Hydro Tasmania
the renewable energy business

28 August 2009

Mr Glenn Appleyard, Regulator,
Office of the Tasmanian Economic Regulator,
GPOBox770,
Hobart,
Tasmania 7001

Dear Glenn,

Declaration of Electrical Services

Please find attached Hydro Tasmania's submission.

We also confirm our request for the opportunity to make a presentation to you and your consultants. Given the complexity of the issues canvassed in our submission and the fact the proposed regulation is specifically directed at Hydro Tasmania, we believe it is important to be afforded the opportunity to explain our submission and the far reaching implications of this decision on the efficiency of the NEM.

Please contact the undersigned on 0418136493 if you have any queries.

Yours faithfully

D. Bowker.

David Bowker

Manager Regulatory Affairs

Hydro Tasmania's Response to OTTER Notice on Notice of Intention to Declare Raise Contingency FCAS Services

28 August 2009

Executive Summary

The Regulator has issued a notice of intention to declare the supply of raise contingency FCAS by Hydro Tasmania as a declared electrical service under the *Electricity Supply Industry (Price Control) Regulations 2003*.

The Regulator has taken the view that:

> "Hydro Tasmania has substantial market power in the provision of raise contingency FCAS and that the promotion of competition, efficiency and the public interest requires the making of the declaration".

Hydro Tasmania is a participant in the National Electricity Market (NEM) and competes in an environment where the nine NEM "spot markets" (energy and the eight types of FCAS) are co-optimised in real time to produce the least cost solution to meet demand across all regions. This concept is fundamental to any analysis of competitive dynamics and market outcomes but it is not evident that this has been taken into account in the notice.

Hydro Tasmania has consistently stated over the last 12 months, through the Review of Tasmanian Frequency Operating Standards (FOS) and other forums, that there are shortages of local supplies of raise[1] contingency FCAS in Tasmania. It was accepted that this would be exacerbated by any tightening of the Tasmanian FOS. As recognised in the FOS Review, this can lead to inefficient outcomes in the co-optimisation of energy and FCAS that are a greater cost to the market and result in higher energy prices to consumers than would be the case with increased local supplies of FCAS.

The most efficient and effective manner to address this FCAS shortage is to allow the market to develop new sources of supply. These may come from a variety of sources (gas fired generation, customer load and other "stand alone" technologies). **Regulation will aggravate the local supply inadequacy problem and deter investment in new sources of supply**.

There is a separate issue, affecting much smaller volumes of fast raise contingency FCAS (around 30MW), in the formulation of the input equation for the loss of Basslink when flowing southward in the co-optimisation process.

[1] This submission focuses on fast raise contingency FCAS as that is primarily the subject of the Regulator's Notice. However, Hydro Tasmania acknowledges that the proposed declaration is intended to encompass slow and delayed raise contingency services. The fundamental arguments are essentially the same in these two markets although the supply/demand balance is potentially quite different.

Regulation is not a solution to this (albeit minor) inefficiency. Indeed the need to cover a share of this small volume is likely to encourage Tasmanian generators to enable their plant for FCAS.

In this regard, Hydro Tasmania notes that during the FOS Review both AETV and a proponent of another CCGT plant made representations as to their capability to provide fast raise contingency FCAS from new CCGT plants. In addition the State Government proposed to transfer the Bell Bay thermal station to Aurora on 31 March 2009 which had been providing both fast raise and fast lower contingency FCAS (which has reduced available supplies). This transfer did not proceed.

Participants in the NEM, have a variety of risks to manage including physical dispatch and price. Managing these risks is an important element of the competitive dynamics of NEM. Most participants attempt to manage these risks through a portfolio of derivative products aligned with their physical capability and risk profile. Participants generally rebalance their physical and derivative portfolio to market conditions. This has certainly been the experience of Hydro Tasmania since entering the NEM.

Regulation which seeks to insulate particular market participants from having to manage these normal market risks does not promote competition and is not in the public interest.

In this submission we have described the relevant NEM processes, identified some incorrect assumptions and factual inaccuracies in the Notice. The implications of the contemplated regulation will be far reaching both regionally and across other “spot markets” and is very likely to distort the market and reduce the efficiency of the whole NEM.

Hydro Tasmania therefore requests that the Regulator must seriously reconsider its intention to make a declaration. This will allow market dynamics to develop and thus facilitate the emergence of market solutions to the real problem of inadequate supplies of FCAS.

Introduction:

To understand the competitive dynamics of the NEM and how these dynamics are applied to the Tasmanian region it is necessary to have a thorough understanding of the NEM dispatch engine (NEMDE), the co-optimisation process, constraints on that process and the risk management alternatives available to market participants. Accordingly, the body of this submission commences with a description of the spot market dispatch and the co-optimisation process as it applies to the Tasmanian region, particularly Basslink's important contribution (Section 1).

Building on the knowledge of the market design principles and limitations on the implementation of optimal co-optimisation, we outline the risk mitigation strategies typically applied by market participants. We then examine how the market design and risk mitigation products combine to form the basis of a competitive environment that would suffer from the regulatory intervention currently under consideration (section 2); ultimately increasing the cost to customers.

Finally, Hydro Tasmania believes there are five major incorrect assumptions (Section 3) and a number of factual inaccuracies (section 4) in the Notice.

1. Background – Market principles applied to Tasmania and Basslink

To be able to draw any conclusions from observable price events in the market, it is first necessary to understand the principles being applied in dispatch before being able to analyse how the various inputs contribute to the dispatch outcome.

1.1 Co-optimisation by the NEM dispatch engine[2]

The starting point is to understand the principles of the NEM and the nature of the dispatch engine that lies at its heart. The key objective of the NEMDE is to maintain the power system in a secure state in the most economic and cost effective way on a 5 minute basis. The system security element is sometimes overlooked in the interpretation of the NEM objective but is roughly translated into higher price signals to encourage generators to meet demand and avoid load shedding. Hence the highest "spot market" price is set at a high value of $10,000, the Market Price Cap.

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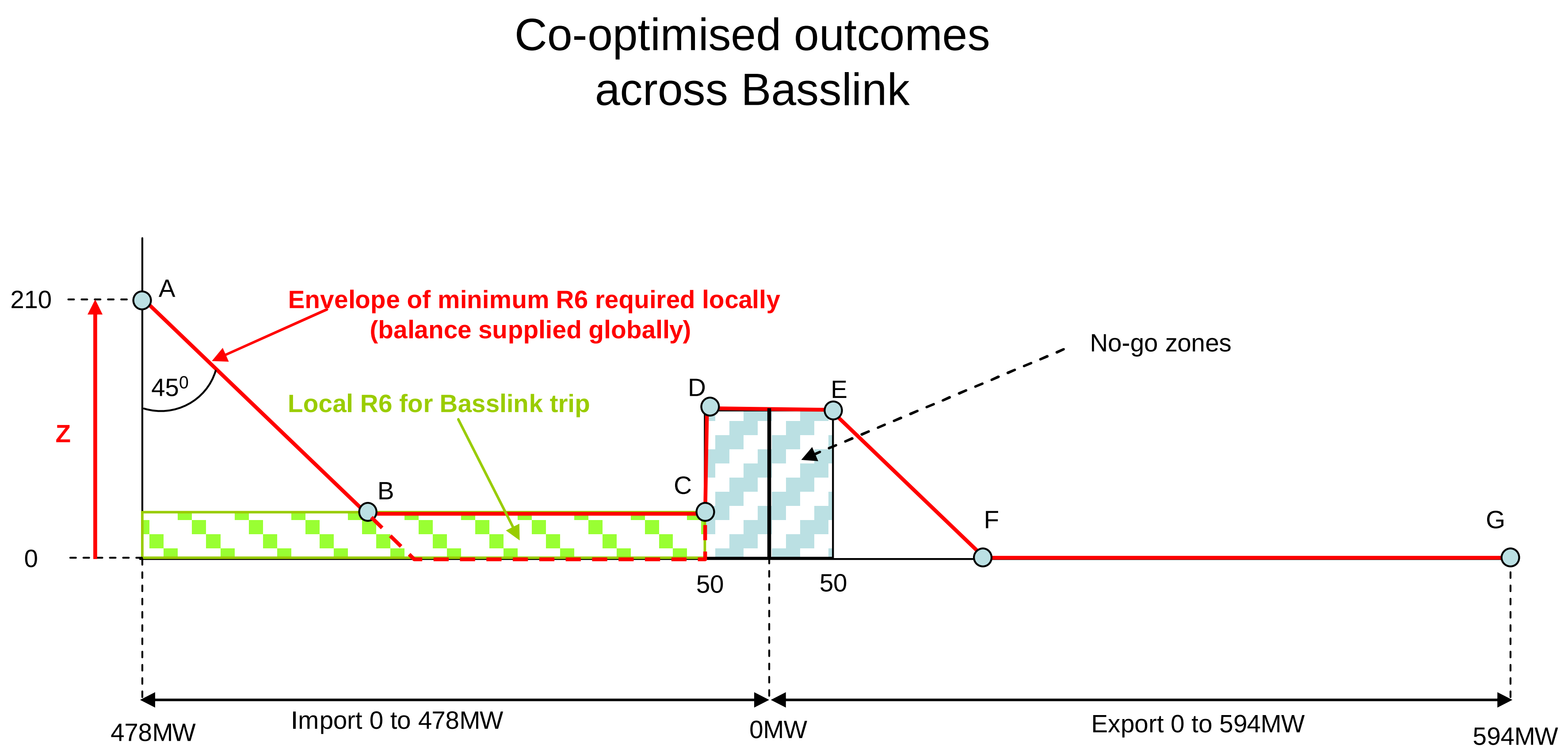
[2] Please note that this discussion must necessarily be a simplified reflection of reality given the multiple variables and complexity in the way the NEM dispatch engine works. Further, to use figures and show outcomes for illustrative purposes, some variables have to be held constant and some fixed assumptions have to be made. This is an inherent limitation in any modelling of the NEM.

