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7 October 2010

Mr John Pierce
Chairman
PO Box A2449
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Submitted online

Dear Mr Pierce,

Transmission Frameworks Review – Submission to AEMC's Issues Paper

AEMO appreciates the opportunity to respond to this very important review of the National Electricity Market's transmission sector. Transmission plays a crucial role in the efficient and reliable functioning of the NEM. It enables bulk electricity to reach customers from large, relatively low-cost, distant generation sources as well as lower-cost, inter-connecting regions. This review is critical to the goal of finding the most efficient way of carrying electricity from its source to consumption in a time of uncertainty and change and AEMO is very pleased to be able to play a central role in it.

In the attached submission, we argue that there is potential to realise efficiency gains from establishing a different approach to investing in and operating the existing transmission network. To avoid unnecessary and inefficient duplication, transmission network owners are monopolies that provide monopoly services. Further, inherent in the nature of a network, the owner's investment in and operation of the network, and each participant's conduct within that network, will have a consequence (good and bad) on other connected participants.

Importantly, this review must consider how to better link the provision of transmission services with the efficient operation of the market, in particular, the effects of the transmission framework on generation location and operational incentives. Better integrating the decisions of those operating with market pressures with the transmission sector will ensure that we are in the best position to meet the challenges presented by climate change policies, technological advancements and competition for investment dollars.

AEMO will continue to provide further information to the AEMC in regards to this review to support our arguments.

If you have questions please do not hesitate to contact me on (08) 8201 7371.

Yours sincerely

David Swift

Executive General Manager Corporate Development

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1 Executive summary

The National Electricity Market (NEM) has been in operation for over ten years and during that time there have been many reviews which have resulted in substantial operational improvements. We now better understand how the elements of the market work together effectively. The next step is to better understand and integrate the transmission planning, operations and connections with the markets operation. This will ensure that we are in the best position to meet the challenges presented by climate change policies, technological advancements and competition for investment dollars.

In guiding our thoughts while preparing this submission we have identified a number of principles that we believe need to be incorporated into the market design. The principles are:

- Service Provision – The role of network businesses should be focused on the provision of defined service levels, rather than the provision of assets. The rewards for providing these services should be commensurate with the risks faced in providing these services.
- Network Regulation – Regulation should be on a national, rather than regional, basis. Transmission infrastructure should remain regulated rather than rely fully on market prices for their financial returns. Regulated investments should be subject to 'ex-ante' assessment of their needs and not 'ex-post' reviews.
- Planning arrangements – Planning arrangements must be nationally based, but should be capable of accommodating individual needs of areas or jurisdictions. Planning information should be consistent across the NEM such that any generator or customer has access to the same information irrespective of their location.
- Integration of network planning and economic regulation – The regulatory arrangements need to be designed around the challenges faced in planning transmission network.
- Locational signals for connections – Generators and customers should be exposed to appropriate network related locational signals with either negotiated or legislated rights to receive a defined level of service. Negotiations with TNSPs should be around a defined minimum level set out in legislation and TNSPs should not have unfettered discretion during negotiation processes.
- Market pricing - Generators should face a price signal that reflects the value of their product to the market
- Network congestion – It will always be efficient to have some level of congestion in the NEM. Congestion should therefore be a result of efficient dispatch and not a product of deficiencies in the market.

There are many ways in which these principles can be translated into market design approaches. In this submission we outline potential solutions. The list is not an exhaustive one. Some of these solutions will work in concert with others, while some could be considered transitional solutions to prevailing problems. These are summarised below.

Network Planning

- Service Based Revenue Regulation – linking regulated revenues to network capacity or market outcomes identified during a RIT-T assessment
- Negotiated Transmission Expansions - all future expansions to be determined by the network users through voting rights
- Economic Cost-Benefit Planning – using a probabilistic approach to transmission planning
- National Planner Investment - entrust responsibility for planning and investment decision making into a nationally focused body

Network connection, access and pricing

- Centrally determined access levels – clearly defining the connect standards in the NER for all new generators;
- Negotiated access levels – generators receive an entitlement to the service standard;
- Transmission Pricing – a nationally applied transmission pricing regime that incorporates generation;

Network Operation

- Service Based Revenue Regulation – as above linking regulated revenues to network capacity or market outcomes identified during a RIT-T assessment
- Market Based Service Incentive Scheme - Developing a more powerful market based incentive

Network Congestion

- Access rights regime - provide a defined level of access to generators
- Constrained compensation- provide compensation to those generators who are constrained on or off from the zonal price
- Localised constraint support contracting/constraint support pricing (CSC/CSP) - applying the CSC/CSP scheme in localised pockets of congestion for limited periods. Such schemes in theory remove the incentive for disorderly bidding.
- Smaller Regions – moving to granular regions and therefore settlement prices.
- Generalised CSC/CSP with rights allocated according to presented availability - implement a generalised CSC/CSP arrangement where the CSC (constraint residue) is allocated according to the product of presented availability multiplied by the constraint coefficient.

