snowy hydro Limited
renewable energy

26th March 2014

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Submission lodged online at: www.aemc.gov.au

Project Number: ERC0165

Dear Mr Pierce

Submission to: Generator ramp rates and dispatch inflexibility in bidding rule 2014 – Consultation Paper

Snowy Hydro Limited welcomes the opportunity to make a submission to the AER's ramp rates and dispatch inflexibility in bidding rule change proposal.

We have serious concerns with this Rule change proposal. The rule change Proponent appears to either not understand or misrepresents how the NEM operates at a holistic level. The NEM is a Regional / Zonal based market with a well-functioning Contract/Forward market for Participants to manage their energy and capacity risk. In reality the majority of electricity is sold ahead of time in the Contracts market and the Spot market is used in real time to determine the floating price for these fixed contracts and to 'clear' or balance any unhedged electricity quantities (through the Spot price).

Being a Regional based market allows contract trading to be centred on five (5) Regional pricing nodes. From a purely theoretical perspective economic literature suggests that a greater number of pricing nodes may improve economic dispatch but at the expense of a reduction in depth and liquidity in the Contracts markets. The NEM design recognised this inherent trade-off in market design. We contend that the efficiency of the Contract market is of much greater economic importance than any perceived and uncertain small incremental improvements in dispatch efficiency.

The core of the AER rule change is market or transmission access to each Regions pricing node where all loads for that region are priced and settled. We believe the implementation of the AER's rule change would adversely reduce the depth and liquidity of the Contracts market. The AER rule change focused on ramp rates is a small subset of the much more substantial issues to be considered as part of the Optional Firm Access (OFA) project. Our submission has focused on ramp rates but our arguments against the ramp rate aspect of the rule change can be validly and similarly applied to the Fast Start Inflexibility Profile. As such we believe the AER rule change should be rejected in its entirety by the Commission and the Proponents' issues can be holistically considered as part of the design, testing, and assessment of the OFA.

Our submission can be summarised by the following observations.

The AER appears not to understand or misrepresents the "problem"

The AER appears to not understand the nature and magnitude of the "problem". This "problem" as represented by the AER proposed rule is disorderly bidding and specifically the use of ramp rates. However we contend that:

- The real issue is not ramp rates but rather market access in the face of transmission constraints caused primarily through ill-timed transmission outages and network planning failures;

- The "problem" is economically immaterial. Numerous studies have shown that the economic cost of disorderly bidding to be in the order of $8 million per annum or approximately 0.1% of the NEM's wholesale energy value. The economic cost attributable to ramp rates would be a very small and negligible component of this cost;

- There appears to be no system security issue. The NEM is grossly over supplied[1] and the decline in demand growth shows on signs of reverting back to historical positive growth rates. In this current environment there is sufficiently more ramping capability to meet AEMO's system security obligations than the requirement advised by AEMO in 2009. Any enhancement in system security is not required and if mandated would increase economic costs as this is simply not a one side "free" option;

- There is no material price volatility created by ramp rates as the Regional price is materially determined by generators on the "receiving" end of the binding transmission constraint not the sending end generators which are constrained;

- The proposed "solution" won't work but will create much bigger issues in both the Spot and Forward markets; and

- The rule change won't increase competition but rather will decrease competition and hence the true economic dis-benefits to both the Spot and Forward markets would be much greater the claimed "dispatch" benefits.

The AER is proposing expropriation of generators' resources through regulation

The rate of ramping is fundamentally a commercial parameter (not technical):

- Commercial drivers in both the long and short run determine the rate that generators are willing to be loaded and unloaded;

- If there is a broader market/system benefit (which we doubt) of having greater ramping capability then create an explicit market signal for this service;

- Ramping capability is not a zero cost option. In fact it is a very high cost option as shown in our detailed response in Question 8.

- The AER proposal will provide a very real and perverse incentives on generators that are not in the interest of the market or consumers:

[1] AGL have asserted the NEM being currently more than 9000 MW oversupplied.

    - Strong incentive to "engineer" technical solutions to commercial interest (the engineering task is relatively simple);

    - Other bidding parameters can simply be used to thwart the ramping Rule (ie. availability bidding). However, this driven behaviour would create its own inefficiencies.

- The rule proposal would create very real and significant enforcement and compliance risks and costs;

- Fundamentally the AER proposal won't work; and

- If the real issue was ramping capability to enhance system security then a market based approach through the procurement of network support and control ancillary services (NSCAS) and/or the establishment of market for ramping capability would provide the appropriate incentives for service providers to make this service available.

The root cause of the "problem" is inappropriately timed transmission outages

The root cause of the "problem" of disorderly bidding through the use of ramp rates is transmission outages particularly those caused by TNSPs taking ill-considered outages at inappropriate times for the market and also constraints caused by gross failure of network planning.

- Ironically the AER is responsible for these two aspects of market regulation; and

- The "problem" is not material in comparison to broader market design trade-off benefits in a deep and liquid forward markets.

Snowy Hydro commissioned independent review by Acil Allen Consulting

Snowy Hydro has commissioned an independent critique of this Rule change by Acil Allen Consulting. Their report forms part of Snowy Hydro's submission. Acil Allen Consulting concludes that:

- *Disorderly bidding is a rational response by generators to shortcomings in market design. Proposed rule changes should deal with the shortcomings not the response.*

- *Ramp rate or rate of change is as much required by AEMO to fulfil its market and system operator role as capacity. It should be sourced competitively through a market rather than through regulation.*

- *The present lack of an explicit payment for ramping capacity in the NEM is not determinative of the classification of ramp rate as a technical rather than commercial parameter.*

- *Productive efficiency losses associated with disorderly bidding are small and not all due to rebidding ramp rates.*

- *It is doubtful whether price volatility caused by disorderly bidding acts as a deterrent to investors in peaking plant and materially affects the pricing of hedges.*

- *It is doubtful whether the increasing prevalence of counter price flows materially affects inter regional trading as settlement residues have never been considered an effective interregional hedge.*

- *The proposed rule change is unfair as it will commercially disadvantage flexible plant. Superior technical capability should be rewarded not penalised.*

Snowy Hydro strongly opposes the Rule change

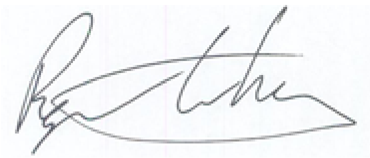
In summary Snowy Hydro strongly opposes the Rule change. The problems the Rule change purports to address are either immaterial or unsubstantiated. The Rule change would reduce the overall efficiency of the NEM, introduce a very complex and costly enforcement and compliance regime, and result in increased costs to consumers with no benefit.

Snowy Hydro believes the proposed Rule should be rejected in its entirety. The OFA project is considering the issue of market access and “disorderly” bidding with the use of ramp rates a minor subset of these considerations. The OFA project is the appropriate forum to investigate all issues associated with market access in a holistic manner.