In order to achieve the NEM objective NEMDE has been designed to co-optimise nine “spot markets” (energy and eight types of FCAS) for all NEM regions so as to achieve the most economic dispatch of production in the NEM as a whole for the next 5 minute dispatch interval, while maintaining system security. Fundamentally NEMDE takes all the appropriate inputs (generator bids, transmission constraint equations, FCAS trapeziums, system demand, etc.) and processes them through its central algorithm. This produces all the individual outputs (generation targets, interconnector flows, FCAS enablements, prices, etc.) that in combination make up the dispatch for each 5 minutes.

Although, it can be argued that NEMDE has some key limitations, such as the inability to consider more than a single dispatch interval and the marginal MW approach that doesn’t account for large differences in volume between the different “spot-markets”, given the already highly complex nature of the dispatch engine, it is not considered feasible to come up with a better algorithm that can overcome these inherent limitations. Hence, where there is co-optimisation, the outcome produced by the dispatch engine is considered the most economic outcome realistically achievable.

The reason for Tasmania joining the NEM and physical interconnection via Basslink was to introduce the competitive market dynamics that are delivered through co-optimisation by NEMDE. Figure 1 is a diagrammatical representation of how co-optimisation impacts on Basslink flows.



Co-optimised outcomes
across Basslink
210
0
Z
A
B
C
D
E
F
G
45°
Envelope of minimum R6 required locally
(balance supplied globally)
Local R6 for Basslink trip
No-go zones
50
50
478MW
Import 0 to 478MW
0MW
Export 0 to 594MW
594MW

Figure 1

1.2 Co-optimisation relevance to Basslink flow

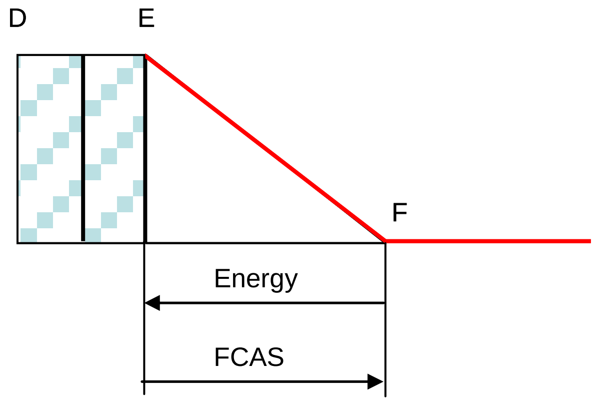
First, it is extremely important to appreciate that Basslink flow is determined as a result of the co-optimisation of the spot markets, being an output of the NEMDE dispatch solution. To understand the relative differences in outcomes it is necessary to explain the different sections of Basslink flows[3] as illustrated in figure-1 and the different limitations acting on the co-optimisation process at any given point in time. In all cases NEMDE solves to find the most economic outcome based upon the marginal cost of the sourcing of an additional MW. Any variation from this approach produces a less economic outcome.

For simplicity, it is assumed the Victorian region is representative of the NEM (ie no other constraints impacting)

Point G: At this point the supply side limitation has fully counteracted the co-optimisation process (due to the physical export limit) and price separation occurs in the particular spot market or spot markets.

Point F–G: If NEMDE dispatches Basslink in this region then there is no limitation on the co-optimisation process. The flow is purely determined by the combination of the global energy and FCAS bid stacks without the influence of any limitations.

Point E-F: Through this section NEMDE has determined that the most economic outcome is to provide a proportion of FCAS regionally and another proportion globally that enables the relative energy flow between Tasmania and Victoria. Assuming all other variables are the same, higher priced energy bids in Tasmania will tend to push the flow towards point E, while higher priced FCAS bids in Tasmania will tend to push the flow away from point E (as illustrated below). The co-optimised outcome reflects the availability and relative pricing of supply side services. This is where a shortage of a particular supply side service may "trap" Basslink, effectively denying a flow reversal.

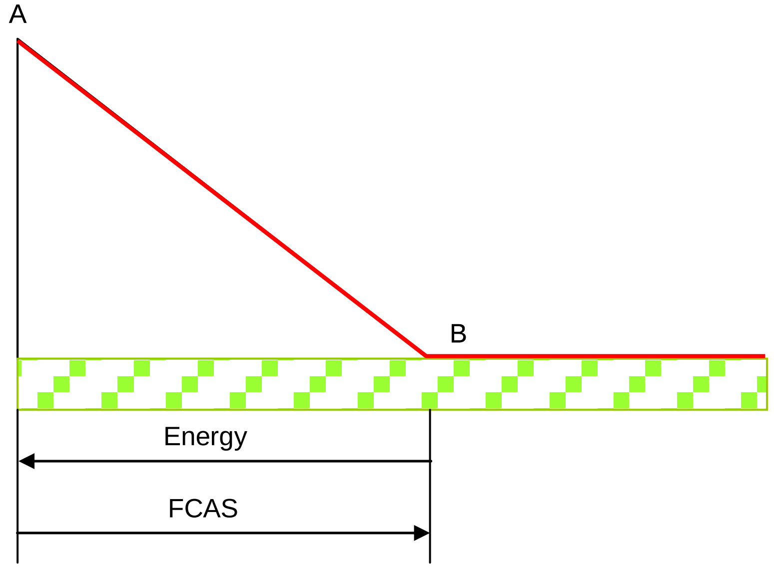


[3] To avoid unnecessary complexity the lower FCAS spot markets have been ignored for the purposes of this explanation. For the record they operate almost completely the inverse to the raise spot market co-optimised outputs.

Point D-E: To transition the no-go zone, spot market separation is required (all energy and FCAS must be supplied locally), which generally requires a reasonable differential in energy price to overcome FCAS services within the co-optimisation process. So even though the spot markets are separated this is still the optimal economic outcome for the market as a whole. Generally, it is unlikely that Basslink would remain in the no-go zone for any more than 1 dispatch interval because there will generally be a lower cost solution than supplying the two regions independently once the cable de-blocks (can flow in either direction for next interval).

Point B-C: This is very similar to F-G where global bid stacks are fully co-optimised to determine most economic solution without limitations on the co-optimised outcome. The difference here is that there is a limitation acting on the co-optimisation process that specifically requires some local FCAS to accommodate the loss of Basslink. This requirement is allocated locally with the rest of the maximum generator contingency (MG) requirement sourced from the global bid stack (which includes Tasmanian bids). Under the current formulation this local requirement is reasonably constant and averages around 30MW. It is important to note that, in submitting FCAS bids, Tasmanian providers cannot differentiate between this 30MW of local requirement and the global bid stack (ie if Tasmanian bid prices are high, local providers will only be enabled for this 30MW and the rest of MG for Tasmania will be sourced from the global bid stack.

Point A-B: Again, through this section NEMDE has determined that the most economic outcome is to provide a proportion of FCAS regionally and another proportion globally that enables the relative energy flow between Tasmania and Victoria. Assuming all other variables are the same, higher priced energy bids in Tasmania will tend to push the flow towards point A, while higher priced FCAS bids in Tasmania will tend to push the flow away from point A (as illustrated below). The co-optimised outcome reflects the availability and relative pricing of supply side services.



Point A: At this point the supply side constraint has fully counteracted the co-optimisation process (due to the physical import limit) and price separation occurs in the particular spot market or markets.

As can be seen from this segmentation, with the exception of points A and G, the various "spot markets" are co-optimised across the entire range of Basslink flow. The optimal level of co-optimisation achievable is inversely related to the limitations that are acting on the co-optimised outcome itself.

1.3 Co-optimisation - effect of the supply limitation

The most significant limitation on the co-optimisation process is the shortage of low cost fast raise FCAS in the Tasmanian region. This point was clearly made during the 2008 FOS Review where Hydro Tasmania and NEMMCO[4] both explained that hydro plant is not a good provider of fast FCAS (see the discussion in section 3.1 of this submission and Appendix A, which gives a more detailed explanation of the capabilities of providing FCAS from hydro plant).

The potential for FCAS to cause uneconomic energy outcomes was a key issue recognised during the 2008 FOS Review. The concern identified was that inadequate supply of local fast raise and fast lower contingency FCAS could, under some circumstances, severely limit the NEMDE solution space. In the worst case, this could mean "trapping" Basslink flow in one direction and preventing least cost outcomes in future dispatch intervals. Such situations can result in uneconomic outcomes for the market as a whole and have the potential for individual participants to have significant trading exposures. These uneconomic outcomes flow through to increased cost to customers.

To explain the degree of this constraint, referring back to figure 1, it is first necessary to understand how the raise contingency FCAS requirement (Z) is determined. The calculation has three key inputs;

- size of the maximum generator contingent event (MG),
- system inertia (now excluding the largest single contributor) and
- load relief (as a function of Tasmanian demand).

Taking these key inputs into consideration the calculation determines the required FCAS to maintain frequency with the generator contingency band (48Hz) should the largest unit inadvertently trip. The Regulator has quoted a range of requirement for the MG event as 48 – 93MW based on an assumption of zero Basslink flow. This assumption would appear to be inappropriate as Basslink spends very little time in the no-go zone and hence

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[4] 26 August 2008 NEMMCO advice to the AEMC Reliability Panel (during the review of Tasmanian frequency operating standards)

it is suggested that a range of 48 – 210MW is a better representation of the likely range of requirement under the new FOS.