2 Background

2.1 MCE Terms of Reference

In April 2010 the Ministerial Council on Energy (MCE) wrote to the Australian Energy Market Commission (AEMC) requesting that it conduct a review into the arrangements for the provision and utilisation of electricity transmission services and the implications for the market frameworks governing transmission investment in the NEM (Transmission Frameworks Review).

The MCE has asked that the AEMC focus on four key areas, namely:

- transmission investment – including incentives on timely and efficient service delivery and alignment between the planning process and revenue setting framework;
- network operation – incentives on efficient network operation by transmission businesses;
- network congestion – mechanism for promoting efficient bidding and pricing behaviour;
- network charging, access and connection – improved locational signals for generators and load and the connections process

The AEMC is required to report back to the MCE by 30 November 2011.

2.3 Structure of this submission

This submission is structured to address each of the four key areas identified in the MCE's Terms of Reference. In sections 3 through 6 we highlight the incentives inherent in the current framework, the potential problems skewed incentives yield and the symptoms of those problems. To the extent possible we have quantified the economic efficiency losses arising from the design, particularly those arising from the wholesale market design and its effect on congestion.

Section 7 outlines a number of principles that we believe need to be incorporated into the market design to address the problems and a number of solutions that will achieve these principles. Not all of the solutions need be implemented and some of those identified highlight that there are alternative methods to address the same problem.

2.2 The challenge of this review

This review is, nevertheless, a discussion about the future role of transmission and the manner in which it is, and should be, integrated into the market. Consideration and detailed analysis of historical problems will be unable to shed light on the future challenges facing the NEM.

As has been noted by the AEMC, the NEM has evolved from strongly integrated state owned and planned monopolies to a robust competitive and regulated market. Historically, under the state owned and often integrated utilities, generation and network expansion decisions were taken together and based on overall considerations to meet forecast load growth and grow the network.

Generators now operate and invest in a market environment against a range of competitors. Generation investment decisions are driven by commercial and economic factors such as their expected revenue from the market, their cost of fuel, their expected capital and operating costs, the availability of contracts with counterparties and numerous other factors.

Network investment, on the other hand, is considered to be planned and provided more efficiently by a single service provider rather than two or more parties. That is, it exhibits natural monopoly characteristics. As a result, revenues of the network service providers have been subject to economic regulation

There is general acceptance that climate change policies, in whatever form, changing technologies and international competition for fuels, will change the commercial and economic considerations of generation locational decisions. Some locations which are currently not well supported by the network may become attractive for substantial generation investment.

It is with this background that the AEMC needs to be cognisant of the limited extent to which historical issues can provide guidance on future challenges.

3 Transmission investment

3.1 Network Planning Governance Arrangements

As noted earlier network investment is considered to exhibit natural monopoly characteristics and as a consequence the revenues of the network service providers have been subject to economic regulation.

The NEM is unique in that it enables different forms of governance and institutional arrangements to co-exist in a single market in order to fulfil these planning obligations. This is facilitated through the National Electricity Law (NEL), National Electricity Rules (NER) and state based licensing arrangements and are summarised in Table 1.

Table 1 Summary of Transmission Institutional Arrangements

	Qld	**NSW**	**Vic**	**SA**	**Tas**
Planning Responsibilities	Powerlink	TransGrid Energy Australia	AEMO	ElectraNet / AEMO	TransEnd
Processing Transmission Connections	Powerlink	TransGrid Energy Australia	AEMO	ElectraNet	TransEnd
Service Provider	Powerlink	TransGrid Energy Australia	AEMO	ElectraNet	TransEnd
Asset Owners	Powerlink	TransGrid Energy Australia	SP AusNet TransGrid RTF Origin	ElectraNet	TransEnd
Ownership	State Government	State Government	AEMO (40% industry / 60% government) SP AusNet (51 % Singapore Govt, 49 % listed) TransGrid (state owned) RTF (Origin (100 % listed)	Proprietary Company	State Government

3.2 Planning a transmission system

The development of a transmission network is complex and requires consideration of the long term needs of the competitive energy sector and consumers. It requires the transmission planner to take views as the future actions of customers and generators as well as changes in the economy, technology and policy over a long time horizon. Network planners often have a choice of a very large number of different projects, many of which can be carried out at the same time and are not mutually exclusive. Ideally, finding the optimal path of network development requires consideration of all possible combinations of different projects.

