
<td>654</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - R40JV</td>
<td>10</td>
<td>23</td>
<td>10</td>
<td>5</td>
<td></td>
<td></td>
<td></td>
<td>48</td>
</tr>
<tr>
<td>Hydro Tasmania Investment - Momentum</td>
<td>17</td>
<td>35</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>52</td>
</tr>
<tr>
<td>Aurora Energy Capex</td>
<td>83</td>
<td>102</td>
<td>134</td>
<td>125</td>
<td>134</td>
<td>168</td>
<td>169</td>
<td>915</td>
</tr>
<tr>
<td>Aurora Energy Investment - TVPS</td>
<td></td>
<td></td>
<td></td>
<td>294</td>
<td>66</td>
<td></td>
<td></td>
<td>360</td>
</tr>
<tr>
<td>Aurora Energy Investment - Gas contracts and dispatch rights</td>
<td></td>
<td></td>
<td></td>
<td>15</td>
<td></td>
<td></td>
<td></td>
<td>15</td>
</tr>
<tr>
<td>Transend Capex</td>
<td>61</td>
<td>74</td>
<td>89</td>
<td>55</td>
<td>64</td>
<td>97</td>
<td>132</td>
<td>572</td>
</tr>
<tr>
<td>Transend Investment - Telco</td>
<td>16</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>16</td>
</tr>
<tr>
<td>Total Capex and Equity Investment</td>
<td>279</td>
<td>281</td>
<td>351</td>
<td>244</td>
<td>276</td>
<td>698</td>
<td>503</td>
<td>2632</td>
</tr>
</tbody>
</table>

3.2.2. Debt

The SOEB total debt position has increased by $940 million, or 63 per cent, between 2004 and 2010 ($1.482 billion in 2004 to $2.419 billion in 2010), as shown in Figure 30. The primary drivers of increased debt have been the construction of the TVPS and network investment by Aurora Energy’s distribution business, network investment by Transend and investment in business diversification by Hydro Tasmania.
On disaggregation, Hydro Tasmania retained the dominant share of the former HEC’s debt, which is reflected in its proportion of overall portfolio debt. By comparison, Transend was established in 1998 with nil debt, reflecting its expected need to finance a substantial capital spending program on the transmission network to replace aged assets and improve performance standards.

Although capital investment in the transmission network has required increases in debt over time, Transend has had the requisite balance sheet capacity (the ability to borrow and service additional debt), as the value of its asset base and its revenue has continued to grow.

Historically, Aurora Energy’s debt primarily related to its distribution business for capital investment in the network, for which it receives a return. More recently, the TVPS has impacted Aurora Energy’s debt profile. This is reflected in the increase in debt in 2009 from $555 million to $933 million. Aurora Energy’s prudential requirements caused a temporary fluctuation in debt in 2009 and 2010.

To support the overall debt that would be held by Aurora Energy, Tascorp required a letter of comfort from the Treasurer in respect of the TVPS debt.241

The Tasmanian Government has retained an oversight role in relation to the debt profile of the sector, and has undertaken three Capital Structure Reviews since disaggregation to assess the capital structure position of each entity in the overall SOEB portfolio.

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241 The Panel understands that these support measures have been used by TASCORP in the case of other businesses when debt has exceeded levels that TASCORP is comfortable with on a stand-alone basis.
In 2008, the SOEB Shareholders approved an equity transfer of $270 million from Transend to Hydro Tasmania, of which $220 million was executed effectively as a ‘debt swap’ between the two entities, and $50 million (also borrowed by Transend) was transferred to Hydro Tasmania, via Government. This is reflected as an increase in Transend’s debt in 2008 and a consequential decrease in Hydro Tasmania’s debt in the same year.

The Government undertook its third capital structure review in 2010 which concluded that, at that time, no equity rebalancing would take place. In the 2011-12 State Budget, the Government announced a further equity contribution from Transend ($100 million over five years), this time to meet the equity requirements of TasRail to relieve the burden on the Consolidated Fund. Prior to this policy, the Government had intended to recapitalise TasRail by means of direct payments from the State Budget.

While Transend has the balance sheet capacity to borrow in order to fund these Shareholder equity withdrawals, Transend’s increased interest costs on this debt, against which no income is generated, will directly impact financial performance and consequently the dividend returns to Shareholders.

3.2.3. Returns to Shareholders - dividends paid

This section considers returns to Shareholders on the basis of dividends paid. The Panel considers that the financial performance of the SOEBs is most appropriately considered on a return on equity basis to provide a competitively neutral comparison with private sector utilities. As such, competitive neutrality payments such as tax equivalent and guarantee fee payments, which do provide cash payments to the Tasmanian Government, are treated as an expense of doing business and not considered a suitable performance indicator. Private sector companies also pay these costs, albeit to other institutional recipients.

Figure 31 illustrates the total SOEB dividend payments to Shareholders, including contribution by each entity over the period 2004 to 2010.

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242 2011-12 State Budget speech.
243 This view is consistent with the Tasmanian Government’s dividend policy for government owned businesses which is available at www.treasury.tas.gov.au.
244 The Panel notes that these do provide a benefit of public ownership to the Budget and are typically large by comparison with dividend returns.
Over the period 2004 to 2010, total dividend returns to Shareholders from the SOEB portfolio totalled $309 million. Hydro Tasmania was the largest contributor at 48 per cent (or $150 million), with Aurora Energy and Transend each contributing around 25 per cent (Aurora Energy $79 million and Transend $81 million). Hydro Tasmania’s dividend contribution includes special dividends totalling $52 million (comprising $27 million in 2004, $17 million in 2005 and $8 million in 2006) or 17 per cent of the total SOEB portfolio dividend return.

Between 2004 and 2006, total SOEB dividend payments were relatively consistent at around $65 million per annum, largely as a result of the special dividend policy for Hydro Tasmania. However, there has been a significant decline in dividend returns from 2006 ($66 million) following the end of special dividends, declining to a low of $19 million in 2009 and 2010.

Figure 32 illustrates the total SOEB portfolio dividend payments to Government both as a proportion of total portfolio revenue and portfolio equity over the period 2004 to 2010.
Over the period 2004 to 2010, total dividend returns to Government from the SOEB portfolio, on both a revenue and equity basis, declined, with the most significant decline being the dividend return on equity. This is despite growth in revenue and equity (excepting the 2004 financial year) as illustrated in Figure 33. In the most recent financial period, returns have been at or below 1 per cent for both measures.

**Note:** The decline in SOEB portfolio equity in 2005 relates to a change in Hydro Tasmania’s equity from $2.056 billion in 2004 to $942 million in 2005. In 2005 there was a fall in Hydro Tasmania’s asset revaluation reserve of $523 million arising from an asset revaluation decrement. In 2006, with the introduction of international accounting standards, the 2005 financial statements were restated in accordance with the new standards – this resulted in a further decline of $19 million arising from an asset impairment loss. In addition, AIFRS required the recognition of additional deferred tax assets and liabilities resulting from adopting a different recognition principle than AGAAP. (Source: Hydro Tasmania).
Returns to Government, through dividends paid, reflects the Shareholder’s acceptance of a portion of after tax profit. In setting dividend policy for the SOEBs, the Government balances several key considerations:

- Variability of returns – stability and predictability versus direct links to actual profitability;

- Level of returns – retain capital in the SOEBs to fund growth strategies or return to the community through the Budget; and

- Managing debt levels\(^{245}\) – retain or withdraw capital in the SOEBs to achieve target capital structures commensurate with each business’s risk profile, or accept an alternate credit rating.

For much of the review period, in accordance with the Government’s dividend policy, this was generally a 50 per cent return on after tax profits. However, a reduced, or nil, dividend has been applied under a range of circumstances. Notably, external events such as the impact of extreme hydrological conditions on Hydro Tasmania are reflected in nil dividends paid in the 2008 and 2009 financial years; and Aurora Energy’s 2010 financial results are reflected in a nil dividend paid in 2011. During the period of special dividends, the Government required a fixed amount of total dividends (ordinary plus special) from Hydro Tasmania which is reflected in the stronger dividend returns for the period 2004 to 2006.

In the 2011-12 Budget, the Government announced a preference for improved dividend returns from its businesses, including those in the SOEB portfolio. For 2011 dividend arrangements for the SOEB’s are:

- Hydro Tasmania’s dividend will increase from a 50 per cent to 70 per cent of underlying profit;\(^{246}\)

- Aurora Energy’s dividend will increase from a 50 per cent smoothed over five years to a 60 per cent of underlying profit; and

- Transend’s dividend will increase from 50 per cent to 60 per cent of underlying profit.

Both improvements in financial performance and the Government’s preference for improved dividend returns (effective dividends payable in 2012) are illustrated in the following recently announced dividends:

\(^{245}\) Government’s may also make decisions regarding debt allocation between the public trading enterprise sector and the general government sector when considering dividends, but this does not change the overall debt levels in the total Tasmanian Public Sector.

\(^{246}\) In accordance with the Tasmanian Government’s dividend policy, dividends are to be negotiated with reference to after tax profit, although it is recognised that sometimes, reported profit may not be supported by cash flows and it may be appropriate for the dividend to include the adoption of a suitable smoothing arrangement or to include on an underlying profit measure rather than accounting net profit after tax. An underlying profit removes the impact of intermittent non-cash events such as significant asset revaluation or a change in accounting standards artificially increase or decrease operating profits without a supporting movement in cash flows.
• In its 2011 annual report, Hydro Tasmania paid a dividend in respect of 2010 of $26 million and announced a dividend of $49 million in respect of the 2011 year (payable in 2012);

• In its 2011 annual report, Aurora Energy paid a nil dividend in respect of 2010 and announced a dividend of $11.9 million in respect of the 2011 year (payable in 2012); and

• In its 2011 annual report, Transend Networks paid a dividend in respect of 2010 of $13 million and announced a dividend of $29 million in respect of the 2011 year (payable in 2012).

3.2.4. Superannuation defined benefits obligations 2010

Each of the SOEBs has employees that are members of the Tasmanian Government’s defined benefit superannuation scheme, reflecting a legacy from the original HEC.247 The scheme has been closed to new members since 1999. As this liability is unfunded, each business has an obligation to fund the scheme as member’s entitlements fall due.248 Hydro Tasmania’s liability includes all scheme members retired at disaggregation, regardless of the alignment of employees with the post-disaggregation entities.

Figure 34 illustrates the increasing net financial liability associated with the defined benefits scheme and the relative contribution of each SOEB. The liability represents the present value of the expected payments to members in the scheme. The three SOEBs are collectively, currently making payments to superannuants of around $25 million per annum.

247 Historically, the Defined Benefit Scheme covered all employees of General Government and government instrumentalities, including the HEC.

248 As members retire, the SOEBs are required to fund 75 per cent of the member benefit, with the Retirement Benefit Fund’s plan assets funding the balancing 25 per cent. If members elect to take a lump sum, the SOEB is required to fund 75 per cent of that lump sum at the time it is taken. If members take a pension, the SOEBs are required to fund 75 per cent of the pension on an emerging costs basis.
The Panel’s investigations reveal that the SOEBs do not routinely have actuarial forecasts for the emerging funding requirements beyond the forthcoming year, and for planning purposes typically assume a fixed roll forward of current payments. Given the age profile of the membership in each of the SOEBs, there can be expected to be a large flow of members from the workforce to retirement over the coming five years, which could lead to a significant change in funding requirements.249

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249 The Panel has been advised that a large portion of the liability relates to past employees that are now 80 years and older. As the liability for these members falls away, it will be replaced by that of current employees.
4. Financial risks and opportunities

The SOEB entities, and consequently the Shareholders’ value in the SOEB portfolio, face a number of financial risks with few financial opportunities. These are discussed below.

4.1. Hydrological conditions

In a predominantly hydro-based generation system, hydrological conditions are a major influence on the financial performance of Hydro Tasmania. With the flexibility provided by Basslink, Hydro Tasmania is in a much stronger position to manage the physical (energy) aspects of hydrological risk than in the past and the fundamental nature of the risk has, therefore, changed.

Prior to NEM entry and Basslink, Hydro Tasmania was charged with responsibility for maintaining energy security under the Electricity Supply Industry Act 1995, and Hydro Tasmania was effectively required to meet the full energy requirements of the Tasmanian market. While this obligation was formally removed with NEM entry, with the sustained period of low inflows into the hydro system, the Government identified energy security as its first priority for Hydro Tasmania until the TVPS was commissioned in October 2009.

Hydro Tasmania’s Ministerial Charter continues to require it to prudently manage its water storages consistent with advised long run energy capability. Hydro Tasmania’s preferred operating zone is a storage system level between 30 and 50 per cent of capacity. The lower level represents an ‘insurance level’ that can be used to generate electricity during some years of drought, while the higher level represents a reasonable buffer that can be used to provide flexibility in trading operations.

Table 5 illustrates water inflow variability between 2004 and 2011, and the impact of water storage levels on Hydro Tasmania’s station output and overall hydro system rating. 2011 water storages reflect improved inflows and Hydro Tasmania’s deferral of generation (‘banking’ water) to maximise business value through the introduction of a price on carbon.

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250 Hydro Tasmania’s obligation to supply was imposed under section 26(1) of the Electricity Supply Industry Act 1995 which was repealed on NEM entry on 29 May 2005.

251 Hydro Tasmania’s 2010 Annual Report.
Table 5 - Water inflow variability and system output 2004 to 2011 (as at 30 June)

<table>
<thead>
<tr>
<th></th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro system rating GWh</td>
<td>10 200</td>
<td>10 200</td>
<td>10 200</td>
<td>9 500</td>
<td>9000</td>
<td>8700</td>
<td>8700</td>
<td>8700</td>
</tr>
<tr>
<td>Yield (inflow) GWh</td>
<td>11 034</td>
<td>7 318</td>
<td>10 923</td>
<td>6 606</td>
<td>7 146</td>
<td>8 419</td>
<td>9 410</td>
<td>10 731</td>
</tr>
<tr>
<td>Hydro station output GWh</td>
<td>9834</td>
<td>9610</td>
<td>9688</td>
<td>8128</td>
<td>7100</td>
<td>7203</td>
<td>8184</td>
<td>9273</td>
</tr>
<tr>
<td>BBPS output GWh</td>
<td>796</td>
<td>934</td>
<td>585</td>
<td>936</td>
<td>1 169</td>
<td>608</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Water storage levels</td>
<td>38.2%</td>
<td>22.7%</td>
<td>30.5%</td>
<td>19.3%</td>
<td>19.1%</td>
<td>27.7%</td>
<td>36.6%</td>
<td>45.9%</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania

During the drought conditions in 2007 and 2008, Hydro Tasmania’s overall contract position limited its ability to pass through to customers the additional costs associated with operating the BBPS and purchasing electricity from the NEM.252 However, the methodology used to determine the energy price set in the 2007 Price Determination (effective 1 January 2008 to 30 June 2010), included a drought premium of slightly less than $3/MWh, or an additional 5 per cent to the base estimate allowance determined by independent consultants.253

In this sense, while Hydro Tasmania predominantly bore the financial risk in backing its contract position from alternative, more expensive on-island generation from the BBPS and from purchases from the market via Basslink, inclusion of a drought premium in the regulated energy allowance for non-contestable customers meant that these customers also carried some of the financial risk. Over the period 2007 to 2010254, this amounted to $28 million paid by non-contestable customers. Additionally, due to the financial impact of the drought, Hydro Tasmania did not pay a dividend to its Shareholders in the 2008 and 2009 financial years, and paid a dividend of only $5 million in 2010.255 Thus, Hydro Tasmania’s Shareholders, and consequently the Tasmanian community, also bore some of the financial risk of the drought through nil or reduced dividend returns.

Hydro Tasmania now has access to flexible options to use its own water to back its contract position or trade through Basslink and effectively purchase from the market. Moreover, with the changes in its regulatory arrangement, Hydro Tasmania has much more commercial flexibility to choose its level of contracting in line with prevailing water availability.

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252 Spot market prices; however, rose as water value increased and renegotiated contracts were recontracted at higher prices, reflecting water value.
254 Based on 8,192,609 MW/h to meet the non-contestable customer load during this period.
255 Dividends payable in respect of a financial years operating performance are payable in the following financial year.
From Hydro Tasmania’s perspective, hydrological risk is now primarily a balance between revenue certainty and its own risk appetite for maximising the value of its water, rather than a matter of Tasmania’s energy supply security.

4.2. Carbon Pricing

The Australian Government has announced a framework to implement a price on carbon emissions and legislation to implement these arrangements was passed by the House of Representatives on 12 October 2011 and the Senate on 8 November 2011. A price on carbon will increase the relative costs of carbon emitting generators and consequently, the average market price of all electricity.256 As a non-carbon emitting generator, Hydro Tasmania’s cost structure will not be materially impacted by carbon pricing, resulting in a potential value gain as market prices rise.

In the short to medium term, the extent to which Hydro Tasmania can ‘capture’ this value is partially dependent on its contract position and its ability to pass through changes in the market value of electricity as a result of carbon pricing to its customers.

A key consideration for Government and the Tasmanian community is how this additional value is used, particularly the degree to which it is retained within Hydro Tasmania to fund business development and expansion opportunities or returned to taxpayers through dividends for wider use in the Budget process.

Under its current dividend arrangements, Hydro Tasmania is required to return dividends based on 70 per cent of underlying profit, so that a significant portion of any additional revenue will be returned as dividends under that arrangement.

On the other hand, the introduction of a price on carbon will increase the costs of the TVPS, resulting in a deterioration of its competitive position in the Tasmanian market compared to Hydro Tasmania. In the short term, the extent to which a price on carbon impacts on Aurora Energy’s financial position will depend on the extent to which the regulatory framework allows the pass through of these costs to non-contestable customers.257 Carbon pricing will improve the relative competitiveness of gas fired generation compared to coal generation (given its lower carbon intensity). Over the medium term, to the extent that Tasmanian wholesale electricity prices reflect market prices in the NEM, carbon pricing may assist the competitive position of the TVPS. However, without access to the NEM, for example via Basslink IRRs, the TVPS will remain ‘trapped’ in the hydro dominated Tasmanian system.

256 See the Panel’s ‘Issues Paper’ available on the Panel’s website www.electricity.tas.gov.au
257 Currently Aurora Energy utilises the TVPS to back its non-contestable customer load. The pass-through of carbon costs is provided for in the current regulatory determination of maximum prices for non-contestable customers.
4.3. Renewable energy certificates

Any improvement in REC prices, for example arising from recent amendments to the Australian Government’s Renewable Energy Target\(^{258}\), will also be a source of value to Hydro Tasmania. In addition, with deferral of generation to capture the benefits of carbon pricing, Hydro Tasmania is likely to see additional REC value arising from increased generation to utilise the stored water, provided the base line threshold is reached.

4.4. Retail competition

As a relatively small retail business in the context of the NEM, Aurora Energy is already exposed to scale disadvantages. The introduction of full retail contestability (FRC)\(^{259}\) in the context of a competitive retail market would be expected to diminish Aurora Energy’s customer base and consequently negatively impact financial performance, as its largely fixed cost base will be spread across fewer customers.

A consequential effect of FRC is a move to a more market-based wholesale energy price. In its submission to the Panel’s Issues Paper, Hydro Tasmania noted “that Tasmanian non-contestable contract prices are higher than those charged for contestable contracts”. The current regulatory arrangements provide ‘headroom’ from which Aurora Energy is able to contract with the TVPS on a basis which allows it to recover its relatively high capital and operating costs.

Reflecting the benefits of competition, the implementation of FRC will result in the transfer of the value inherent in the difference between market prices and the regulated wholesale energy allowance from the SOEB portfolio to Tasmanian electricity customers. A similar outcome could be achieved by more closely aligning the regulated wholesale energy allowance to market prices, noting that this would similarly impact on Aurora Energy’s ability to fund the current cost structure of the TVPS.

4.5. Expenditure exceeding regulatory allowances

For the distribution and transmission network businesses, revenue is primarily determined through the application of the regulatory framework, which provides for a return on assets invested in the network and covers operating costs\(^{260}\).

Actual performance by Aurora Energy and Transend against their respective regulatory allowances is both a potential risk and a potential opportunity.

\(^{258}\) To separate the Large-scale Renewable Energy Target (LRET) and Small-scale Renewable Energy Scheme (SRES) and provide a more sustainable forward path for LRET to support large scale renewables development.

\(^{259}\) A key policy of the Tasmanian Government’s energy market reform since 1997\(^{259}\) was the introduction of greater competition in the retail market. At this time the introduction of Full Retail Competition (FRC) is dependent on a public benefit test determining the benefits of FRC will outweigh the implementation costs.

\(^{260}\) Refer Sections 2 and 3 of Part 2 of this Paper.
Overspending regulatory allowances within a regulatory period directly impacts on financial performance and consequently returns to Shareholders through dividends. Overspending regulatory operating expense allowances has a direct and equivalent impact on financial performance in the year in which occurs, while for capital expenditure the impact on financial performance is limited to the additional depreciation and interest charges. Conversely, underspending regulatory allowances, particularly operating expenditure will positively impact on financial performance in the year in which it occurs.

On a cumulative basis, over the two regulatory periods the 2004 to 2010 review period spans, both Transend and Aurora Energy have overspent their respective regulatory allowances for both capital expenditure and operating expenditure for the network businesses. For the full regulatory period covered by the analysis, both Transend and Aurora Energy overspent their respective capital and operating allowances. However in the initial years of the current regulatory period, both companies have constrained operating expenditure to within the annual allowances. For instance:

- Aurora Energy overspent its capital expenditure allowance in the 2003 regulatory period by $179 million and to date within the 2007 regulatory period has overspent its capital allowance by $29 million.

- Aurora Energy overspent its operating expenditure allowance in the 2003 regulatory period by $16 million and to date within the 2007 regulatory period has underspent its operating allowance by $2 million.

- Additionally, Aurora Energy’s actual ‘costs to serve’ has consistently exceeded its regulatory allowance.

- Transend overspent its capital expenditure allowance in the 2003 regulatory period by $37 million and to date within the 2009 regulatory period has underspent its capital allowance by $28 million (largely due to the Waddamana-Lindisfarne project being delivered under budget).

- Transend overspent its operating expenditure allowance in the 2003 regulatory period by $28 million and to date within the 2009 regulatory period has underspent its operating expenditure allowance by $3 million.

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261 However, provided it is found by the regulator to have been warranted, capital expenditure in excess of the regulatory allowance impacts on customer prices as overspend is included in the opening regulated asset base of the next regulatory period.

262 For drivers of capital expenditure refer Section 2 of Part 2 of this Paper.

263 For drivers of operating expenditure refer Section 2 of Part 2 of this Paper.

264 For drivers of capital expenditure refer Section 3 of Part 2 of this Paper.

265 For drivers of operating expenditure refer Section 3 of Part 2 of this Paper.
As there are adverse consequences for financial performance from consistent overspending in this way, it will be important to ensure in future that the network businesses operate within allowances approved by the regulator. The Panel notes that the Shareholders’ most recent letters of expectation to the Boards of the network businesses have identified this as a requirement.

4.6. Major financial obligations

Each of the SOEBs has major fixed financial obligations in addition to debt and unfunded superannuation liabilities.

4.6.1. Transend

Following the 2011-12 State Budget, an equity transfer to TasRail totalling $100 million - $20 million per annum for five years - is included in the forward estimates in order to relieve that business’ equity burden on the Consolidated Fund. Based on the analysis of Transend’s use of cash from operations to fund capital expenditure, it is probable that this equity withdrawal will be funded through increased borrowings. This draw on equity is in addition to the Government’s previous decision to rebalance equity across the portfolio via a debt swap from Hydro Tasmania to Transend ($220 million) and to withdraw equity in Transend ($50 million) in 2008 which was also provided to Hydro Tasmania.

Transend’s increased interest costs on this debt, against which no new income is generated, will directly impact financial performance and consequently dividend returns to Shareholders. It will, however, have no impact on electricity prices.