Once Z is known then drawing a line at 45 degrees determines point B which is where a supply limitation begins to affect co-optimisation (assuming no local supply). A realistic assumption is that 20-40MW of fast raise is economically available in the dispatch, therefore point B[5] can be calculated as -478+210-30= -288MW. This means that the co-optimisation process is potentially limited over the last 190MW of import capability.

Possible sources of raise contingency FCAS that could be made available via eligible market bids fall into three main categories (all with different cost implications):

- generators who have registered to provide a particular type of raise contingency FCAS (by reserving part of their energy production[6] so they can, if required for system security, provide an increase in MW output within a specific period of time, using governor response);

- customer loads registered to provide a particular type of raise contingency FCAS (by providing fast load reduction, if required, based on frequency triggers); and

- "stand alone" technologies registered to provide equivalent mitigation (such as flywheels).

In the NEM as a whole, there is generally more than enough raise contingency FCAS available from registered generators (at low prices) to cover the MG. Consequently, there has been no need or incentive to explore other possible sources.

In Tasmania, until recently, there has been no incentive to provide additional sources as the spot price, over any sustained length of time, in the FCAS "spot markets" has not been reflective of the cost of provision as a result of the co-optimisation of the energy "spot market" and FCAS "spot market" in dispatch. It is this dynamic which has seen Tasmanian FCAS pricing depressed below economic cost in a market where there has effectively been a single entity (Hydro Tasmania) as the sole supplier and majority acquirer.

[5] Point F is calculated in much the same way, although it is realistic to assume that with more on island generation required to be exporting, inertia is much higher therefore FCAS requirement reduced.

[6] The MW amount reserved for FCAS is "enabled" (as determined by the dispatch engine) and payment is for the MW amount enabled at the relevant FCAS spot clearing price. In other words, the dispatch engine chooses whether to use this MW for energy or FCAS, with different spot revenue outcomes for the generator.

1.4 Co-optimisation – effect of the Basslink constraint

The formulation of the Basslink import constraint requires that a small amount of fast raise FCAS, typically 30MW, is sourced locally to cover the residual contingency once the FCSPS has operated after a Basslink trip (green section in figure-1). This formulation was chosen to maximise the import capability of the interconnector and seen, at the time, to be the best compromise to achieve best economic outcomes[7]. It could be argued that given the supply side changes expected in the medium term that this formulation could become uneconomic. It is also worth noting that as it currently stands the relationship between the FCSPS and FCAS prevents any of the contracted FCSPS load providers registering the same load to be bid as raise contingency FCAS.

2 Risk Management in the NEM

Having established how NEMDE uses the principle of co-optimisation to achieve the NEM objective and how that process works; market participants are then able to assess their risk profile (cognisant of any global or regional limitations) and select the combination of risk mitigation strategies that suit their individual risk appetite. This section discusses how generators typically cover liability for their share of raise contingency FCAS in the broader NEM. It is fair to assume a prudent new entrant generator would understand the landscape before entering the NEM.

2.1 FCAS Liability

Generators dispatched for energy in the NEM are exposed to a liability to meet a proportionate share of the cost of providing sufficient raise contingency to meet the maximum generator contingency. This exposure creates a risk that each generator can manage in various ways.

The inherent risk of co-optimisation (and major source of competitive tension) in NEM is that a shortage in any of the supply elements that are taken into account in the dispatch engine (including transmission elements) can have significant and unexpected impacts on price outcomes across one or more of the “spot markets” for which the dispatch engine sets a clearing price. It is for this reason that generators typically use a combination of physical capability and financial hedge products to manage their overall exposure. The particularly close interdependency of the energy and raise contingency FCAS “spot markets” is further evidenced by the raise contingency FCAS settlement process where liability is apportioned using the energy output of generators.

[7] The prevailing conditions and projected assumptions at the time of this decision have changed some what since that time.

Operating in the NEM involves having to manage a complex web of inter-related risks that arise from the integrated operation of the nine “spot markets” which affect dispatch volumes and the financial trading that is referenced to the clearing price of these. This often involves a series of trade offs. Whilst it may seem difficult for generators to manage their risks at times, that is the intention of the NEM market design. Those firms who can manage these risks and trade offs in the most efficient (least cost) manner can be expected to out perform, in the long run, those firms who do so in a less efficient manner.

2.2 Competition at work

It would be much easier for a market participant if it could insulate itself from the pressure of these risks and trade offs. For example, it would be much easier for a generator if it could put itself in a position equivalent to a non-NEM plant which has sold all its physical output long term to one customer giving it certainty of revenue and profitability without exposure to the externalities inherent in the NEM. However, that would undermine the point of being exposed to the pressure of risk management, which is what produces dynamic efficiency in the NEM and makes it a robust and competitive environment.

So, recognising that there is a lot of flexibility and diversity in how firms seek to manage these risks, (and the accepted wisdom that an integrated risk management strategy is more effective than trying to manage exposures independently of each other) the following simplified examples illustrate what generators might typically do to manage risk across energy and FCAS:

2.2.1 Example 1

A generator may choose to be fully exposed to the “spot markets” (i.e. no financial hedges in place). In this case the generator uses its physical capability to manage its risks. Typical responses would include:

- High energy price / low FCAS price – operate at high output

- High energy price / high FCAS price – provide a mix of energy and FCAS so as to optimise financial outcome; optimal output could be high or low based on energy spot revenue v FCAS spot liability (assuming that the technology doesn’t have FCAS capability)

- Low energy price / low FCAS price – reduce output to minimum / possibly shutdown

- Low energy price / high FCAS price – shutdown

This strategy may be suited to intermittent generation such as wind power that cannot rely on providing physical capability. Appendix C contains an example of this strategy for a wind generator given by Roaring 40s in a submission to the 2008 FOS Review.

2.2.2 Example 2

A generator may choose to sell financial (energy) contracts against its physical capability and manage its exposure to FCAS as follows:

- High energy price / low FCAS price – operate at high output

- High energy price / high FCAS price – provide a mix of energy and FCAS so as to optimise financial outcome; optimal output could be high or low based on energy contract price v energy spot price, dispatch volume v contract volume, and FCAS spot price exposure.

- Low energy price / low FCAS price – reduce output to minimum / possibly shutdown

- Low energy price / high FCAS price – reduce output to maximise FCAS capability

This strategy may be suited to a generator able to physically manage its FCAS exposure with excess capacity above its contracted volume. Note: managing the mix of energy and FCAS is done though energy and FCAS bids with consideration for the FCAS capability trapezium, as shown in Appendix B.

2.2.3 General application

The above examples are very simplified and it is possible to mix and match any number of combinations of physical and financial products in order to optimise the risk position of any particular generator or generation portfolio.

In addition, as the NEM evolves, the competitive pressure of risk management has led to the development of new and more sophisticated financial products. This is an important aspect of dynamic efficiency in the NEM.

It is logical to assume similar risk management strategies would be used in Tasmania – and indeed, the pressure to do this will produce more economic outcomes than regulation which removes the incentive of individual firms to find the lowest cost, most efficient risk management outcome and suppresses the development of new risk management products.

3 Assumptions in the Regulator's reasoning

The Regulator has taken the view that:

> "Hydro Tasmania has substantial market power in the provision of raise contingency FCAS and that the promotion of competition, efficiency and the public interest requires the making of the declaration".

The Regulator's view has not been based on transparent analysis of the structure and competitive dynamics of the commercial environment in which raise contingency FCAS is supplied. There are a number of assumptions behind the Regulator's stated reasoning, which are not consistent with this commercial environment. Given the complexity of this commercial environment (as discussed in sections 1 and 2 above), these assumptions are an erroneous basis for regulatory decision making.

The five erroneous assumptions are:

- The Regulator has drawn conclusions based on the fact that Hydro Tasmania is currently the only Tasmanian registered provider of raise contingency FCAS, without a proper examination of why this is the case or likely to be the case in the near future.
- The Regulator assumes that because there is some FCAS for Basslink that must locally, local providers are not constrained by mainland providers.
- The Regulator has assumed there is little or no cost in providing raise contingency FCAS out of the hydro system.
- The Regulator has assumed that what is in the best interests of Aurora is what is best for consumers.
- In applying the "future with and without" test, the Regulator has made assumptions about the future based on the past.

These assumptions are discussed below.

3.1 The Regulator has drawn conclusions based on the fact that Hydro Tasmania is currently the only Tasmanian registered provider of raise contingency FCAS, without a proper examination of why this is the case.

As discussed in section 1, raise contingency FCAS can technically be provided in a range of different ways, not just using generation. As long as there is sufficient generation available to be used for raise contingency FCAS (as is the case in the global market) and the opportunity cost of using generation for this purpose is relatively low (as is also the case in the global market) then there is no need or incentive[8] to utilise other potential sources of raise contingency FCAS.

What makes Tasmania different is the historical reliance on one form of generation technology to provide raise contingency FCAS, namely hydro plant. Thus the 26 August 2008 NEMMCO advice to the AEMC Reliability Panel (during the review of Tasmanian FOS) noted that:

> **"Hydroelectric plant has difficulty in providing fast response in the 6 second time frame and so provision of fast lower and raise services will always be an issue for systems such as Tasmania which have predominance of hydroelectric plant."**

Indeed, recognising that, as a technology, gas fired generation is better suited to providing fast contingency FCAS than hydro plant, ***"potentially increased FCAS capability from modern thermal plant"*** was one of the benefits assumed to result from the introduction of CCGT plant in the benefit cost analysis on which the AEMC Reliability Panel based its decision to change the Tasmanian frequency operating standards in 2008[9].