The planning process consists of a number of steps which are important to understand in order to ensure that the design process is appropriate. It will require a planner to forecast demand and supply growth. In the case of load growth it is usually for a ten year period, under high, medium and low economic growth scenarios and for 10%, 50% and 90% probabilities of exceedance (P.O.E) maximum demands. Most investment decisions are driven by reliability concerns and therefore based on the 10% P.O.E.

For supply it will involve consideration of the need for generation based on economic forecasting or government policy that may drive generation entry (e.g. RET).

From this it is possible to identify the likely timeframe that a constraint will emerge and its effect on the network over this period. A number of options to address the constraint are then considered and from these alternatives the most economic solution is determined using appropriate criteria.

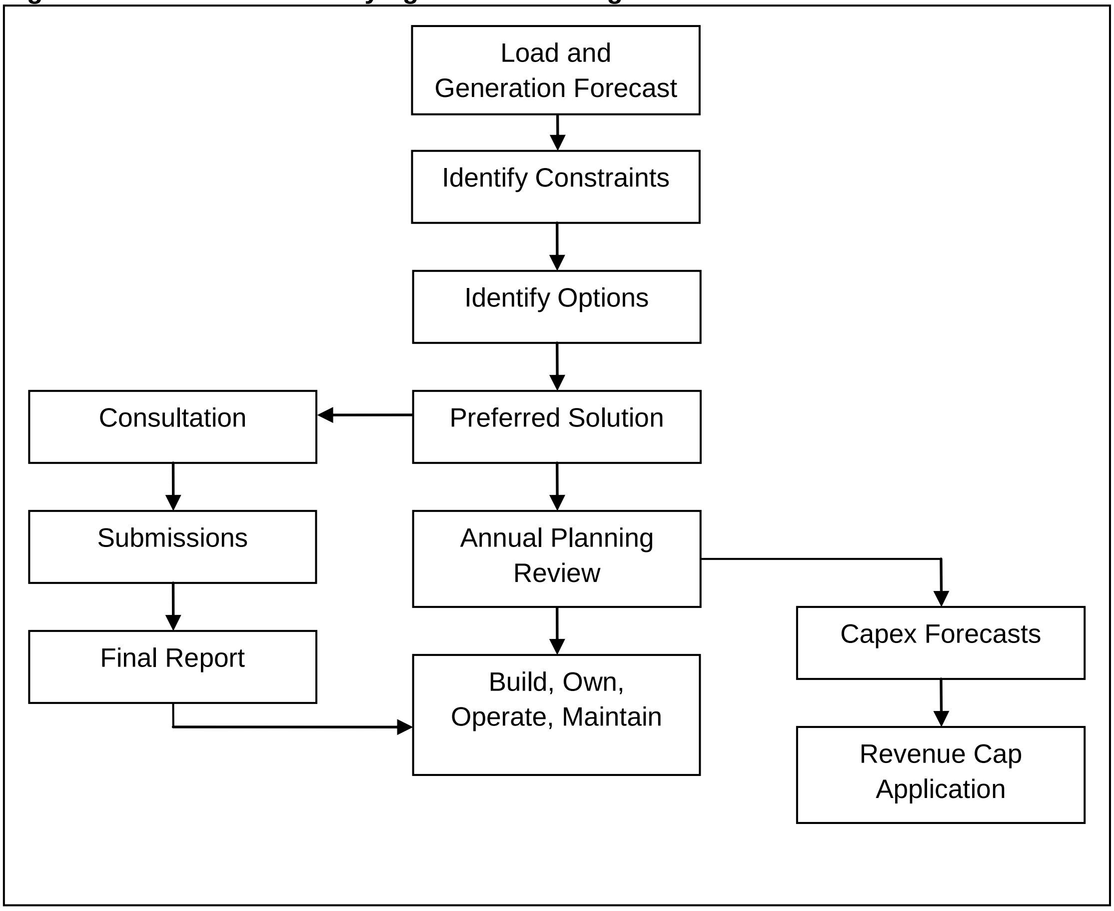
This solution is then consulted on with the market.[1] Following the completion of the consultation process the business would build (or at least contract the building), own, operate and maintain the asset.

For businesses that are responsible for planning and owning assets this information is used in support of its application to the Australian Energy Regulator (AER) for regulated revenue.

Figure 1 provides a diagrammatic representation of a typical planning process.