Snowy Hydro’s detailed submission is attached to this covering letter together with our independent Consultants critique of the Rule change.

Snowy Hydro appreciates the opportunity to respond to this review. Please contact Kevin Ly, Manager Market Development and Strategy on (02) 9278 1862 if you would like to discuss any issue associated with this submission.

Yours sincerely,



Roger Whitby
Executive Officer, Trading

Introduction and Context

It is important to lay out the context from which the AER rule change proposal will be assessed. This context is relevant because a narrow assessment of the proposed rule in our opinion would be poor regulatory practice and would ignore the many competing trade-offs in the current NEM design.

The NEM is a Regional structured market where energy is settled based the Regional Reference Price (RRP). As such all forward contracting is done on a Regional basis with generators predominantly selling these contracts in their own region. The extent that generators forward sell contracts outside their region is small and at the margin since doing so would incur additional interconnector risks.

Any market change that introduces more dispatch risks to generators must be assessed against the impact of this change to the forward markets. We are of the opinion that the AER rule change would fundamentally increase the risk of generators forward contracting in their own Region resulting in less forward contracting. This reduction in forward contracts will not be fully offset or replaced by inter-regional generators who would be facing both dispatch risk and interconnector risks.

This is an inherent trade-off in the current market design. Small and incremental dispatch efficiency changes would adversely impact to a much greater extent the hedging and forward markets.

Fundamentally the AER rule change is about Market Access. Which generators get access to limited transmission capability when transmission constraints bind (typically when transmission outages occur)? The response to this issue could radically alter the risks of forward contracting in the NEM. The OFA project administered by the AEMC is poised to assessed all the competing trade-offs in the NEM design in a holistic manner. While Snowy Hydro does not endorse the OFA, we believe that the AEMC administered OFA project is the appropriate body and process to properly assess issues which impact generators access to customers' loads. The AER rule change is simply a subset of market access issues which are being considered in the OFA project. As such we firmly believe that the rule change should be rejected and instead market access should be considered as part the OFA project.

The following sections show our detailed response to each question in the AEMC's consultation paper.

Question 1

(a) Does the current minimum required ramp rate of 3 MW/minute hinder AEMO's ability to determine an economically efficient dispatch arrangement while maintaining system security?

Response: No. The 3MW/minute was set by AEMO and has not been an issue for system security. Looking forward with the oversupply of the NEM and the decline in demand growth the current ramping requirement would continue to sufficiently meet AEMO's system security obligations. Furthermore AEMO has the safety net power of direction. To the best of our knowledge AEMO has not used its power of direction since 2009 to source more ramping capability to meet system security. This is a clear indication that the current ramping requirement is sufficient.

The current minimum ramp rate has a negligible impact on AEMO's ability to determine efficient dispatch. The rebidding of ramp rates and changes to dispatch inflexibility profiles is not the underlying cause of inefficient dispatch. As per the NGF response to the AER Special Report released in December 2012 multiple and non-credible transmission outages taken at inappropriate times were the primary cause of the volatile market events in 17 of the 20 events highlighted in the AER Special report. These multiple and non-credible transmission outages reduced transmission capability and as a result generators behind a binding transmission had to use "disorderly bidding" to manage their dispatch and contract risks. The table below highlights the multiple transmission outages for 17 of the 20 market events.

Flow From	Date/Time	Outage
VIC to NSW	9/02/2010 16:30	Out = Dederang to Glenrowan No.1 or No.3 220kV line
VIC to NSW	10/02/2010 14:30	Out = Dederang to Glenrowan No.1 or No.3 220kV line
VIC to NSW	21/04/2010 12:30	Out= Eildon to Mount Beauty No. 1 220 kV line and one Dederang to South Morang 330 kV line
VIC to NSW	22/04/2010 15:00	Out= Dederang H2 330/220 kV txfmr and one Dederang to South Morang 330 kV line
VIC to NSW	21/06/2010 9:00	Outage = Lower Tumut to Wagga 330kV line
VIC to NSW	22/10/2010 11:00	Out = Hazelwood #6 220 kV bus , Murray better coeff than NSW
VIC to NSW	28/11/2010 6:00	Out= Thomastown No. 1 220 kV bus
VIC to NSW	31/01/2011 15:30	Out = Nil. HHE 15:00 flow was very positive (4 periods) then unexpected Darlington constraint caused VOLL price VIC (and flow negative). Price stayed VOLL and flow slightly positive due to low RHS V>>V_NIL_1B constraint (1556).
VIC to NSW	30/05/2011 13:30	Out= one of Dederang-Murray(67 or 68)
VIC to NSW	31/05/2011 8:30	Out= one of Dederang-Murray(67 or 68)
VIC to NSW	2/07/2011 13:00	Out = one 500 kV line between Heywood and Moorabool
VIC to NSW	11/09/2012 9:00	Outage = Lower Tumut to Wagga 330kV line
NSW to VIC	7/12/2009 12:00	Out = Sydney West-Yass(39)
NSW to VIC	22/01/2010 15:00	Out = Nil, but low rated Mt Piper-Wwang (70) line
NSW to VIC	4/02/2010 12:00	Out = Nil, but low rated Mt Piper-Wwang (70) line also Kemps Creek - Syd South out
NSW to VIC	11/02/2010 14:30	Out = Nil, but low rated Mt Piper-Wwang (70) line also Yass-Syd West (39) line out
NSW to VIC	26/03/2010 13:00	Out = Dapto-Marulan(8)
NSW to VIC	13/04/2010 14:00	Out = Dapto-KangarooValley(18)
NSW to VIC	29/06/2010 17:30	Out = Nil, but low rated Mt Piper-Wwang (70) line
NSW to VIC	9/11/2011 15:30	Out = Dapto-SydneySouth(11)

Table 1: Market events and corresponding key transmission outages

From Table 1, only 3 of the events were System Normal (NIL) events (highlighted in yellow), However, even in these NIL events other constraints / outages were already limiting transmission flows leading up to the "disorderly bidding" event.

To be clear disorderly bidding is the result of transmission constraints. Transmission constraints cause volatile price outcomes and not disorderly bidding. In the face of transmission constraints, disorderly bidding by generators behind the constraint is how generators manage their dispatch and contracting risk. The key issue is what causes transmission constraints and all evidence shows that it's transmission outages taken at inappropriate times.

Is the economic cost of disorderly bidding material?

Dispatch inefficiency due to disorderly bidding (to which only a small quantum can be attributed directly to ramp rates) is immaterial in total as shown by two separately commissioned reports:

1. AEMC 2008 (Frontier Economics) – Quantified the cost of disorderly bidding to be $8 million per annum which is immaterial compared to a market turnover of approximately $9 billion per annum.

2. NGF 2013 (Frontier Economics) – Re-run of the 2008 modelling with updated constraints from the AEMO 2012 constraints workbook. The results showed the economic impact of the disorderly bidding to be immaterial and similar to the 2008 study at upto $10 million per annum.

