SUPPLEMENTARY REPORT

Prepared For:

Australian Energy Market Commission: Reliability Panel

Supplementary Report on Benefit-Cost analysis for Tasmanian Frequency Operating Standards

DISCLAIMER

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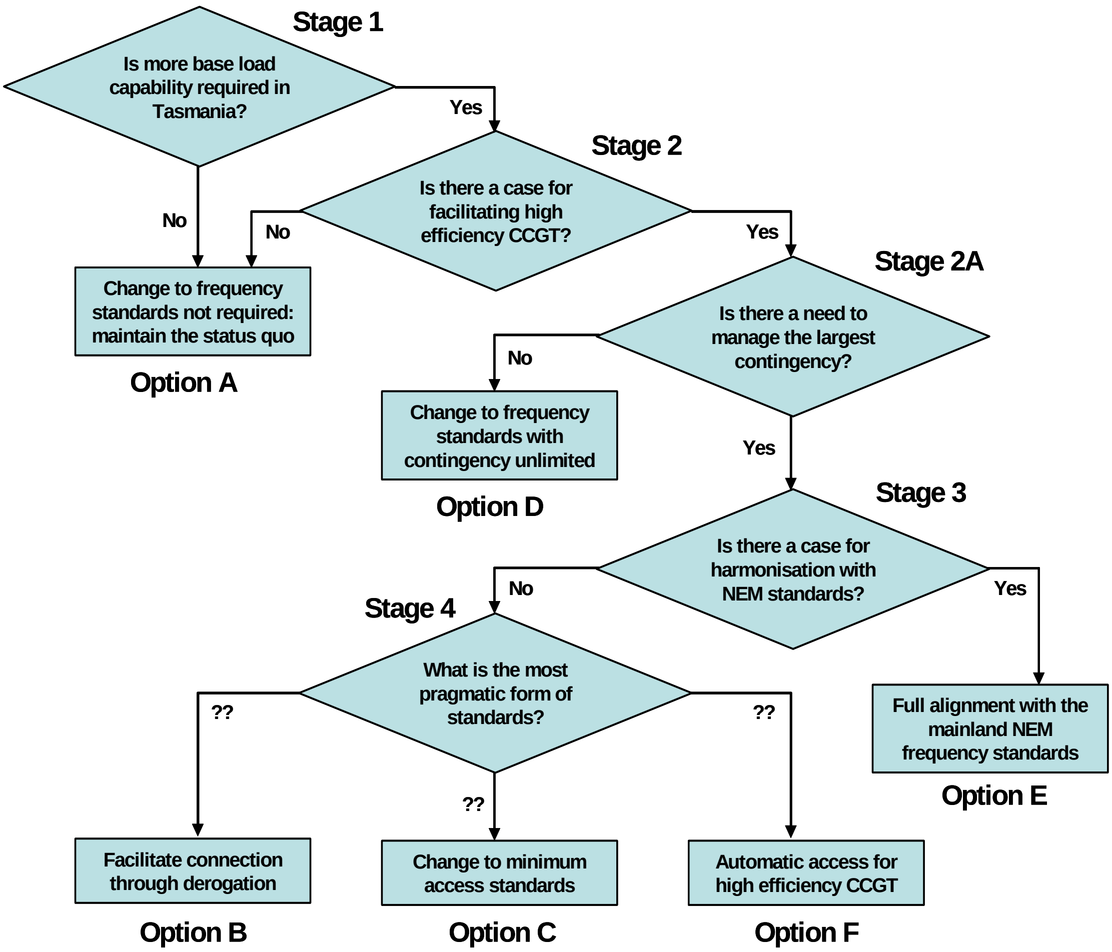
1. BACKGROUND

This document supplements the benefit cost analysis of potential changes to the Tasmanian Frequency Operating Standards (TFOS) prepared for the Reliability Panel in August 2008 (August Report). A change to the TFOS is being considered to ensure that the standards are not a barrier to entry of modern high efficiency gas-fired generating plant.

The August Report presented a comprehensive framework for assessment of the merits of change using a chain of decisions that assessed the need for any change in principle, and the nature of any change that is found to be warranted. The framework is reproduced in Figure 1.

Figure 1 Analytic Framework



The August Report:

- Answered YES to the Stage 1 question – more baseload capability is required in Tasmania. It was answered YES in the sense that there is sufficient probability that additional baseload capacity will be required that the TFOS should not be a barrier to baseload entry.

- Answered YES to the Stage 2 question: there is a case for facilitating entry of high efficiency CCGT plant, providing there is a net benefit.

- Answered YES to the Stage 2A question that there is a need to manage the size of the largest contingency on the basis that assessments showed that entry of plant that resulted in contingencies significantly larger than the current (max. 144MW) would result in very high costs for spinning reserve (Frequency Control Ancillary Services).

- Answered NO to the Stage 3 question: there is not a basis for full harmonisation of frequency standards with other regions of the NEM.

The August Report also considered the most pragmatic form of amended standards in Stage 4. The report concluded that there were a number of options but the choice was intertwined with regulatory policy and market rules – for example, relating to the allocation of costs for ancillary service and network access responsibilities.