1 Currently, the consultation occurs either through an annual planning report (for assets less than $25 million) of via a separate consultation process (for assets greater than $25 million).

Figure 1 - Process for identifying and addressing constraints



3.3 Network Planning Standards

Inherent in the planning process is the trigger on when to augment. In most cases, load growth will trigger an obligation to invest if the ratings on transmission plant is exceeded assuming that an element is out of service, otherwise referred to as N-X planning. Applying an N-X type standard in a network is not simple and requires network services providers to make a number of assumptions including, importantly, assumptions about the availability and dispatch of critical generators.. This approach normally requires the chosen augmentation to meet the identified need at the least cost.

In Victoria, augmentation for load is triggered by a probabilistic cost-benefit assessment. This requires assumptions to be made and probabilities to be assigned to network availability. If there is any potential load at risk, or unserved energy, this amount will be multiplied by an independently determined value of energy, known as the Value of Customer Reliability (VCR). An augmentation will proceed where this value exceeds the forecast cost of the project.

In some instances, such as South Australia, this VCR has been used to inform the deterministic standard and has been taken into account in the reliability standards. This requires assumptions to be made many years in advance of the likely augmentations to address an emerging constraint and for a standard to be derived based on longer term planning requirements.

For generation, TNSP planning is largely reactive and in response to the needs of that connecting generator. The framework requires TNSPs and Generators to negotiate in good faith on the size, timing and type of connection to the system with all charges allocated to that new generator. The TNSP is also required to determine what the impact of that generator's connection will have on the quality of supply to other generators. This is discussed further in Section 4.

The planning approach across the NEM is summarised in Table 2.

Table 2 Summary of Planning approaches for load and generation

	Qld	NSW	Vic	SA	Tas
Planning Approach - load	Deterministic (N-X criteria)	Deterministic (N-X criteria)	Probabilistic (based on VCR)	Deterministic (Informed by VCR)	Semi-Hybrid (informed by VCR)
Planning Approach - Generation	Negotiated between TNSP and Generator	Negotiated between TNSP and Generator	Negotiated between TNSP and Generator combined with some probabilistic	Negotiated between TNSP and Generator	Negotiated between TNSP and Generator

3.4 NEM Transmission Planning framework

Given the complexities in transmission planning decisions and the potential effects of poor decision making on the competitive sectors of the market, Chapter 5 of the NER sets out a planning process to drive financially motivated parties to consider and invest for 'the common good'.

The framework consists of five key elements:

- the Annual Planning Report – which sets out forecast growth and generation developments, emerging network constraints and solutions to address those constraints,
- the Regulatory Investment Test for Transmission (RIT-T)– a cost-benefit tool which defines how augmentations benefits and costs are to be calculated as well as the parameters that must be adopted when comparing alternative solutions;
- public consultations and disputes process – this provides for interested parties to comment on network developments and potentially dispute the process and outcomes;
- a last resort planning power – while not an obligation on TNSPs this function resides with the AEMC and is intended to enable a direction to be issued to a TNSP to conduct a RIT-T and public consultation on an identified need.
- National Transmission Planning and Inter-Network Impact assessment – the national transmission planning arrangements are vested in AEMO and provide it with the responsibility for developing a plan for the national transmission grid and to oversee its development. While the Inter-network Impact Assessment is a process to ensure that the implications of investments in one network are taken into account by another.

Each of these is discussed in turn below.

3.4.1 Annual planning reports

The NER requires TNSPs to work together with DNSPs in their region to carry out an annual planning review. This annual planning review involves the collection of information on forecasts loads, generation, market network service providers, demand side developments and proposed network developments. The outcome of the review is the Annual Planning Report (APR) which sets out, amongst other things, a forecast of the future network constraints or inability to meet the network performance requirements set out in schedule 5.1 or relevant jurisdictional legislation over 1, 3 and 5 years. Where constraints are identified the APR must set out the

- the reason for the actual or potential constraint or inability to meet the network performance requirements (if any exists);
- the proposed solution to address the constraint or inability to meet the network performance requirements (if any exists);
- whether the proposed solution will have a material inter-network impact (according to criteria published by the Inter-regional Planning Committee); and
- other reasonable network and non-network options (including interconnector, generation, demand side, and all other network service options).

The APR must also set out the proposed replacement program of a TNSP over the review period.

However, a review of recent APR's shows a trend of limited information disclosure. For example, there is no information provided to potential non-network suppliers of the amount of MW's at risk or the duration over which a planning standard short-fall will be prevalent. This brings into question the value that is being provided by the current provisions for the APR.