In addition to these two studies AEMO commissioned IES[2] to examine dispatch efficiency under a dynamically allocated transmission capacity rights model. In the examples IES used the economic cost of dispatch increases with disorderly bidding removed. The results of this IES study directly contradicts AER's assertion that dispatch efficiency would improve with disorderly bidding removed.

(b) If so, would the AER's proposed rule improve the economic efficiency of the dispatch process in this regard?

Response: No. The AER have not quantified the economic efficiency of the dispatch process if this rule change was implemented. We have highlighted three independent studies that has modelled and quantified the economic cost of disorderly bidding to be extremely small. The economic cost of dispatch attributable to Ramp rates would be a small fraction of this already small economic cost of disorderly bidding. Hence we conclude from the available evidence the AER rule may have a negligible impact on economic efficiency of dispatch.

However the rule change will reduce the ability for intra-regional generators to hedge and hence alter incentives in the Spot market. Generator behaviour is dynamic and would change if this Rule was implemented. The AER assumes that the level of Spot market volatility would reduce with this Rule change. We strongly disagree and highlight that a less hedged peaking generator has radically different incentives than one which is hedged. In our opinion an unhedged peaking generator has strong incentives to create more Spot price volatility.

(c) What evidence is there that system security has been compromised by ramp rate limitations?

Response: There is no evidence that system security has been compromised by the current ramp rate requirements. The onus of proof rests with the Rule proponent.

There is also no concept of "improved" system security as system security presents a trade-off between cost and risk. If system security is improved then it means there is some

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[2] IES, MODELLING THE [Shared Access Congestion Pricing] SACP MODEL, A report to AEMO, 23 April 2012.

economic cost increase. We show in Appendix A that the economic costs of mandating technical ramping capability at all times is extremely expensive, increases the risk of catastrophic failure, and is therefore simply not a “free” option. Further to this AEMO could achieve system security through the increase use of market ancillary services and/or network support agreements with Market Participants. We also add that providing a safety net to AEMO (which is not free or costless) simply distorts AEMO’s incentives to procure necessary market ancillary service or more importantly network support ancillary services to the long term disbenefit of consumers.

Further to this if ramping capability was indeed compromising system security then the AEMO could propose an explicit market for the offering of this service.

Question 2

(a) Do you agree with the AER’s assessment of the costs associated with counter-price flows?

Response: Absolutely not. The AER need to acknowledge that the root cause of these market events were multiple non-credible transmission outages. We have analysed Table 5.2 of the Consultation Paper and found that multiple and non-credible transmission outages accounted for $25.1 million of the total of $25.8 million of counter price flows for the Vic to NSW interconnector. This is over 97% of the negative settlement residues. For the NSW to Vic interconnector multiple and non-credible transmission outages accounted for $8.1 million of the total of $8.9 million or over 91% of counter price flows.

Interconnector	Period	Negative Settlement Residue ($ millions)	Caused by Multiple Tx Outages ($ millions)	Caused by NIL Outages ($ millions)
Vic - NSW	Since Feb 2010	25.8	**25.1**	0.7
NSW - Vic	Since Dec 2009	8.9	**8.1**	0.8

Table 2: Analysis of the root cause of counter price flows.

In the face of multiple and non-credible transmission outages Generators on the wrong side of these transmission constraints were simply using all available means to manage their contract price exposure risk. It should be noted that the AER is responsible for administering the various TNSP incentive schemes that should in theory incentivise the TNSP to schedule planned transmission outages at benign market times. From the analysis presented in Table 2 it is clear the AER should assess the performance of the relevant TNSP and assess its own performance in relation to the incentive arrangements that it has established for TNSPs.

We also believe regardless of who causes the counter price flows, the cost of counter price flows need to holistically assess against the benefits of increased competition in the Contracts and secondary markets. This comes back to looking at the trade-offs in BOTH the Spot and Contract market.

(b) To what extent is generator rebidding a cause of counter-price flows on interconnectors? Is this primarily due to generators’ ramp rates or other forms of bidding behaviour?

Response: As highlighted in Table 2 the cause of counter price flows is transmission outages not generator rebidding. To manage the risk of transmission outages generators primarily use volume and price bids and not the use of ramp rates to mitigate the risk of the bidding constraint. This issue would be more appropriately assessed in the OFA project which is holistically considering the issue of transmission access in both the Spot and Contract markets.

Question 3

(a) Is it valid to conclude that changes in the merit order of dispatch results in productive efficiency losses?

Response: No. The short run marginal costs of all generation plant can change over time. For coal fired generation the spot price for coal varies by coal grade and location and is thus dynamic. For gas turbines the spot price of gas varies by location and the type of market arrangements that facilitate that gas transfer. Therefore in the short term it would be incorrect to assume that all “out of merit” order dispatch (as assumed by a static assumption on fixed fuel costs) results in inefficiency losses.

There may also be strategic reasons as to why an owner of a portfolio of generation assets may run some of its plant out of merit order. For instance a vertically integrated generator/retailer with a portfolio of generation assets and a large retail book may choose to manage its retail book exposure by running high short run marginal cost generation when Spot prices are below the plants SRMC but above the retail price agreed with their Retail customers. A narrow Spot market assessment of this behaviour would assume dispatch inefficiency however Contract market assessment would conclude that Retail customers received a competitive Retail price. Hence the net economic impact of out of merit order dispatch is dependent on both an assessment of productive efficiency losses and gains in the efficiency of the Contract markets.

(b) Is there a difference in productive inefficiencies caused by the rebidding of ramp rates and other forms of bidding behaviour?

Response: No. We note however that the quantum of the economic cost attributable to ramp rates may be insignificant and in our opinion based on market modelling from three independent sources and an assumption that 5% of the economic cost is directly attributable to ramp rates, the economic cost is much less than $0.5 million[3] per annum for the entire NEM.

(c) Assuming productive efficiency losses can be caused by other forms of rebidding, would the AER’s proposed rule reduce the extent of productive efficiency losses?