4.6.2. Aurora Energy

As discussed previously, the TVPS is the most immediate issue in the SOEB portfolio. The TVPS current financial viability is supported by the regulated energy allowance for non-contestable customers and Aurora Energy’s contractual arrangements with Hydro Tasmania. There is no certainty of these arrangements beyond the current regulatory period (ending at 30 June 2013), although the Price Control Regulations provide the Treasurer with the ability to maintain the existing arrangements. The overall debt associated with the TVPS is a key risk should the current contractual and regulatory arrangements not continue beyond the current regulatory period.

Aurora Energy also has large fixed cost financial obligation relating to its commercial gas arrangements.

4.6.3. Hydro Tasmania

Hydro Tasmania’s ability to fund its Basslink Services Agreement (BSA) relies in part on the arbitrage of energy sales and purchases to other NEM regions. Hydro Tasmania’s ability to generate this arbitrage revenue under the BSA in this manner is influenced by:
the volume of generation in Tasmania, which is a function of water storages;

- electricity price differences between the Tasmanian and Victorian regions; and

- the differences between peak and off-peak prices in Victoria as this drives the value of arbitrage opportunities.

This arbitrage opportunity involves Hydro Tasmania holding back generation of electricity at times of low prices in Victoria, allowing cheap electricity to flow southward as a substitute for on island generation, and then later at times of high Victorian prices generating that same volume and selling it into Victoria, thus achieving higher value from Tasmanian hydro generation. This opportunity is a key component of the Basslink business case.266

4.6.4. Diversification activities and operation in national/international markets

In general terms, the performance to date by the diversified business activities undertaken by Hydro Tasmania and Aurora Energy has meant that those investments have failed to deliver material free cash flows and, consequently, dividend returns to Shareholders.

In terms of capital invested, the largest financial investment within the SOEB portfolio, Hydro Tasmania’s investment in wind assets (of which $96 million267 of direct equity has been expended to date), is yet to return any positive cash flow back to the Tasmanian community. Following the dissolution of the Roaring 40s JV with CLP, Hydro Tasmania has recently announced its intention to sell-down the Woolnorth wind farm assets. It is this process that will determine the level of cash return on Hydro Tasmania’s previous investment. Similarly, Hydro Tasmania’s investment to date in the Musselroe wind farm will not be realised until that project is completed.268

The distribution of returns from Hydro Tasmania should be a matter of fundamental interest for its ultimate Shareholders, the Tasmanian community. This is a potential source of value that can be used to redress structural issues within the TESI, provide a source of funds for public capital spending by the Tasmanian Government in a budget constrained environment or be reinvested by Hydro Tasmania on value creating activities. Hydro Tasmania has announced that the proceeds of the sale of Woolnorth will be utilised to fund its new wind development model with the “divestment of a stake of up to 75 per cent in Woolnorth will assist with the construction of the Musselroe wind farm and progress ongoing wind plans both in Tasmania and on mainland Australia.”269

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267 Of which $50 million was provided as an equity contribution from the Government.
268 On 6 December 2011 Hydro Tasmania announced that the Musselroe wind farm would proceed with construction expected to be completed by July 2013. Hydro Tasmania is in the process of seeking an equity partner in its Woolnorth wind farm and this partner will also have opportunity to take an equity position in the Musselroe wind farm.
269 Hydro Tasmania’s 2011 Annual Report.
A clear strategic or policy link to the core purpose of public ownership would provide a more transparent basis for resolving the tensions inherent between investment in business diversification activities and the opportunity cost of that capital that could be invested or utilised elsewhere for the benefit of the community.

Resolution of tensions of this kind would be greatly assisted by the establishment of a well-articulated rationale for public ownership to guide key decisions such as the reinvestment of equity within the portfolio and the split of that investment between functional business activities and diversification activities. This matter is further addressed in part E of this volume.
PART TWO

A review of the financial position of the State Owned Electricity Businesses
5. Hydro Tasmania

5.1. Scope of business operations

Prior to 1998, the Hydro-Electric Commission (HEC)\textsuperscript{270} operated as a statutory monopoly with responsibility for all aspects of the electricity supply industry. The Electricity Companies Act 1997 (Tas) provided for the establishment of State-Owned-Companies (SOC) in respect of transmission, distribution and retailing of electricity in Tasmania. On 1 July 1998, the HEC was structurally disaggregated into three separate businesses, generation and system control (Hydro Tasmania); transmission (Transend) and distribution and retail (Aurora Energy). System control subsequently transferred to Transend on 1 July 2001.

Hydro Tasmania is a wholly owned Government Business Enterprise (GBE), established under the Hydro-Electric Corporation Act 1995 and the Government Business Enterprises Act 1995. Hydro Tasmania is responsible to the Treasurer and its Portfolio Minister, the Minister for Energy.

Hydro Tasmania’s business operations are diverse and cover a range of activities across the electricity supply chain:

- Generation assets are, for the most part, comprised of Tasmania’s hydro-generation system of 30 power stations located across six high-rainfall water catchments formed around natural river systems. Additionally, Hydro-Tasmania owns wind generation assets which currently include wind farms and development sites located in Tasmania, Victoria and New South Wales, but have previously included assets located in South Australia and international markets.

- Hydro Tasmania is an energy trader in the National Electricity Market (NEM) and has customers both in Tasmania and other NEM regions.

- Its retail business, Momentum Energy Pty Ltd (Momentum), is located in Melbourne with customers in Victoria, South Australia, Queensland, the ACT and New South Wales. Hydro Tasmania is currently prevented from retailing electricity in Tasmania (other than the Bass Strait Islands) due to legislative constraints based on competition requirements.

- Hydro Tasmania’s consulting services business, Entura, operates locally, nationally and internationally, providing engineering services to clients in the power, water and environmental services fields; and on a reducing basis to Hydro Tasmania.

\textsuperscript{270}In 1995, the Hydro-Electric Commission was corporatised and was renamed the Hydro-Electric Corporation, which currently trades as Hydro Tasmania.
5.2. Key events impacting on financial performance

Figure 35 below illustrates the key events in history of Hydro Tasmania post-disaggregation that have influenced the performance of the business.

Figure 35 - Key events influencing Hydro Tasmania's financial performance

The outcome of the Gordon below Franklin debate in the late 1970s and early 1980s effectively signalled the end to the development of new major hydro generation capacity in Tasmania. Around the same time, at the national level, the electricity sector was subject to significant competition reform initiatives. Combined, these led to the Tasmanian Government’s 1997 Energy Strategy which changed the landscape of the Tasmanian energy sector and has been the primary driver of Hydro Tasmania’s business direction and focus since 1998.

For Hydro Tasmania, the broader market benefits of greater competition and customer choice for energy in Tasmania gave rise to changes in business risk. These new risks come on top of managing hydrological inflows and the possible stranding of energy in a constrained market from the loss of a large industrial load which have been key risks to the business for a long time. Tasmania’s participation in the NEM also provided the stimulus for the pursuit of business opportunities outside Tasmania.

Consequently, Hydro Tasmania’s business strategies between 1998 and 2011 have been based on leveraging advantage (market and knowledge) to manage risk and the pursuit of value creating opportunities in the NEM and internationally.

Following the end of dam construction, Hydro Tasmania’s consulting business, now trading as Entura, was retained to provide operation and maintenance services to the existing hydro-generation assets and provide engineering services to other SOEBs. Subsequently, Hydro Tasmania utilised its engineering capacity for the development of wind farms. Hydro Tasmania has an ongoing strategy to diversify Entura’s revenue base away from Hydro Tasmania including into national and international markets. To this end, in 2011, services provided to Hydro Tasmania comprised 28 per cent of Entura’s total revenue compared to 68 per cent in 2004.

The commissioning of the Tasmanian Natural Gas Pipeline (TNGP) in 2002 resulted in on-island energy and (eventually) electricity generation competition. Without an alternative market, Hydro Tasmania risked stranded load as a result of a large industrial load leaving the State. This provided the impetus for Hydro Tasmania’s pursuit of the Basslink interconnector. Basslink also provides Hydro Tasmania with an additional source of value through arbitrage.

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273 The Tasmanian Natural Gas Pipeline was underwritten in part the Bell Bay Power Station as a foundation customer-supported by off-take agreements with Hydro Tasmania.

274 With the introduction of the TNGP, the Bell Bay Power Station drought support capacity was converted from oil to gas. It was anticipated that Unit 2 would be repowered to a 220MW combined cycle gas turbine and operated competitively in the market. As an alternative Alinta developed a new proposal to construct what is now the Tamar Valley Power Station, owned and operated by Aurora Energy.
Hydro Tasmania’s initial basis for building wind farms in Tasmania (Woolnorth and Studland Bay) was to secure additional on-island generation capacity following the end of dam construction. Subsequently, Hydro Tasmania developed wind assets in the national and international markets (under its joint venture arrangement with CLP) as a value strategy not related to energy supply in Tasmania. Hydro Tasmania’s current wind strategy is secure RECs to support its retail business growth.

With the commissioning of the TVPS in 2009, and to the extent that Aurora Energy utilises the power station to its back non-contestable customer load, Hydro Tasmania has excess capacity in Tasmania, where the predicted load growth is low. This is a similar risk Hydro Tasmania faced with the TNGP and the proposed redevelopment of the BBPS with additional gas generation capacity. Hydro Tasmania’s retail strategy, through its acquisition of Momentum, is to capture the wholesale and retail value of excess generation capacity in Tasmania on the basis that the NEM wholesale energy market liquidity is dominated by a few large integrated rival energy businesses.

That is, Hydro Tasmania has taken the view that there is sufficient market risk to the value of its energy that it needs to secure its own retail load to capture the full value of its energy. On this basis, Momentum is about increasing value to the Shareholder. As previously discussed, the current wind strategy is linked to Momentum’s availability and price risk of securing the necessary RECs for its retail load. In the medium term, Hydro Tasmania has indicated that it is investigating gas generation opportunities on the mainland to back retail sales and to diversify revenue streams.275

Hydro Tasmania’s current strategy is about building value, a significant move from 2004 where the focus was clearly on providing energy to Tasmanian customers and using Basslink to mitigate the stranding risk of on-island generation. Hydro Tasmania is now seeking to be a material participant in the NEM based on a retail growth strategy of achieving 15 000 GWh of total sales (both to wholesale customers such as Aurora Energy and through Momentum retail sales) by the end of 2014.

In addition to market changes, the review period included a period of extreme hydrological significance, described by Hydro Tasmania as a ‘1:1 000 year event’ of low inflows. Water storages fell to historic lows of 19 per cent across 2007 and 2008.

Figure 36 illustrates Hydro Tasmania’s water storages (as at 30 June) compared to Hydro Tasmania’s preferred operating zone is a storage system level between 30 and 50 per cent full.

275 Hydro Tasmania annual report 2011.
Historically, the Tasmanian Government’s highest priority for Hydro Tasmania has been its responsibility for maintaining the reliability of electricity supplies for the Tasmanian customers. Although statutory enactment of this obligation was repealed when Tasmania adopted NEM arrangements in 2005, Hydro Tasmania was only formally released from this priority by its Shareholders when the TVPS was commissioned in October 2009. Combined with additional generation available in Tasmania through the TVPS resulting in loss of market share to Hydro Tasmania, this has provided the opportunity for a more aggressive mainland business plan.

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276 Hydro Tasmania’s Ministerial Charter still requires it to manage prudently its water storages consistent with advised long run energy capability.
5.3. Summary of financial results 2004 to 2010

A summary of Hydro Tasmania’s key financial results for the period 2004 to 2010 are set out in Table 6 below.

Table 6 – Hydro Tasmania’s key financial results 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenue¹</td>
<td>440</td>
<td>462</td>
<td>467</td>
<td>489</td>
<td>466</td>
<td>626</td>
<td>726</td>
</tr>
<tr>
<td>Electricity Revenue²</td>
<td>378</td>
<td>399</td>
<td>406</td>
<td>446</td>
<td>408</td>
<td>553</td>
<td>688</td>
</tr>
<tr>
<td>EBIDTA³</td>
<td>237</td>
<td>250</td>
<td>210</td>
<td>180</td>
<td>105</td>
<td>201</td>
<td>236</td>
</tr>
<tr>
<td>EBIDTA/ Total revenue</td>
<td>54%</td>
<td>54%</td>
<td>45%</td>
<td>37%</td>
<td>23%</td>
<td>31%</td>
<td>32%</td>
</tr>
<tr>
<td>Gross Debt⁴</td>
<td>1,081</td>
<td>1,212</td>
<td>1,077</td>
<td>1,192</td>
<td>971</td>
<td>941</td>
<td>873</td>
</tr>
<tr>
<td>Capital Expenditure</td>
<td>135</td>
<td>105</td>
<td>128</td>
<td>54</td>
<td>55</td>
<td>81</td>
<td>96</td>
</tr>
<tr>
<td>Dividends Paid ordinary</td>
<td>17</td>
<td>23</td>
<td>32</td>
<td>21</td>
<td>0</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Dividends Paid special⁵</td>
<td>27</td>
<td>17</td>
<td>8</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Equity Transfer⁶</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>270</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania annual reports

Notes:

¹ Total revenue includes revenue from electricity sales, consulting services, the Bass Strait Islands CSO, Momentum sales revenue and other revenue.

² Electricity revenue represents Hydro Tasmania’s revenue from electricity generation and trading.

³ EBIDTA in 2000, 2008 and 2009 are impacted by reduced generation as a result of the drought and increased costs of sales due to the operation of the Bell Bay Power Station and energy purchases from the NEM to meet contracted load. Source: Panel analysis.

⁴ Source Hydro Tasmania annual reports.

⁵ Dividends paid between 2004 and 2006 reflect a policy of extracting special dividends from Hydro Tasmania, which reflected a withdrawal of equity.

⁶ Equity transfer from Transend effectively resulted in a debt swap of $220 million and an equity contribution of $50 million.
Figure 37 illustrates Hydro Tasmania’s electricity sales compared to station output over the period 2004 to 2010.

**Figure 37 - Hydro Tasmania’s electricity sales to Tasmanian customers and station output 2004 to 2010**

![Graph showing electricity sales and station output](image)

Source: Panel analysis

Over the review period, electricity sales to Tasmanian customers increased from $356 million in 2004 to $454 million in 2010, an increase of 28 per cent, through a combination of an increase in total demand and price growth (refer section 5.4). Over the same period, Hydro Tasmania’s level of generation was strongly influenced by a sustained low inflow period in 2007 and 2008 and the consequential ‘de-rating’ of the hydro system from 10 200 to 9 500, 9 000 and 8 700 GWh progressively.

Largely as a result of drought conditions, EBITDA reduced between 2006 and 2008. During this period, Hydro Tasmania was a net purchaser of energy from the market (via Basslink), although it still achieved revenue in the order of $60 million over this period in arbitrage opportunities. The decrease in margin indicates that Hydro Tasmania was unable to pass on to customers the majority of additional costs arising from these conditions. The financial cost was reflected in decreased earnings and consequently lower returns to the Shareholders through dividends.

277 Arbitrage refers to the use of Basslink on a balanced trade basis, where electricity is effectively purchased from Victoria at low prices (i.e. water is conserved by Hydro Tasmania) and at a later time is sent from Tasmania when prices are high (that conserved water used). The difference in value between the high and low periods is the arbitrage value of Hydro Tasmania’s generation flexibility.
5.4. Hydro Tasmania’s role as the main source of generation in the Tasmanian market

Prior to the existence of large-scale alternative electricity sources (Firstly Basslink in 2006 and then TVPS in 2009) and the introduction of retail contestability, Hydro Tasmania effectively met the full energy requirements of all Tasmanian market participants, broadly defined into three groups, Major Industrial (MI) customers, commercial and industrial customers; and business and residential customers (via its contractual arrangements with Aurora Energy’s retailing business).

With the development of alternative generation, the proportion of total Tasmanian demand met by Hydro Tasmania contracts has decreased over time. However, in 2010, Hydro Tasmania still sold load representing 76 per cent of total demand in the Tasmanian market. With the rollout of retail contestability, most customer groups have transitioned to being contestable customers (MIs, commercial and industrial customers, and more recently business customers), meaning that Hydro Tasmania’s contractual arrangements have diversified to include new entrant retailers in addition to Aurora Energy.

Figure 38 illustrates changes to the Tasmanian generation profile between 2004 and 2010 – noting that in 2004 gas related to the BBPS and in 2010 gas related to the TVPS.

**Figure 38 - Tasmanian generation profile 2004 and 2010**

![Graph showing changes in generation profile]

Source: Panel Analysis
5.4.1. Overall performance of the energy business 2002 to 2010

Hydro Tasmania characterises its energy business as its ‘cash engine’. Key drivers of financial performance have been new market opportunities outside Tasmania facilitated by Basslink, the impact of hydrological conditions and changes in Tasmanian load demand and contract prices across customer groups.

Impact of hydrological risk and Basslink

Tasmania’s adoption of NEM arrangements, facilitated by the Basslink interconnector, resulted in changes to the way Hydro Tasmania manages its energy capability.

The value of hydro-generation has also been positively influenced by the arbitrage opportunity derived from Hydro Tasmania holding back generation of electricity at times of low prices in Victoria, allowing electricity to flow southward as a substitute for on island generation, and then later generating that same volume and selling it into Victoria at higher value. Because Hydro Tasmania is active in both the Tasmanian and Victorian spot markets, the differential between these markets will impact on financial performance.

The margin on energy revenue dipped in 2007 and 2008 as a consequence of extreme hydrological conditions in Tasmania which resulted in reduced hydro-generation capacity. Limited generation volume had the combined effect of requiring Hydro Tasmania to purchase energy from the market to fulfil customer contracts and limited its opportunity to utilise Basslink for arbitrage. Moreover, it did not provide opportunity for generation to support net northward flows and impacted negatively on the production of REC revenue.

The majority of the combined costs of the drought and Basslink imports were not passed onto customers, who had contractual cover that spanned the dry period. The financial cost of these events is therefore reflected in decreased earnings and consequently, through lower dividends paid to the Shareholders over the period 2007 to 2010.

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278 Hydro Tasmania annual report 2006.
279 The Panel has released a separate paper on the Basslink business case and operational performance.
280 A small number of contestable customers who recontracted towards the end of the drought period did see higher prices as a result of the drought and non-contestable customers paid a $3/MWh drought premium for the period of the 2007 price determination.
281 Note that dividends paid in 2010 were in respect of the 2009 financial year.

A review of the financial position of the State Owned Electricity Businesses
Major Industrial contract revenue

Hydro Tasmania serves Tasmania’s four largest energy demand customers, known as the MI customers. In 2010, MI contracted load comprised approximately 55 percent of Hydro Tasmania’s total contracted load. Notwithstanding some year-on-year fluctuations during the review period, MI contract load as a proportion of total contracted load has remained relatively consistent at that level. MI customer revenue makes a material contribution to Hydro Tasmania’s revenue at around 40 percent in 2010.

Throughout the review period, contract prices for MI customers have increased steadily as contracts have been re-negotiated at market prices reflective of those loads, but still remain the lowest of the three customer groupings. Increasing the value achieved from MI customers was an important aspect of Hydro Tasmania’s business case for Basslink as it provided a credible alternative path to market for electricity supplied to MI customers.

Ascribing the commercial value of MI customers to Hydro Tasmania is typically more complicated than for other customers as customer value to Hydro Tasmania is more than the electricity price contained in the electricity supply contracts. The very flat and predictable nature of the MI customers is also a significant factor in pricing.

An important source of value to Hydro Tasmania is MI customer participation in the Basslink load tripping system. This scheme allows Basslink’s southward flows to be operated at higher capacity than otherwise, creating greater arbitrage opportunity for Hydro Tasmania.

The prices paid by MI customers for wholesale energy reflect robust commercial negotiations between Hydro Tasmania and their counterparties, with pricing outcomes representing a tension between what the customers are willing to pay setting the maximum of the ‘bargaining arena’ and the opportunity value of the electricity to Hydro Tasmania setting the lower band. The Panel is satisfied that there are no cross subsidies between regulated customers and MI customers in relation to wholesale energy. Further information on MI customer pricing is contained in the Panel’s Report.

282 The Panel understands that Hydro Tasmania negotiates directly with these large customers in relation to wholesale contracts, which are then transferred to a retailer to be the counterparty to Hydro. This is different to the arrangements for smaller customers, who generally seek to negotiate contracts with retailers, who separately negotiate wholesale energy contracts to back these retail positions.

283 The pricing for MI customers is structured differently to that of other customers as the MI customers consume energy in a very even and daily seasonal pattern. The balance of Tasmania’s demand varies drastically so that peak demand can be twice that experienced at low demand periods. Therefore, MI customers utilise assets used to supply them almost 100 per cent of the time, while other demand requires vast volumes of capacity to be available that is only used for short periods.
Non-contestable contract revenue

Non-contestable contract revenue is revenue derived from Aurora Energy in relation to volume contracted to cover Aurora Energy’s regulated customer load requirement (non-contestable customers).

Historically, non-contestable contract revenue has been an important revenue source for Hydro Tasmania’s energy business. For the period of the 2007 price determination (2007 to 2010), the energy price included in the contract arrangements between Hydro Tasmania and Aurora Energy moved in line with the higher energy allowance set in the pricing determination.

Notwithstanding this, Hydro Tasmania’s non-contestable customer contract revenue decreased from $203 million in 2007 to $173 million in 2010. The decline in contract revenue was driven by a 33 per cent reduction in Hydro Tasmania’s contracted load volume for non-contestable customers over that period. This was due to the phased introduction of retail contestability beyond tranche 2 (large industry customers) and by a reduction in load contracted with Aurora Energy to meet its non-contestable customer requirements.

For the period of the 2010 price determination (2010 to 2012), Hydro Tasmania’s non-contestable contract revenue will further decline as a result of both price and load. In 2011, revenue decreased to $99 million (a reduction of $74 million from 2010) and load reduced a further 38 per cent. Aurora Energy’s utilisation of the TVPS to back its non-contestable customer load means that it is only required to source around one half of its non-contestable customer load requirements from Hydro Tasmania. Further, the net effect of the contract arrangements between Hydro Tasmania and Aurora Energy is that the average price per MWh received by Hydro Tasmania is below the wholesale energy cost allowance set in the 2010 price determination.

Because the wholesale energy allowance determined for non-contestable customers has been typically higher than prevailing market prices for contestable and MI customers, energy prices for the non-contestable load are the highest paid in the Tasmanian market and are higher than the average energy price paid by contestable customers.

As a result, Hydro Tasmania earns a higher energy margin on the supply of the non-contestable load than from other customer groups.

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284 In March 2007, supporting Alinta’s construction of the TVPS, Aurora Energy entered into a long term hedge arrangement to support Aurora Energy’s non-contestable customer load requirements following the commissioning of the power station in 2009. This resulted in Aurora Energy sourcing less of the non-contestable customer load from Hydro Tasmania.

285 Even in a non-regulated environment (i.e. market based pricing), prices paid by non-contestable customers would be expected to be higher for reasons. In particular, the load profile for household customers is very peaky and sensitive to low temperatures requiring capacity to be available that is only used for short periods.
Other contracts (contestable customers)

Beginning on 1 July 2007, retail contestability has been progressively rolled out to eligible customers based on annual power consumption. Contestable customer contract revenue for Hydro Tasmania includes revenue from Aurora Energy and other retailers licensed to operate in the Tasmanian market.

Contestable customer contract revenue has increased steadily from $39 million in 2007 to $93 million in 2010 driven by both an increase in load and average contract price. On average, energy prices to contestable customers are above prices to major industrials and below prices to non-contestable customers.

The pricing framework used by Hydro Tasmania for setting wholesale customer contracts is described more fully in the Panel’s Report. In brief, these prices are set between Hydro Tasmania’s valuation of its water, which is referenced to Victorian contract prices, and its estimate of the LRMC of new entry in Tasmania.