The modelling results presented by Alinta (then owner of AETVPower) to the Reliability Panel on 30 July 2008[10] showed that changing the frequency operating standards to allow industrial thermal units such as AETV's 210MW CCGT would result in:

> "More competition in energy and Frequency Controlled Ancillary Services (FCAS) market"

and that:

> "The modelling indicates:
> 1. FCAS local requirement is higher due to FOS change; however
> 2. Local FCAS supplies will increase substantially following subsequent new entry of thermal plant in Tasmania"

The modelling assumed both AETV and Gunns providing the following additional supplies of FCAS[11]:

[8] This is the general position. However, it noted that there is a current practice by some market loads in the NEM to use their capability for the purposes of "cashing in" on high price events (usually where FCAS raise and energy have both reached extreme prices).
[9] See CRA Final Report for Reliability Panel Appendix B

[10] See reference on page 24 of CRA's Final Report for the Reliability Panel

[11] See ROAM Consulting and Hill Michael 29 July 2008 report

- for the Gunns Pulp Mill:

  "The facility is assumed to trip the pulp mill load on loss of the cogeneration facility to limit the net FCAS enablement required to levels well below the current largest unit. It is noted that the Gunns cogeneration facility can provide FCAS and/or FCSPS services, although the commercial implications of providing these services are unclear. Information provided by Gunns [footnote reference to Gunns presentation to the Stakeholder Forum, Friday 6th June 2008] suggests that the facility may provide 170MW of FCAS Lower services, as this will be readily achievable through controlled generation reduction. FCAS Raise services may also be provided through reduction in internal load of up to 65MW. (Note that 130MW Lower and 50MW Raise service offers have been included in the modelling following consultation with Gunns Limited)"

- for the AETV CCGT plant:

  "As the Alinta plant is a CCGT, FCAS enablement and offer prices have been constructed such that technical requirements are adhered to, such as minimum load for steam generator operation. The Alinta CCGT FCAS provision has been modelled based on information from the developer and calibrated against the Swanbank E generator which is of similar technology. The Alinta CCGT has been configured to provide around 30MW of raise and lower services into all but the five minute FCAS market."

There is no inherent impediment to these or other additional non-Hydro Tasmania supplies of raise contingency FCAS being brought to market. No inherent impediments to investment were raised by market participants during the lengthy FOS Review in 2008, when concerns about shortages of local FCAS supplies were raised by Hydro Tasmania and AEMO (then NEMMCO).

The reason for additional supplies not being brought to market and lack of investment is the low raise contingency FCAS spot price and the low price expectations based on the availability of low-priced global supplies (co-optimisation achieving its objective). This was clearly understood by market participants during the 2008 review of the Tasmanian frequency operating standards and continues to be understood at the present time.

Indeed, the Regulator's own comments about historical prices reinforce this:

> "The average weekly raise contingency FCAS price since NEM entry, and prior to 1 April 2009, was less than $20/MWh for 95 per cent of the time and never exceeded $50/MWh." **[12]**

Low prices are the reason why there is a shortage of local supply and Hydro Tasmania is currently still the only Tasmanian registered provider of FCAS.

[12] In comparison, the average Tasmanian spot price for energy for 2008/09 was $62 MWh.

Even if the economic cost of providing FCAS is high, Hydro Tasmania has had no choice but to ensure that there is sufficient local supply to meet the local requirement. It has also had an incentive at various times to meet the maximum Tasmanian generator contingency (at significant cost to transition Basslink through the no-go zone) so that Basslink can respond promptly and not become trapped.

However, the drive to produce an optimal co-optimised dispatch outcome in terms of both energy and FCAS has meant Hydro Tasmania has been unable to recover the true economic cost of providing FCAS without creating an adverse revenue outcome in energy.[13] This provides an opportunity for free-riding by new Tasmanian gas fired generation and traps Hydro Tasmania into having to provide even more FCAS on an uneconomic basis.

The problem that is looming is that Hydro Tasmania does not have sufficient capability to address future needs when global sourcing is not possible, which is likely to increase the risk of co-optimisation producing uneconomic outcomes (such as counter-priced flows) and higher energy prices for consumers.

The Regulator contrasts the position for the year to 28 March 2009 to the position in the period 29 March to 18 April 2009 stating that the average weekly price for raise contingency FCAS during the period 29 March to 18 April 2009 was $311 MWh. However, the simple reality is that a persistent spot price of this magnitude (or the genuine expectation that spot prices of this magnitude would persist) would result in immediate investment in additional supplies of raise contingency FCAS and Hydro Tasmania would no longer by the only registered provider (and the Regulator would not be proposing regulation).

3.2 The Regulator assumes that because there is some FCAS for Basslink that must be met locally, local providers are not constrained by mainland providers.

The Regulator has drawn conclusions from the fact that, as described in section 1, there some FCAS for Basslink that must be met locally (see the discussion about flows between points B to C in figure 1), but without any analysis of how the NEMDE works and the implications for how providers bid. The Regulator has simply assumed that:

> “In the absence of competitive forces, Hydro Tasmania can, therefore, price its services in Tasmania as it sees fit.”

As discussed in section 1, this is simply incorrect.

[13] In the absence of Basslink co-optimisation would not be available and Hydro Tasmania would be able to reflect the economic costs of providing the services continually.

Hydro Tasmania must determine its bid prices with regard to the mainland bids against which its bids will be assessed by the NEMDE and it cannot discriminate in price between supplying this local requirement supplying MG which can be sourced from the global bid stack.

3.3 The Regulator has assumed there is little or no cost in providing raise contingency FCAS out of the hydro system.

The Regulator's view is that:

> "The costs of provision of raise contingency FCAS from hydro-generators should be relatively low as it is normal to operate them as close as possible to their point of maximum efficiency which is normally less than their maximum capacity. Hence raise contingency FCAS can generally be provided by hydro generators without needing to forego generation."

This is totally incorrect (see Appendix A). As quoted above the 26 August 2008 NEMMCO advice to the AEMC Reliability Panel:

> "Hydroelectric plant has difficulty in providing fast response in the 6 second time frame and so provision of fast lower and raise services will always be an issue for systems such as Tasmania which have predominance of hydroelectric plant."

and

> "In the case of some plants the reductions in output in order to provide additional R6 service would be disproportionate. Such suboptimal operation would likely lead to significant increases in energy prices and may also affect reliability. This is because inefficient operation would reduce the amount of electricity energy that could be generated from a given amount of stored water."

For all generators providing raise contingency FCAS out of their production, the cost of supply comprises:
- the direct cost of enablement (which is relatively small); and
- the economic cost (opportunity cost of energy effectively lost by being reserved for raise contingency FCAS and cost associated with inefficient operation).

These will differ from generator to generator.

The economic cost for Hydro Tasmania is relatively high. For the reasons discussed above, this cost has not been reflected in the historical spot price for raise contingency FCAS, but this does not mean that there is little or no cost to providing this from the hydro system.

At historical levels, the raise contingency FCAS spot price essentially covers just the (small) direct cost of enablement for generators, not the economic cost. If all generators are assumed to provide their share of raise contingency FCAS, an inefficient assumption in its own right, this may not matter as each generator is assumed to bear its own opportunity cost of lost energy production (which, historically, for many mainland generators may have been relatively small) as part of its risk management trade off. However, this means that care should be taken in drawing conclusions about the economic cost of supply from historical spot or bid prices.

		Tas	Vic
Raise6sec available	average	63MW	
Raise6sec dispatch	average	28MW	
Raise6sec price	average	$12.52[14]	$3.22
Raise6sec price	maximum	$10,000	$10,000

Table 1: Historical data since Basslink commenced until present (29/4/06 – 26/8/09)

3.4 The Regulator has assumed that what is in the best interests of Aurora is what is best for consumers.

The benefit cost analysis that underpinned the change to the Tasmanian frequency operating standards looked at the Tasmanian supply side as a whole and assessed (i) a supply side benefit in terms of the production cost saving for gas fired generation (in the order of around $4 MWh) from using CCGT instead of more expensive forms of gas fired generation; and (ii) a supply side cost in terms of inefficient operation for the hydro system (being largely the increased loss of energy production from the hydro system if hydro system has to provide more raise contingency FCAS).

Whilst it was identified in that process that the supply side benefits would mostly accrue to Aurora (as owner of all the gas fired generation) and, if gas fired generation does not provide FCAS, the supply side costs would be borne by Hydro Tasmania, it did not form part of that exercise to deal with the implications of this mis-match between supply side benefits and costs (hence the suggestion that a rule change be explored).

One of the implications is whether the cost saving from lowering the cost of gas fired generation will be passed on to all retailers – given that all the gas fired generation is owned by Aurora. Presumably it will be passed on to just Aurora, given the Regulator's comments about the long term hedge agreement in place between AETV and Aurora (which presumably means that AETV is not intending to offer contracts to other retailers). This raises the

[14] Using average dispatch amounts and average prices to calculate economic costs would be totally misleading as the issues referred to in Appendix A would be largely ignored or discounted.

issue of whether Aurora is passing on the cost saving to customers or simply keeping it by way of a higher return to its shareholder.

In relation to the increased loss of energy production from the hydro system if gas fired generation does not provide FCAS, either the cost of this will be borne by Hydro Tasmania by way of a lower return to its shareholder or it will be passed on to retailers – which effectively is likely to mean new entrant retailers as Aurora already has pre-existing contracts in place with Hydro Tasmania. Hydro Tasmania does not wish to see the latter outcome as Hydro Tasmania wishes to see robust competition in the retail sector.

However, either way, Aurora stands to benefit relative to new entrant retailers.