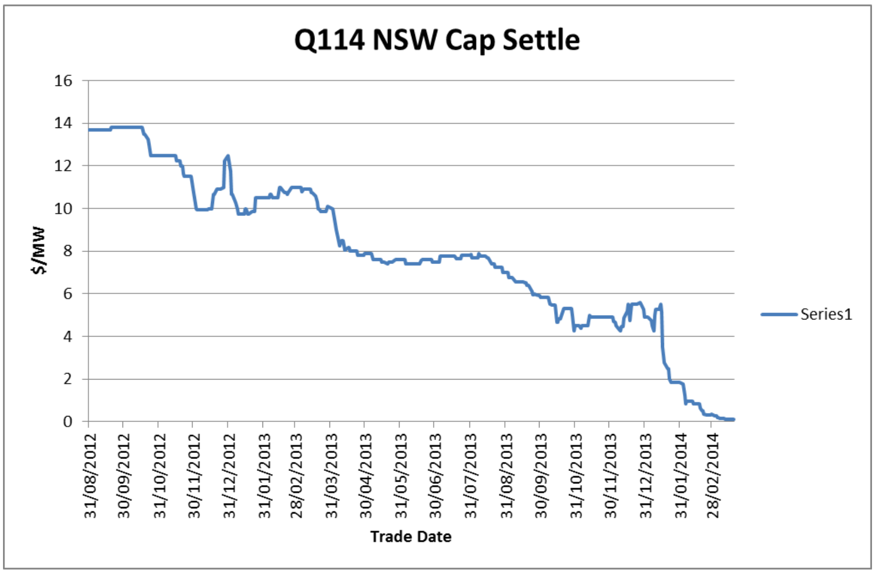
Response: No. It is incorrect to assume that Participant behaviour would be the same after the Rule change.

[3] Noting the maximum figure of $10 million per annum economic cost of disorderly bidding from modelling outlined in Question 1.

Question 4

(a) To what extent have participants experienced a quantifiable increase in the costs of managing wholesale market risks through higher risk premiums on hedge contracts and, if so, to what extent can this be attributed to the issues discussed above?

Response: The cost of managing wholesale market risks have gone down in the last few years. This is clearly depicted Figure 1 which shows the Contract traded price of the 2014Q1 NSW $300 Cap. This figure is not surprising given the current oversupply of generation in the market and forecast continuation of falling demand.



The extent of any higher risk premiums on hedge contracts attributed to the use of rate ramps is impossible to quantify and there is no credible evidence to suggest that ramp rates have impacted on the risk premiums in any way. We therefore assert that the risk premium on contracts is more a function of fundamental supply and demand and the market structure including transmission rights allocation.

(b) Assuming the adoption of a prudent risk management and purchasing strategy, do these higher risk premiums represent a real and measurable cost to consumers?

Response: The market events depicted by the AER are transitionary. The events analysed were caused by multiple non credible transmission outages. If transmission is out or the capability is reduced then generation supply is adversely affected. Allocating that transmission outage risk to intra-regional generators by forcing these generators closest and most affected by the constraint to ramp down generation is inappropriate as these generators cannot control the timing and scheduling of the transmission outages which caused the constraint in the first instance. The entity that directly influences incentives on the timing of outages by the TNSP is the AER.

Market Participants are sophisticated enough to discount the impact of these market events in assessing the fundamental cost of future hedge products.

From our analysis the current rigorous competition for the supply of hedge contracts has benefited consumers immensely. The AER rule change would adversely impact the vigour of competition to supply forward contracts in exchange for highly insignificant and uncertain improvements in dispatch efficiency and a non-existent requirement to enhance system security.

Question 5

(a) To what extent has the rebidding of ramp rates under constraint conditions led to inefficient price signals? Is there evidence to suggest this has led to investor uncertainty?

Response: None. It is critical to establish that generators behind the constraint do not materially influence the Regional Reference Node (RRN) price which is set by generators on the other (unconstrained) or receiving side of the constraint. Snowy Hydro illustrates this point with an example with the market event on the 7th December 2009. Some facts surrounding this market event are:

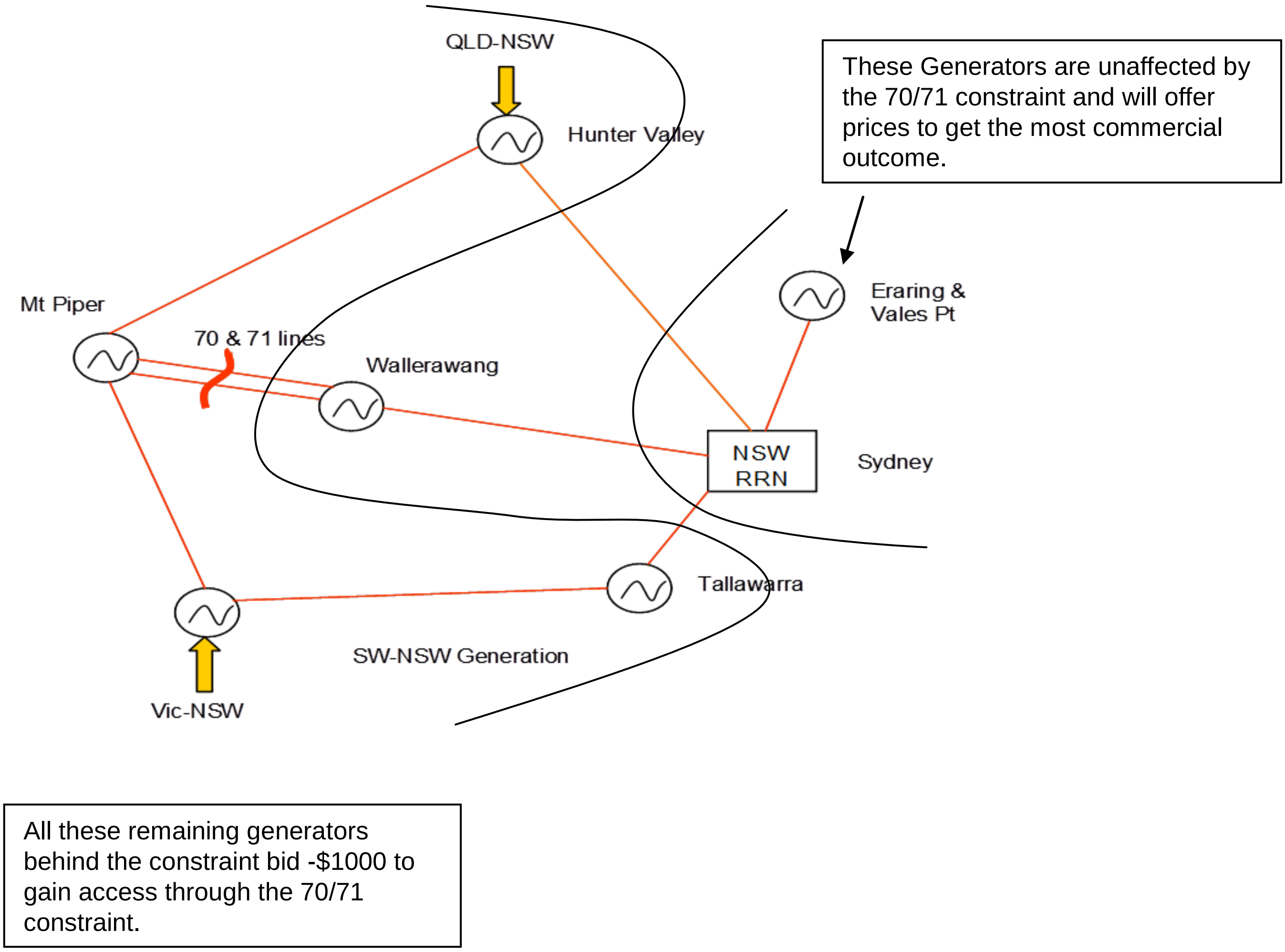
- Network outages were taken as part of TransGrid's 500kV upgrade
- The 70 / 71 line constraints bound for 7 hours on the day
- Spot prices in the NSW Regional Reference Node (RRN) reached over $9000/MWh

During this constraint the high Spot prices in the NSW RRN can only be set by generators on the receiving side of the constraint. The price volatility that the AER refers to in its Special report has very little to do with generator behaviour behind the constraint but is dictated by generators on the receiving side of the constraint effectively setting the RRN price.