5.5. Diversification of business activities

The increase in the scope of Hydro Tasmania’s operations has resulted in an increase in the financial complexity of the business. With the future retail growth strategy, this is expected to continue. Over the financial review period, the key financial flows have been:

- Internal revenue generated by Entura in relation to work completed for Hydro Tasmania (hydro-generation and wind development). The value of internal revenue has been a significant proportion of Entura’s revenue, particularly through years where external work has been difficult to secure;

- Payments made in relation to Roaring 40s wind farm asset development, and direct cash investment (equity) in the Roaring 40s JV. Hydro Tasmania also has an off-take agreement for energy and RECs on the Waterloo wind farm, previously owned by Roaring 40s; and

- Wholesale energy pricing between Hydro Tasmania and Momentum.

5.5.1. Entura - 2002 to 2010

Entura is Hydro Tasmania’s consulting business that currently provides services to global power, water and environmental markets. Entura operates on a stand-alone basis and has offices in Hobart, Melbourne, Brisbane and New Delhi, India. The Australian operations of Entura are operated as a division rather than a separate legal entity to Hydro Tasmania. Hydro Tasmania Consulting (Holdings) Pty Ltd is a wholly owned subsidiary of Hydro Tasmania established to hold the shareholding of the Indian consulting company.

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286 Activities considered non-core within the Review financial analysis process may be considered to be core within the SOEBs operations.
Historically, internal revenue, generated through the provision of services to Hydro Tasmania’s generation business, has been a key component of Entura’s total revenue. Internal revenue has decreased from 68 per cent in 2004 to 39 per cent in 2010 and is forecast to decrease further with business expectation that an increasing proportion of revenue is to be sourced from work in the national and international markets.\(^{287}\)

Figure 39 illustrates Entura’s revenue by customer segment for the period 2004 to 2010.

**Figure 39 - Entura’s revenue by customer segment 2004 to 2010**

Since 2002, Entura has made an EBIDTA contribution to Hydro Tasmania of between $1 million and $4 million per annum up to 2009, with a loss of $4 million recorded in 2010 associated with a substantial downturn in activity across the engineering consulting sector during and after the GFC. In general terms, increased revenues have been offset by increased expenses; particularly labour costs, which are a key driver of earnings. Labour costs rose by 59 per cent between 2004 and 2010. Prima facie, over the review period it appears that Entura’s operating results reflects reliance, albeit diminishing, on internally generated revenue from Hydro Tasmania as the financial growth opportunities from external sales anticipated at disaggregation have been slow to eventuate.

\(^{287}\) Hydro Tasmania has advised that internal revenue has fallen to 28 per cent in 2011.
Over the past five years, there has been an emphasis on moving from an internal service focus to an external focus through diversification of markets (Tasmania, nationally and internationally); and regions (Australia, the Asia Pacific, including Malaysia, India and Papua New Guinea; and Southern Africa).

There has been a clear transition of this segment of Hydro Tasmania’s business operations from engineering services fundamental to the construction and maintenance of electricity infrastructure in Tasmania, to the provision of services predominantly to other market participants in markets unrelated to Hydro Tasmania’s own hydro-generation operations.

While Entura’s financial results have not materially affected Hydro Tasmania’s financial position, there is likely to be significant additional business and financial risk from operating in emerging international markets rather than in the Tasmanian or national market. Beyond standard risks, operating internationally introduces currency risk and insurance risk associated with the local operating and political environment. Entura will also need to compete in a field dominated by a few large global firms.

5.5.2. Roaring 40s (Hydro Tasmania’s wind generation development vehicle) 2002 to 2010

In response to national policy incentives aimed at growing Australia’s renewables base and to utilise and market its engineering capability, in early 2000 through its subsidiary company Roaring 40s Renewable Energy Pty Ltd (Roaring 40s), Hydro Tasmania commenced the development of a large-scale wind farm at Woolnorth.

In 2005, based on Hydro Tasmania’s perceptions of the future opportunities for wind development in Australia, and its desire to grow value in this part of its business, Hydro Tasmania’s wind strategy shifted from direct investment in wind farm assets in Tasmania and Australia, to growth opportunities in the Asia region with a Joint Venture (JV) partner. Hydro Tasmania realised part of its equity in Roaring 40s through a JV arrangement with China Light and Power (CLP) in 2006. The Roaring 40s JV invested in assets both within Australia (on-island and mainland) and internationally (China and India). Following the sale of Roaring 40s JV international assets (China and India) to CLP in 2009, the Roaring 40s JV was dissolved in 2011.

Table 7 below illustrates Hydro Tasmania’s carrying value in the Roaring 40s JV since inception in 2006.

Table 7 - Hydro Tasmania’s carrying value in the Roaring 40s JV

<table>
<thead>
<tr>
<th>$ Million</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Beginning carrying value</td>
<td>85</td>
<td>80</td>
<td>88</td>
<td>108</td>
<td>122</td>
</tr>
<tr>
<td>Equity contribution</td>
<td>-</td>
<td>10</td>
<td>23</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Share in operating profit/(loss)</td>
<td>(5)</td>
<td>(1.9)</td>
<td>(2.7)</td>
<td>4.4</td>
<td>(6)</td>
</tr>
<tr>
<td>End carrying value</td>
<td>80</td>
<td>88</td>
<td>108</td>
<td>122</td>
<td>121</td>
</tr>
</tbody>
</table>

Source: Hydro Tasmania annual report
The Roaring 40s JV has required significant cash investment from Hydro Tasmania to fund capital investment in renewable energy assets. Revenue generated from the wind assets includes generation sales and revenue from the sale of RECs. In 2009, the Roaring 40s JV returned a small profit after tax of $4 million. However, it has returned losses in all other years. Hydro Tasmania has not received any dividend payment from the Roaring 40s JV.\(^{288}\)

The opening value of Hydro Tasmania’s 50 per cent equity share of the JV in 2006 was $85 million. This increased by $41.8 million or by 52 per cent between 2006 and 2010. However, annual increases in carrying amounts have been driven by annual equity contributions totalling $48 million, offset by share in total operating losses of $11.2 million.

The Roaring 40s JV was disaggregated on 30 June 2011, resulting in the distribution of mainland assets to CLP and the retention of Tasmanian assets, including development sites by Hydro Tasmania. In September 2011, Hydro Tasmania announced the next stage of its wind farm development model, which includes the intention to sell 75 per cent of the Woolnorth wind farm assets and for those funds to be re-applied to further wind developments that accompany Hydro Tasmania’s strategy of retail growth. Hydro Tasmania’s underlying value in its wind farm investments will be determined through any sale process, rather than on the carrying value of its share of the joint venture dissolution.

Hydro Tasmania’s view is that it anticipates a material financial benefit from the sell-down process, which it will apply to develop further wind farms without the need for additional Shareholder equity.

### 5.5.3. Momentum - 2008 to 2010

Momentum is Hydro Tasmania’s retail arm that offers energy contracts, energy efficiency advice and GreenPower products sourced from wind generation. Momentum is based in Melbourne and specialises in business customers located in Victoria, South Australia, Queensland, the ACT and New South Wales. Momentum does not have a retail licence to operate in the Tasmanian market and is prevented from gaining one due to legislative constraints based on competition requirements.

Hydro Tasmania’s strategy to acquire a retail presence in the NEM was primarily based on defensive positioning, in the context of continuing consolidation in the energy sector; and revenue growth through direct access to customers leveraging Hydro Tasmania’s renewable brand. More recently, with the decrease in non-contestable customer load due to the operation of the TVPS in the Tasmanian market, Hydro Tasmania has ‘excess’ physical generation capacity which is effectively utilised to back Momentum load in the short term.

\(^{288}\) Hydro Tasmania’s JV share of the Asia asset sale was $81.8 million ($66 million from China portfolio and $15.5 million from India wind farm) on an investment of $67.8 million. This equity was retained in the JV for investment in renewable energy projects in Australia and not returned to Hydro Tasmania.

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A review of the financial position of the State Owned Electricity Businesses
Momentum has energy supply agreements with Hydro Tasmania. Hydro Tasmania uses excess load generation/supply in Tasmania to back Momentum through northward capacity on Basslink and through direct participation in the contracts market in other NEM regions.

Hydro Tasmania’s retail strategy is to achieve total sales of 15,000 GWh by growing Momentum’s retail business sales to at least 5,000 GWh by 2014, in addition to its Tasmanian-based business. As Momentum’s targeted load growth is realised, this growth is significantly in excess of Hydro Tasmania’s current generation capacity and Hydro Tasmania has noted that “any growth created from new investment will be capital intensive and it will be necessary to explore innovative methods of raising capital”.\textsuperscript{289} In its 2011 annual report, Hydro Tasmania has indicated the investigation of gas generation opportunities on the mainland to back retail sales.\textsuperscript{290}

Hydro Tasmania purchased an initial 51 per cent share in Momentum in September 2008 for $17 million and the remaining 49 per cent in October 2009 for $35 million (total acquisition cost $52 million).

Since part acquisition in 2008, Momentum made net losses of $14.3 million in 2009 and $1.4 million in 2010. The Momentum business is emerging from its start-up phase, reflecting underlying business performance which has improved with sales revenue increasing 79 per cent (or $50 million) from $64 million in 2009 to $114 million in 2010 due to a growth in customer numbers. Over the same period, load sold has increased by 81 per cent. Acquisition and marketing costs in obtaining new customers have impacted on profit in the limited trading period since acquisition. This has not been unexpected.

Hydro Tasmania has advised the Panel of further improvements in business performance in 2011, with sales revenue increasing by 115 per cent (or $131 million) from 2010. In 2011, Momentum made a net profit of $0.8 million. Momentum’s financial performance is included in Hydro Tasmania’s consolidated accounts, meaning that dividends payable in respect of 2011 will include net profit attributable to Momentum.

\textsuperscript{289} Hydro Tasmania annual report 2010.
\textsuperscript{290} Hydro Tasmania annual report 2011.
6. Aurora Energy Pty Ltd

6.1. Scope of business operations

Aurora Energy Pty Ltd (Aurora Energy) was formed on 1 July 1998, from the disaggregation of the then Hydro-Electric Commission (now trading as Hydro Tasmania).

Aurora Energy is a wholly owned State-owned Company (SOC), established under the Electricity Companies Act 1997 and is incorporated under the Corporations Act 2001 (C’wth). The Company’s shares are held in trust for the Crown by its Shareholder Ministers, the Minister for Energy and the Treasurer.

Aurora Energy is a vertically integrated energy company with operations in Tasmania and other regions of the NEM. Specifically, Aurora Energy:

- Retails electricity to customers in Tasmania, New South Wales, South Australia, the ACT and Queensland; and gas to customers in Tasmania and Victoria;
- Trades wholesale gas in Tasmania and other jurisdictions;
- Owns and operates the TVPS through its subsidiary company AETV and has dispatch rights over the Bairnsdale power station in Victoria; and
- Owns and operates the electricity distribution network in Tasmania.
6.2. Key events impacting on financial performance

Figure 40 illustrates the key events in history of Aurora Energy since disaggregation which have influenced the financial performance of the business.

**Figure 40 - Key events influencing Aurora Energy’s financial performance**

Since disaggregation, the Tasmanian Economic Regulator has undertaken three regulatory reviews to determine the Aggregate Annual Revenue Requirement (AARR) for distribution services:

- 1999 Distribution Price Determination (1 January 2000 to 31 December 2003)
- 2003 Distribution Price Determination (1 January 2004 to 31 December 2007)
- 2007 Distribution Price Determination (1 January 2008 to 30 June 2012)

Further, Aurora Energy has been subject to a number of regulatory reviews to determine the Maximum Allowable Revenue (MAR) for the retail allowance for non-contestable customers:

- 1999 Retail Price Determination (1 January 2000 to 31 December 2003)
- 2003 Retail Price Determination (1 January 2004 to 30 June 2007)
- 2007 Retail Price Determination (1 July 2007 to 30 June 2010)
- 2009 Retail Price Determination (1 July 2010 to 30 June 2013)
Following Tasmania’s adoption of NEM arrangements in May 2005, the phased roll-out of retail contestability has introduced competition into the retail market, resulting in the transition of contestable customers away from regulated retail tariffs to market-based prices and, for Aurora Energy’s retail business, a loss of market share to new entrant retailers. Aurora Energy estimates that it has retained 85 percent of the Tasmanian contestable market. To offset this decline Aurora Energy has increased the sale of electricity in other NEM regions.

In 2008, Aurora Energy was directed by its Shareholders to acquire, complete construction; and operate the TVPS. The TVPS was commissioned in October 2009 and is currently operated to back around half of Aurora Energy’s non-contestable customer load.

Shortly after the TVPS acquisition, Aurora Energy acquired a suite of wholesale gas arrangements from Babcock and Brown Power, primarily to mitigate the risk of obtaining gas supply for the TVPS from a third party (gas supply to the TVPS formed the nexus of the contracts acquired). Consequently, Aurora Energy has commenced retail and wholesale gas sales, in both the Tasmanian and Victorian markets, and has dispatch rights over the Bairnsdale power station in Victoria.

6.3. Summary of financial results 2004 to 2010

A summary of Aurora Energy’s key consolidated financial results for the period 2004 to 2010 are set out in Table 8 below.

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenue¹</td>
<td>643</td>
<td>692</td>
<td>717</td>
<td>790</td>
<td>876</td>
<td>994</td>
<td>1173</td>
</tr>
<tr>
<td>Total Sales Revenue</td>
<td>640</td>
<td>687</td>
<td>716</td>
<td>778</td>
<td>861</td>
<td>971</td>
<td>1150</td>
</tr>
<tr>
<td>EBITDA</td>
<td>118</td>
<td>114</td>
<td>115</td>
<td>116</td>
<td>141</td>
<td>146</td>
<td>128</td>
</tr>
<tr>
<td>EBITDA / Total Revenue</td>
<td>18%</td>
<td>17%</td>
<td>16%</td>
<td>15%</td>
<td>16%</td>
<td>15%</td>
<td>11%</td>
</tr>
<tr>
<td>Debt</td>
<td>366</td>
<td>437</td>
<td>461</td>
<td>505</td>
<td>555</td>
<td>933</td>
<td>1029</td>
</tr>
<tr>
<td>Capital Expenditure</td>
<td>83</td>
<td>102</td>
<td>134</td>
<td>125</td>
<td>134</td>
<td>168</td>
<td>169</td>
</tr>
<tr>
<td>Investment Expenditure- TVPS</td>
<td>294</td>
<td>66</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Investment Expenditure- gas</td>
<td>15</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dividends Paid</td>
<td>14</td>
<td>14</td>
<td>12</td>
<td>10</td>
<td>11</td>
<td>10</td>
<td>10</td>
</tr>
</tbody>
</table>

Source: Aurora Energy annual reports and Panel analysis

Notes:
¹Total revenue excludes Aurora Energy’s Community Service Agreement as this is a pass through cost and customer contributions.

Energy retail businesses have scale economies that can result in marked changes in average per customer costs. The Panel understands that Aurora Energy’s strategy of pursuing retail opportunities was to build customer numbers to spread its fixed retail costs (such as IT systems, finance and regulatory functions) and as a risk mitigation measure to preserve scale economies.

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A review of the financial position of the State Owned Electricity Businesses
A review of the financial position of the State Owned Electricity Businesses

Aurora Energy’s returns (measured by EBITDA) have not kept pace with electricity sales trends, primarily due to higher costs across all components of retail pricing and, most significantly, increases in distribution and transmission network costs. Significant increases in transmission costs represent pass-through costs from Transend to Aurora Energy, resulting in a decreased margin as a percentage of sales revenue. EBITDA decline in 2010 is attributable to increased energy costs and the expensing of $21 million billing system costs.292

While generating approximately 40 per cent of total electricity revenue, Aurora Energy’s distribution business has been the main value driver of Aurora Energy’s consolidated business, contributing, on average, approximately 90 per cent of total EBITDA.

Figure 41 below illustrates the historical contribution to EBITDA by business activity.

![Figure 41 - Contribution to EBITDA by business activity 2004 to 2010](image)

Source: Aurora Energy

Note: Aurora Energy's wholesale energy business (electricity and gas) did not exist prior to 2009. Network service comprise predominantly contracting activities to Transend and Ezikey is Aurora Energy’s subsidiary company that undertakes its Wirealert development and sales. Wholesale includes electricity and gas trading. AETV EBITDA is a function of the tolling arrangements between Aurora Energy and AETV.

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292 A discussion on the circumstances influencing Aurora Energy’s energy costs in 2010 is included at Appendix 1.
6.4. Energy business (retail and wholesale energy)\textsuperscript{293}

Figure 42 illustrates Aurora Energy’s retail sales by customer segment for the period 2004 to 2010. During this time, Aurora Energy’s retail sales moved from a Tasmanian electricity revenue base in 2004 to a significantly more diversified revenue base in 2010. Although electricity sales to Tasmanian customers remains the dominant sales segment, electricity sales in the national market contributed around 16 per cent of revenue and retail/wholesale gas sales contributed around 4 per cent of revenue in 2010.

\textbf{Figure 42 - Retail sales by customer segment 2004 to 2010}

![Retail sales by customer segment 2004 to 2010](image)

\begin{itemize}
\item Tas electricity revenue
\item External revenues
\item Retail gas
\item National sales
\item AEMO pool income
\item Wholesale gas
\end{itemize}

Source: Panel analysis

Note: AEMO pool income (i.e. income from the spot market) from generation assets AETV and Bairnsdale. Retail business and cost to serve allowance.

Aurora Energy’s retail business, similar to its energy business, includes both regulated and non-regulated business activities. Under the Retail Price Determination, Aurora Energy receives a cost to serve allowance for regulated (non-contestable) customers. In the current Pricing Determination, the TER allowed Aurora Energy an industry benchmarked cost to serve allowance of $95 per customer per annum, this compares to Aurora Energy’s submission cost of $105 per customer per annum. Aurora Energy’s retail business is negatively impacted by its actual cost to serve in excess of its regulated allowance.

\textsuperscript{293} For the purposes of the presentation of analysis, Aurora Energy’s functional components have been separated. This presentation is different to Aurora Energy’s operational divisions where retail, wholesale energy (electricity and gas) and generation are amalgamated under the Energy Division.

A review of the financial position of the State Owned Electricity Businesses
In 2009 Aurora Energy commenced the development of a new customer care and billing system. The initial estimated cost of the system was $15 million but the actual cost to complete was $60 million. Of the additional cost, $32 million has been recognised by Aurora Energy as a direct expense in its profit and loss statement, of which $21 million was expensed in 2010 with a direct impact on financial performance.

6.4.1. Energy revenue and retail contestability

As Figure 42 illustrates, Aurora Energy’s Tasmanian electricity revenue has increased from $636 million in 2004 to $864 million in 2010, an increase of $228 million, or 30 per cent. Over the same period, sales in the national market increased from $0.3 million to $185 million. Aurora Energy’s energy business revenue growth in 2010 also includes AETV spot market sales and wholesale gas sales.

For the Tasmanian electricity revenue component of sales, despite revenue increasing, total load sold has decreased as a result of increased competition arising from the phased roll-out of retail contestability. Although revenue, through prices to customers, has increased, this has been largely driven by through-put costs (network, energy and RECs) and has not reflected improved retail margins.

Load

As retail contestability has been rolled-out across business customers, Aurora Energy has realised a decreasing load, primarily in the very large industrial customer market segment (Tranche 1 customers). Figure 43 illustrates Aurora Energy’s Tasmanain load by customer type over the period 2004 to 2010, showing the decline in large industrial customers since 2007 when that customer type became contestable.

For other tranche customers, Figure 43 illustrates that retail contestability has only had a minimal impact on Aurora Energy’s volume, noting that Tranche 5a, which has become contestable from 1 July 2011, and with an estimated 4000 eligible customers, may present a different result in future years.
Source: Panel analysis
Note: The decline in non-contestable business and the growth in contestable business largely reflect the rollout of retail contestability (change in definition of customer), rather than a fundamental shift in Aurora Energy’s market share.

Retail revenue components

Over the review period, Aurora Energy realised an increase in average revenue per unit of load sold, which was a key driver of total energy business revenue. However, the increase in average revenue (or price to customers) reflects an increase in all components of retail pricing, including network costs and wholesale energy costs. While an increase in distribution network costs has benefited Aurora Energy’s distribution business, revenue growth reflects an increasing component of transmission network costs and wholesale energy costs. These negatively impact Aurora Energy’s margin of revenue over direct costs, as they are a pass-through cost to Transend and Hydro Tasmania respectively. Figure 44 illustrates total electricity sales, total electricity costs and the resulting retail margin (EBITDA) between 2004 and 2010.
6.4.2. Wholesale cost of energy

Increased energy costs have been a key driver in the negative retail margin results, particularly in 2010. In general terms, the financial analysis undertaken for the Panel indicates that Aurora Energy’s reported wholesale energy costs have consistently exceeded the proportion of total revenue allowed in the regulated price determination for non-contestable customers, negatively impacting the profitability of Aurora Energy’s retail business, and subsequently its energy business after its restructure.

The wholesale energy allowance for non-contestable customers is determined under the Price Control Regulations. In both the 2007 and 2010 price determinations, the regulated wholesale energy allowance is higher than the market cost estimate. For example, in 2011 the regulated allowance is 11 per cent higher than the market estimate, although it has been considerably higher in the past.

While the process for determining the wholesale energy allowance for regulated customers changed a number of times through the review period, prior to July 2010 the contract arrangements between Aurora Energy and Hydro Tasmania for backing the regulated customer base consistently allocated all of the value to Hydro Tasmania. Aurora Energy received no additional margin on its retail business for any ‘savings’ on the cost of wholesale energy.

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The energy business outcome in 2010 was directly related to the operation of the TVPS though a combination of ‘take or pay’ gas contracts (which incentivised Aurora Energy to run the TVPS as a base load generator) and the nature of Aurora Energy’s contractual arrangements in place with Hydro Tasmania (refer Appendix 1 of this section of the paper).

The impact of higher energy costs for Aurora Energy’s energy business was not directly felt by customers as regulated prices do not allow for changes as a result of differences in costs compared to the allowance. The additional cost of the TVPS was effectively absorbed by Shareholders (the community) through a fall in profitability and reflected in no dividend payable in respect of the 2010 financial year.

6.5. Tamar Valley Power Station

A full account of the TVPS is provided separately in the Panel’s Report. In brief, the project was advanced by several private sector parties and was to be underpinned by a contract between Alinta and Aurora Energy for a large portion of the output of the facility. The project was acquired by Babcock and Brown Power from Alinta in 2008; however due to the deterioration in the global credit market, Babcock and Brown Power found itself unable to complete the project. On the basis of energy supply security, in 2008, the Tasmanian Government directed Aurora Energy to acquire the partially completed TVPS, complete construction and operate it on a commercial basis.

The Government provided Aurora Energy $100 million in equity for the purchase, while completion costs of $260 million were debt funded by Aurora Energy. Gas supply arrangements for the TVPS formed part of the acquisition of the power station. The TVPS was commissioned in October 2009 and the power station is currently operated to back around one half of Aurora Energy’s non-contestable customer load.

In establishing its commercial arrangements for the TVPS, Aurora Energy replaced the hedge arrangement that it had previously established with Alinta (which was subsequently transferred to Babcock and Brown Power) with a tolling fee arrangement between itself and its subsidiary entity AETV, which owns the TVPS. With the acquisition of the TVPS by Aurora Energy, the power station effectively became a ‘merchant’ generator (i.e. exposed to the spot market) as Aurora Energy sat on both sides of the hedge. The tolling fee effectively transfers the rights and obligations associated with the pool income from the generation of TVPS from its holding company, AETV, to Aurora Energy.