The Regulator has stated that:

> "Consumers need to be assured that they are paying economically efficient prices for all electrical services to assist them in maintaining economically efficient prices themselves in the global market."

There is no evidence to establish why providing a benefit to Aurora relative to new entrant retailers would assure Tasmanian energy consumers that they are paying economically efficient prices.

3.5 In applying the "future with and without" test, the Regulator has made assumptions about the future based on the past

The Regulator has stated that it is applying a "future with and without" test:

"To fully consider the public interest the Regulator would need to consider what the future would be with and without the regulation of a given service under the Price Control Regulations"

There is very little evidence that the Regulator has properly considered the future (with or without regulation) over the longer term or even the period of the intended regulation, being 3 years. The Regulator seems to have assumed that the future is simply the status quo of the past (the only difference being that under regulation Hydro Tasmania's pricing would be different).

However, this is an extremely dynamic situation. For example, the next new entrant is likely to be a wind farm as many have already made connection inquiries. Transend have identified that more wind generation in Tasmania will cause significant system issues. The following is an extract from their recently conducted study[15];

[15] Future wind generation in Tasmania TNM-GR-809-0874-001 Issue 1.0, May 2009. Available at: https://www.transend.com.au/files/D09-50930.PDF

"The results of the study indicate that the most pressing issues are:

a. system inertia …..
b. fast FCAS supply, which will soon require action if other significant sources of the services do not become available. With the imminent change in frequency operating standards in Tasmania, the future supply of local frequency control ancillary services is highly uncertain at present. In order to maintain system security and to allow Basslink flow direction reversal, wind generators may be required to provide FCAS;
c. wind generator fault ride through…… "

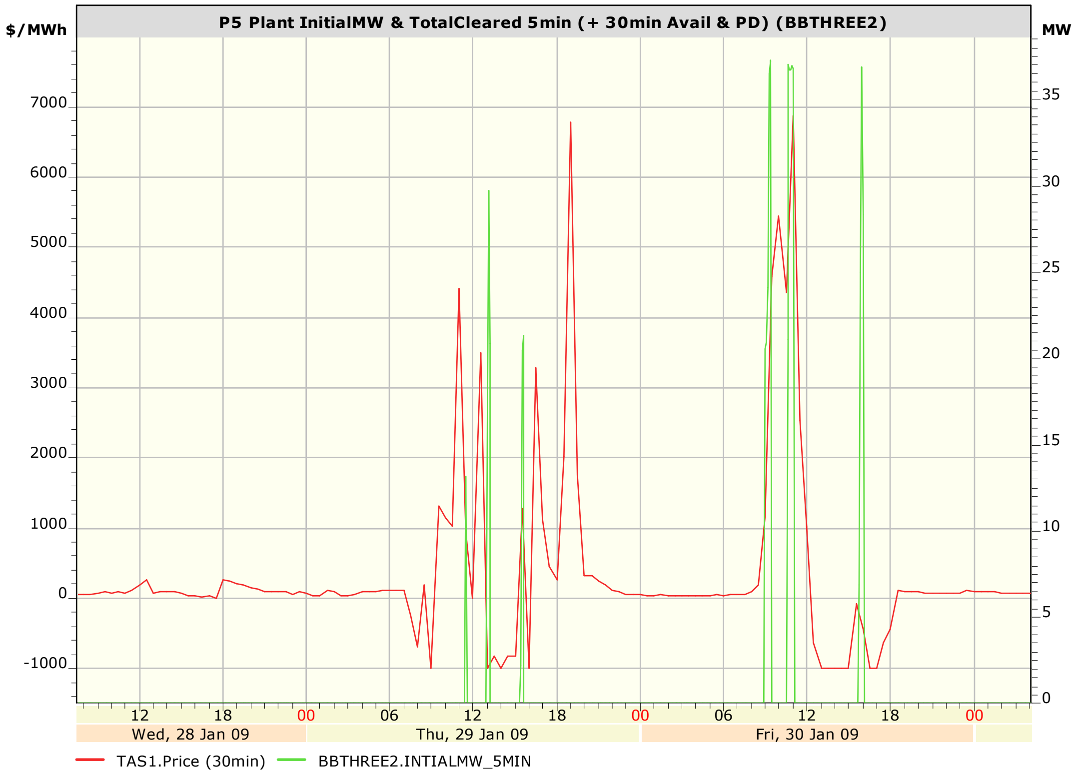
The Regulator has not undertaken a forward looking assessment as to the fast raise supply/demand imbalance in the region when applying its "future with and without test".

4 Factual errors and omissions in Regulator's notice

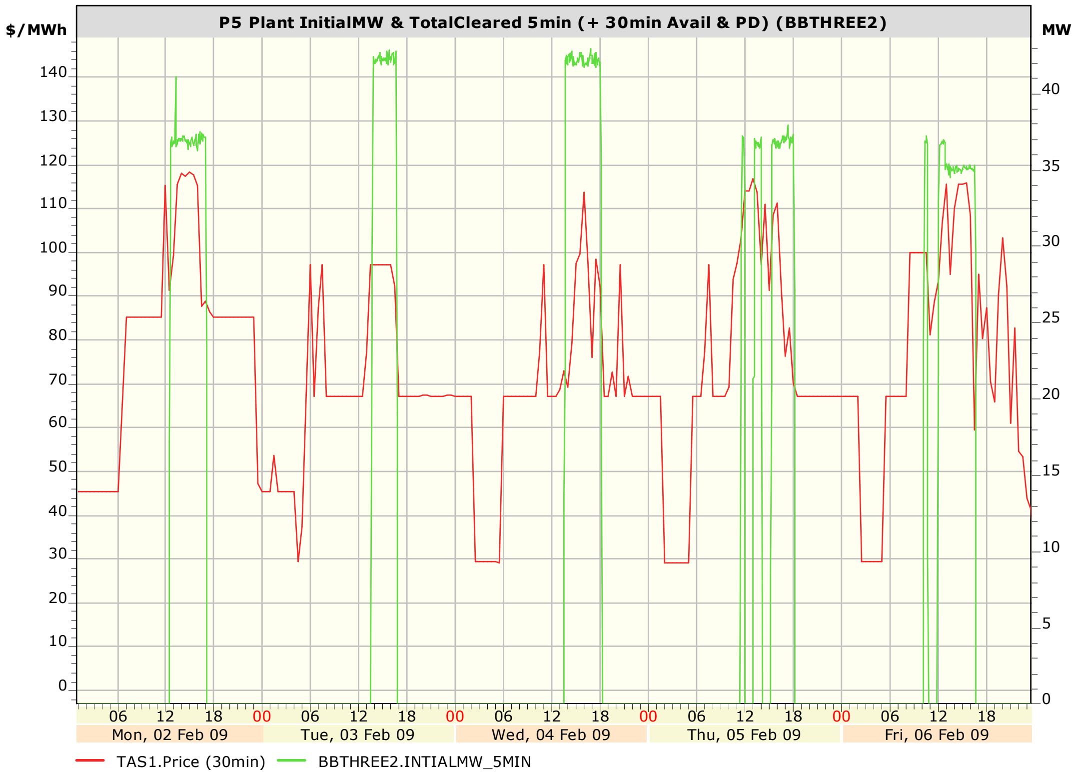
This section comments on incorrect factual statements in the Notice and provide additional information with the intention of correcting the Regulator's understanding.

Section 2 Background:

- The two statements that AETV commissioned the FT8 turbines in the last six months and commenced commercial operations on 1st April 2009 are questionable, given;
  - The FT8 turbines were commissioned by Hydro Tasmania in 2006; and
  - The graphs below illustrate BB3 unit 2 operations during the last week of January and first week of February 2009 that appears to be responding to market price.
  - During the 1st Quarter 2009 AETV had the following re-bids
    - change in price forecast (11 times)
    - change in actual prices (9 times)
    - change in price expectations (11 times)
    - optimisation energy constraints (5 times)
    - gas use optimisation (3 times)



Bell Bay Three Unit 2 operations -28th-30th January



Bell Bay Three Unit 2 operations – 2nd – 6th February 2009

- Peaking plant operate at periods of high price (not demand);

- The amount of localised requirement for raise contingency FCAS varies considerably based on a number of inputs, as discussed in section 1;

- Hedge contracts are purely financial; they are used in conjunction with physical capability, as discussed in section 2.

- The figures through this section fail to recognise the actual liability of generators. “If AETV continued to run they would have incurred” is irrelevant as they had made a commercial choice to stop generating. Additionally, Hydro Tasmania paid for the largest share of these services during this period, so to quote numbers such as $10M / week is simply choosing to ignore the settlement aspect of the market and is misleading and erroneous.

- The references to AETV’s predicament fail to recognise that they should be quite capable of managing their operational and commissioning risks using a combination of physical capability, hedge products and operational practice. The Notice omits to clearly state that AETV did not pursue any mitigation prior to becoming exposed to the market. In fact, quite contrary, it actively stopped the proposed transfer, by the State Government, of the Bell Bay thermal[16] units. As previously stated, these units were registered and capable of providing energy and FCAS.. This was purely a commercial choice. Appendix B shows how a similar plant in the NEM typically manages its FCAS exposure.

Section 2.1 Frequency control ancillary services

This section fails to recognise the integration of the FCAS "spot markets" and the energy "spot market", as discussed in section 1. In addition NEMDE has the opportunity to use regulation raise (Rreg) where it is a better solution than delayed raise (R5). This relationship needs to be recognised.

Section 2.2 Provision of contingency FCAS in Tasmania

- In reference to alternative technologies: to determine "expensive" must be relative to the next best solution. The big advantage of these technologies (as with load participation) is that they are decoupled from the generator and therefore don't impact energy generation (I.e. higher capital cost / low operating cost). These technologies are indeed very well suited to Tasmania where the current FCAS providers have high operating costs and there is a general supply shortage.