All other generators and interconnectors are effectively behind the constraint and jostling for the limited transmission access through the 70/71 line constraint. Rebidding by generators behind the constraint only reallocates the reduced access behind the constraint and does not materially affect price volatility.

Critically rebidding of generators behind the constraint does not materially influence the behaviour of generators on the unconstrained side of the constraint. Hence there would be no difference to the Spot price outcome if access was redistributed differently behind the constraint.

The high Spot price signals in the NSW region were not inefficient. These price signals showed where there was a network constraint caused by transmission outages and hence clearly signal to the new investors the locational risk of potential new plant. There is no evidence to show that these price signals lead to investor uncertainty. On the contrary we believe they improve investor certainty by highlighting locations that can experience transitionary over supply of generation or lack of transmission capability.



(b) Have participants with peaking generators experienced higher levels of price unpredictability arising from the issues discussed above? Can these impacts be quantified?

Response: No. As discussed above no price volatility can be caused by generators behind a binding constraint reducing ramp rates through re-bidding. The price volatility is driven by generators on the unconstrained side of the binding constraint.

Question 6

(a) To what extent can a reduction in the effectiveness of SRA units be attributed to the rebidding of ramp rates under constraint conditions compared to other forms of generator rebidding?

Response: The accruals on SRAs are fundamentally driven by the market clearing outcomes which is affected by the supply and demand balance in the market. The market has experienced much lower energy and peak demand growth and in this environment it is be expected that SRA Spot accruals would be lower as has been seen. As a result the SRA proceeds are lower. It is completely inappropriate to therefore attribute lower SRA proceeds on rebidding of ramp rates.

(b) As a NEM participant, do you consider SRA units to be an effective instrument for the management of inter-regional price risk and have you used SRA units for these purposes in the past? To what extent has this changed due to the issues discussed above?

Response: At the margin Snowy Hydro uses SRA units as risk management tools to supplement our existing portfolio of generation assets. We empathise that the use of SRAs is highly risky and unpredictable as a myriad of factors can impact the effectiveness of the SRA units. We believe this view is consistent across all the NEM Participants. Our view is that the majority of all contracting is done intra-regional with generators selling predominantly in their own pricing region. This view is supported by a number of independent sources. For instance Danny Price[4] highlighted the difficulty in hedging contracts inter-regionally.

> *there's a whole bunch of risks that we haven't accounted for. We've broadly defined it as execution risk, and that captures a lot of things in that sort of term, and I note people have said, "Well, there's no executive risk because you can buy pairs or any combinations of IRSRs." That's true, we understood that, but it really relates the additional complexity and risk of (1) being able to predict the appropriate price and (2) being able to secure the quantity so you can achieve that risk position. It becomes harder and harder every time you have to go through an additional region to do that, which is why nodally-price markets are so illiquid generally. It's because people can't predict once you go through to our three regions.*
>
> *It would be like, for example, South Australian generators selling into New South Wales or Queensland into Victoria. I'm sure it happens, and I know that it does happen,* ***but it's actually pretty rare, because of the difficulties of trying to predict the price differences and secure the appropriate pairs quantities of IRSRs*** (empathise added)***.***

Our key point here is that the ramp rates rule will:

- increase the risk for intra-regional generators closest to the a relevant binding constraint; and
- would disproportionately increase the dispatch risk for peaking generators who generally have the higher ramping capability.

As a result of these increase dispatch risk for intra-regional and peaking generators there would be a decrease in the volume of Contracts available. This loss of Contract volume would not be replaced by generators remote from the Region due to the increase risk of inter-regional trading and the imperfect nature of the SRA units. The net impact would be a decrease in the overall volume of Contracts available to the market. This loss in Contract market efficiency would be orders of magnitude greater than any incremental increase in dispatch efficiency.

Question 7

Would the application of the AER's proposed rule affect the valuation of SRA units and the impact on network charges?

[4] Danny Price, AEMC Consultation Forum – Abolition of Snowy Region – Transcript of proceedings, page 22.

Response: By the AER's own logic (which we do not agree with) less volatility will mean less value in SRAs accrual and hence less SRA proceeds. Hence the AER rule if implemented would undermine the AER's stated objective of increasing the value of the SRA proceeds.

To be clear, the value of SRA units drops as price volatility drops. SRAs are less sensitive on flow in the interconnector (2-5 times), but more sensitive on Spot price as prices can jump 100 times. So according to the AER if this Rule is implemented price volatility will reduce which would reduce the SRA value and hence reduce its contribution to reducing network charges. We don't agree with the AER's simplistic view on static generator behaviour. With any major market change the incentives on generators change and hence to pre-empt future market outcomes would be highly speculative. We believe the price of these SRA units would still be driven by fundamental supply and demand and Generator bidding behaviour if this Rule is implemented.

Question 8

(a) Is it valid to assume that generators would generally be able to operate at their maximum ramp rates submitted in accordance with schedule 3.1 of the NER?

Response: Absolutely not. For hydro generators the maximum ramp rate provided in schedule 3.1 is a function of many factors such as head pond levels etc. In some circumstance Snowy Hydro's plant could achieve much higher ramping but at very significant increased cost and risk and in other circumstances much less ramping rates than those submitted in schedule 3.1.

(b) To what extent are the cost differences associated with different levels of ramp rates material and should this be taken into account in the determination of maximum technical ramp rates?

Response: Cost differences associated with different levels of ramp rates are very material and sensitive between different generation technologies. The AER's rule change proposal requires that at all times a generator must bid up and down ramp rates that reflect the maximum technical capability of the generation plant. <u>That is, the rule would require that the ramping capability of the plant be maximised at all times that the plant is available to the market.</u> We set out in Appendix A the economic cost increases associated with complying with this Rule change. The following is a summary of examples illustrating the impact of requiring generators to maximise the ramping capability of generating plant.

1. Genuine Fast Start Hydro Generating Units – "Speed no load' Spinning Reserve

   The economic cost impact would be $150M per annum across the whole Snowy Scheme. Operating in this mode would consume very significant water (energy) stored in our dams and in the case of Tumut 3 all of the average annual energy output of this station. The economic loss of the wasted energy is potentially small in comparison to the longer term maintenance cost and consequential loss from turbine repairs outages.