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295 In preparation for NEM entry, the Tasmanian Government submitted transition arrangements to the ACCC for authorisation under the Trade Practices Act, including a vesting contract between Hydro Tasmania and Aurora Energy for the rollout of retail contestability. In authorising this contract under the ACT, the ACCC included a requirement that from, the commencement of Basslink, Aurora Energy was to source at least 10 per cent of its energy for the non-contestable customer load from an entity other than Hydro Tasmania. This provided a regulatory requirement for Aurora Energy to find an alternative supplier of contract cover in Tasmania. See the Panel’s paper ‘The Evolution of Tasmania’s Energy Sector’ available at www.electricity.tas.gov.au.
The initial tolling fee in 2010, which was structured to replicate Aurora Energy’s earlier arrangement with Alinta, was insufficient to cover AETV’s operating costs and service its debt. In 2011, the tolling fee was supplemented by a second arrangement, sufficient to provide AETV with cash flows to cover its operating costs and debt obligations. Under these arrangements, AETV is forecasting positive profit before tax and the ability to repay its debt over the life of the TVPS. Importantly, the tolling arrangement effectively transfers all of the wholesale risk associated with TVPS to Aurora Energy’s energy business.

In 2010, gas commodity and transport costs comprised the majority of TVPS cost of generation. The ‘take or pay’ nature of the gas supply contract, which was put in place at the time of acquiring the power station on the basis that it was expected to operate at high capacity factors (and therefore needed a large volume of gas) incentivised Aurora Energy to continue to operate and produce electricity in 2010. However Aurora Energy’s non-contestable load requirements were largely covered by an existing hedge with Hydro Tasmania. This reflected commercial arrangements that were in place prior to the Government’s decision to have Aurora Energy acquire AETV (refer Appendix 1 of this section of the paper). This resulted in AETV being exposed to spot market prices that reflected oversupply in Tasmania and resulted in the TVPS generating revenues substantially less than its costs.296

Analysis indicates that the average cost of generating using the TVPS is higher than the wholesale energy allowance and Aurora Energy’s total cost of supply for non-contestable customers is supported by the contractual arrangements with Hydro Tasmania such that Aurora Energy’s weighted average wholesale energy costs are broadly in line with the wholesale energy allowance.

### 6.6. Distribution business

Aurora Energy’s distribution business is a regulated monopoly asset owner and electrical service provider, delivering approximately 24,000 km of line to approximately 225,500 domestic and 48,400 business customers. In 2010, the asset base, comprising high and low voltage overhead power lines, underground cables, distribution substations, street lights and poles was worth $1.2 billion.

Costs charged to Aurora Energy’s retail business (and other retailers servicing the contestable market) from the distribution business include charges relating to the distribution and transmission networks (transmission charges are a pass-through from Transend). The discussion in this section relates only to distribution charges.

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296 From a commercial perspective, as long as spot prices are higher that the avoidable costs of operating the TVPS, Aurora Energy was better off generating than not, as it provided positive net revenues, given fixed financial obligations in relation to gas supply.
The distribution business has achieved revenue growth each year of the review period, driven by the regulatory pricing determinations. Regulated income in 2004 was $148 million increasing to $240 million in 2010, an increase of 62 per cent. The primary driver of revenue growth has been significant growth in the regulated asset base, primarily driven by capital investment. Notwithstanding revenue growth, Profit Before Tax (PBT) declined in 2006 and 2007, attributable to a decline in customer contributions, increases compared to budget for emergency fault, oil management and vegetation costs and increases in financing costs. Figure 45 illustrates regulated distribution income (DUOS) compared to other income over the 2004 to 2010 period.

**Figure 45 - Distribution total income compared to PBT 2002 to 2004**

![Figure 45 - Distribution total income compared to PBT 2002 to 2004](image)

Source: Panel analysis
Note: Other income includes network services and operating net PBT relates to the total distribution business.

Similar to transmission network services\(^{297}\), regulated income is determined through a building block approach. Figure 46 illustrates the distribution business' AARR split into its building block components over the three regulatory determinations.

\(^{297}\) A more comprehensive discussion of the building block approach to regulated network income is included in Appendix 1 to the discussion on Transend's historical financial performance.
Key drivers of AARR are Return on Capital (ROC) and operating expenditure. These components are discussed in turn below.

6.6.1. Return on Capital

As can be seen from Figure 46, ROC is the key driver in the increase in AARR over the current and imminent regulatory control periods. Drivers of ROC are the WACC or return earned by the business, and the RAB on which the Weighted Average Cost of Capital (WACC) is applied.

**WACC**

WACC (as determined by the regulator, the AER) increased marginally from 6.61 per cent in the 2003 regulatory period to 6.64 per cent in the 2007 regulatory period. However, WACC is anticipated to increase for the period of the 2011 regulatory period (2013 to 2017). Aurora Energy has proposed a WACC of 10.33 per cent; however the AER in its draft determination has put forward a WACC of 8.08 per cent. The final WACC when determined will be applied to Aurora Energy’s total RAB.

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298 Under the regulatory framework, WACC for distribution network service providers is determined by the AER. The AER’s WACC determination is based on an assumed capital structure having regard to general market conditions and taking into account bond rates as well as industry specific factors. For example, the current determination assumes a 60:40 debt equity ratio and a credit rating of BBB+. 
**Impact of capital expenditure on the regulatory asset base**

The distribution opening RAB has increased by 59 per cent, from $726 million to $1,157 million between CY2004 and FY2010. The majority of this increase occurred due to increased capital spending during the 2003 regulatory period.

Aurora Energy’s proposal for the 2011 regulatory period (2013 to 2017) has an opening RAB of $1.5 billion. Aurora Energy is proposing capital expenditure totalling $675 million over the five year regulatory period. The opening RAB for the final year is estimated to be $1.8 million.299

Figure 47 illustrates Aurora Energy’s actual opening RAB and WACC (2013 to 2017 forecast) over the regulatory periods, incorporating annual capex.

**Figure 47 - Return on Capital components calendar year 2004 to financial year 2017**

Source: Aurora Energy

**Capital expenditure**

As discussed above, the impact of capital expenditure is a key driver of revenue through its impact on the regulated asset base. Figure 48 illustrates Aurora Energy’s actual capital expenditure compared to the regulatory allowance.

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299 The AER in its draft determination has put forward the total forecast capital expenditure at $584 million, a reduction of approximately $139 million from Aurora Energy’s proposed capex.
Figure 49 illustrates that on an annual basis, during the 2003 regulatory period and the 2007 regulatory period to date, Aurora Energy’s actual capital expenditure exceeded its allowance in each year. However, the over-spend is more pronounced over the 2003 regulatory period, with actual capital expenditure more closely aligned with the determined allowance from the 2007 Price Determination (years to date)

- Actual capital expenditure for the 2003 regulatory period was $404 million, $179 million more than the determined allowance of $224 million. This variance was principally driven by customer connections arising from economic and population growth. Actual capital expenditure on customer connections amounted to $130 million, compared to the allowance of $53 million.

- For the 2007 regulatory period to date, 1 July 2008 to 30 June 2010, actual capital expenditure of $340 million exceeds the determined allowance of $311 million by $29 million. Similar to the 2003 regulatory period, to date, actual capital expenditure on customer connections exceeds the determined allowance by $33 million. However, actual capex on system capacity is under the allowance by $20 million.

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A more detailed account of the differences between regulatory allowances and actual expenditure can be found in part A of this volume.
In addition to the impact on ROC\textsuperscript{301}, additional capital expenditure over the determined allowance has increased actual (accounting) depreciation and interest costs, resulting in lower returns than those determined through the regulatory process. This has impacted on returns to Shareholders through dividends.

6.6.2. Operating expenditure

The distribution business' actual operating expenditure, relative to regulatory allowances, is a key driver of value creation (or erosion).

Figure 50 illustrates Aurora Energy’s actual regulatory operating expenditure against the determined allowance over the period 2004 to 2010.

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\textsuperscript{301} Capital expenditure in excess of the regulatory allowance, so long as it is subsequently assessed by the regulator as being prudent, is included in the opening regulated asset base (RAB) for the following regulatory period. The WACC is applied to the RAB to determine the capital allowance.
Figure 50 - Annual operating expenditure comparison 2004 to 2010

Source: Aurora Energy

Figure 51 illustrates that actual operating expenditure fluctuates against the allowance.

- On aggregate, actual operating expenditure for the 2003 regulatory period was $204 million, $16 million more than the allowance of $188 million. Actual expenditure on network asset management contributed to this variance, exceeding the allowance by $13 million. However, this was offset on savings on emergency response and repair of $11 million.

- For the 2007 regulatory period to date (1 July 2008 to 30 June 2010) on aggregate actual operating expenditure of $174 million is below the allowance of $176 million by $2 million.

Overall, there has been a relatively minor deterioration in financial value in Aurora Energy’s distribution business over the review period as a result of overspending of operating cost allowances, in the order of four per cent (see Figure 51).

In its 2011 regulatory proposal, Aurora Energy has forecast $340 million of regulatory operating expenditure for the five years of the regulatory period. The AER, in its draft determination has put forward a total forecast operating expenditure of $311 million, a reduction of approximately $29 million from Aurora’s proposal.
6.7. Diversified business activities

Aurora Energy’s diversified business activities include gas wholesaling and retailing, telecommunications and the development and commercialisation of the household electrical safety device wirealert (marketed as ‘Cable PI’).

6.7.1. Wholesale and retail gas

Subsequent to the purchase of TVPS, in 2009 Aurora Energy made a separate commercial decision to purchase the assets of a wholesale gas trading business, AEATM, from Babcock and Brown Power. Aurora Energy invested $15 million in wholesale gas contracts and dispatch rights, which provide Aurora Energy with gas for wholesale sales to customers in Tasmania and on the mainland, and a tolling arrangement with the Bainsdale power station in Victoria (giving Aurora Energy mainland generation capacity to back its retail position). These arrangements contain large fixed obligations in relation to both gas commodity (the proportion of gas that is ‘take or pay’) and to gas transportation arrangements. The Panel understands that these were the arrangements that were in place when Aurora Energy acquired the AEATM business. These gas arrangements sit within Aurora Energy’s energy business.

6.7.2. Telecommunications

Aurora Energy’s telecommunications business was established during 2007 and is currently structured into two main streams:

1. A wholesale optical fibre-based telecommunications service provider to the Tasmanian market that competes with the monopoly provider utilising the Basslink cable to connect Tasmania to the national networks; and
2. Aurora Energy is the agent for the NBN project in Tasmania in relation to the roll-out of the Fibre to the Premises (FTTP) network in Tasmania. As an agent, this revenue stream bears less operational risk than the commercial telecommunications operations, and consequently produces marginal returns.

The telecommunications activity also support Aurora Energy’s internal needs for high speed telecommunication links between its distribution assets.

From 2008, the telecommunications activity has derived negative EBITDA returns, partly arising from the accounting treatment\(^{302}\) of funding provided by the Tasmanian Government to support Aurora Energy as the Government’s telecommunications strategic partner. 2010 operating EBIT was negative $0.8 million. However, Aurora Energy received an equity installement from the Tasmanian Government of $4.9 million.

6.7.3. WireAlert (undertaken through Ezikey subsidiary)

Historically, WireAlert has not traded as a retail product. The expenditures associated with the provision of the WireAlert device to Tasmanian households (not the historical development costs) have been capitalised in the accounts of Aurora Energy’s distribution business. The total amount capitalised in relation to cost of supply is represented by Aurora Energy as $8.8 million in 2010 and a further $0.3 million in 2011.

On 22 September 2011, Aurora Energy announced its intention to divest the WireAlert business and associated intellectual property in markets outside Tasmania.

Although Aurora Energy has forecast improved results for both the telecommunications and WireAlert activities, analysis of the viability of the assumptions underpinning profit growth has not been undertaken.

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\(^{302}\) The Tasmanian Government provides Aurora Energy with an equity contribution to support its role as the Government’s telecommunications strategic partner. Because of the accounting treatment of the Government’s funding (i.e. contributed as equity rather than revenue), Aurora Energy’s results for telecommunications presents as a loss. This impacts overall profitability but is equitable from a cash perspective.
7. Transend Networks Pty Ltd

7.1. Scope of business operations

Transend Networks Pty Ltd (Transend) was formed on 1 July 1998, from the disaggregation of the then Hydro-Electric Commission (now trading as Hydro Tasmania).

Transend is a wholly owned State-owned Company, established under the Electricity Companies Act 1997 and is incorporated under the Corporations Act 2001 (C’wth). The Company’s shares are held in trust for the Crown by its Shareholder Ministers, the Minister for Energy and the Treasurer.

Transend owns and operates the Tasmanian electricity transmission network. Transend transmits electricity from power stations in Tasmania and from the Basslink converter station in George Town to its customers around the State and to Basslink (customers in Victoria). Under the NEM arrangements, Transend is a registered Transmission Network Service Provider (TNSP). Transend currently has 16 customers, including generators, networks (Aurora Distribution and Basslink) and MIs, all of whom connect directly to the transmission network.

Transend’s core business model is to earn a return on assets invested in the transmission network and to cover its operating costs. This revenue falls into two categories – prescribed revenue, which is revenue determined directly through the application of the regulatory framework for transmission services; and non-prescribed revenue, which is either commercially negotiated revenue sourced from customers that are not determined directly by the regulator or returns from other non-regulated commercial activities (e.g. the provision of contestable transmission services and communication services to third parties).

As a result, Transend’s financial performance is primarily a function of:

1. The level of allowances (capital and operating) determined under the regulatory framework and particularly the WACC that is applied to the RAB; and
2. Amendments to the regulatory regime over time (i.e. how Transend manages its participation in the regulatory framework); and
3. The degree to which Transend is able to meet these allowances in operation.

Transend Networks has provided the Panel with a summary of arrangements associated with the regulatory regime over the three price determinations discussed in this Paper. This is included at Appendix 2.

As noted in its Statement of Approach, it is not the Panel’s intention to revisit specific regulatory decisions. The purpose of this Paper is to understand the impact of under and over spend compared to the regulatory allowance on the financial sustainability of the business.
7.2. Key events impacting on financial performance

Figure 52 illustrates the key events in history of Transend since disaggregation which have influenced the financial performance of the business.

Transend has been subject to three regulatory reviews to determine Maximum Allowable Revenue (MAR) for Prescribed Transmission Service (PTS) revenue, each undertaken by different regulatory authorities.305

Prior to the commissioning of Basslink, Transend was required by its Shareholders to resolve a number of complex technical issues such as power system security, wholesale energy metering and determining the operational boundaries between Transend and the NEM system operator (at that time the National Electricity Market Management Company (NEMMCO), now the Australian Energy Market Operator (AEMO)). The cost of undertaking this work was outside the regulatory allowance and not recouped from electricity customers and was effectively funded from profits.

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7.3. Summary of financial results 2004 to 2010

A summary of Transend’s key financial results for the period 2004 to 2010 are set out in Table 9.

Table 9 - Transend’s key financial results 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Revenue</td>
<td>97</td>
<td>119</td>
<td>130</td>
<td>127</td>
<td>137</td>
<td>159</td>
<td>183</td>
</tr>
<tr>
<td>Prescribed Revenue</td>
<td>86</td>
<td>108</td>
<td>115</td>
<td>123</td>
<td>130</td>
<td>144</td>
<td>166</td>
</tr>
<tr>
<td>EBITDA(^1)</td>
<td>62</td>
<td>73</td>
<td>93</td>
<td>82</td>
<td>89</td>
<td>107</td>
<td>127</td>
</tr>
<tr>
<td>Debt</td>
<td>35</td>
<td>53</td>
<td>93</td>
<td>118</td>
<td>409</td>
<td>488</td>
<td>518</td>
</tr>
<tr>
<td>Dividends</td>
<td>8</td>
<td>10</td>
<td>14</td>
<td>19</td>
<td>15</td>
<td>9</td>
<td>4</td>
</tr>
<tr>
<td>Equity Transfer(^2)</td>
<td>2</td>
<td>7</td>
<td>0</td>
<td></td>
<td></td>
<td></td>
<td>270</td>
</tr>
</tbody>
</table>

Source: Transend annual reports

Notes:
\(^1\) EBITDA is calculated on a whole-of-business basis (i.e. prescribed and non-prescribed income).
\(^2\) Equity transfer to Hydro Tasmania in 2008 $50 million to develop wind farm asset and $220 million equity was transferred to Hydro Tasmania via increased debt. In the 2011-12 State Budget; the Tasmanian Government announced Transend will meet the equity requirements of TasRail ($20 million per annum over five years) via increased debt.

Electricity transmission levels have remained relatively constant at just over 10,000 GWh over the period 2004 to 2010. However, since the commissioning of Basslink, the operation of the transmission system has changed significantly with substantially different flows within the system as a result of large power flows through the Northern parts of the network and across Basslink.

PTS revenue is Transend’s primary source of income, on average accounting for around 90 per cent of Transend’s total revenue for each year throughout the historical period.

Dividends in 2010 were notably lower than historical averages due to the impact of increased depreciation arising from asset revaluations in 2007 and 2008, additional borrowing costs and defined benefit superannuation liabilities.

Table 10 sets out building block components for MAR for the period 2004 to 2010. For simplicity this table does not show the unsmoothed MAR and adjustment lines between the building block components and MAR (smoothed). As such, there is a variance between the cumulative building block components and MAR (smoothed).
Table 10 – MAR building block components 2004 to 2010

<table>
<thead>
<tr>
<th>$ million</th>
<th>H2004</th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Return on Capital</td>
<td>25</td>
<td>55</td>
<td>61</td>
<td>64</td>
<td>71</td>
<td>73</td>
<td>84</td>
</tr>
<tr>
<td>Regulatory Depreciation</td>
<td>8</td>
<td>18</td>
<td>20</td>
<td>22</td>
<td>23</td>
<td>23</td>
<td>26</td>
</tr>
<tr>
<td>Operating Expenditure</td>
<td>16</td>
<td>29</td>
<td>34</td>
<td>33</td>
<td>31</td>
<td>32</td>
<td>51</td>
</tr>
<tr>
<td>Tax Allowance</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>MAR (smoothed)</td>
<td>50</td>
<td>107</td>
<td>118</td>
<td>121</td>
<td>129</td>
<td>137</td>
<td>165</td>
</tr>
<tr>
<td>MAR – actual¹</td>
<td>50</td>
<td>106</td>
<td>118</td>
<td>122</td>
<td>130</td>
<td>142</td>
<td>166</td>
</tr>
</tbody>
</table>

Source: Transend

Notes:
¹After adjusting for actual CPI and pass-through items. Note: In 2010, revenue of $165 million was recovered based on the AER’s original decision. The Australian Competition Tribunal subsequently amended the decision resulting in allowed revenue in 2010 being $177 million. The difference will be recovered over the remaining four years of the regulatory period. The above table reflects the AER’s original decision because revenue recovered in 2010 was on that basis.

Transend’s returns (measured by EBITDA) have not kept pace with MAR trends, primarily due to higher than determined operational expenditure and differences between the regulated asset base and statutory asset base (see below).

Figure 53 illustrates Transend’s MAR building block components for the 2003 regulatory period and the 2009 regulatory period.

Figure 53 - MAR building block components 2003 and 2009 Regulatory Periods

Source: Transend

Note: Figure 53 illustrates the adjustment to return on capital discussed under Table 10.
Figure 53 shows that the single largest driver of Transend’s revenue is the return it is allowed to receive on the regulatory asset base (return on capital). Over the review period, this allowance is typically between 50 and 54 per cent of the total allowance. The operating costs allowance typically comprises between 23 and 28 per cent of the total allowance, and on an annual basis declined through the 2003 regulatory period. Regulatory depreciation, which is linked to the value of the regulatory asset base, has typically accounted for 17 per cent of the total allowance.

Key drivers of the building block component and Transend’s actual performance against the regulatory allowances is discussed in section 7.4 below.

7.4. Core driver of performance is actual expenditure (capital and operational) against regulated allowances

7.4.1. Operating expenditure for prescribed transmission services

Figure 54 illustrates actual operating expenditure and determined operating expenditure over the 2003 regulatory period (noting that 2004 is a half year); and the first year of the 2009 regulatory period (2010).

Figure 54 illustrates that on an annual basis, during the review period, Transend’s actual operating expenditure has variously been over and under the annual determined allowance. However, there is a trend of actual operating expenditure exceeding determined operating expenditure and during the 2003 regulatory period, for the over-spend to increase in magnitude.
In those years where actual operating expenditure exceeded the regulatory allowance, the amount of the over-spend negatively impacts on earnings and subsequently returns to Shareholders through dividends. Conversely, in those years where actual operating expenditure was below the regulatory allowance, the amount of the under-spend positively impacted earnings and subsequently returns to Shareholders.

- During the 1999 regulatory period (1 January 2000 to 31 December 2003), Transend’s actual operating expenditure throughout the regulatory period was characterised as being higher than the regulated allowance on an annual basis (noting that over-spend did not occur in every year). In part, this can be attributed to costs associated with preparation for Tasmania’s entry into the NEM, and costs associated with preparing for Basslink connection, neither of which were factored into the 1999 regulatory period (or provided for in the extension to the determination).

- During the five and half year regulatory period from 1 January 2004 to 30 June 2009, actual operating expenditure amounted to $210 million, which was $28 million or 15 per cent higher than the determined operating expenditure of $182 million. This overspend negatively impacted on earnings, particularly in the 2008 and 2009 years, when actual opex amounted to $93 million, which was $23 million or 33 per cent higher than determined opex of $70 million for those years.306

- For the first year of the 2009 regulatory period, 2010, actual operating expenditure of $48 million was $3 million below the forecast operating expenditure of $51 million. Determined operating expenditure is forecast to total $221 million between 2011 and 2014 compared to determined operating expenditure of $154 million in the preceding four-year period, (2007 to 2010), an increase of $67 million or 44 per cent.

Figure 55 illustrates a cumulative, rather than annualised, operating expenditure comparison over the 2004 to 2010 period.

---

306 In preparing this paper Transend has advised that the operating expenditure allowance determined under the regulatory framework in the 2003 Price Determination was not sufficient and that the Board made an active decision to spend higher than allowed operating expenditure and that its Shareholders were informed of this. It is Transend’s view that this need was recognised in the 2009 Price Determination where a higher operating expenditure allowance was accepted by the AER.
7.4.2. Capital expenditure for prescribed transmission services

Since Transend’s establishment there has been substantial capital investment in the transmission system to augment and upgrade the network to meet higher load, higher peak demand, service new load centres, meet contemporary standards, replace ageing assets and improve the reliability of the system. This program of work was expected at the disaggregation of the Hydro-Electric Commission.

The transmission system that Transend inherited had been largely constructed between the late 1950s and early 1970 and many key items of the plant were approaching, or had passed, the end of their economic life.\textsuperscript{307} In its 1998-99 annual report, Transend noted that the key elements of its plant were older than the industry average, citing transformers with an average age of 33 years compared to the industry average of 25, circuit breakers that were, on average, more than 30 years old compared to the industry average of 22 years and transmission lines that were still in service after more than 80 years of continuous operation.\textsuperscript{308} A ten-year capital investment program to upgrade and modernise Tasmania’s electricity transmission system began in 1996.\textsuperscript{309} In addition to this program, during 1999 Transend began a comprehensive program aimed at eliminating substandard conductor to ground clearances on a number of transmission lines around the State (in June 1999 1 250 substandard spans were identified).\textsuperscript{310}

\textsuperscript{308} Transend Annual Report 1998-99.
\textsuperscript{309} Ibid.
\textsuperscript{310} Transend Annual Report 1999-2000.
Historical capital expenditure, as illustrated in Figure 56 below, predominantly relates to replacement ($252 million or 44 per cent) and renewal ($274 million or 48 per cent) costs, with significant renewal work occurring between 2004 and 2006, amounting to $147 million of capital investment over that period.

The significant increase in capital expenditure from 2009 (and forecast through the 2009 regulatory period) relates to development (augmentation) and connection-driven investment.

**Figure 56 - Capital expenditure profile 2004 to 2010**

Since the commissioning of Basslink in 2005, the nature of flows through the transmission system have changed substantially, with large power flows through the Northern parts of the network and across Basslink. Transend was the first TNSP in Australia to employ dynamic rating\(^{311}\) of its transmission lines, with a view to deferring capital expenditure in light of changing utilisation of the network.

Transend’s annual capital expenditure over the review period is characterised as being generally above the determined allowance, although this varies year-on-year with significant spikes in the last two years of the 2003 regulatory period. Figure 58 illustrates actual capital expenditure and determined capital expenditure over the 2003 regulatory period (noting that 2004 is a half year); and the first year of the 2009 regulatory period (2010).