  For example: Assuming that the DPS inductive coupling costs $700k and there is a small 30MW installation which has been allocated the highest frequency trigger for a switch control FCAS provider.
  The annual costs would be $70k and with availability of 95% the average costs of operation would less than $10MWh. This is significantly less than the alternative based on average energy costs. It needs to be noted that this device will also contribute to system inertia (25-30 MWsecs) and voltage regulation. It is believed that the device can be implemented within 6 to 12 months.

- While Hydro Tasmania may have a maximum R6 capability of >200MW[17] it needs to be understood that to deliver this capability would require all 2200MW of installed capacity to be on-line and not be able to generate more than 800MW due to co-optimisation. This figure would also be reduced by physical rough running constraints on some plant. It is consequently not reasonably achievable. See Appendix A

[16] During the period of January to March 2009, it was proposed to transfer (for zero consideration) the still operating Bell Bay Power station from Hydro Tasmania to Aurora Energy.
[17] The recent publication of the AEMO Electricity Statement of Opportunities 2009 quotes an impossibly theoretical Tasmanian region capability of 348MW fast raise.

- **Fact: Hydro plant does not provide high R6 capability at their efficient output.** Whilst it is true that the efficient running range is often around 90% of full output, it is often erroneously assumed that the additional 10% can be used for fast raise. This is not generally true as the plant can not respond sufficiently quickly due to the inertia of large column of water in the penstock.
  In contrast to AETV (1.5:1), the upper angles of the Hydro Tasmania machine trapeziums mean that energy would be reduced by an average factor of 4:1 to provide the high FCAS required under the new FOS i.e. sacrificing 4MW of energy for every 1MW of fast raise FCAS. Again more detailed technical discussion is contained in Appendix A.

- FCAS provision is better suited to small loads than large loads from a technical perspective. In any case, the perceived barriers to entry for large loads (including those participating in FCSPS) could be removed (i.e. rule and constraint formulation changes).

- Assuming loads would not be attracted to providing FCAS because of interruptions to production is very questionable. The probability of tripping more than twice a year is very low and it is only for a short duration. Some loads would see this as a very attractive commercial diversification. The ability and willingness of loads to participate in system protection schemes is demonstrated by the successful Basslink SPS and AETV's TVGCS arrangements.

- The description in 2.2.2 almost suggests that Basslink flow is determined prior to the calculation of FCAS requirements. This is definitely not the case as explained in section 1. The Basslink flow target is an output, along with energy targets and FCAS enablements, of the NEMDE co-optimisation.

- Section 2.2.2 also suggests that FCAS and FCSPS are co-optimised, this is simply not correct.

- The numbers in section 2.2.3 are merely reflective of a chosen dispatch, which Hydro Tasmania does not consider "typical" as it assumes Basslink flow of zero.

  With 900MW Tasmanian demand 93MW of R6 is required with the 5000MWs inertia assuming 144MW largest generator contingency size. It is noted that this figure is not representative (too high) for such low load. The inertia figure should be reduced by the inertia of the largest Tasmanian generator which in the case of AETV would be 1700MWs. With inertia of 3300MWs the R6 demand would be 120MW.

  It is important to understand that in order of magnitude the influential factors on the requirements are;
    - Inertia;
    - Contingency size; and
    - Tas demand

  The way these numbers are represented makes assumptions about the supply that is meeting the Tas demand to determine the inertia. It is much better to establish numbers that are more representative of the typical low demand/inertia dispatches where the requirements are going to be most costly to provide. For example, reasonable imports during off-peak times; the dispatch that has dominated since Basslink was commissioned.

With wind generation (100MW), AETV generation (150MW) and 400MW of Basslink import, the hydro plant loading would be 900 - 650 = 250MW. Assuming 50% loading of hydro there is only 500MW of hydro capacity connected offering 2000-2500MWs of inertia. The R6 demand in such case would be 160 to 200MW.

In any case it is easy to see that the available R6 in an economic dispatch (20-40MW) is much less than what is required and the more energy that is provided by sources not providing FCAS (AETV & wind) and inertia (Basslink & wind) the worse the problem becomes.

Section 2.5.4 System Inertia

The regulator makes a statement that AEMO (NEMMCO) on 21 May 2009 that the change in calculations of Tasmanian FCAS requirements covers ‘the inertia of largest generator is now taken into account in calculating local FCAS requirements’.

For clarification, the introduced change now **excludes** the inertia of the largest generator **significantly increasing FCAS requirements**.

5 Conclusion

Hydro Tasmania is a participant in the National Electricity Market and competes in a market where energy "markets" and the eight FCAS "markets" are co-optimised in real time to produce the least cost solution to the market. This is fundamental to any analysis of the market and competitive outcomes in the market. Regulating one market participant in an integrated environment like the NEM will lead to inefficient outcomes which will be felt throughout the NEM, deterring investment, retarding the development of market responses and leading to higher prices for consumers.

The Regulator appears to have drawn conclusions based on the fact that Hydro Tasmania is currently the only registered Tasmanian provider of raise contingency FCAS, without a proper competition analysis, and formed a view based on complaints by Aurora / AETV as to high price events that occurred in early April 2009:

> "...it is not the actual costs of delivery of the services that is at issue, but rather, it is the behaviour of Hydro Tasmania."
>
> "Although this behaviour is not contrary to the NER, it illustrates the exercise of market power as Hydro Tasmania was able to significantly increase prices for raise contingency FCAS without detriment to its own business, while its competitors were unable to take any action within the market to affect this outcome."

These statements effectively pre-judge any objective analysis of market structure and competitive dynamics.

Participants in the National Electricity Market, "energy" market and 8 FCAS "markets", have a variety of risks to manage including physical dispatch and price. Most participants attempt to manage these risks through a portfolio of derivative products aligned with their physical capability and risk profile. Participants generally rebalance their physical and derivative portfolio to market conditions. This has certainly been the experience of Hydro Tasmania since entering the NEM.

It is unreliable, misleading and dangerous regulatory practice to attempt to draw conclusions from short run price events in this manner.

Regulation of Hydro Tasmania will not solve the real problem, which is the inadequacy of local supplies of raise and lower contingency FCAS, as discussed in this submission. On the contrary, regulation is likely to preclude the development of potential solutions.

Hydro Tasmania therefore requests that the Regulator must seriously reconsider its intention to make a declaration. This will allow market dynamics to develop and thus facilitate the emergence of market solutions to the real problem of inadequate supplies of FCAS.

Appendix A Hydro Tasmania Fast Raise FCAS Capability

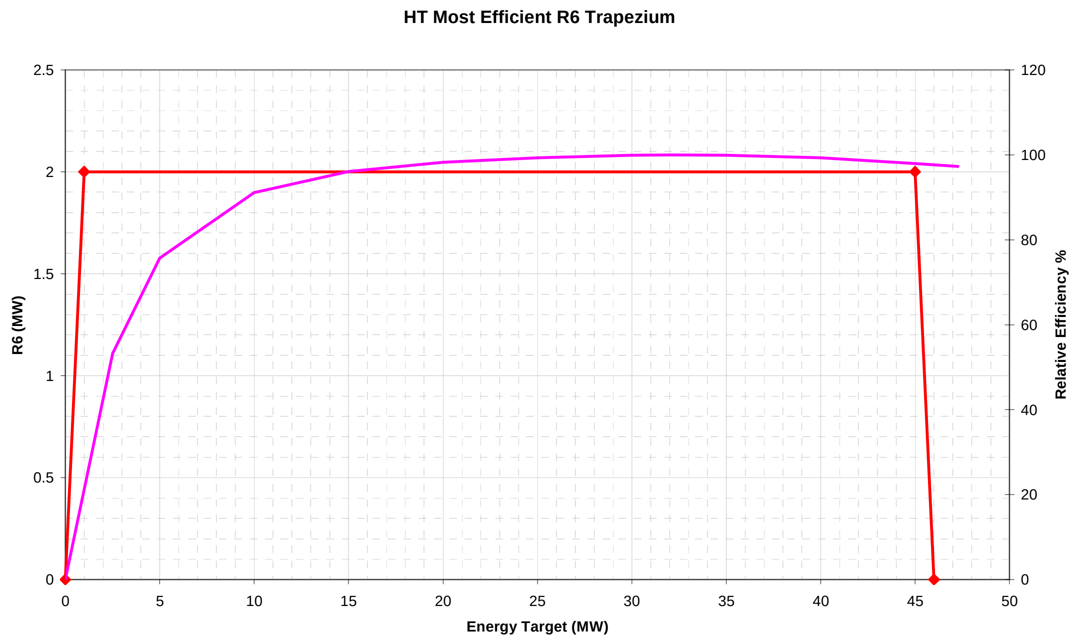
This appendix should be read in contrast to "Section 2.2 Hydroelectric Generator" of OTTER's Notice.

This section summarises capability of hydro generators to provide ancillary services. Unfortunately there are a number of statements indicating misunderstanding of the physical performance of hydro plant. Advantages attributed by the Regulator paper are discussed below.

Fast response is listed as an advantage. However, there is distinction in hydro performance in different FCAS time frames.