2. Genuine Fast Start Hydro Generating Units – Synchronous Condenser Operation

   The economic dead weight loss remains very material for operation in this mode – of the order of 4 MWs per unit ($10M pa economic dead weight loss for just Tumut 3 Power Station) ignoring the substantial ongoing wear and tear cost.

3. Inefficient Aggregate Hydro Generation Unit Operation

   The AER proposed rule would mandate a dramatic reduction of energy conversion efficiency (from the renewable potential energy of the stored water) in order to maximise ramping capability. A 10% loss of conversion efficiency is plausible and would come at an economic dead loss of the order of $20M p.a.

4. Hydro Generator Starting/loading Wear and Tear
   In addition to the impact on the turbine, high loading ramping rates have very real and material impacts on hydro generators life in the longer term (hence high generator loading rates have very material economic impacts).

5. Hydro Station Surge Tank Risks

   Tunnel fed hydro power stations typically have 'surge tanks' to control pressure rises when station flows are rapidly varied arising from the inertia of the water column.

   The AER proposed rule change proposal would require the station to be offered to the market at the technical envelope of the surge tank air entrainment risk (ie fully rely on the control and protection systems) to manage the catastrophic failure risk. Any control and protection system has in itself a failure risk. Who would compensate Snowy Hydro for this increased risk burden cost?

6. Gas Turbine Starting (FSIP) and Ramping Rates

   Gas Turbines can typically be started and loaded at differing rates (for example slow and fast loading rates). However the impact on the maintenance costs and indeed the operational life of the plant is very material.

   Fast start/loading of a gas turbine also increases the risk of start failure, for example due to high vibration levels due to the rapid/uneven temperature changes in the gas turbine.

7. Generator Unit Tripping

   All generating units are required by the NEM rules to protection equipment including manual emergency shutdown facilities. Hence all generators are capable of 'safely' reducing output to zero instantaneously (infinite down ramp rate). There may be significant implications in tripping a unit, but these are all 'commercial'. Substantial 'wear and tear' may occur to the generating unit.

(c) Are there any issues relating to the ability of generators to determine the maximum ramp rates of their generating units?

Response: There would be many technical issues and assumptions made to determine maximum ramp rates. Quantifying the risk and uncertainty of cost would be the most problematic issue.

(d) Are there any issues relating to the enforcement of the AER's proposed rule?

Response: Enforcement and compliance with the AER's proposed rule would create material uncertainty and hence increase the cost of participation in the NEM. Enforcement of the proposed Rule would also be very costly as the AER would need to employ external advice to perform audits of submitted data. All the additional resources needed for participants to comply with the rule and for the AER to enforce the rule would be an economic dead weight loss.

Question 9

Would a requirement to submit ramp rates that reflect the technical capability of generating plant increase risks to generators? What form would these risks take and can they be quantified?

Response: Undoubtedly this Rule would materially increase risks to all generators especially peaking generation who would be ramped back disproportionately more. It would result in less Contract hedge quantity being available to the market. This volume would not be replaced by inter-regional Participants as they would face other additional risks trying to get access to the remote sold hedge region.

The risks and therefore cost of wear and tear of equipment would dramatically increase as well as the risk of catastrophic failure of generation plant. These risks are outlined in detail in Appendix A.

Question 10

(a) Would the proposed rule create an incentive for generators to actively reduce the technical ramp rate capability of their generating plant?

Response: Yes. Ramping capability of generating plant is determined in three quite distinct timeframes:

i. Capital Investment Timeframe(typically through the initial design/specification of the generating system)
ii. Operational/Maintenance Policy Setting Timeframe
iii. Real Time

With respect of capital investment, there if a significant trade-off between the level of investment and the inherent ramping capability of the plant. Higher ramping capability cost more! For example - Tumut 3 Power Station and Dinorwig Power Station in Wales were centrally planned to have a similar functions in their respective power systems (load following, back up of large generator failure, pump storage etc). However the power system requirements were radically different in the two different power systems, hence the response speed requirements of Dinorwig is much greater than Tumut 3 which in turn require a higher level of initial investment.

In the medium term, operational and maintenance engineering settings constrain the ultimate capability set by the capital investment decisions. For example the pumping capability/settings of hydraulic circuits controlling the guide vane servos of hydro turbines typically limit the maximum loading rate rates of hydro generators. These settings are based on the commercial trade-off between the benefits of faster ramping verses the wear and tear and operating risks of faster settings.

In real time operational decisions influence ramping capability within the constraints set by the engineering decisions. For example the number and level of physical unit operation, auxiliary fuel firing of boilers and number of mills operating of thermal generators etc.

In all of these time frames, plant settings can alter the commercial and technical outcomes. With newer digital technology some settings can be rapidly changed, but separating technical from commercial is not possible!

How will the AER understand, monitor, and enforce separation between technical and commercial?

Who bears the compliance risks and costs in this process?

There are obvious commercial drivers to change settings in the investment/engineering/operational timeframes in response to the AER rule change proposal. ‘De-engineering’ capability for commercial reasons is not in the interests of the market.

(b) Since the making of the AER’s previous rule change request, have conditions in the NEM changed such that a minimum ramp rate of 3 MW/minute is no longer sufficient?

Response: The falling energy consumption and peak demand means the current minimum ramp rate of 3MW/minute is more than sufficient. We are not aware of any evidence to support AER’s assertion that technical ramping capability would enhance system security.

(c) Would generators be able to negate the effects of wear and tear by bidding volumes within price bands as suggested by the AER?

Response: No. It would be sub-optimal and completely ineffectual for generator to negate wear and tear through bidding volumes within price bands.

There is no explicit ‘load following service’ in the current ‘energy only’ market design. However the AER in its rule change proposal asserts that a participant generator can manage the commercial risks of excess dispatch ramping due to the requirement to bid maximum technical ramp rates by bidding into different price bands.

However there is only limited ability to manage dispatch ramping in this manner. This is a completely ineffective/inefficient mechanism to manage the commercial issues of ramp rate offering.

It is highly unlikely that the AER understands the potential impact on the market by bidding changes that may flow from what it proposes. The proposals will considerably alter incentives on highly flexible generators. For example, energy constrained hydro generators are driven by the scarce energy resource to bid at the margin of the market (ie opportunity cost of scarce resource). These happen to be the very same generators with high inherent ramping capability and well suited to ‘load following’ duty. The AER seems to be proposing that these generators should vary the marginal priced energy offers (despite this being very inefficient/ineffective mechanism) to manage the commercial cost and risks of excessively high technical ramping impact on plant. Given the marginal pricing clearing mechanism of the market and that market spot prices tend to be most sensitive at times of highest demand and prices the resultant price impact is likely to be highly leveraged across the entire energy spot market.