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\(^{311}\) Dynamic rating is the continuous monitoring of wind speed and ambient temperature at key locations to recalculate conductor current ratings to maximise the capability of the transmission system.
Figure 57 - Annual capital expenditure comparison 2004 to 2010

Source: Transend

Figure 58 - Cumulative capital expenditure 2004 to 2010

Source: Transend

Note: The basis for the capital expenditure allowance has changed between the 2003 PD and 2009 PD from commissioned to incurred (refer Appendix 2).
During the 2003 regulatory period, actual capital expenditure amounted to $373 million, which was $37 million or 11 per cent higher than the determined capital expenditure of $336 million. Higher than determined capital expenditure spend was predominant in the 2008 and 2009 years when actual capital expenditure amounted to $127 million, which was $43 million or 51 per cent higher than determined capital expenditure of $84 million for those years.

For the first year of the 2009 regulatory period, 2010, actual capital expenditure of $132 million was $28 million below the forecast capital expenditure of $160 million, primarily due to the delivery of the Waddamana-Lindisfame project under budget. For the 2009 regulatory period, determined capital expenditure is $641 million.

7.4.3. The impact of capital expenditure on Return on Capital is a key driver of Maximum Allowable Revenue

ROC is calculated by applying a determined WACC to each year of the determination’s opening RAB. The WACC is the cost of capital based on the return that would be required by investors in a commercial enterprise of a similar nature and with a similar degree of non-diversifiable risk as that faced by a network business. Under the national transmission pricing arrangements, the regulatory-determined WACC is set using the same methodology for each transmission business during a regulatory cycle. The WACC is based on a standardised capital structure so that the actual gearing and equity position of each transmission business is not taken into consideration.

Transend’s ROC component of MAR increased at a relatively steady rate over the 2003 PD regulatory period, with stepped increase at the opening of the 2009 PD regulatory period.

ROC increased significantly in FY10 for two reasons:

1. The opening RAB for the 2009 regulatory period incorporates all capital expenditure incurred in the 2003 regulatory period (including capital expenditure in excess of the regulatory allowance). The RAB for 2010, the first year of the 2009 regulatory period was $951 million, some 15 per cent higher than the RAB for 2009 of $828 million. The RAB for 2010 included work-in-progress of $55 million, reflecting a change to the regulatory framework from as-commissioned capital allowances to as-incurred capital allowances (refer Appendix 2).

---

312 Some parameters used to determine the WACC are locked in under the Rules, however the risk free rate and debt risk premium are determined at the time of the respective decisions. Therefore, the WACC is not necessarily the same for each business during a regulatory cycle.
2. WACC increased from 8.8 per cent in the 2003 regulatory period to 10 per cent in the 2009 regulatory period. The WACC will apply to the capital expenditure allowance, irrespective of whether that allowance is actually expended. For example, in 2010 capital expenditure allowance was $160 million and actual capital expenditure expended was $132 million. Transend will earn a return on the $28 million unexpended capital expenditure allowance. Similarly, if Transend were to significantly overspend its capital expenditure allowance (as it did in the 2003 regulatory period) it would not earn a rate of return during the regulatory period on that over-spend.

As discussed above, the 2009 regulatory period had a significantly higher capital expenditure allowance ($641 million) compared to the 2003 allowance ($337 million) and for the first year, 2010, capital expenditure has been underspent by $28 million. If forecast capital expenditure is less than determined for the remainder of the regulatory period, Transend will effectively over-recover ROC, positively impacting profit. Savings will not be passed onto customers through lower prices until the following regulatory period (i.e. from 1 July 2014). These arrangements reflect the current operation of the NEM regulatory framework. Similarly, in periods when Transend has overspent its capital allowance, there has been no immediate impact on customer prices, with the funding cost consequences effectively met through a shortfall in profit and dividends to Government.

7.4.4. *Return on capital (regulatory) Vs. return on assets (accounting)*

There is a significant, and often not well understood, variance between Transend’s ROC for regulatory purposes ROA for statutory or accounting purposes. This can lead to questions such as ‘where is the money going’?

Figure 59 illustrates a comparison of the value of Property, Plant and Equipment (PPE) as presented for accounting purposes compared to the RAB.

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313 Transend was one of a number of TNSP providers to appeal the WACC determined through the regulatory process. On appeal, the Australian Competition Tribunal increased the WACC applying to revenue determinations from the 8.8 per cent originally set by the AER to 10.0 per cent.

314 Note the capex allowance in the 2003 PD was on an as-commissioned basis. The capex forecast basis changed in the 2009 PD to an as-incurred basis (see Appendix 2).

315 Closing PPE value.
Differences in asset values arise because different asset values are used for the regulatory process and for statutory reporting. These differences are driven by a number of factors, including differences in the rate of depreciation (economic versus accounting) and revaluations undertaken for accounting purposes. There was a significant revaluation of assets for accounting purposes in 2007 of $349 million, from $761 million in 2006 to $1.111 billion in 2007.

Asset values in the statutory accounts are based on periodic reviews of the depreciated optimised replacement cost of the whole network, whereas under the regulatory framework a historic cost approach is used. For assets in existence in 2001, asset values are ‘locked in’ based on a depreciated optimised replacement cost determined in that year and for subsequent capital investment, assets are depreciated historic cost. Both components are adjusted for inflation.

Values are also impacted by the timing of expenditure; for example, for statutory (accounting) purposes, all expenditure is included in asset values as it is incurred, regardless of whether it was ‘approved’ under the regulatory framework. For regulatory purposes, any under or over spend is adjusted in the RAB before rolling over to the next regulatory period, but not included during the regulatory period. Regulatory financial statements are audited and submitted to the AER each year in which the RAB is calculated based on actual expenditure, disposals and inflation in the relevant years. However, income for the period remains based on the forecast RAB as per the regulatory decision.

---

316 The then Minister’s valuation.
As illustrated in Figure 60, the rate of return on assets for accounting purposes is significantly lower than the regulatory return. In addition to the difference in asset values, additional capital expenditure above the regulatory allowance impacts profit through higher depreciation and interest charges from the year in which it is incurred and commissioned.

Returns are calculated as earnings before interest and tax (EBIT) as a percentage of assets. Statutory returns are based on average assets while regulatory returns are based on the opening asset base for each year in line with the revenue decision methodology.

Comparisons between the returns on statutory and regulated assets do not compare like with like. For example, statutory returns are based on the entire business with (both regulated and non-regulated) and a higher asset valuation, whereas the regulated return as per the regulator’s decision only relates to the regulated assets, using a valuation methodology set out in the National Electricity Rules.

Differences in the returns therefore result from different valuation treatment of the assets and the inclusion of non-regulated assets and expenditure in calculating the statutory returns. The year-on-year return on statutory assets is impacted by asset revaluations. For example, the asset value was re-valued upward in 2007 which resulted in a lower return on statutory assets that year. The analysis indicates that Transend’s regulatory returns have generally been consistent with the returns envisaged by regulators.

**Figure 60 - Rate of return on assets v return on capital 2005 to 2010**

Source: Transend
Note: the analysis commences with the 2005 financial year because 2004 spanned two revenue decisions.
In summary, even if Transend was consistently operating in line with its regulatory capital expenditure allowances, its return on assets for accounting purposes would still be lower than the regulatory WACC because of differences in asset valuations for accounting and regulatory purposes.

7.5. Pricing

Some of Transend’s customers (which include Aurora Energy’s distribution business and MI customers) are partially charged for use of system on a locational basis. That means that Aurora Energy’s distribution connection points in the same or similar locations to major industrial connections pay the same or very similar locational prices. However, some of Tasmania’s major population centres, such as Hobart, are more distant from generation and, in general, will face higher locational prices than some of the major industrial connections that are closer to generation.

Aurora Energy’s distribution business is also serviced by more connection assets than the major industrial connections despite direct connect customers accounting for approximately 60 per cent for Tasmania’s electricity demand. Principally, this is because there are almost four times as many distribution connection points compared to direct connection customer points, although some major industrial customers own their connection points and some have negotiated connection charges (and associated non-regulated charges related to assets connecting them to the transmission network), which are not included in the revenue analysis in Figure 61 below.

Under the existing Price Control Regulations, the pricing of network costs (which includes both the transmission and distribution elements), applied by Aurora Energy to a particular class of customer is required to be uniform, regardless of where in Tasmania the customer is supplied with electricity. This means that locational signals included in transmission network costs levied on Aurora Energy by Transend are lost in end customer prices.

Some industrial customers own their own high voltage connection assets and, therefore, reduce connection charges, while others – as a result of having requested changes to their services – pay ‘negotiated’ service connection charges. Once services become ‘negotiated’, they cease to form part of the regulated asset base. While negotiated service charges are not part of the regulated pricing methodology, the NER require that these will be cost reflective. As such, any reduction in the connection charges may reflect reductions in Transend’s costs, for example maintenance savings arising from changes in the agreed level of service. Because negotiated assets sit outside Transend’s RAB, they do not impact on calculations of Transend’s MAR or the connection charges borne by other customers.

Figure 61 illustrates Transend’s revenue by customer type over the period 2006 to 2010. On average, transmission charges per MW/h for direct-connect customers have increased by 35 per cent between 2006 and 2010 and transmission charges for retail customers have risen by 30 per cent.
Figure 61 - Total revenue analysis by customer type 2006 to 2010

Source: Panel Analysis
Note: The analysis period 2006 to 2010 has been selected for consistency purposes. Prior to 2006 the direct connect customer base included some major industrial customers that were charge through to Aurora Energy.

7.6. Diversified business activities

Transend business operations remain closely aligned to its functional business activities.

Transend’s diversified business activities are limited to the purchase of its telecommunications business from Hydro Tasmania on 1 November 2008 for $15.8 million. Transend utilises this business for its own telecommunication needs relating to the operation of the transmission network and also offers telecommunication services to third parties, including the Tasmanian Government’s trunk mobile radio network.
Appendix 1: Summary of the regulatory process as it relates to pricing and profitability.

The economic regulation of Transend’s transmission service is currently the responsibility of the Australian Economic Regulator (AER). The AER undertakes five year reviews of Transend’s network business and determines the allowable revenue that it is permitted to charge, which Transend then translates into network prices in accordance with its approved pricing methodology and the National Electricity Rules (NER).

Transend charges these prices to direct connect customers (generators, Mls and Basslink) and Aurora Energy’s distribution business. Aurora Energy then passes on the Transmission Use of System (TUOS) cost to electricity users as a component of the Distribution Use of System (DUOS). While the AER assesses and approves Transend’s pricing methodologies, it does not approve the actual transmission charges established at particular connection points. Like other TNSPs, it is up to Transend to establish its transmission charges in accordance with its approved pricing methodology and the NER.

Maximum Allowable Revenue - building block approach:

Transend’s MAR is determined by the AER assessing the following building block factors:

1. **Return on capital** is calculated by applying a determined WACC to each year of the regulatory period opening RAB. The opening RAB for one year comprises the opening RAB at the end of the preceding year, adjusting it for inflation; adding any additional capex; and subtracting disposals and regulatory depreciation for the year. The closing RAB for one year then becomes the opening RAB for the following year.

2. **Regulatory depreciation** is based on the concept of ‘economic depreciation, which is essentially a straight-line method of depreciating the regulated asset base from commissioning date over the economic life of the asset, adjusted for inflation.

3. **Operating expense** allowance is determined based on the following criteria: efficient costs of achieving operating expenditure objectives; the costs that a prudent operator in the circumstances of Transend would require to achieve these objectives; and a realistic expectation of the demand forecast and cost inputs in order to achieve opex objectives.

4. **Tax allowance** is calculated based on the determined income tax liability modelled on the tax depreciation and cash flow allowances. The amount of tax payable is determined using 60 per cent benchmark gearing, rather than Transend’s actual gearing and a benchmark income tax rate of 30 per cent. The benchmark value of imputation credits of 50 per cent is applied to the determined income tax payable in order to arrive at the net tax allowance.
### Appendix 2: Summary of regulatory arrangements over time (as provided by Transend)

<table>
<thead>
<tr>
<th>Regulator</th>
<th>Merits appeal</th>
<th>Regulatory Base</th>
<th>WACC</th>
<th>Capex forecast</th>
<th>Capex incentive</th>
<th>Capex outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>OTIER</td>
<td>Could be subject to periodic review based on depreciated optimised replacement cost.</td>
<td>Could be subject to periodic review based on depreciated optimised replacement cost.</td>
<td>Locked in and rolled forward based on new additions, disposals, depreciation and CPI.</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>ACCC</td>
<td></td>
<td>Pre-tax real</td>
<td>As-commissioned based on profile of commissioned projects including interest during construction.</td>
<td>Annual true-up.</td>
<td>Bellow allowance largely reflecting delays in development of jurisdictional planning arrangements to consider and approve augmentation and connection works.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Post-tax nominal</td>
<td>As-commissioned based on profile of commissioned projects including finance during construction.</td>
<td>Ex post review.</td>
<td>Exceeded allowance in era of high increases in labour, materials and other inputs. AER found capex to be prudent and efficient.</td>
</tr>
<tr>
<td></td>
<td>AER</td>
<td></td>
<td>Post-tax nominal</td>
<td>As-incurred based on profile of annual capital spend. Transition to this model required roll-in of work in progress at start of the period.</td>
<td>Ex ante review.</td>
<td>Presently tracking under allowance. Largest capital project (Waddamana-Lindisfarne 220kv transmission line delivered on time and under budget).</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Opex forecast</th>
<th>Opex incentive</th>
<th>Opex outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ex ante allowance</td>
<td>In period only. Retain underspend, penalised for overspend.</td>
<td>Slight overspend in latter years reflecting growing obligations and preparation for NEM entry.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Service incentive</th>
<th>Service outcome</th>
</tr>
</thead>
<tbody>
<tr>
<td>No incentive scheme.</td>
<td>Incentive payment in each year of period for continual improvement.</td>
</tr>
<tr>
<td>Service target performance incentive scheme – up to 1% of annual revenue reward or penalty.</td>
<td>Incentive payment for first 6 month period.</td>
</tr>
</tbody>
</table>
Part E
Governance: Issues and reform
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Introduction

Governance is a central component of the broader framework of incentives that influences the operation of the Tasmanian Electricity Supply Industry (TESI). Strong governance arrangements in combination with effective market and regulatory arrangements will drive both efficient prices for Tasmanian electricity customers and sustainable financial returns to the taxpayers. In this context, ‘governance’ is used to describe the way in which the Government exercises its various functions of strategic energy policy-setting, economic and technical regulation and business ownership (including major capital investment decisions) within the TESI.

This Paper discusses the Panel’s findings from its investigation of governance matters. The Panel has not sought to conduct a comprehensive ‘audit’ of all relevant governance arrangements across Tasmanian energy sector. Rather, it has focused on key issues that have emerged from its investigation into the efficiency and effectiveness and financial performance of the SOEBs, as well as major infrastructure development decisions.

Most of these issues are linked, in one way or another, to the way in which the Government, in its role as Shareholder, oversees the broad direction, operation and performance the businesses. Accordingly, the Panel has focused on the current functioning of the Government/SOEB relationship and has not sought to assess the internal corporate governance arrangements that are in place within each of the individual businesses.

In simple terms, the effectiveness of current SOEB governance arrangements can be judged by how well they deliver the following outcomes:

- Confidence within the Tasmanian community - both from the perspective of electricity customers and as the ultimate owners of the businesses - that the SOEBs are being operated according to a clear and consistently applied set of goals;

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317 The Panel’s Terms of Reference do not specifically require an investigation into governance matters. However, the Panel has determined that governance is directly relevant to the scope of its Review, in view of its influence on a range of observed outcomes in the TESI.

318 In this Chapter, ‘the Government’ refers to the Tasmanian State Government in the general sense, and does not refer to the current State Labor Government specifically.

319 In this way, the Panel’s analysis is focused primarily on ‘external governance’ arrangements. That is, the systems and mechanisms utilised by the Government in its role as shareholder to oversee the broad direction and operation of its businesses. ‘Internal governance’ refers to the systems of direction and control within the SOEBs, which is the responsibility of the boards and senior management of each of the businesses (see: Productivity Commission (2005) Financial Performance of Government Trading Enterprises 1999-00 to 2003-04, pp.46)
Clearly specified roles and delegations from the Government, as custodians of public capital – both equity and debt – invested in the SOEBs, through to the SOEB Boards and senior management, such that there is a clear ‘line of sight’ between the strategic objectives set by Government and the operational and investment decisions of the SOEBs; and

A ‘level playing field’ across the energy sector (between energy sources and market participants) where market outcomes are not distorted by virtue of the Government’s ownership of the SOEBs.

The key arrangements that formally underpin Tasmania’s SOEB governance framework are, prima facie, consistent with good practice principles, including those established by the OECD. Therefore, the Panel has sought to establish whether key aspects of the framework are working as intended and delivering the core governance outcomes described above. Advice and input has been received from a range of key stakeholders, including those with practical experience of how governance and decision-making currently plays out in the Tasmanian sector.

The following three priorities have been identified as being critical to ensuring the robustness and transparency of SOEB governance arrangements:

1) Clear strategic objectives, including the transparent delivery of non-commercial activities;

2) An accountability framework that gives priority to efficient, effective and transparent performance; and

3) Separation of the Government’s multiple roles of policymaker, regulator and businesses owner.

In 2005 the OECD released its Guidelines on Corporate Governance of State-owned Enterprises, which are widely regarded as the ‘best practice’ benchmark against which to assess the governance of State-owned businesses.

The Secretariat, on behalf of the Panel, conducted a series of one hour, semi-structured interviews with key stakeholders, including Chairpersons and senior management from the SOEBs, heads of relevant Government agencies, Shareholder Ministers, Greens and Liberal Party Energy Spokespersons, Members of the Legislative Council, representatives from the Tasmanian Chamber of Commerce and Industry and an academic with corporate governance expertise. Interviewees were provided with a schedule of interview questions ahead of time, which was used to guide the discussions. In all cases, interviews were given on the understanding that responses provided would not be individually attributed in the Panel’s report(s). The interviews were supplemented by written submissions received on governance matters from a range of stakeholders, including the SOEBs.

It is important to note that these are not intended to be a comprehensive list of ‘good governance’ principles. As noted above, the Panel has not sought to benchmark existing governance arrangements in Tasmania against best practice from a ‘top down’ or ‘first principles’ perspective. However, the Panel’s investigations and analysis have been informed by best practice guidelines, such as those published by the OECD, as well as observed good practice in other jurisdictions. Reference is made to both of these where relevant throughout the paper.

Governance: Issues and Reforms
This Paper is divided into three sections, which examine each of these priorities in more detail. For each priority, the following issues are discussed:

- the key guiding principles and architectural elements that good practice suggests should underpin relevant governance arrangements, and why;

- the relevant governance mechanisms that are currently in place in Tasmania, including both formal and informal arrangements;

- issues, strengths and weaknesses identified in the practical operation of these existing mechanisms, drawing on both stakeholder feedback and the Panel’s own observations; and

- recommendations to address identified issues.

The evidence gathered by the Panel suggests a need to strengthen certain elements of the framework. Specifically, six key areas have been identified. These are:

1. Clearer Shareholder ownership objectives
2. Transparent identification, delivery and funding of all non-commercial activities
3. Greater Shareholder focus on business performance
4. Effective Shareholder oversight and strategic energy policy functions
5. Enhanced public reporting and accountability
6. Confidence in the independence of regulatory processes

The Panel makes a number of recommendations for strengthening SOEB governance. The recommendations do not call for significant changes. In most instances, the Panel believes that effective improvements to governance outcomes can be made simply by the more consistent application in practice of principles and frameworks that are already in place. Therefore, the focus is on the incremental improvement and more closely aligning the Tasmanian governance framework with ‘best practice’.

The Panel’s key findings and recommendations are summarised below.
Summary of findings and recommendations

1. Clearer Shareholder ownership objectives

Key Points:

- Clear Shareholder ‘ownership objectives’ are important for a range of reasons, including that they provide the SOEBs with established parameters within which to operate (particularly with regard to non-commercial expectations) and send a clear message to the community about what the Government is trying to achieve through public ownership.

- The Panel endorses the view put forward by a number of stakeholders that Tasmanian Governments could more clearly, and publicly, state their overarching strategic objectives for the SOEBs - that is, the specific outcomes Government is ultimately trying to deliver through its ongoing ownership and control of the businesses.

- Without a clear set of overarching ownership objectives to guide its decision-making as a Shareholder, the Government will not have a reference point from which to consider, in a clear and consistent way, fundamental questions of strategic business direction.

- An Energy Business Ownership Policy would provide specific expectations with regard to the delivery of non-commercial objectives, financial performance, the Government’s risk appetite, particularly with regard to investments in diversification and growth activities beyond the SOEBs' core business.

- The SOEBs need to be as commercially successful as possible within the parameters set by the Government, but it is critical that the scope of business activities is firstly precisely defined, with clear reference to broader strategic policy objectives.

- The Panel notes that some significant improvements to the strategic objective-setting process are already in train, primarily through the implementation by the Government of its new Reform Principles for the Oversight and Accountability of Government Businesses.

Recommendation:

- That the Tasmanian Government develops a publicly available Energy Business Ownership Policy to more clearly articulate its overarching strategic objectives for the SOEBs.
2. **Transparent identification and delivery of all non-commercial activities**

**Key Points:**

- The Tasmanian Government’s CSO policy provides that the delivery of all non-commercial objectives should be explicitly provided for in legislation or regulations, formally documented and publicly disclosed so the impact on the business of delivering the activity is publicly transparent.

- The Government’s policy also advocates the direct funding of CSOs from the State Budget, consistent with good practice captured in relevant intergovernmental agreements.

- However, the Panel has noted that, in practice, there is a level of non-transparency in the funding and delivery of some non-commercial activities by the SOEBs.

- The most prominent example relates to Aurora Energy’s operation of the TVPS. The TVPS has not been recovering its costs from the market and its commercial viability is instead underpinned by a combination of the current regulatory regime and contractual arrangements with Hydro Tasmania for supplying the non-contestable load.

- The arrangement effectively transfers the shortfall in market value for the TVPS to Hydro Tasmania. This is not transparent or sustainable. As discussed in more detail in the Final Report, there are alternative, more transparent means to support the TVPS on the grounds of energy supply security ‘risk insurance’ that the Panel considers more appropriate.

- The Panel has also identified other examples where the CSO framework has not been applied where it would have been appropriate to do so. Acceptance of lower SOEB dividends has been used as a substitute for funding non-commercial activities from the Budget.

- The funding of non-commercial activities via CSOs rather than other mechanisms is not simply a matter of bureaucratic process. It is fundamental to good governance, performance management and ability of the Government to hold the SOEBs to account.
Recommendation:

- That the Tasmanian Government transparently identifies, endorses, costs and funds all CSO activities undertaken by the SOEBs, consistent with its existing CSO policy framework. CSOs should be directly funded through the budget process, rather than through internal transfers and acceptance by the Shareholders of reduced rates of return.

3. **Greater Shareholder focus on business performance**

Key Points:

- From the Tasmanian taxpayers’ perspective, efficient service delivery within the SOEBs is critical as it drives financial performance and, ultimately, returns to the Tasmanian community in the form of dividends.

- Shareholder oversight of the SOEBs should provide a sufficient level of accountability, through the SOEB Boards, to drive continuous improvement in the efficiency, effectiveness and financial performance of the businesses.

- The Panel has observed a low level of engagement between the Shareholders and the businesses through the corporate planning process, on efficiency-related matters. Where broad expectations have been communicated, it has not always been clear how they have been incorporated into the business strategies of the SOEBs or have been monitored by the Shareholders. There have been some improvements in this area in the past year.