The focus of this supplementary report is to revisit the assessments in Stages 2 and 2A. Along with submissions from a number of stakeholders, the analysis in the August Report used a combination of cost and pricing material to assess the merits of change to the TFOS and the probable impact of change on customers. Submissions also referenced the effect of cost allocation and market-wide prices in their evaluations.

Assessment of the case for change is complex, as any tightening of the frequency standards is expected to increase the amount of frequency control ancillary services required to be provided from within Tasmania; services already in short supply. A change to the standards may also impact operating limits on Basslink, a complex consideration because of the "no-go" zone for transfer of FCAS from mainland regions of the NEM and interaction with schemes to protect the integrity of the Tasmanian power system.

This amended assessment uses a strict cost-based approach that is decoupled from any consideration of cost allocations and pricing that, in hindsight, clouded previous debate. We expect that a number of the issues raised in the previous analysis and by stakeholders relating to pricing and cost allocation may give rise to proposals for changes to cost allocations and negotiations about conditions of access to the network. Brief comment on these matters is included, but it is beyond our scope to develop these in detail.

There is likely to be a range of benefits and costs, some of which will be able to be quantified, while others will be either difficult to quantify or purely qualitative. Typically, a benefit cost analysis will consider the quantifiable elements first and then assess the likely impact of qualitative elements.

2. QUANTIFIABLE BENEFITS AND COSTS

2.1. METHODOLOGY

In the case being examined, the potentially quantifiable benefits and costs can be broken into two categories[1]:

1. The change in cost of producing **energy** to meet customer demand. These costs can be further subdivided into:

   - direct costs of operating the different types of plant that would be expected under different TFOS settings (i.e. high efficiency CCGT plant if the TFOS are tightened and smaller OCGT and possibly small CCGT plant if no change is made); and

   - consequential changes in energy dispatch across the NEM required as a result of different ancillary service requirements or operating restrictions on Basslink. Any restrictions on the operation of Basslink that affect the flow on Basslink will inevitably change the balance of dispatch between the Tasmanian region and other regions of the NEM. Such a change will affect the cost of producing energy. For example, if import to Tasmania is restricted it will mean more energy must be generated in Tasmania and less produced in other regions. Analysis is complex because the amount of energy available from hydro resources is limited by the amount of available water, and an increase in hydro generation at the time of a restriction will need to be made up by a decrease later - possibly progressively over subsequent months. Each change in dispatch results in a decrease in cost at the location where energy is not produced and an increase at the replacement site. The net effect of a restriction or inefficiency is thus the net change in cost of production.

2. The change in cost of providing **ancillary services** to maintain power system security. Provision of ancillary services can require generating plant to operate inefficiently – which may require a consequential change in dispatch of energy noted above, and can also impose additional operation and maintenance costs on generating plant.

1 Although there is some overlap between them and the boundary is somewhat arbitrary.

A change in the TFOS will allow the system to sustain a mix of generating plant in the power system that is different to the mix that could be sustained were the TFOS to remain unchanged. A benefit cost analysis of a change must therefore assess the difference in relevant costs (e.g. the costs of producing energy and providing ancillary services) that would arise under each of the resultant alternative generation mixes. Quantifying these benefits and costs is complex and, for the purposes of this work, has been undertaken without the use of detailed market modelling, an approach that has necessitated the use of a number of assumptions and approximations.

For a number of the elements of cost we did not have independent sources of data. However, the objective of the analysis was to advise the Reliability Panel if the benefits and costs were positive, marginal or negative. The exact value of the net benefit or cost was less important. Accordingly we have used the approach of building a “first pass” estimate of costs from the best available data and where necessary the claims made and assessing if the final result would be likely to change if more optimistic or pessimistic values were used. We found the first pass result showed a net benefit but was within the range that should be regarded as marginal and thus qualitative measures are also an important consideration in any final assessment. More accurate quantitative assessment is unlikely to change this position.

The following quantifies and comments on claims about the elements of the relevant costs, to the extent practicable using available information, each of the above benefits and costs.

2.2. COST OF PROVIDING ENERGY

The cost of producing energy from the different types of plant requires an understanding of the level of dispatch likely from each type of plant. Our estimate is based on the expected high utilisation of proposed plants – this is consistent with our assessment of the need for additional base load plant in the August report. The assessment is as follows:

- A high efficiency Combined Cycle Gas Turbine (CCGT) plant, with a capital cost in the order of US$1050/kW running at high utilisation will have a Long Run Marginal Cost (LRMC) of approximately A$66/MWh.

- Submissions differed on whether a CCGT based on plant that can meet the current TFOS, would be available. Hydro Tasmania submitted that it anticipates a small CCGT plant would be available and proposes costing and operational parameters consistent with an LRMC of A$71.

There is some uncertainty about the costs and likely rates of utilisation, but in comparing the high efficiency CCGT plant with that of plant Hydro Tasmania suggests would be capable of operating under existing TFOS, a minimum LRMC difference of A$4.50/MWh appears justified. While the LRMC of each type of plant may fluctuate – for example, as a result of changes in exchange rates and global supply and demand for generating plant – it is the difference between the respective LRMCs that is important for this analysis. We have adopted a value at the lower end of the likely range. The $4.50/MWh LRMC difference equates to an annual saving of $7M in the cost of energy production as a result of facilitating the entry of high efficiency CCGT plant. The difference would be greater if suitable small CCGT plant were not available as Hydro Tasmania suggest.