It is certainly not clear what the impact might be, but it is not safe to assume that the impact would be immaterial, nor is it safe to assume that other competing generation would also not react.

Question 11

(a) What are the costs and benefits of requiring generators to submit minimum ramp rates for each of their individual physical units rather than a single minimum ramp rate for the aggregated total?

Response: Nothing has changed. 3MW/minute is sufficient to maintain system security so there is no basis for changing the current ramping requirements.

(b) Does the view still hold that the aggregation provisions can be used to manage concerns around incentives to aggregate?

Response: Yes.

Question 12

(a) What are the costs and benefits of requiring generators to submit maximum technical ramp rates only at times of network constraints?

Response: The ability to commercially determine ramp rates is most valuable at times of network constraints. Hence this option would be unsatisfactory and unworkable to practically apply.

(b) Are there any variations to this approach, such as the use of average ramp rates, which may be more preferable?

Response: Artificial rules which impose or incentivise certain behaviour in the present would in the long run result in less efficient outcomes as the existing resource would not be optimally used in the present. For energy limited flexible plant this problem would be more pronounced.

Question 13

(a) What are the costs and benefits of requiring generators to submit a ramp rate that reflects a percentage of the capacity of their generating plant?

Response: AEMO have already stated that they have sufficient ramp capability to maintain system security so there is no need to change the existing requirements.

(b) Assuming adoption of this approach, what percentage of capacity should be required?

Response: Not applicable.

Question 14

Are there any other alternative approaches? To what extent could an alternative approach be based on incentives rather than relying on regulatory/technical requirements?

Response: If ramp capability was really the key issue (which we don't think it is) then set up a market for this ramping capability.

We also re-iterate that ramp rates is a small subset of disorderly bidding and the key issue of who gets market access to limited transmission capability. This market access should be considered through the OFA project.

Appendix A

The AER's rule change proposal requires that at all times a generator must at bid up and down ramp rates that reflect the maximum technical capability of the generation plant. That is, the rule would require that the ramping capability of the plant be maximised at all times that the plant is available to the market. The following sets out a limited number of examples of the impact of requiring generators to maximise the ramping capability of generating plant.

1. Genuine Fast Start Hydro Generating Units – "Speed no load' Spinning Reserve

Energy constrained fast start hydro generating units by definition operate at full load for a relatively small portion of the year as measured by 'capacity factor'. For Snowy Hydro's Tumut 3 Power Station the capacity factor is very small, approximately 5% ignoring pump storage operation. These generators if dispatched can start up, synchronise to the power system and partially/fully load within 5 minutes. The start-up process and synchronisation process however significantly limits the loading rate that can be performed within a 5 minute period.

If Snowy Hydro was required to maximise ramping capability of Tumut 3 Power Station, this would require Snowy Hydro to operate all of it Tumut 3 generating units at 'speed no load' while not generating MWs but available to the market. 'Speed no load' is the operating state where the generator is synchronised to the power system but its electrical power output is zero MWs. Electrical and mechanical losses are provided by the hydraulic flow in the turbine, but the Turbine is operating at an zero efficiency point (ie no power output for the potential/hydraulic energy consumed). Each Tumut 3 turbine consumes approximately 20 MWs 'equivalent water' in this operating mode. In the 'speed no load' state, the generator can be very rapidly loaded. Subject to engineering due diligence, the loading rate could be as high as the maximum turbine guide vane opening rate which is currently set at 30 seconds. Hence each Tumut 3 generator could ramp at a rate of approximately 600 MWs/minute or combined 3600 MWs/minute for the station. With relatively simple engineering modification the guide vane opening rate could be doubled, achieving a station loading rate of 8000 MWs/minute.

While these are impressive theoretical ramping rates this would come at very significant cost to Snowy Hydro (and at a pure economic dead loss – there is no market or system benefit to such ramping and in fact very significantly increased systemic system security risk). The wasted potential renewable energy would be in the order of 120 MWs on a Tumut 3 Station basis, which would have a current market value of the order of $50M per annum (and by extension of the order of $150M p.a. across the whole Snowy Scheme). In fact operating in this mode would consume all of the average annual energy output of Tumut 3 Power Station! Further the economic loss of the wasted energy is potentially small in comparison to the longer term maintenance cost and consequential loss from turbine repairs outages.

While it is 'safe' to operate Tumut 3 turbines at 'speed no load' for short and perhaps even medium periods, extended periods of operation will cause significant maintenance 'wear and tear'. The 20 MWs of wasted energy at 'speed no load' in addition to heating the turbine discharge water causes significant vibration and cavitation damage to the turbine. Snowy Hydro currently conducts major overhauls for Tumut 3 Turbines approximately every 20 years. With such an operating regime however, the overhaul timing may need to be reduced by an order of magnitude

Further, while it is perhaps a very remote probability, operating a hydro turbine at a loading point that has high vibration levels may ultimately lead to catastrophic failure of the turbine and horrific consequential damage. Reference is made to the Russian hydro plant failure

(Sayano–Shushenskaya) that cost 75 lives in 2009 due in part to extent operation of a turbine at a high vibration loading point.

2. Genuine Fast Start Hydro Generating Units – Synchronous Condenser Operation

Similar to ‘speed no load’ operation outlines above, hydro generating units if so equipped, can be operated in ‘synchronous condense mode’. In this mode the generator is synchronised to the power system but acts as a motor consuming some power system load driving the dewatered turbine/generator. This mode is not quick to respond to ramping as ‘speed no load’ operating mode due to the time taken to re-water the turbine, it is however much quicker that a stopped generating unit (as the generator is already started and synchronised) and but is somewhat more efficient then “speed no load” operational mode. The economic dead loss however remains very material for operation in this mode – of the order of 4 MWs per unit ($10M pa economic dead loss for the all of Tumut 3 Power Station) ignoring the substantial ongoing wear and tear cost.

3. Inefficient Aggregate Hydro Generation Unit Operation

Snowy Hydro bids its major power stations on an aggregated unit basis. This means that if the aggregated unit is dispatched to a specific loading (say 90 MWs for ‘Murray’ generation unit) then one or more the relevant physical units may be operated to comply with the dispatch instruction. However the efficiency of the energy conversion process varies radically with different loading points and is typically higher near maximum loadings (refer to Fig A for example power station efficiency curve).The dispatch level of 90 MWs could be met by dispatching one Murray 1 physical unit at 90 MWs (very close to its maximum efficiency operating point but with only 5 MWs of spinning reserve). Alternatively the 90 MWs dispatch could be met by two physical units at 45 MWs each (operating quite inefficiently but with 100 MWs of spinning reserve) or three units at 30 MWs each (very inefficient but 195 MWs of spinning reserve).