- The historic absence of a strong performance focus may be symptomatic of a view that the economic regulatory environment and independent regulators will provide the dominant drivers for SOEB’s efficiency and effectiveness. The Panel’s view, however, is that the regulatory framework is a poor proxy for the business pressures delivered through effective competition. Further, and most importantly, effective governance of the SOEBs is also necessary to complement the incentives of economic regulation. Regulation and/or competitive market structures alone are not enough.

- The Panel notes, and endorses, recent improvements to SOEB oversight and accountability mechanisms, including the introduction of Annual Performance Agreements between the SOEB Boards and the Shareholders.

- These kinds of mechanisms need to be supported by sufficiently detailed ongoing monitoring, reporting and follow-up processes. This is particularly important where the Shareholders have approved investments in non-core diversification activities that may have a higher risk profile.

- A key component of this is to ensure that the SOEBs’ financial accounts continue to provide sufficient transparency with regard to the performance of discrete elements of the business.
Recommendation:

- That SOEB oversight continues to be refined and improved with a specific focus on putting in place accountability and incentive mechanisms that provide a clearer ‘line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and board management and staff performance on the other.

- In the context of the SOEB’s growing complexity, reporting of financial accounts must continue to provide sufficient transparency with regard to the performance of discrete elements of the businesses in order to support effective Shareholder oversight.

4. Effective Shareholder oversight and strategic energy policy functions

Key Points:

- The Panel’s Terms of Reference (ToR 8) require it to review the “advice that was provided to the State Government by the senior management or Directors of Aurora Energy from 1 October 2009 to 16 June 2010 inclusive”, in the context of the Company’s changing financial position over this period.

- This example provides an insight into the practical functioning of communication channels between a SOEB and its Shareholders. The Panel has found that in this particular instance the ‘continuous disclosure’ process in place between Aurora Energy and the Shareholders functioned as intended. This view accords with the Auditor-General’s findings, which concluded that reporting of financial issues and risks over this period was adequate.

- What was not anticipated by Aurora Energy or the Shareholders, however, was the magnitude of the financial risks the Company’s Energy Business was exposed to in the wholesale market. While the circumstances surrounding Aurora Energy’s deteriorating financial position during 2009-10 were unusual, this example does serve to highlight the inherent risks of being an owner of merchant energy businesses in a highly complex market.

- The Government has indicated to the Panel in broad terms that it will be considering the current distribution of its various energy responsibilities across the bureaucracy, in the context of the Panel’s findings and recommendations. A strong Shareholder oversight function is clearly a fundamental role that will need to be continued, and possibly enhanced.

- Reflecting the separate but interrelated roles that government plays in the sector, the Panel highlights that SOEB oversight should also be complemented by a strategic energy policy function within the portfolio Department that is separate from the Shareholder oversight function.
**Recommendation:**

- That the following key functions should underpin any Government review of energy responsibilities across the bureaucracy:
  - A strong SOEB ownership and oversight function, focused on driving the efficient performance of the businesses from a Shareholder perspective;
  - An energy policy function with sufficient mandate, capacity and authority to provide robust advice to Government, preferably through the Portfolio Minister; and
  - A strategic, 'whole of government' policy oversight capacity with the ability to weigh and consider the impacts of energy policy proposals from a more holistic perspective, taking into account broader social, economic and environmental impacts, potentially coordinated by a central agency.

5. **Enhanced public reporting and accountability**

**Key Points:**

- As the ultimate owners of the SOEBs, it is important that the Tasmanian community can access regular information about how well the businesses are achieving their stated objectives. The Parliament plays a key ‘intermediary’ role in holding the SOEBs to account on behalf of the community.

- Currently, the Tasmanian public accountability framework for the SOEBs is based around the Annual Reporting process and Government Business Scrutiny Committee Hearings, with little in the way of dynamic, ongoing disclosure of performance information.

- The Panel believes that there is merit from an accountability and transparency perspective in improving the timeliness and currency of key SOEB performance information provided to the Tasmanian Parliament, consistent with good practice in other jurisdictions. Specifically, this should include a Statement of Corporate Intent, a Half-Yearly Report and an Annual Report.

- Although flagged in the Issues Paper as a possible reform, the Panel is not convinced at this time that public, 'continuous disclosure' model for the SOEBs would yield sufficient accountability benefits to justify its imposition on the businesses at this time. Nonetheless, it is vital that this approach remain in relation to information flows between Shareholding Ministers and the SOEBs.
While not within the Panel’s remit, it is noted that a number of stakeholders were highly critical of the effectiveness of the current Government Business Scrutiny Committee Hearings process, specifically its potential to blur the line between accountability for SOEB performance (including the oversight performance of the Shareholder Ministers) and the general performance of the Government of the day for the delivery of other (often unrelated) policy objectives.

The Panel’s proposed improvements to the provision of relevant and timely SOEB information, proposed above, may enhance the Committees’ capacity to perform its SOEB oversight function in a more informed and effective manner.

Recommendation:

That, at a minimum, each of the SOEBs provides to the Parliament - and therefore the wider Tasmanian community - the following:

- an annual Statement of Corporate Intent at the commencement of the Financial Year, summarising the key objectives and performance targets from the SOEB’s Corporate Plan;

- a Half Yearly Report that provides a summary of year-to-date performance against targets set out in the SCI; and

- an Annual Report.

6. Confidence in the independence of regulatory processes

Key points:

- The primary aim of the regulatory framework should be to support the efficient operation of the energy market. Value in the SOEBs should be an outcome of efficient operations, not a core driver of policy or regulatory settings.

- When the Government is both a business owner and regulator, it is crucial that clear demarcations between these functions are, and are seen to be, maintained.

- It is important that market participants cannot reasonably form the impression that specific direction provided by the Government to the Regulator is driven by its own Shareholder value considerations.

- The Government’s involvement in specific elements of recent pricing determinations - including going beyond the establishment of the broad principles and objectives that underpin the regulatory framework and, in 2007, setting the wholesale energy allowance itself - raises potential concerns about the actual or perceived level of ‘functional’ independence that the TER has been afforded in making certain pricing decisions.
• The Panel’s view is that the Regulator needs to have the autonomy to determine and apply methodological approaches within the principles and objectives set by the Government.

• Complete transparency in regulatory pricing arrangements will become critically important for the new entry of private capital in the market with the introduction of full retail contestability (FRC) and attendant ‘fall-back’ regulatory arrangements that will apply to all retailers.

**Recommendations:**

• That the TER is given the discretion to independently apply appropriate approaches and methodologies, within the context of the principles and objectives set by the regulatory framework. If there are specific outcomes that the Government, as the Shareholder, believes should be taken into account, then it may put the case to the TER in submissions to the independent regulatory process.
1. Clear strategic objectives, including the transparent delivery of non-commercial activities

1.1. Key principles

1.1.1. Strategic objective-setting by the Shareholders

Like all State-owned enterprises, Tasmania’s SOEBs face the fundamental tension inherent in being commercial entities on the one hand, and instruments of Government policy for the achievement of broader social and fiscal objectives on the other. In this sense they are ‘hybrid’ organisations, having the features of both private and public sector organisations.323

The key difference between public and private enterprises is that shareholders in a private enterprise have a broadly common purpose – to maximise risk-adjusted returns on their investment – while shareholders in a public enterprise often have conflicting objectives. This multiplicity of principals with potentially conflicting objectives can, and often does, lead to the unclear transmission of objectives.324

In the context of its multiple roles, it is critical that the Government, acting as the ‘proxy’ owner on behalf of the community, provides clear direction to the SOEBs on its expectations of the businesses.

Clear ‘ownership objectives’ are important for a range of reasons, including that they provide the SOEBs with established parameters within which to operate (particularly with regard to non-commercial expectations) and send a clear message to the community about what the Government is trying to achieve through public ownership, as well as how this is consistent with and contributes to the Government’s broader strategic policy goals.325 As the Productivity Commission notes:

“A clear definition of the public interest reasons for government ownership, and consequent ministerial control, is crucial for sound government trading enterprise governance. For ministers to be held accountable, their actions should be open and transparent. The public should be confident that the public interest has been defined, is widely known and is being served”326

324 Trivedi, P (2005), Designing and Implementing Mechanisms to Enhance Accountability for State-Owned Enterprises - Presentation to UN Expert Group Meeting on Re-Inventing Public Enterprise and its Management.
Good strategic objective-setting is also the ‘foundation stone’ upon which the accountability and oversight of the SOEBs is based. Having clear objectives enables the establishment of sound performance measurement and reporting mechanisms, based on a shared understanding of what is to be achieved.

The OECD notes that strategic direction should be provided with regard to both the Government’s general expectations of its State-owned businesses from an overall ‘portfolio’ perspective, as well as at the individual business level. Therefore, objective-setting for the SOEBs by the Shareholders should be considered at two levels–

- the overall rationale, goals and objectives that the Government is seeking to achieve through public ownership of the businesses (within its wider portfolio of assets); and

- the more specific commercial and strategic direction that is set for each of the businesses over the short, medium and long term, within this broader context.

Like all owners, in setting high-level strategic objectives, the Shareholder Ministers must manage issues around sustainable capital structures, approving major capital investment – particularly where it relates to business diversification or expansion – and maintaining a dividend policy that delivers the desired level of cash flow from the businesses.

A State Government’s approach to these issues will depend on its reasons for holding investments in these businesses in the first place. Its objectives as an investor or owner should be seen in the context of the role of State Government and the fiscal strategy needed to support that role.

At the most fundamental level, State governments can be said to have three roles:

1) They are in the business of supplying services, including hospitals and health care, school education, roads and public transport, public order and safety and welfare services such as child protection;

2) Through their legislative powers, they also regulate private sector activity. Examples include land use planning and environmental regulation, allocation of property rights for natural resources, through to occupational health and safety and workers compensation; and

3) They impose taxes and charges to fund these activities. In the case of Tasmania, just over 60 per cent of General Government Sector revenue comes from Commonwealth Grants, around 20 per cent from state taxation, 8.5 per cent from the sale of goods and services and just under 5 per cent from financial distributions\(^\text{327}\) from State-owned businesses.

\(^{327}\) This includes dividends, tax equivalents and guarantee fees.
Given the primary roles of State Government, the next question becomes: “what fiscal strategy or approach to financial management best aligns with these roles; and what does this imply for the management of its investments in the SOEBs?”

As a number of countries are currently experiencing, and as others have in the past, in the longer term, economic and social sustainability depends among other things on the rate of growth in government expenditure matching the rate of growth of its revenues.

The nature of State government services is such that expenditure growth on these services does not vary significantly over the course of an economic cycle. For example, the number of children enrolling in schools or people being admitted to hospital from year to year does not tend to change significantly in response to the normal changes to Gross State Product (GSP) growth. Rather, State-level public expenditure growth is driven by longer-term trends in economic development, technology, demographics and the policy choices made by governments concerning the level of services that they choose to provide.\(^{328}\) Revenue growth however is very much tied to short-term variations in economic conditions, particularly with respect to consumption, asset prices and private investment.

In these circumstances, it is reasonable to expect that a State governments’ approach to fiscal and financial management will be targeted to delivering, as far as is reasonably possible, a sustainable and consistent rate of growth in General Government Sector services, despite the ‘ups and downs’ of the economy and revenue growth. The primary implications of such an objective are:

- that General Government net debt and financial liabilities will be managed to a low enough level to allow them to absorb differences between actual and trend rates of growth in revenue; and
- as an investor in assets or owner of businesses outside of the General Government Sector, the Government will have a low risk preference, preferring a steady, reliable stream of dividends and financial distributions over capital gains (i.e. the promise of future dividends or a higher, more volatile dividend stream).

A Government may wish to manage its General Government Sector balance sheet to minimise the extent to which it needs to reduce health, education and other services due to cyclical downturns in, for example, property transactions. In the same way, it would be appropriate for the Government’s decisions with respect to its governance and ownership of SOEBs to be driven by the impact on General Government Sector service provision.

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\(^{328}\) This can be contrasted with Commonwealth expenditure which is dominated by transfer payments, a significant proportion of which is directly linked to economic cycles, for example unemployment benefits.
A key differentiating feature of government businesses that has a significant influence on strategic direction setting (particularly when compared to their publicly listed counterparts) is the community’s inability – as ‘captive’ shareholders - to access the value of capital growth in the same way that the shareholders in a publicly listed company can (i.e. through trading their shares). This means that the main way in which the community as owners can benefit financially is by way of regular dividend flows to the Government.
2. Identification of non-commercial objectives

A related, but fundamental, component of the SOEB objective-setting process is clearly defining the way in which the SOEBs are to undertake non-commercial activities and/or community service obligations. While the Board is ultimately answerable to the Shareholder Ministers, it is also obliged to act commercially in the interests of maximising shareholder value. Good practice therefore dictates that non-commercial activities should be undertaken on the formal direction of the Shareholders and be accompanied by appropriate and transparent compensation – usually in the form of specific ‘Community Service Obligations’ (CSOs). In this way, social policy objectives achieved through CSOs are funded by the taxpayer rather than the electricity consumer.

As the Productivity Commission notes:

“The mandatory identification of CSOS and the transparent costing and funding methods...not only promotes good governance, but also reduces the incentive to underfund CSOs. It helps clarify what constitutes appropriate funding, as both the public and intended service recipients are made aware of the cost to society of pursuing social objectives through [government businesses]”329

The OECD recommends that CSOs or similar arrangements should be explicitly provided for in legislation or regulations, formally documented (for example in service contracts between the Government and the SOEB) and publicly disclosed so the impact on the business of delivering the CSO is publicly transparent.330

2.1. Summary of current arrangements

The high-level objectives and strategic direction for the SOEBs are currently set by Government through a series of key governance instruments that operate at three main levels, namely:

1) At the statutory level through relevant legislative instruments;

2) At a general level through guidelines, parameters and expectations that are set for all Government businesses; and

3) At a more specific level through expectations and directions for each of the individual SOEBs, primarily via the annual Corporate Planning process.

The key documents that currently operate under each of the above headings are summarised briefly below.

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Governance: Issues and Reforms
2.1.1. Legislation

The legislation under which the SOEBs are established provides very high-level guidance and direction with regard to the scope and direction of the businesses.

For Hydro Tasmania, this broad direction is provided under:

- The Government Business Enterprises Act 1995 (the GBE Act) which specifies that the ‘principal objectives’ of the business are to “perform its functions and exercise its powers so as to be a successful business by operating in accordance with sound commercial practice and as efficiently as possible” and “achieving a sustainable commercial rate of return that maximises value for the State in accordance with its corporate plan and having regard to the economic and social objectives of the State”. The Act also lists as a principal objective “to perform on behalf of the State its community service obligations in an efficient and effective manner”. The GBE Act provides for the establishment and prescribes the contents of a Ministerial Charter for each of its GBEs that outlines the broad expectations of the Shareholder Ministers; and

- The Hydro Electric Corporation Act 1995 (the HEC Act), which defines core functions and powers of Hydro Tasmania with regard to electricity generation, the operation of Basslink, participation in the NEM and the delivery of consultancy services.

For Aurora Energy and Transend, strategic direction at the statutory level is limited to the following:

- The Electricity Companies Act 1997 (the Electricity Companies Act), which states that the ‘principal objectives’ of the Companies are to: operate its activities in accordance with sound commercial practice; and to maximise its sustainable return to its shareholders. These same objectives are mirrored in each of the Companies’ Constitutions; and

- The Corporations Act 2001 (Commonwealth).

2.1.2. General expectations of all Government-owned businesses

The Government provides general direction on its expectations for all of its businesses through the Guidelines for Tasmanian Government Businesses. The Guidelines are an administrative document only and do not have any formal legislative status. As well as general guidance on matters such as the Government’s low risk appetite as an investor, the Guidelines provide policy direction on the following:

- Board appointments, induction and performance assessment;
- The establishment of subsidiary companies and joint ventures; and
- Government Business borrowings and dividends.
The Treasurer’s Instructions\textsuperscript{331} cover the principles, practices and procedures to be observed in the financial management of Government Business Enterprises. Some Treasurer’s Instructions (specifically with regard to tax equivalents and guarantee fees) are also applicable to SOCs through their Portfolio Acts. The Instructions cover application of tax equivalent regime, guarantee fees and dividends, CSO framework, corporate planning, and financial reporting (including the application of accounting standards).

The Existing Guidelines and Treasurer’s Instructions have recently been supplemented by new Principles for Strengthening the Oversight and Governance of Government Businesses. The Principles provide an updated view the Government’s expectations relating to:

- The level of strategic control by Government over business activities;
- How objectives for the businesses are set and reflected in core governance documents;
- Its broad risk appetite as an investor, particularly in relation to ‘non-core’ business activities;
- Efficiency measures; and
- Accountability and reporting mechanisms.

2.1.3. Specific expectations of the individual SOEBs

The most substantive and specific direction at the individual business level is provided via the annual Corporate Planning Process. Currently, each of the SOEBs must submit to the Shareholder Ministers an annual Corporate Plan for a period of four years. For Hydro Tasmania, the Corporate Plan must be approved by the Shareholders; however there is no such formal approval requirement for the SOCs.

Prior to the annual planning cycle (usually December), Shareholder Ministers will write to the SOEBs outlining the strategic priorities and broad expectations of the businesses in the development of the Corporate Plan. The letters have historically been limited to two to three pages and focus on setting high-level parameters around the content of the Corporate Plan on matters such as financial performance and risk identification and mitigation. The Government will also generally use the letters to provide direction on its dividend policy.

\textsuperscript{331} Treasurer’s Instructions are issued under section 23 of the Financial Management and Audit Act 1990
After developing their Corporate Plans, taking into account the broad strategic direction provided by the Shareholder Ministers, the SOEBs submit them by the end of March. Treasury then undertakes analysis of the Plan and provides advice with regard to whether or not the Plan is consistent with the broad expectations issued at the beginning of the planning process and provides recommendations regarding the approval of the Plan, which may include conditional approval of some elements. Advice is provided to the Treasurer, who in turn advises the Minister for Energy on the content of the Plan and the Shareholders’ proposed response. The Panel understands that separate advice has not typically been sought by the Minister for Energy from the portfolio agency, with Ministerial advisers instead providing support in this capacity. The corporate planning process is summarised in Figure 1, below.

Figure 9 - Development and Approval of the SOEBs' Corporate Plans

1. Shareholder Ministers write to the Chairperson of the SOEBs, communicating their broad expectations for the forthcoming year.
2. SOEB submits draft Corporate Plan to the Shareholder Ministers, following officer-level consultation with Treasury.
3. Treasury analyses Corporate Plan and prepares advice and recommendations for the Treasurer’s approval.
4. Treasurer writes to the Minister for Energy, forwarding Treasury’s analysis of the Corporate Plan, a recommended response and a letter to the Chairperson from the Shareholders for the Minister’s signature.
5. Minister for Energy considers the Treasurer’s recommendations and the letter to the Chairperson is signed and sent.
6. Corporate Plan is Finalised.
2.1.4. Framework for the delivery of non-commercial objectives

With regard to non-commercial objectives, the Government retains the power to direct the SOEBs to undertake various activities. For the SOCs (Aurora Energy and Transend) a wide power of direction exists under the Electricity Companies Act, whereby the Shareholding Ministers may give a lawful direction to Company on any matter and the directors must comply. The direction power for GBEs, on the other hand, is limited under the Government Business Enterprises Act to the following matters:

- Long-term objective-setting for the business;
- Financial performance objective setting;
- The requirement to undertake a community service obligation; and
- The payment of income tax equivalents and dividends.

The Tasmanian Government also has in place a framework, provided for under the Treasurer’s Instructions, for managing the delivery of specific non-commercial policy objectives through the SOEBs. Again, there are some minor differences in the arrangements that apply to Hydro Tasmania (as a GBE) and Aurora Energy and Transend (as SOCs)332, however, as Treasury notes, the principles of the framework applying to both SOCs and GBEs are ‘effectively identical’333.

The Treasurer’s Instructions note that “the main objectives of the CSO policy are to ensure that the Government's economic, social and other objectives are achieved without impacting on the commercial performance of GBEs and to improve the transparency, equity and efficiency of CSO service delivery”.

If the Government requires one of the SOEBs to undertake (by either directive or statute) an activity or service that the business would not ordinarily choose to provide on a commercial basis, or would provide at a higher price, then this product or service must be clearly purchased by the Government from the SOEB under a contractual arrangement with the relevant portfolio agency.334

The two CSOs currently undertaken by the SOEBs are:

- The delivery by Aurora Energy of electricity concessions to health care and pensioner card holders under an agreement with the Department of Health and Human Services; and

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332 One of the key differences between GBEs and SOCs in this regard is that the Government Business Enterprise Act 1995 makes specific reference to the delivery of broader objectives beyond the commercial operation of the company, including the objective of “...achieving a sustainable commercial rate of return that maximises value for the State in accordance with its corporate plan and having regard to the economic and social objectives of the State”. It also makes specific mention of the delivery of CSOs as a principle objective of GBEs.
334 Ibid.
The delivery of subsidised electricity supply by Hydro Tasmania of electricity to Bass Strait Island customers and the provision of concessions to pensioner customers on the Bass Strait Islands, under an agreement with the Department of Treasury and Finance.

The Tasmanian Government’s CSO policy advocates the direct funding of CSOs from the State Budget. This is consistent with good practice captured in relevant intergovernmental agreements. Direct funding is preferred for several reasons, including:

- **Efficiency** - prices for non-CSO functions can be set to reflect the cost of the commercial services supplied by the government business;
- **Transparency and Accountability** - the level of funding is publicly notified and subject to scrutiny in the budget process; and
- **Equity** - funding is sourced from general tax revenue so the cost of social policy is shared by the whole community. 335

### 2.2. Issues and recommendations

#### 2.2.1. Clearer Shareholder ownership objectives

The Tasmanian Government, as a Shareholder, has not always communicated its overarching strategic objectives for the SOEBs in a clear and consistent way.

This issue has manifested itself in two key areas:

1) **The Shareholders' expectations with regard to the delivery of broader non-commercial outcomes through the businesses, particularly where these objectives are not specifically prescribed in CSOs** - Stakeholders from the SOEBs indicated that they have difficulties in resolving the inherent tension between their obligations under legislative and other instruments to act commercially on the one hand, and the expectations that the Shareholders may or may not have explicitly stated with regard to delivering broader policy objectives (for example reducing the impact on cost of living for customers or the retention of members of the local Tasmanian workforce as employees of the businesses). SOEB feedback indicated that, outside the established CSOs, there is an element of ‘second guessing’ involved in determining what the Government’s broader policy expectations of the Businesses were, and therefore how these should be delivered.

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2) The Shareholders’ views on whether the SOEBs should be pursuing growth opportunities in national and international markets or whether they should be focused on the delivery of core, on-island services to Tasmanians - There has at times been a lack of consistency with regard to the Government’s risk appetite as a Shareholder and what this means at a practical level for the expansion of the businesses into areas beyond ‘core business’. Despite the Government identifying itself as a ‘risk-averse shareholder’, it has nonetheless approved the SOEB corporate objectives of pursuing business diversification opportunities, often outside of the Tasmanian market. As a consequence, the SOEBs are now operating in areas that are well outside their traditional core business. While some of these diversification activities have been pursued primarily as defensive, risk mitigation measures, others have been sought as value creating in their own right, often with relatively high levels of attendant risk. Examples include Hydro Tasmania’s national and international expansion of its interests in wind farms (through Roaring 40s) and its pursuit of retail growth opportunities on mainland Australia (through Momentum) if it were to extend beyond the level that can be backed by its existing generation portfolio (as is currently contemplated). Similarly, Aurora Energy has recently diversified into the wholesaling and retailing of gas, in Tasmania and elsewhere.

Fundamentally, the Government’s position on these high-level, strategic issues should be guided by its overall ownership objectives for the businesses - the fiscal, wider economic and broader social policy outcomes that the Government is seeking to ultimately achieve through its ongoing public ownership of the SOEBs.

The Panel agrees with the observation made by a number of stakeholders that, instead of being maintained for the achievement of clear policy goals, the policy of public ownership of the SOEBs has become a ‘default position’ or ‘an end in itself’, for all three parties in the Tasmanian Parliament. Consequently, there is a policy gap at the strategic level around what the outcomes of public ownership are, or should be.