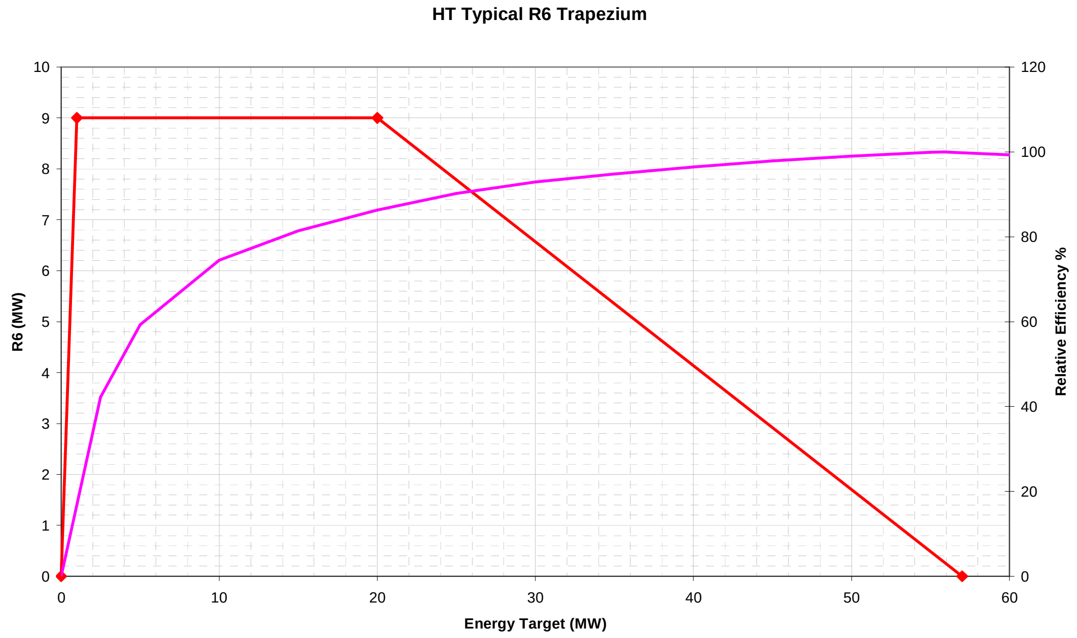
- In the six second time frame the initial response of hydro machines is in opposite direction to FCAS requirements. Only after 2 to 3 seconds hydro machines start to contribute to FCAS, obviously this limits the contribution as the machines are only operating in the correct direction for the last 3 -4 seconds of the 6 second period.
- Not all hydro machines contribute to fast FCAS and actual contribution depends on the generator pre-contingency output. The physical dimensions of waterways affect acceleration and deceleration of the water column and the turbine's ability to change its output quickly. Guide vanes limiters constrain the acceptance of additional load. Consequently contribution to R6 in particular is not a forte of hydro machines.
- Hydro is very good provider of regulation service and slower and sustained response required by slow FCAS. Obviously this capability is constrained by operational issues of each machine.

Better part load efficiency – the maximum efficiency of hydro machines is typically around 70 to 90% of full load flow or machine MW output depending on turbine design. The maximum efficiency is typically around 90%. Turbine manufacturers do not provide efficiency data for machine outputs below 30-50%. Most owners of hydro plant in the US and Europe will not operate below 50% of turbine rating for any significant time period. It is considered too high cost. When hydro plant operates at maximum efficiency fast FCAS capability is significantly reduced. (see graphs below)
At low turbine output (20 to 60%) turbines are subject to very rough operation (rough zones) usually requiring air injection to minimise vibration. It is not a good practice to operate within this zone for long periods of time as this will deteriorate plant conditions and increase the maintenance cost. Use of jet pumps to inject air further reduces efficiency of operation.
Hydro Tasmania quite often operates some plant at output of 10 to 20% to supply FCAS. Current experience indicates that such low load operation significantly deteriorates the turbine (cavitations), increases significantly maintenance requirements, advances timing of major overhaul and contributes to loss of life of the plant. The efficiency of water use at low output is very poor and at Gordon power station low load operation uses more than double the water compared to efficient operation to produce each 1MW output.



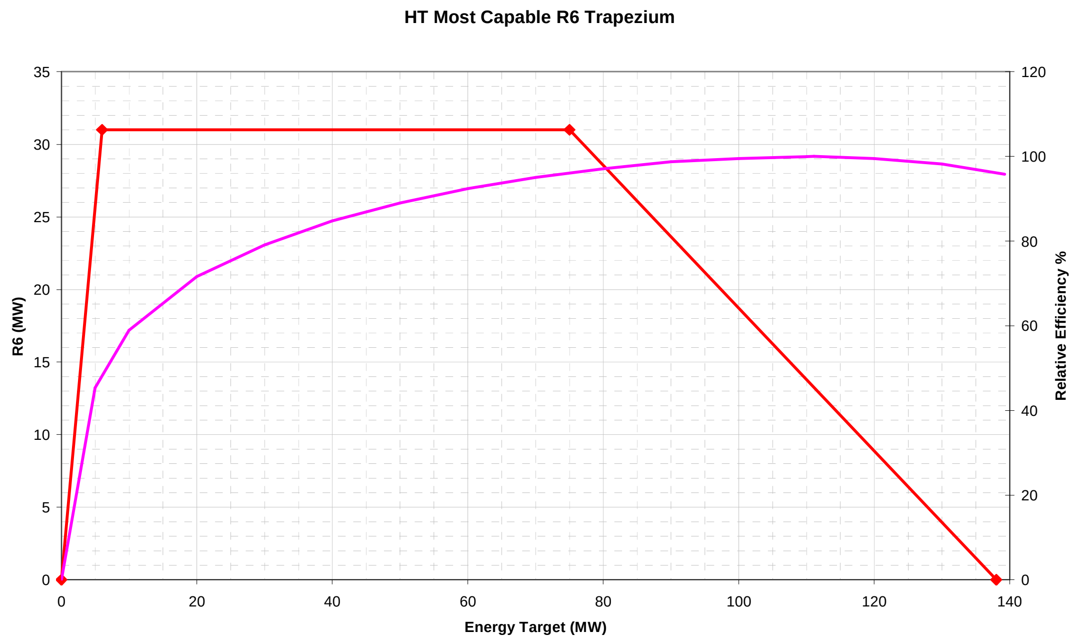
This first graph is the most efficient provider of fast raise FCAS in the Hydro Tasmania portfolio. There is only one machine in the portfolio that has these characteristics. Key points to note:

- Small maximum capability (2MW)
- Small energy reduction to achieve maximum capability



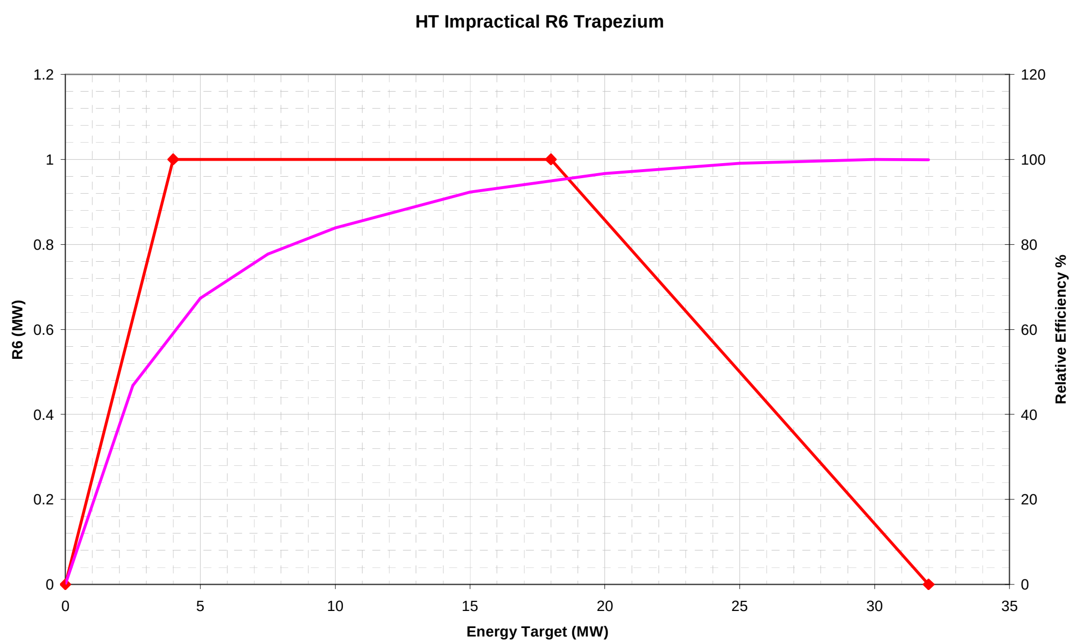
This is representative of most Hydro Tasmania plant. Key points:

- Energy to FCAS ratio averages 4:1
- Maximum enablement at part load (5 – 30%) – high cost due to low efficiency and rough running.



This is the most capable of the Hydro Tasmania plant in terms of volume of fast raise FCAS. This particular plant is supplied by a seasonal storage; therefore, it is not possible to run it all year round making any loss of efficiency a direct cost in terms of lost energy. Key points;

- High maintenance costs when run at low output (I.e. specifically to provide FCAS). Historically, hundreds of hours per year.
- Very poor efficiency at low load.