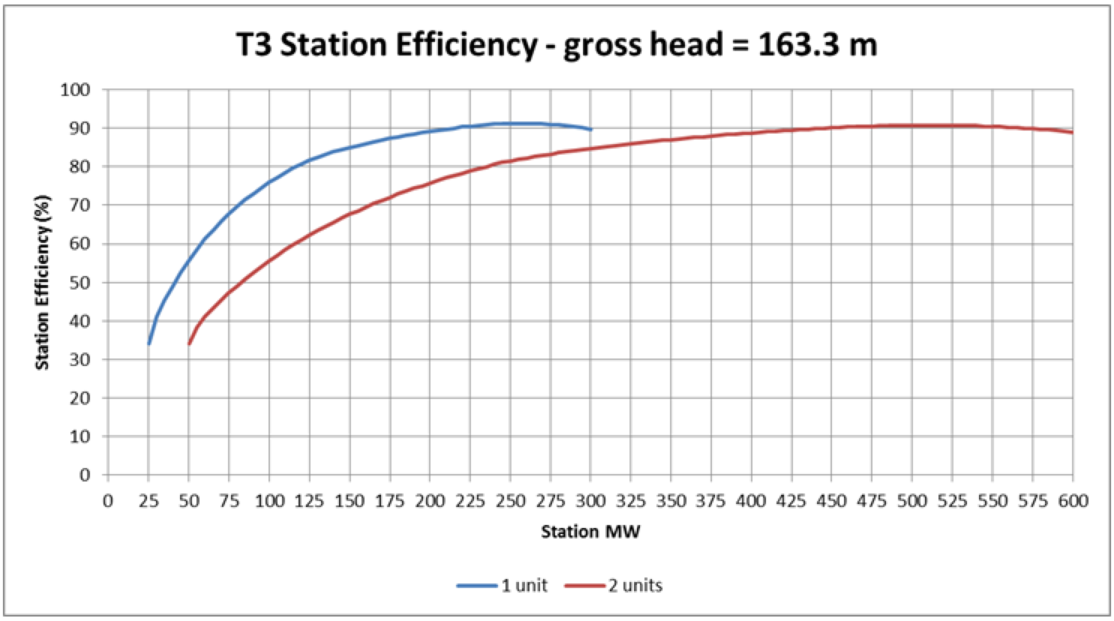


Fig A- Tumut 3 Power Station Example Efficiency Curves

Accordingly there is a very material and direct trade-off between the efficiency of the energy conversion and the quantum of available spinning reserve (which equates directly to the ramping capability of the aggregate unit). Again the AER proposed rule would mandate a dramatic reduction of energy conversion efficiency (from the renewable potential energy of the stored water) in order to maximise ramping capability. A 10% loss of conversion efficiency is plausible and would come at an economic dead loss of the order of $20M p.a across the Snowy Scheme.

4. Hydro Generator Starting/loading Wear and Tear

In addition to the impact on the turbine, high loading ramping rates have very real and material impacts on hydro generators life in the longer term (hence high generator loading rates have very material economic impacts). The copper cores of hydro generator stator windings heat rapidly as the loading is increased, but the surrounding high voltage insulation material and the stator cores do not. As the stator winding copper core heats rapidly, it expands causing a shear stress to the insulation. Overly rapid loading of the generator will potentially cause separation from the winding copper core to the surrounding insulation, which will in turn cause partial discharge erosion to the insulation. Resultant relatively rapid stator winding failure will potential thus occur.

A well maintained and operated hydro generator stator winding may have a life span of 50 plus years. However, a winding damaged by being excessively rapidly loaded as outlined above may have decades moved from it expected life span. By way of example the direct cost of replacing a single Tumut 3 generator stator winding is of the order of $10M, however the indirect costs including outage costs would be much greater. Further an unexpected stator winding failure due the mechanisms outlined may in fact damage or destroy the stator core/whole generator and thus a orders of magnitude higher cost.

5. Hydro Station Surge Tank Risks

Tunnel fed hydro power stations typically have ‘surge tanks’ to control pressure rises when station flows are rapidly varied arising from the inertia of the water column. These arrangements set up the potential for air entrainment into the water flow if loading rates are excessive. Air entrainment into the water flow has the potential to cause catastrophic failure of hydro turbines/the entire power station. Obviously control and protection systems are designed and utilised where necessary to manage this catastrophic failure risk.

Snowy Hydros Murray 1 Station (ten 95 MWs units) maximum station ramping capability is often limited by this air entrainment risk at high station output. While individual units could be potentially loaded very rapidly, collectively a high number of units must be substantially limited in its ramping capability.

The AER proposed rule change proposal would require the station to be offered to the market at the technical envelope of the surge tank air entrainment risk (ie fully rely on the control and protection systems) to manage the catastrophic failure risk. Any control and protection system has in itself a failure risk. Who would compensate Snowy Hydro for this increased risk burden cost?

6. Gas Turbine Starting (FSIP) and Ramping Rates

Gas Turbines can typically be started and loaded at differing rates (for example slow and fast loading rates). However the impact on the maintenance costs and indeed the operational life of the plant is very material. Slow starting/loading obviously has far less impact. According the choice of a slow start/loading verses a fast start/loading rate is by definition a ‘commercial’ rather than a ‘pure technical’ choice.

For example one industrial frame gas turbine manufacturer requires in its recommended maintenance requirements that every time the gas turbine unit is operated for a fast ramp up or fast ramp down, there is a penalty of 10EOH (equivalent operating hours).

Using fast ramp has a real effect on the thermal fatigue damage (cracking) to the hot-end components of the gas turbine, and the use of fast ramp will increase the repair costs of the hot-end cases, blades, vanes, combustors, diffuser and exhaust stack at the time of the major maintenance. This cost increase is dependent on the amount fast ramp is used in between the maintenance intervals.

In the case of Snowy Hydro's Laverton Gas Turbines there is a design defect in the generator rotor windings. Excessively rapid loading of the generator risks in the long run incurring catastrophic failure of the generator rotor winding and/or incurring the substantial cost of an early rewinding of the rotor.

Fast start/loading of a gas turbine also increases the risk of start failure, for example due to high vibration levels due to the rapid/uneven temperature changes in the gas turbine. The AER rule change proposal would require the FSIP/ramp rates be set at the maximum technical capability thereby forcing the generator owner to operate the plant at the highest technical risk point and increasing the risk of plant tripping/failing.

7. Generator Unit Tripping

All generating units are required by the NEM rules to protection equipment including manual emergency shutdown facilities. Hence all generators are capable of safely reducing output to zero instantaneously (infinite down ramp rate). There may be significant implications in tripping a unit, but these are all 'commercial'. Substantial 'wear and tear' may occur to the generating unit. For example hydro generators when tripped from full load will experience significant generator over speed stresses due to the hydraulic inertia, but must be designed to survive tripping at least on a very infrequent basis. There may be very commercial detriment to owner following generator tripping including substantial period of generator non availability required for inspection and restarting processes.

The AER rule change proposal on face value would require all generators to offer infinite down ramp rates to the market.