Currently, the only public, high-level statement of Government policy intent with regard to ongoing business ownership is contained within the Guidelines for Government Businesses, which notes that:

“Government ownership continues for various reasons including historic ownership, the need to ensure the continued provision of important and/or essential services that may not otherwise be provided by the private sector, and a greater ability to regulate services through public ownership.”

337 See part D of this volume the Panel’s final report.
This statement does not provide sufficiently clear direction on what specific public interests or benefits the Government is trying to achieve through ownership of the SOEBs. Further, the Panel questions the above statement’s relevance to the network businesses, where the regulatory environment is such that ownership (whether it be public or private) should in practice be largely irrelevant.

Without a clear set of overarching ownership objectives to guide its decision-making as a Shareholder, the Government will not have a reference point from which to consider, in a clear and consistent way, fundamental questions of strategic business direction. Further, the SOEBs, other stakeholders and the broader Tasmanian community will be left with a degree of uncertainty with regard to the Government’s policy intentions. This is a less than ideal outcome from a governance perspective.

The Panel is of the view that the Government should return to ‘first principles’ and establish a set of clear ownership objectives - including an explanation of how and why these objectives are best delivered through ongoing public ownership - through the development of an Energy Business Ownership Policy (Ownership Policy). The Ownership Policy should be revised and updated with changes in government to reflect shifting direction, priorities and business drivers.

The Ownership Policy should provide clear answers to key questions relevant to setting long-term strategic business direction. For example, to what extent does the Government need or wish to expose its ability to maintain a steady rate of growth in General Government Sector services to the commercial success or otherwise of its SOEBs? And does the Government wish to forgo short-term returns from the SOEBs in the form of dividends, which could be used to fund other policy priorities for the benefit of the community, in pursuit of potentially higher returns from commercial investments that have attendant risk?

These are particularly important questions when considering major new investment decisions by the SOEBs that are not required to maintain security of supply or serve to deliver lower electricity prices to Tasmanian consumers (identified policy priorities for Governments), but which may nonetheless have solid business cases in their own right and may be broadly linked to core business. Examples in this regard include business acquisitions (e.g. Hydro Tasmania’s acquisition of Momentum Energy and Aurora Energy’s expansion into retailing in other NEM regions) or the construction of new generation capacity outside of Tasmania (e.g. wind farms in international markets).

Irrespective of how these kinds of investments are funded, be it any combination of retained earnings from the business or additional debt – or, as has been observed, the direct provision of equity by the Government - the capital has an opportunity cost in terms of its ability to support General Government Sector service delivery.
Such investments may or may not be commercially successful or have an acceptable level of earnings volatility. In making these investments, the Government may have a reasonable expectation of earning a commercial return. However, it may also be asked whether such investments and activities are appropriate investments for government at all, given that, in making them, the Government is also accepting that General Government Services will need to be adjusted in the event that they are not successful.

These issues are germane to the scope of the businesses activities that the Government specifies or, in other words, the boundaries of the field on which it allows the SOEBs to operate. The SOEBs need to be as commercially successful as possible within the parameters set by the Government, but it is critical that the scope of business activities is firstly precisely defined, with clear reference to broader strategic policy objectives. This is a primary function of the Shareholders. Significant input from the SOEBs is both necessary and appropriate in understanding the consequences and trade-offs involved in strategic policy direction setting.

An Ownership Policy would also improve transparency and accountability, by making clear which objectives for the SOEBS are set by the Shareholders and which are set by the businesses themselves. This would allow more public scrutiny of who is accountable for the ultimate delivery of each of the various objectives.

The Panel notes that improvements to the strategic objective-setting process for Government Businesses are already in train. The Government’s February 2011 release of its Reform Principles for the Oversight and Accountability of Government Businesses338 has re-opened the discussion between the Government and the SOEBs on the Government’s overarching ownership objectives, particularly in the context of what constitutes core and non-core business activities for each of the entities.

For example, the Principles now explicitly refer to the need for clear objectives to be set by the Shareholder Ministers, including core activities of the businesses and any public policy objectives. The Principles also reinforce the Government’s low risk appetite as an investor and suggest a focus on ‘on-island’ activities, unless the businesses can provide a strong, risk-based business case.

While the Principles have been broadly welcomed, some stakeholders from the SOEBs raised questions about how they will be applied in a practical sense, and in particular how they will interact with existing legislation, where it appears in some instances there may still be the potential for ambiguity or conflict, particularly with regard to the Board and management’s businesses’ legal obligations to operate commercially.

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The new Principles must therefore be cognisant of director’s duties and the intent and objectives of the relevant Acts in order to resolve potential confusion or ambiguity. Specifically, clear guidance should be given as to how Boards are expected to prioritise objectives provided via the new Principles in relation to their existing legislative and other responsibilities. As noted above, there is a need to specify the scope or ‘reach’ of business activities, thereby setting the boundaries within which their commercial performance will be judged.

**Recommendation:**

That the Tasmanian Government develops a publicly available Energy Business Ownership Policy that more clearly articulates its overarching strategic objectives and scope for the SOEBs.

### 2.3. Transparent identification, delivery and funding of all non-commercial activities

The Tasmanian Government has in place a clear framework through which the SOEBs may undertake non-commercial activities for the achievement of broader policy objectives. In the case of the electricity concession and Bass Strait Island CSOs, the cost of delivering these activities is transparently recorded through the annual State Budget process.

The CSO process is a key component in minimising the potential disconnect between directors’ duties and the legislative framework on the one hand and the delivery of broader policy objectives on the other. The treatment of CSOs in this way also enables the SOEBs to be held accountable for efficient delivery of the service and for the Government to be held accountable for the policy itself and its overall cost.

However, the Panel has observed a level of non-transparency in the funding of some non-commercial activities.

The most prominent example relates to Aurora Energy’s operation of the TVPS. The TVPS has not been able to recover its costs from the market. Rather, the current commercial viability of the TVPS is underpinned by a combination of current regulatory arrangements and contractual arrangements with Hydro Tasmania for supplying the non-contestable load. The arrangement effectively transfers the shortfall in market value for the TVPS to Hydro Tasmania. This is not transparent or sustainable.
There are alternative, more transparent means to support the TVPS on the grounds of energy supply security ‘risk insurance’.

There are other examples where the CSO framework has not been deployed where it would have been appropriate to do so. For instance, in 2009 the Government wrote to Aurora Energy to express a desire for tariff increases charged under the Aurora Pay as You Go (APAYG) billing system to be effectively ‘capped’ for concession cardholders at a rate below that at which Aurora Energy was intending to charge. 339

The Panel understands from its discussions with Aurora Energy that an agreement was subsequently reached with the Shareholders through a negotiated process, which resulted in the Shareholders accepting a commensurately lower dividend in order to ‘fund’ the cost of delivering the price cap for these customers. 340 While the APAYG ‘price cap’ was publicly announced by the Government and Aurora Energy, its actual cost was only ever captured in confidential Corporate Plans, rather than transparently as a line item in the State Budget, as would be expected for an activity of this kind.

The Panel has also viewed evidence 341 that shows the Government had also planned to deliver its ‘five per cent price cap’ promise through an arrangement where it would accept reduced dividends from the relevant SOEBs, rather than through a transparent CSO contract.

The practice of accepting a lower rate of return from businesses in return for the internal funding of a CSO runs contrary to the agreed policy of operating government businesses on a fully commercial basis and reduces the businesses own retained earnings. 342 The practical consequence of reducing dividends to fund non-commercial activities is that it undermines government’s ability to be an effective business owner and sends mixed messages to Boards and management as to what the owner regards as success. Businesses without clear, unambiguous lines of accountability to their owner or where the owner sets mixed or contradictory objectives invariably begin to be run in the interests of the management, with consequences for both customers and owners.

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339 As a ‘product of choice’ for Tasmanian customers, APAYG tariffs are not set by the Regulator, but at commercial rates determined by Aurora Energy.

340 On 8 July 2009, Aurora Energy announced that APAYG prices would be increased by an average 12 per cent in 2009-10, largely as a result of “…the product’s higher technology costs, higher than expected transmission charges and inflation” (Aurora Energy Media Release, 26 July 2009). Following intervention from the Government, average price increases for eligible APAYG concession customers were subsequently brought down to the rise approved for customers on regulated tariffs - 7.2 per cent. The reduction was achieved by the abolition of the daily standing charge and a reduced increase in the standard and off-peak winter prices in the 11am to 4pm, 4pm to 8pm and 8pm to 6.30am time-slots.

341 Cabinet documents.

The central issue is not whether the Government should utilise the SOEBs to deliver wider policy objectives - this is one of the core reasons that governments continue to own businesses. Rather, it is the way in which the Government implements these policy outcomes that is central. The funding of non-commercial activities via CSOs rather than through the acceptance of lower than otherwise dividends is not an accounting ‘nicety’ or a reflection of the technocrats’ desire to tie things up in neat boxes. It is fundamental to good governance, performance management and ability of government to hold the businesses to account.

**Recommendation:**

That the Tasmanian Government transparently identifies, agrees and funds all CSO activities undertaken by the SOEBs, consistent with its existing CSO policy framework. CSOs should be directly funded through the Budget process, rather than through internal transfers and acceptance by the Shareholders of reduced rates of return.
3. An accountability framework that drives efficient, effective and transparent performance

3.1. Key principles

3.1.1. Accountability to the Shareholders

The Shareholder Ministers’ oversight of SOEB performance should provide a sufficient level of accountability to drive continuous improvement in the efficiency and effectiveness of the businesses. The economic regulatory framework will only partly drive efficiency in the businesses. There is, therefore, a clear responsibility on the Shareholders, through their interaction with the Boards, to provide additional impetus for efficiency.

However, the Shareholders’ role in driving SOEB performance needs to be tempered by the general principle that Government should not seek to interfere with the day-to-day management of the SOEBs or step over the important line between the roles of ‘owner’ and ‘director’.

In this way, the Panel agrees with Transend’s view that, with regard to the SOEBs, “[t]here needs to be a balance between giving Shareholding Ministers control over the businesses so that they can be properly answerable to Parliament and taxpayers for its performance and ensuring that the ‘control’ is not so intrusive that it usurps the legitimate and strategic role of the board or becomes in effect another layer of quasi-regulation”.

Striking this balance relies on a number of key governance elements working together effectively, including:

- Clear performance-based agreements between the Shareholders and the Board based on the achievement of agreed objectives, including appropriate sanctions and rewards. Rewards and sanctions should be applied to Boards by the Shareholder Ministers, in turn Boards (in consultation with the Shareholders) should reward and discipline CEOs and management;

- Arrangements that allow for the Shareholders to act as informed owners, including dynamic reporting systems that give the Government’s ownership entity a true and timely picture of the SOEB’s ongoing performance and financial situation; and

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344 See Transend Networks’ submission to the Issues Paper.
345 Clear in the sense that, ex-post, it is easily discernible whether or not objectives have been achieved.
The capacity and expertise within Government to then interpret information provided to it by the businesses and provide good advice to the Shareholders, without seeking to duplicate key SOEB management functions in the bureaucracy.

The lack of capital market-based discipline on State-owned businesses means that the Shareholders Ministers (and ultimately the Parliament and the broader community) are largely reliant on administrative monitoring procedures as the main accountability mechanism for the SOEBs.\footnote{NSW Auditor-General (2005), Performance Audit – Oversight of State Owned Electricity Corporations.} In broad terms, the Panel notes that such a performance-monitoring regime should adhere to the following principles:

- Formal contact between the Shareholders and the SOEB Boards should be kept to a broad strategic level in order to preserve management autonomy and facilitate accountability;

- The monitoring process should concentrate primarily upon overall commercial performance. However, targets and measures for non-financial performance, including the efficiency and effectiveness of the SOEBs, should also be used; and

- There needs to be regular provision of quality information from the SOEBs to enable effective assessment of performance against all set targets. Reporting should comprise both regular publicly available information and the provision of commercially sensitive information solely to the Shareholders on a timely basis.

### 3.1.2. Accountability to the Parliament and the community

In addition to the critical Shareholder/Board relationship, the other key element of the SOEB accountability framework is the transparency and public disclosure of key performance information. As the ultimate owners of the SOEBs, it is important that the Tasmanian community has the ability to access regular information about how well the businesses are achieving their stated objectives. The Parliament plays a key intermediary role in holding the SOEBs to account on behalf of the community.

However, the Panel notes that the principle of public disclosure again needs to be balanced against a range of other important considerations, including commercial confidentiality and the burden of reporting on the SOEBs. It is also important that performance reporting is genuinely informative, particularly given both the inherent complexities of the energy market and the public’s inability to ‘trade’ their shares in the SOEBs.\footnote{It is important to remember in this context that, because the community’s shares in the SOEBs are held in trust by the Shareholder Ministers, they cannot utilise information about business performance to inform decisions about trading this equity. Ultimately, they can only act on this information in forming a judgement of the Government’s performance in managing its portfolio in their capacity as electors of the Parliament, and not through the SOEBs directly.}
3.2. Summary of current arrangements

The current SOEB accountability framework is underpinned by the relationships between the following entities:

- **The Parliament**, which plays a broad monitoring and accountability function on behalf of the Tasmanian community;

- **The Shareholder Ministers**, who are responsible for assessing and monitoring the financial performance of the businesses. The Shareholder Ministers also play a key role in appointing directors;

- **The Board of Directors**, which is responsible for both business performance and ensuring that the management undertakes its functions in the best interests of the business and in accordance with relevant laws. The Board sets relevant performance targets for the business and reviews and approves strategy and policies designed to achieve the Shareholders' objectives. The Board is responsible for the long-term viability of the business by monitoring business and senior executive performance and continually refining the system of internal controls, liability management practices and solvency level of the business; and

- **The CEO and Management**, who are responsible for the business achieving its goals in accordance with the strategies, policies, programs and performance requirements that are approved by the Board. The CEO and Management have legislative obligations to perform their duties in the interest of the business, including acting in good faith for a proper purpose, exercising due care and diligence and preventing insolvent trading.

The chain of accountability that links these entities is summarised in Figure 2.
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Figure 2 - SOEB accountability framework

The SOEB reporting regime is at the centre of the accountability framework. Reporting by the SOEBs is structured around two main lines of accountability:

1) To the Shareholder Ministers; and
2) To the Parliament and the community.

The SOEBs must also report to the independent TER and the Auditor General with regard to their technical performance and compliance respectively. The SOEBs also have ‘parallel’ reporting obligations to the Australian Energy Regulator with regard to relevant performance measures. The key mechanisms through which the SOEBs currently report to each of these specific audiences are described briefly below.
3.2.1. Reporting to the Shareholder Ministers

The SOEB Board/Shareholder Minister accountability relationship is underpinned by a range of performance reporting mechanisms, ranging from specific, legislative-based requirements through to less formal, officer-level interactions. The current reporting arrangements comprise the following:

**Ongoing Disclosure** - The Shareholder Ministers have expressed through a range of documents – including the annual letters of expectation and more recently the revised Principles for SOEB Oversight and Governance – that they expect that the Boards of the SOEBs to promptly advise them and Treasury, as their principal financial advisor, of any material risks or issues within the businesses, particularly where this has the potential to impact on the State and its balance sheet. In these instances, the SOEB Chairman will generally arrange for a special briefing with the Shareholder Minister.

**Monthly Meetings with the Minister** - The Chairman and the CEO of each of the SOEBs meets with the Energy Minister monthly, following the regular Board meeting. The current practice is that Treasurer attends these meetings quarterly, but is generally represented at the monthly meetings by an advisor.

**Quarterly and Half-Yearly Reports** - Quarterly reporting to the Shareholders is required under the GBE Act, while SOCs are required to report half-yearly, under their Corporations Act obligations. In practice, however, Treasury requires that all the SOEBs report quarterly. The content of quarterly reports includes commentary on the business’ operations and key financial information. Issues may include full year performance expectations, changes in risk factors, progress with major capital projects, strategic issues and any other issues likely to impact on business performance.

After receiving the quarterly reports, Treasury prepares a summary report for the Shareholder Ministers, which includes a ‘traffic light’ assessment of how the businesses are tracking in relation to their key corporate plan objectives and targets. Neither quarterly nor half-yearly reports – nor a summary thereof - are currently tabled in the Parliament or made publicly available.

**Ongoing Interaction between SOEB Management and Treasury Officials** - As the designated financial advisors to the Shareholder Ministers, the Shareholder Policy and Markets (SPM) Branch within Treasury maintains an ongoing dialogue with the management teams in each of the SOEBs. SPM nominates individual officers within the Branch as designated ‘contact points’ for each of the SOEBs to ensure a level of coordination and consistency in its interactions with the businesses.
Annual General Meeting - SOCs are required to hold an Annual General Meeting by 30 November each year, unless approved otherwise. Hydro Tasmania, as a GBE, is not required under legislation to hold an AGM. The AGM is a formal mechanism to appoint the directors and the chairperson, consider the dividend recommendation and consider the financial results for the year. These meetings have typically been functionary in the past and not used as major interactions for focusing on performance and outcomes.

3.2.2. Reporting to the Parliament and the public

Public performance reporting is primarily through the Annual Report and Government Business Scrutiny Committee Hearings, which both focus on end of financial year results. These are described briefly below.

Annual Report - The Annual Report is the main public accountability document prepared by the SOEBs. For Hydro Tasmania, the GBE Act requires the preparation by the Board of an Annual Report to be submitted to the Shareholder Ministers and the Auditor-General. The content of Hydro Tasmania’s Annual Reports is prescribed in the Treasurer’s Instructions. Aurora Energy and Transend’s annual reporting requirements are prescribed under the Commonwealth Corporations Act. The Annual Reports of all the SOEBs must be tabled in the Parliament by no later than 30 October each year.

While GBEs and SOCs have differing requirements in relation to the prescribed content of their Reports, they generally all include the following information:

- Financial statements for the year, including a copy of the Auditor-General’s opinion on the financial statements;
- A report on performance indicators against those outlined in the Corporate Plan;
- A report on the general operations of the business; and
- Details of CSOs delivered.

One key difference between annual reporting requirements for GBEs and SOCs is that GBEs are required under the GBE Act to provide a Statement of Corporate Intent for the next financial year, whereas SOCs are not.

Government Business Scrutiny Hearings - the Tasmanian Parliament has established the annual Government Business Scrutiny Committee Hearings to ask questions and require answers by Ministers, Chairpersons, CEOs and other managers of Government Businesses “...so as to ensure Government Businesses and their shareholders (Ministers) remain accountable to the Parliament”. Effectively, the Hearings are designed to provide the opportunity for Members to inquire in more detail about information provided in the SOEBs’ Annual Reports.

The Hearings are similar in structure and process to those of the annual Budget Estimates Committees, and are generally held in December of each year. Businesses appear before either the House of Assembly or the Legislative Council on an alternating basis from year to year. For the SOEBs, the Hearings are generally attended by the Energy Minister (as Shareholder Minister), the Chairperson, the CEO and senior management. The Committees generally produce a summary report of proceedings for publication. Committee proceedings are also published ‘verbatim’ in Hansard, which is publicly accessible.

**Legislative Council Sessional Committees** - in 2010 the Legislative Council established two Government Administration Sessional Committees whose functions are to inquire into and report on any matters relating to “…the administration, processes, practices and conduct of any … Government Business Enterprise, State-owned Company....” The Panel understands that intention of these Committees is for the Legislative Council to be able to apply more scrutiny to SOCs and GBES on an ‘as needs’ basis, rather than be restricted to the annual Government Business Scrutiny Hearings. The Committees have to date been used to investigate various operational aspects of both Forestry Tasmania and TasRacing.

### 3.2.3. Reporting to the Regulator and the Auditor-General

As part of its functions provided for under the ESI Act, the Tasmanian Energy Regulator prepares an annual report on the performance of the Tasmanian electricity industry, covering service standards, quality, reliability and pricing of the energy supply industry in the State across generation, transmission and retail. The Report is publicly available and is intended to provide a key accountability mechanism through which the Tasmanian community can assess the performance of the SOEBs. As part of this process, the SOEBs are required to provide annual reports to the Regulator across a range of technical and other performance measures.

The Auditor-General is appointed by the Governor as the auditor for all Government businesses, including the SOEBs. Under the Audit Act 2008, Auditor-General must audit the financial statements of all Government businesses and issue reports on compliance with relevant legislation and accounting standards. The Auditor-General also has the power to conduct both performance audits examining the efficiency and effectiveness of a Government business and compliance audits to examine compliance by the business with relevant laws or internal policies. As the Auditor-General’s ‘client’ is the Tasmanian Parliament – and not Government - the results of all audits conducted reported to the Parliament and are also publicly available.

The SOEB Performance Reporting Framework is summarised in Figure 3, below. Where items that are ‘ticked’, this indicates information that is publicly available.

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349 On the recommendation of the Treasurer – see the Audit Act 2008.
3.3. Issues and recommendations

3.3.1. A greater Shareholder focus on business performance

From the perspective of Tasmanian taxpayers, efficiency within the SOEBs is critical as it drives financial performance and, ultimately, returns to Government in the form of dividends. From a customer perspective, the market and/or the regulatory framework can only go so far in driving efficiency and the longer-term trend in electricity prices.

Responsibility for initiating and driving efficiency improvements primarily falls to the SOEB Boards. However, the Shareholders also have a key role to play in ensuring that the Boards remain clearly focused on high levels of productivity and efficiency to achieve sustainable financial returns. The Shareholders must then subsequently hold the Boards accountable for the achievement or otherwise of relevant efficiency and financial performance targets.
The Panel has observed\textsuperscript{350} a trend that where efficiency-based expectations have been communicated to the Tasmanian SOEBs via the corporate planning process, these have often been at a high-level, and Corporate Plans have consequently lacked specific targets or performance measures that can be used to monitor the effectiveness of productivity or efficiency efforts.

One possible view is that the economic regulatory environment and independent regulators will provide the dominant drivers for SOEB’s efficiency and effectiveness. The Panel’s view, on the other hand, is that the regulatory framework can, at best, provide a level of assurance that businesses not exposed to strong and sustained competitive disciplines are not able to routinely operate at generally inefficient levels. A culture of performance must come from within the business – it cannot be effectively imposed by regulation. A high level of interest from Shareholders in efficiency and performance is important in building such a culture.

In Tasmania, there are two key reasons why the Shareholders must be even more active in driving the efficient performance of the SOEBs. Firstly, both the wholesale and retail markets lack effective competition, being dominated by Hydro Tasmania and Aurora Energy respectively. Secondly, because the SOEBs under public ownership they are not subject to the same capital market discipline as private sector entities.

Responsibility for embedding an efficiency-based business culture must start ‘from the top’ by ensuring robust accountability measures exist between the Shareholders and the Boards. The relationship between the parties should recognise that optimising business performance within the broad parameters established by the economic regulatory environments remains the domain of management and Boards, but that Shareholders provide the ultimate incentives and sanctions for efficiency and effectiveness.

In recent times, efficiency has become more of a focus in the governance arrangements between Boards and Shareholders of the SOEBs. For example, Letters of Expectation have become more specific with regard to the Shareholders’ expectation that the SOEBs will develop efficiency improvement programs.

Representatives from the SOEBs have also noted an increase in the level of detail more generally in the most recent Letters of Expectation, compared to previous years. This represents a shift towards oversight that is seeking to better understand and actively engage with the strategic direction of the SOEBs. For example, from this year the SOEB Boards and the Shareholder Ministers will be required to put in place a formal agreement which sets out key performance measures based on agreed objectives, including target dividends and end of year financial results.

\textsuperscript{350} See A Review of the Efficiency and Effectiveness of the State Owned Electricity Businesses.
The Panel endorses the recent improvements in SOEB accountability and oversight. However, it is crucial that these arrangements continue to be refined and improved over time, given that it has not always been clear in the past how expectations are being incorporated into the business strategies of the SOEBs or are then in turn being monitored by the Shareholders. It is also important that, where possible, these improvements are reflected and enshrined in formal and enduring mechanisms (e.g. legislation or subordinate regulations).