If the TFOS are narrowed, material presented to the Panel indicates that there will be additional restrictions on the operation of each of Basslink and of Hydro Tasmania's existing plant that would lead to loss of efficiency of dispatch across the NEM as a whole. There will be a trade off between the inefficiency within Hydro Tasmania's plant and restrictions on Basslink, as the more ancillary service that Hydro Tasmania provides the less Basslink will need to be restricted. This is the most difficult element to quantify without market modelling. We have included an additional energy cost of $0.8M claimed by Hydro Tasmania in the "first pass" calculation on the basis that it can be revisited if the result has a material affect on the final conclusion.

2.3. COST OF PROVIDING ANCILLARY SERVICES

Provision of fast acting ancillary services from hydro plant requires the plant to operate in modes that incur greater maintenance penalties and requires water to be released from plant without generating any or all of the energy that it might have. Some of the (additional) ancillary services may also be able to be provided from demand side resources or from future new entrant generators, thus not all of the burden of providing additional ancillary services necessarily falls on Hydro Tasmania. Presumably alternative sources of ancillary services would only be used if the costs were lower than those of Hydro Tasmania.

Material from NEMMCO, Transend and Hydro Tasmania all noted the trade-off in the amount, and therefore the cost, of ancillary services related to the size of the largest single contingency on the Tasmanian system and the setting for the "normal band" in the TFOS. The material showed that the cost of ancillary services rises significantly for contingency sizes greater than the current largest size of 144MW. It also showed some additional ancillary service was likely to be available much of the time but that requirements in excess of the current level would be increasingly problematic. In principle, the size of the largest contingency and corresponding FCAS requirement could be determined dynamically depending on the prevailing circumstances. This matter has been considered by NEMMCO and Transend and found to be overly complex given the range of parameters that affect the relevant values. Hence a simplified approach is proposed. NEMMCO, Transend, Hydro Tasmania and potential new entrants have proceeded on the basis that some form of restriction to the largest contingency should therefore be included as part of an amended operational regime. Our assessment has been based on data provided to us for a limitation to 144MW contingency size.

For the purposes of assessment (and again leaving the option of revisiting if appropriate) we have used an ancillary service cost claimed by Hydro Tasmania of $0.4M for maintenance penalty and $3.5M[2] as the value of energy not produced because of water releases. This assessment values the foregone energy at $50/MWh, or slightly above the SRMC of gas plant in Tasmania. In practice this is likely to be the highest replacement cost as it implies that all the foregone hydro production will need to be replaced by Tasmanian gas production with no contribution from coal or cheaper gas from other regions at times when Basslink is not constrained.

2.4. NET CHANGE IN COSTS

In summary the net "first pass" benefits and costs are:

Minimum saving in cost of energy production from efficient CCGT relative to less efficient CCGT [see note (a)]	$7.0M benefit
Allowance for inefficient operation to provide ancillary services (water losses)	$3.5M cost
Allowance for inefficient dispatch	$0.8M cost
Allowance for increased maintenance to provide additional ancillary service	$0.4M cost
Net "first pass" net cost/benefit	**$2.3M benefit**

(a) In the event that a suitable small CCGT could not be sourced, and replacement generation would need to be sourced from less efficient technologies, the LRMC of the alternative generators would be markedly higher and the saving in cost of energy production correspondingly larger, potentially significantly so. We note that limited enquiries have been made to ascertain the availability of a small CCGT facility that would be compatible with the existing standards. The results have been inconclusive in that no source has been identified, but on the other hand it has not been possible to find convincing evidence none exist.

3. DISCUSSION

We emphasise that by design, the analysis relates only to demonstrable system wide costs. In particular the result takes no account of:

- Resultant impact on prices and the revenues to generators in general or to particular generators for energy or ancillary services;
- Costs to generators under cost allocation arrangements for ancillary services;

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- Allowance for the changes in prices to customers; or
- Transition costs, for example for Tasmanian generators, NEMMCO and Transend to adjust operating parameters for revised standards.

While the net change in costs shows a positive benefit and potentially may understate the value, the result is still within the range that should be regarded as marginal given the magnitude of the underlying values. However, the nature of the approximations employed, and the values adopted for data we could not validate independently, means that the estimated net benefit is likely to be conservatively low.

In our August Report we included discussion of options for implementation of revised standards and noted the potential for both formal and de-facto changes to the broader market arrangements – including in relation to the allocation of costs in order to provide incentives for efficient provision of energy and ancillary services. For these reasons it is appropriate to consider the set of qualitative measures prior to finalising any decision against the National Electricity Objective. Relevant qualitative factors may include intangible (or at least very difficult to quantify) benefits of additional participants, facilitation of further investment and good regulatory practice. Consideration of these factors may also affect assessments of the timing of when any amended provision should apply from and suggests that some transition measures may be appropriate.