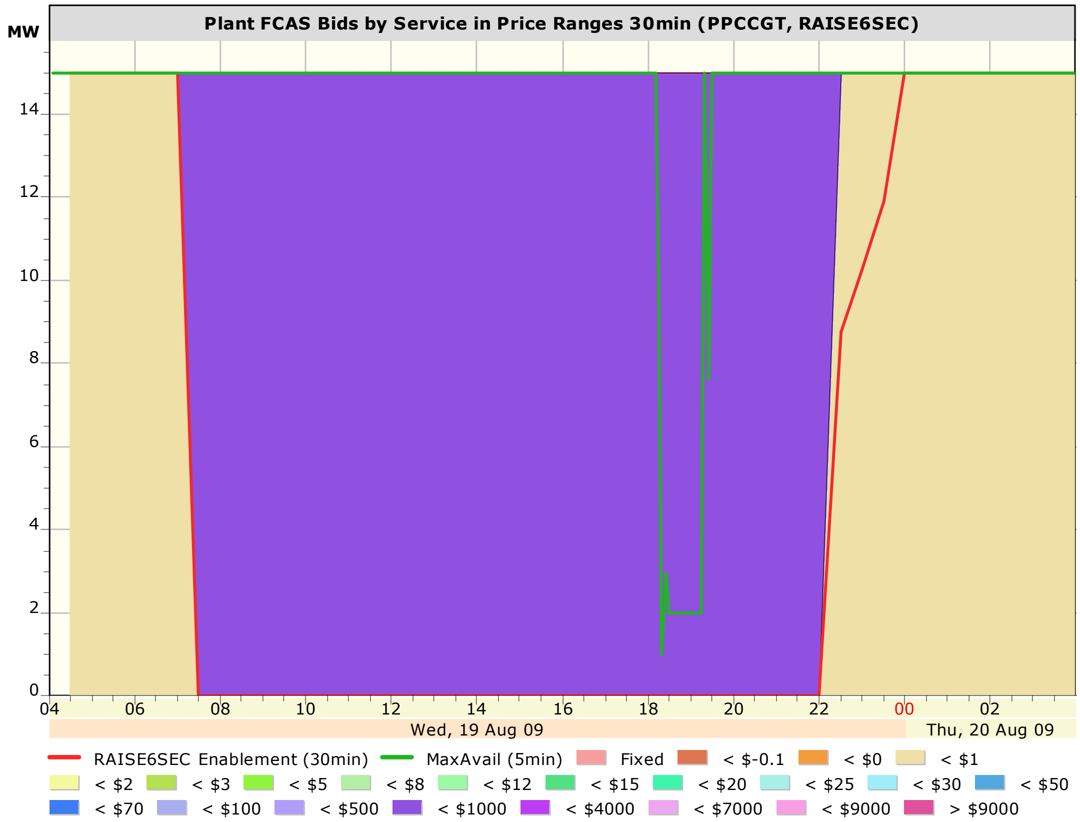
As stated above not all plant can contribute FCAS. This plant is virtually useless in terms of fast raise.

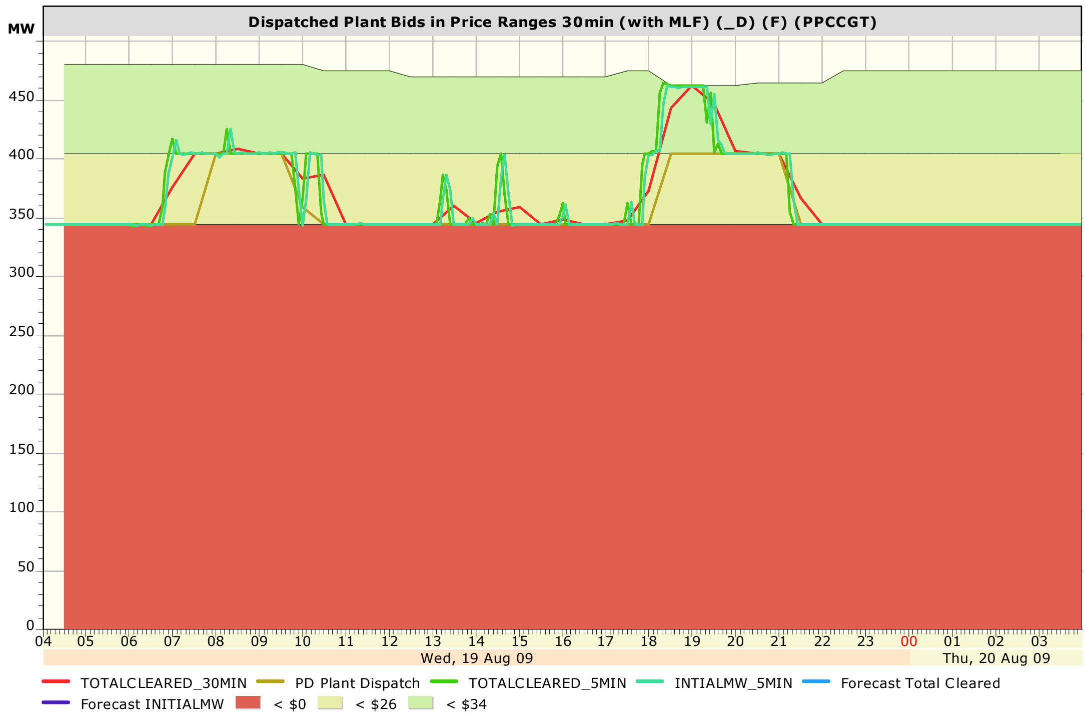
Lower maintenance costs – it needs to be noted that low load operation associated with supply of fast FCAS significantly increases maintenance costs. In recent times some major plant has had serious cavitation issues, significantly exacerbated by low load operation (see comments above).

Minimum to no start-up (unit commitment) costs – this is not a true statement as the main impact on the assets due to higher than normal stresses is during start up and shut down. A rule of thumb used in the hydro industry is that a start and a stop cycle is equivalent to 8 to 10 hours of operation.

Appendix B – Typical FCAS provision (CCGT)

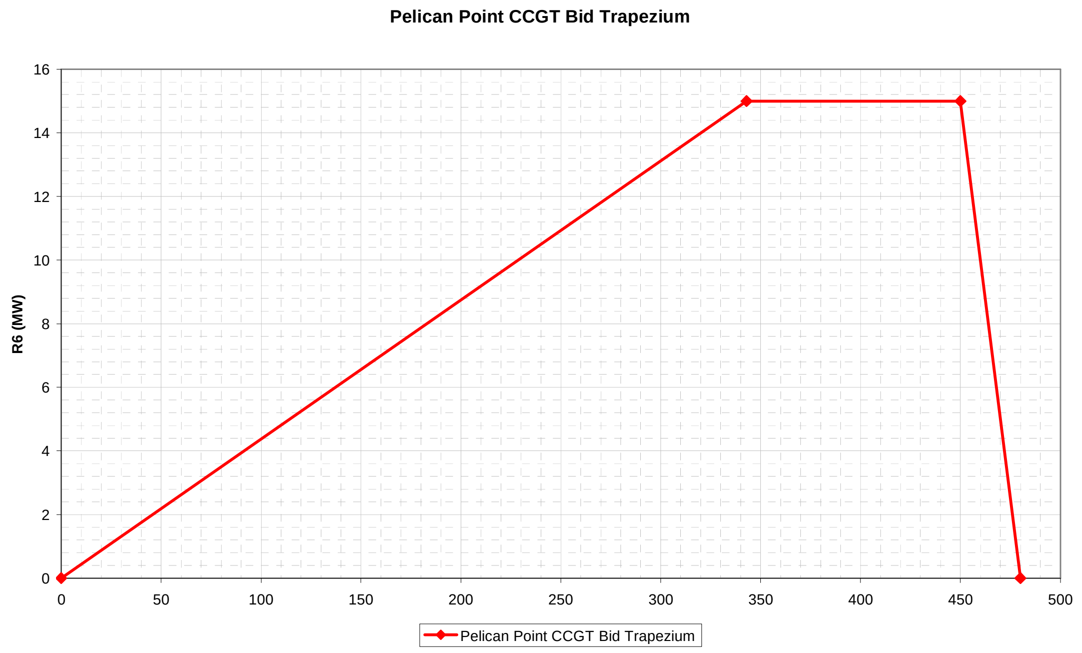
Bid and dispatch data for the Pelican Point CCGT for Wednesday the 19th August shows how the trade off between energy and FCAS can be managed effectively. Note: contract positions are unknown





The graphs show three key points;

- During off-peak the CCGT reduces its output and offers fast raise FCAS to the market at $2. It is dispatched for 350MW of energy and 15MW of fast raise;
- during peak hours fast raise is offered at $1000 but not dispatched with various energy targets above 350MW dispatched on price <$26; and
- fast raise capability reduces as the energy output increases above the upper break point of the units FCAS trapezium (see bid trapezium below)



This bid trapezium is quite different to a hydro plant trapezium with good fast raise FCAS available at up to 93% of full output and a relatively steep upper angle meaning FCAS can be provided at a 2:1 energy reduction ratio.

Appendix C – R40s risk management example

The following example was given by Roaring 40s in its 4 August 2008 submission to the review of Tasmanian frequency operating standards.

Roaring 40s modelled fast raise contingency FCAS (“R6”) costs under certain overnight demand and wind conditions:

- 1000MW demand
- 500MW wind generation
- Basslink flow into Tasmania
- Tasmanian spot price of $30
- the Alinta CCGT plant providing *“an R6 capability of less than 15MW in line with the observed behaviour of the more flexible Pelican Point units in the market”*
- o the Gunns plant contributing *“15MW of R6 at minimal cost...based on the observe capability of the similar Torrens B units in the market..”*

In the example modelled by Roaring 40s, where spot price was low and R6 cost high, wind generators would make a rational assessment as follows:

“The earnings of wind generation can be calculated as REC revenue + Spot Market minus variable O&M costs. So in this example, (with a typical REC revenue of $50), a spot market price of $30 and a typical variable O&M cost of $15 gives a net revenue of $65. So if the contingency FCAS liabilities rise above this level, the wind turbines will be switched off to avoid negative earnings. It can be seen in this example that this occurs once the R6 FCAS requirement exceeds around 102MW.