Of prime importance are the development of specific accountability and incentive mechanisms that provide a ‘clear line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and Board, management and staff performance on the other. The Panel notes Transend’s Employee Regulatory Incentive Scheme is an example of this kind of approach in action.\(^{351}\)

However, these kinds of mechanisms need to be supported by sound and sufficiently detailed ongoing monitoring, reporting and follow-up processes. This is particularly important where the Shareholders have approved investments in non-core diversification activities that may have a higher risk profile.

It is also important given the growing diversity and complexity of the SOEBs. The intra-entity financial linkages within Hydro Tasmania and Aurora Energy means that there is significant scope for value to be shifted within different parts of the business, either by explicit design, or by changes in one part of the business impacting on another.

For example, there have been implications for the financial performance of Aurora Energy’s distribution business arising from the debt levels required to be held by Aurora Energy as a result of the TVPS acquisition. In relation to Hydro Tasmania, as an integrated generation-retail business in the NEM, there are opportunities to shift value between the retail and generation arms.

Detailed reporting of disaggregated or segmented financial information - and a clear explanation and interpretation of this information - is important to ensure that Shareholders and their advisers are in a position to understand core value drivers and how the financial targets established for parts of the SOEBs are being achieved\(^{352}\). For example, Aurora Energy’s energy business now comprises wholesale electricity trading, wholesale gas trading, Tasmanian retailing of gas and electricity and retailing activities in the wider NEM. While there are strong commercial reasons for this structure to be adopted, including efficiency rationales, the potential trade-off is that it is more difficult to understand what is driving overall performance – that is, what aspects of the business are generating genuine value and what areas are underperforming.

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351 See part C of this volume.

352 This is not to suggest that the management and Boards of the SOEBs do not adequately monitor the financial performance of the various aspects of their businesses.
In this context, Shareholders and their representatives need access to sufficiently detailed and disaggregated financial information that allows them to determine how well individual aspects of the businesses are performing in relation to clear expectations and targets that have been set. Aggregation of financial results should not be used as a way of obfuscating the identification of value drivers of the business.

The Panel has reviewed a range of information provided by the SOEBs to Shareholders, including Corporate Plans and ongoing performance reporting. It has also reviewed monthly management accounts and board reporting within the SOEBs and notes that segment reporting is provided. While not identifying any material deficiencies, the Panel emphasises that access to information and explanation at an appropriate level of detail is a cornerstone of the SOEB accountability framework and must be preserved and, where possible, enhanced.

**Recommendation:**

That SOEB oversight continue to be refined and improved over time with a specific focus on putting in place accountability and incentive mechanisms that provide a clearer ‘line of sight’ between Shareholder expectations and the requirements of the regulatory framework on the one hand, and Board, management and staff performance on the other.

In the context of the SOEBs growing complexity, reporting of financial accounts must continue to provide sufficient transparency with regard to the performance of discrete elements of the businesses in order to support effective Shareholder oversight.

### 3.4. Effective Shareholder oversight and strategic policy functions

The ability for the Shareholder Ministers to effectively monitor and drive efficient SOEB performance through the Boards relies in large measure on the ability of the Shareholder’s agent (in this case Treasury) to access and interpret performance information. Equipped with good information, the Shareholders should be in a position to respond to emerging issues in a timely and effective manner.

The Panel’s Terms of Reference (ToR 8) require it to review the “advice that was provided to the State Government by the senior management or Directors of Aurora Energy from 1 October 2009 to 16 June 2010 inclusive”, in the context of the Company’s changing financial position over this period. This example provides a good insight into the practical functioning of communication channels between a SOEB and its Shareholders.
From its analysis of the relevant documents, the Panel has observed that senior management in Aurora Energy and officers within Treasury were in regular dialogue throughout 2009 (beginning in February 2009) with regard to the significant financial impact of the TVPS acquisition on its balance sheet, particularly in relation to the likelihood that the asset would need to be impaired or ‘written down’ in its financial accounts.

Further, when the wider financial issues in Aurora’s energy business began to fully emerge late in 2009 and early 2010\textsuperscript{353}, the Panel notes that the Board took urgent and appropriate action in informing the Shareholders of these developments by firstly writing to the Shareholders and then tasking a special Board sub-committee to hold extraordinary Shareholder briefings in January 2010. These briefings were followed up with presentations in April 2010 (upon the return of the Government after the 2010 State Election) that contained more detailed financial projections of the severity of Aurora Energy’s position, once this was known.

These observations support the Auditor-General’s findings from his investigation into the circumstances around the Government’s ‘five per cent price cap’ promise, that reporting by Aurora Energy to the Shareholders with regard to its financial circumstances over this period was adequate.\textsuperscript{354}

The Government’s Principles for Strengthening the Oversight and Governance of Government Businesses reinforce the requirement that the businesses notify the Shareholding Ministers and Treasury as their principal financial adviser, of any business specific issues and risks that have the potential to impact on the State and its balance sheet’. The Panel supports this ‘continuous disclosure’ approach and notes that in this particular instance the process functioned as intended.

However, this example highlights a broader issue. While the nature of the financial risk exposure itself was known (and had been communicated to the Shareholders), what was not anticipated was its potential (and subsequently realised) magnitude. The large and sustained falls in the financial performance of Aurora Energy’s Energy business was not anticipated by the Company, although a number of ongoing revisions to expected earnings were conducted throughout 2009-10. In other words, it was not known in advance what Aurora Energy’s financial position would be at June 2010 (which saw actual EBIT of some $50 million below the original Budget, at - $31 million), as unanticipated losses continued to emerge as late as May 2010.

While the circumstances surrounding Aurora Energy’s deteriorating financial position during 2009-10 were unusual, this example does highlight the inherent risks of being an owner of merchant energy businesses in a highly complex market.

\textsuperscript{353} The Panel’s Final Report discusses how and why Aurora Energy’s financial difficulties deteriorated so rapidly over this period. Further detail can be found in Tamar Valley Power Station: Development, Acquisition and Operation in this Volume.

\textsuperscript{354} Tasmanian Auditor-General (2010) Special Report No.94, Election promise: five per cent price cap on electricity prices, p.i.
In its submission to the Panel on governance matters, the Government noted in broad terms that it will be considering the current distribution of its various energy responsibilities across the bureaucracy, in the context of the Panel's findings and recommendations. A strong Shareholder oversight function is clearly a fundamental function that will need to be continued, if not further enhanced.

The Panel has not undertaken a detailed review of the resourcing or operation of key functions relevant to the TESI across the Tasmanian bureaucracy. However, reflecting the separate but interrelated roles that government plays in the sector, the Panel highlights that SOEB oversight must also be complemented by an effective strategic energy policy function within the portfolio Department.

Currently, despite having a legislative basis DIER's energy policy function appears to have a relatively broad but indistinct mandate. Stakeholder feedback indicates that in practice, DIER's limited energy resources are currently heavily committed to the support of Tasmania’s involvement in national energy policy forums (e.g. the Ministerial Council on Energy), and leaving little opportunity to focus on State-based strategic policy development.

Treasury has held a central coordinating role in the delivery of a number of major energy reform projects over the past ten years, including NEM entry and Basslink, and retains formal responsibility for managing the progressive rollout of retail contestability. This has led to the accumulation of expertise and credibility by Treasury in the eyes of decision-makers.

However, if Treasury holds the major responsibility for strategic energy policy advice – in addition to SOEB oversight - this can potentially blur the lines between these two functions, as well as adversely impact on the diversity of perspectives being brought to bear in advice to Executive Government on major energy policy decisions.

**Recommendation:**

That the following key functions should underpin any Government review of energy responsibilities across the bureaucracy:

- A strong SOEB ownership and oversight function, focused on driving the efficient performance of the businesses from a Shareholder perspective;

- An expert energy policy function (separate from the ownership and oversight function) with the sufficient mandate, capacity and authority to provide robust advice to Government, preferably through the portfolio Minister; and

- A strategic ‘whole of government’ policy oversight capacity with the ability to weigh and consider the impacts of energy policy proposals from a more holistic perspective, taking into account broader social, economic and environmental impacts, preferably coordinated by a central agency.
3.5. Enhanced public reporting and accountability

The Panel suggested in its Issues Paper that, prima facie, there appear to be limitations on the extent to which SOEB performance could be driven by ‘external’ accountability mechanisms (which includes answering to both the Parliament and the broader Tasmanian community). It should be noted that in many instances these limitations are not unique to the Tasmanian context, but instead reflective of the State-owned enterprise model more generally, where the focus tends to be on executive accountability (i.e. to the Shareholder Ministers) rather than broader Parliamentary or ‘public’ accountability.356

As the ultimate owners of the SOEBs, however, it is important that the Tasmanian community, as well as the Shareholders, can access regular information about how well the businesses are achieving their stated objectives. In this way, the Parliament plays a key ‘intermediary’ role in holding the SOEBs to account on behalf of the community.

The principle of transparent public disclosure needs to be balanced against a range of other important considerations, including commercial confidentiality and the compliance burden of reporting. It is also important that performance reporting is genuinely informative, particularly given both the inherent complexities of the energy market.

Currently, the Tasmanian public accountability framework comprises the Annual Reporting process and Government Business Scrutiny Committee Hearings, with little in the way of more dynamic, ongoing disclosure of performance information. In this way, public accountability of the SOEBs is largely static and focused on end-of-year performance.

In their submissions to the Panel, the SOEBs noted their existing reporting burden, with some suggesting that they already face a higher level of scrutiny than listed companies due to their status as State-owned enterprises.

It is certainly true that the SOEBs, by virtue of being owned by the State, face different kinds of scrutiny to publicly listed private companies, including the unique requirement to appear before Parliamentary Committees. However, publicly listed companies face their own - and in some cases more stringent - accountabilities, both more broadly through their exposure to the discipline of the share market and under the various reporting requirements specified under the ASX’s Listing Rules.357


357 For example, the requirement to immediately disclose to the ASX any matter that in the view of a reasonable person would have a material impact on the share price of the company – see ASX Listing Rules, Chapter 3.
In this context, the publication of annual financial statements and annual appearances by the SOEBs before the Government Business Scrutiny Committees are a relatively weak substitute for the kind of close market scrutiny that continuous public disclosure places on listed companies.

The existing public reporting regime for the SOEBs attracted extensive comment from Members of Parliament, a number of whom expressed the view that the current level of information available to the Parliament in particular was insufficient for it to perform its accountability and oversight function on behalf of the Tasmanian community.

The Panel believes that the most significant barrier to more effective public accountability is the inherent (and growing) complexity of the energy sector and information asymmetry between the SOEBs and those seeking to understand their business activities. However, the Panel also acknowledges concerns that some key information, such as the Government’s and SOEBs’ business objectives for forthcoming year, is often not available, which makes it difficult to determine if relevant goals had been met, even at a very high level.

In a number of other jurisdictions, public reporting by State-owned Enterprises comprises a combination of ‘ex-ante’, ‘process’ and ‘ex-post’ reporting mechanisms, which provide a more dynamic picture of business performance throughout the financial year. This typically comprises the publication of a summary of the corporate plan at the start of the financial year, a half-yearly report and a final annual report.

The Panel believes that there is merit from a public transparency perspective in improving the timeliness and currency of key SOEB performance information provided to the Tasmanian Parliament, consistent with good practice arrangements in other jurisdictions. Specifically, this should include a Statement of Corporate Intent, a Half-Yearly Report and an Annual Report.

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358 A number of interviewees made the observation that without a background in energy markets, Members of Parliament and the general public would (and indeed did) find it very difficult to understand important contextual information about the operation of energy markets relevant to scrutinising the performance of the businesses.

359 For example, the New South Wales State Owned Corporations Act 1989 requires SOCs to provide to the Parliament a Statement of Corporate Intent (SCI), Half-Yearly and Annual Reports (within specified timeframes), as well as any directions issued to the SOCs by the Shareholder Ministers. Similarly, New Zealand State-owned Enterprises are required under statute to lay before the House of Representatives a copy of their SCI and both half-yearly and annual reports. The Commonwealth Government also applies a very similar reporting framework to its Government Business Enterprises.

360 See Bottomley, S (2000) Government Business Enterprises and Public Accountability through Parliament. Bottomley notes the typology developed by John Goldring and Ian Thynne, which usefully describes three kinds of public accountability that can generally be applied to Government Business Enterprises - ‘ex-ante’, ‘process’ and ‘ex-post’ accountability. Examples of the first include the publication of statements of corporate intent, the second could be used to describe reports provided during the financial year (‘ongoing disclosure’) and the third generally applies to mechanisms such as Annual Reports and end-of-year Parliamentary scrutiny.
This kind of reporting regime is unlikely to result in any significant additional compliance burden for the SOEBs, given the existing Corporate Planning process, and the fact that more detailed half-yearly reports are already provided by the SOEBs to the Shareholders. It is noted that Treasury suggested that a very similar reporting regime might improve public accountability in its 2010 Position Paper on the conversion of Government Business Enterprises to State-owned Companies.361

Through its Issues Paper, the Panel also sought stakeholder views on whether there might be some accountability benefits in exposing the SOEBs to public ‘continuous disclosure’ requirements, analogous to those that currently apply to companies listed on the ASX. This was met with mixed responses from stakeholders, most notably from the SOEBs themselves.

After further analysis of similar arrangements in other jurisdictions362 and discussion with stakeholders, the Panel is not convinced that public, continuous disclosure for the SOEBs would yield sufficient accountability benefits to justify the burden of its imposition on the businesses at this stage.

While not within the Panel’s remit, it should also be noted that a number of stakeholders were highly critical of the effectiveness of the current Government Business Scrutiny Committee Hearings process, specifically its ability to provide a genuine forum for the discussion of the SOEBs’ operational and financial performance. Many stakeholders thought the Hearings had become unduly politicised, which was seen by some as having the unhelpful effect of blurring the line between accountability for SOEB performance (including the oversight performance of the Shareholder Ministers) and the general performance of the Government of the day for the delivery of other policy objectives (which are often unrelated to the operations of the businesses).

The conduct of Scrutiny Committee hearings is a matter solely for the Parliament to determine and the Panel makes no further comment or recommendations in relation to this specific aspect of SOEB oversight and accountability. However, the Panel considered it appropriate to make mention of stakeholders’ concerns given the strong feedback received during consultation.

The Panel’s improvements to the provision of relevant and timely SOEB information, proposed above, may enhance the Committee’s capacity to perform its SOEB oversight function in a more informed and effective manner.

362 The Panel looked specifically at New Zealand, where continuous public disclosure requirements for State-owned entities were introduced in 2010. The Panel was sufficiently convinced by an early analysis - see Howell, Bronwyn E., Heatley, Dave and Talosaga, Talosaga, (2011) ‘Can Continuous Disclosure Improve the Performance of State-Owned Enterprises?’. Available at SSRN: http://ssrn.com/abstract=1856287 - that because of the inherently ‘distant’ nature of the SoE/community relationship, this kind of arrangement would be unlikely in and of itself to deliver any significant accountability benefit. It is noted, however, that a number of New Zealand’s SOEs have recently been part-privatised, which increases the relevance and likely effectiveness of continuous disclosure requirements in that country.
**Recommendation:**

That, at a minimum, each of the SOEBs provides to the Parliament and the wider Tasmanian community the following:

- an annual Statement of Corporate of Intent (SCI) at the commencement of the Financial Year, summarising the key objectives and performance targets from the SOEB’s Corporate Plan;
- a Half Yearly Report that provides a summary of year-to-date performance against targets set out in the SCI; and
- an Annual Report.
4. Separation of the Government’s multiple roles of policymaker, regulator and businesses owner

4.1. Key principles

A fundamental governance challenge in the Tasmanian energy sector, as in a number of jurisdictions, is that the State Government is both a major business owner and one of the main arbiters of the policy and regulatory framework within which the businesses operate. This gives rise to the potential for confusion, or possibly conflict, between these roles, whereby outcomes in one area, for example business performance, are delivered by changes or compromises in another.

In the absence of clear institutional and operation lines of demarcation between Government’s roles, it becomes difficult to hold state-owned businesses accountable for the outcomes under their control or management. Further, where the perception of potential ownership/regulatory conflict exists, this can have the effect of undermining the confidence of market participants in the independence of the regulatory framework. It can also drive the perverse outcome of government withdrawing from its obligations under its legitimate shareholder oversight role for fear of being accused of regulating or making policy to benefit its own businesses.

The issue of an ownership/regulatory tension was raised by a number of stakeholders in submissions to the Panel. TasGas Networks, for example, suggested that there is currently a ‘fuel bias’ (either inadvertently or deliberately) towards electricity over gas because of the State’s position as owner of the SOEBs. This issue was also highlighted during the stakeholder interviews, where examples were provided that suggested that important gas interests had, at times, been seen to be excluded from key strategic energy infrastructure planning forums established by Government.

There were also some more general concerns raised with regard to the ability of the SOEBs to influence energy policy because of their superior level of access to Ministers and Government when compared to other, privately owned market participants.

In order to manage these potential conflicts, accepted good practice is that there should be a clear distinction between the State’s ownership function and its regulatory and policy-setting function. Even in the absence of private sector competition, governments have favoured the separation of the roles of Ministers as a means of improving discipline for efficient use of State resources, minimising distortions arising from government ownership and increasing the responsiveness of State-owned businesses to their customers.

As the OECD notes, “...full administrative separation of responsibilities for ownership and market regulation is a fundamental pre-requisite for creating a level playing field for [State-owned Enterprises] and private companies and for avoiding distortion of competition”.364

The outcome from this separation should be a regulatory framework that does not discriminate in any way between public and private sector entities, so that ownership effectively becomes irrelevant to the regulatory decision-making process.

This separation is achieved through the following key mechanisms:

- independent industry regulation (including prices, technical and service standards etc.);
- exposing State-owned businesses to the same laws and regulations as their competitors, with no special exemptions (including payment of all applicable taxes);
- minimising benefits associated with State-owned businesses’ access to state-backed debt finance (typically through the payment of ‘guarantee fees’); and
- the separation of portfolio ministerial responsibilities from shareholder minister/business ownership and oversight responsibilities.

4.2. Summary of current arrangements

The separation of State-owned entities from the regulatory roles of government is a central tenant of the corporatisation concept that has been pursued by Australian governments, including Tasmania, since the late 1980s and formalised in the National Competition Policy (NCP) reforms of the mid-1990s.

For example, the NCP agreements signed by all States and Territories in 1995 specifically required, among other things:

- the separation of policy development and regulation from the operation of industry;
- that regulation of prices for monopoly services and access to networks should be independent of government; and
- that government-owned and private sector businesses should be afforded the same treatment under policy and regulatory arrangements (i.e. the principle of competitive neutrality).

Consistent with the NCP agreements, and in recognition of the important principle of transparent regulatory and ownership separation, there are currently a suite of governance mechanisms in Tasmania to ensure an appropriate demarcation between Government’s different roles in the sector, the key components of which include:

- independent economic and technical regulation of the sector, jointly undertaken by the Tasmanian Economic Regulator and the Australian Energy Regulator;
- the payment by the SOEBs of tax equivalents and guarantee fees; and
- the administrative separation of policy and SOEB ownership functions between the Minister for Energy and the Treasurer (and consequently between the Department of Infrastructure, Energy and Resources the Department of Treasury and Finance).

In the broad, existing governance mechanisms are both consistent with good practice and provide a sound ‘baseline’ framework for appropriately reconciling the ownership/regulatory tension. However, the Panel has made some observations in the course its investigations, which it believes have the potential to weaken their intended outcomes.

4.3. Issues and recommendations

4.3.1. Confidence in the independence of regulatory processes

It is the Panel’s position that financial value in the SOEBs should be an outcome of efficient operations, not a core driver of policy or regulatory settings. Given the sector’s economic and social significance to the State, policy and regulatory settings should be primarily focused on economically efficient outcomes in the energy market.

Economically efficient prices may or may not be consistent with good financial outcomes for the SOEBs at a particular moment in time. As electricity consumers, the Tasmanian community’s interests are best served through economically efficient pricing. As the ultimate owners of the major electricity businesses, the community’s interests are also in achieving good financial outcomes as dividends paid by SOEBs, relieving the pressure on the need to raise Budget revenue through other means.

Achieving both of these objectives simultaneously depends on a range of variables, including the efficacy of decisions around the scope of the businesses activities and investments; the incentives for productivity improvements provided by the way shareholder oversight works in practice and the overall demand and supply balance. It is vital that a framework is established that clearly allocates risk and reward between owners/taxpayers on the one hand and electricity users on the other.
In the Tasmanian framework, the TER is responsible for the setting of the Maximum Allowable Revenue that Aurora Energy may recover from its non-contestable retail customers through regular (typically three-yearly) pricing determinations. In determining maximum prices, the TER is required to take into account all cost components of the supply chain, including the wholesale price of energy, which is the single largest component.  

Under the Electricity Supply Industry Act 1995 (the ESI Act), the TER is independent of Ministerial direction in carrying out its functions, including the setting of retail prices for non-contestable customers. The Act provides the TER with a high level of flexibility in how it undertakes its key functions. However, Parliament remains responsible for defining the framework within which the TER operates, including through the Price Control Regulations (PCRs). Within this framework, government appropriately provides for the consideration and balancing by the TER of a range of broad objectives, including the quality and efficiency of services, the financial sustainability of the businesses and the ‘public interest’ (among others).

In its investigation of recent pricing trends, the Panel has observed that the Government has provided additional, specific direction to the TER with regard to either prices themselves (as in 2007), or the methodology that should be used for arriving at these prices.

Under the 2007 Determination - where the Government, not the TER, set the wholesale allowance, one of the key principles applied Government was that the price should contribute to the sustainability of Hydro Tasmania and Aurora Energy to ensure sufficient revenue capacity to earn a commercial return. This ultimately resulted in an ‘adjustment factor’ of approximately $3MW/h being applied to the price that had been recommended by independent consultants based on the application of a long-run marginal cost methodology.

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365 For a detailed description of how the Regulator determines prices for non-contestable, see the Panel’s Pricing Discussion Paper ‘Tasmania’s electricity pricing trends’.


367 The Panel understands that the adjustment was justified in part based on Hydro Tasmania’s weakened revenue raising capacity while it rebuilt its storages during a period of drought but has found no evidence or clear explanation of how the $3 MW/h figure was derived.
Regulatory frameworks must be adaptive and responsive to change where it is demonstrated that they are not delivering the objectives they have been primarily established to achieve. However, given the primary aim of the regulatory framework is to support the efficient operation of the energy market, it is important that market participants cannot form the impression that specific direction provided by the Government to the Regulator, through changes to the regulatory framework, is driven by Shareholder value considerations. When the Government is both a business owner and responsible for setting regulatory arrangements, it is crucial that clear demarcations between these functions are, and are seen to be, maintained.

The Government’s involvement in specific elements of recent pricing determinations - beyond the establishment of the broad principles and objectives that underpin the regulatory framework - raises potential concerns about the actual or perceived level of ‘functional’ independence that the TER is afforded in making pricing decisions.

The PCRs are designed to provide a high-level of flexibility in the mechanisms that the TER uses in achieving the objectives set out in the regulatory framework.

The Panel endorses the Office of the Tasmanian Economic Regulator’s (OTTER) view\(^\text{368}\) that the high level regulatory framework - once appropriately set by Government - should remain consistent between regulatory periods as far as is possible. Crucially, it should also permit the TER sufficient independence, particularly with regard to the application of technical and methodological approaches.

Complete transparency in regulatory pricing arrangements will become critically important for the new entry of private capital in the market with the introduction of full retail contestability and attendant ‘fall-back’ contract arrangements. A number of electricity retailers have raised this as an issue in their discussions with the Panel.

**Recommendation:**

That the TER is given the discretion to independently select and apply appropriate approaches and methodologies, within the context of the broader objectives set by the regulatory framework.

Where there are specific outcomes that the Government believes should be taken into account, then it may put the case to the TER in submissions to the independent regulatory process.

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\(^{368}\) See OTTER’s submission to the Issues Paper.