3.4.2 Regulatory Investment Test

The RIT-T, previously the Regulatory Test, is a cost-benefit test setting out an economic framework for transmission investment decisions. Historically it consisted of two 'limbs': a reliability limb which was based on a mandated standard requiring assessment on a least cost basis, and a market benefits limb, requiring consideration of the costs and benefits of an option to meet an identified need. It should be noted that the market benefits limb has only be attempted on a few notable occasions outside Victoria. These two limbs have now been combined in the RIT-T however the effect is that it still enables a TNSP to build to meet a mandated reliability standard even if the economics suggest that it would not satisfy a cost-benefit test.

The intention of the RIT-T is to deliver economically justified transmission investment. By its nature there is considerable discretion in the application of the RIT-T. Satisfying the RIT-T does not ensure construction of a project, nor does it prevent construction of an alternative project that may or may not have been identified in the RIT-T assessment.

This raises the question of the role of the RIT-T and how it should best be integrated into the planning and regulatory frameworks.

While some attempts have been made to address this through the Regulatory Investment Test, which now requires consideration of market benefits for all assessments, the reliability driver will continue to drive the investments and prevent more encompassing assessments to be conducted.

3.4.3 Consultations on network augmentations

In the case of augmentations identified as part of the APR process TNSPs must consult using one of two processes[2]. In the case of small augmentations, those with a cost of greater than $5 million but less than $20 million

- A ranking of the alternatives to the proposed augmentation including non-network alternatives (in accordance with the principles contained in the regulatory test); and
- Analysis why the TNSP considers the augmentation satisfies the regulatory test

Small augmentations cannot be disputed.

For large augmentations, those exceeding $20 million, the consultation process is more extensive. The TNSP must produce an "application notice" setting out, amongst other things:

- the reasons for the proposed augmentation (including the actual or potential network constraint or inability to meet the relevant network performance requirements – including all load forecasts and assumptions used);
- all other reasonable network and non-network alternatives to address the identified constraint or inability to meet the network performance requirements;
- a ranking of the proposed new large network asset and all reasonable alternatives, in accordance with the principles contained in the regulatory test; and
- detailed analysis why the TNSP considers the augmentation satisfies the regulatory test.

The TNSP must consider all submissions, meet with interested and prepare a final report setting out its recommendations.

Interested parties may dispute the final recommendation (in particular, whether the right set of alternatives were considered and whether they were ranked correctly, whether the augmentation will have a material inter-network impact and whether the augmentation satisfies the regulatory test). If a dispute arises, the matter goes before a dispute resolution process and a new final report is prepared. A TNSP may also elect to ask the AER to agree that an augmentation satisfies the regulatory test even if the test is not in dispute.

The problem with the current rules definition is that the definition of small and large is based around the size of the augmentation rather than the potential effects on the market, or the service that the augmentation will deliver.

The process relies on interested parties to make informed and non-biased decisions about the outcome of an assessment. On the whole, most parties are incapable of acting as a reasonable check on TNSP investment plans because they do not possess the depth of information or the technical capability to do so. This suggests the consultation regime

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2 Augmentations are defined as works that enhance or enlarge the capability of the network

provides a limited check on the decision process and is therefore of limited benefit in selecting the efficient outcome. .

3.4.5 Last Resort Planning Power

The Last Resort Planning Power (LRPP) empowers the Australian Energy Market Commission (AEMC) to direct one or more Registered Participants to apply the regulatory test in relation to a new transmission network investment aimed at relieving forecast constraints in respect of national transmission flow paths between regional reference nodes (a potential transmission project). The AEMC may also require a Registered Participant to identify such a potential transmission project for the purposes of applying the regulatory test.

It arose out of MCE's concerns that the market arrangements and regulatory processes at the time of implementation may not deliver timely and adequate levels of transmission investment as there are no specific requirements that ensure an inter-regional network investment is fully considered and committed if efficient. This risk is more likely for interregional assets as the potential analysis and investment would require co-ordination between the effected jurisdictional networks. This was considered to have caused delays to the application of the RIT-T for potentially economic projects.

However, as discussed previously, requiring an individual to apply the RIT-T does not guarantee the correct outcome with no obligation on the directed party to develop the proposal if it passed the test. The LRPP has never been exercised and, with the National Transmission Planning Arrangements now in place, the value of the power is questionable.

3.4.6 National Transmission Planning and Inter-Network Impact assessments

AEMO as National Transmission Planner has certain responsibilities over the national transmission grid, including:

- Publishing the National Transmission Network Development Plan (NTNDP);
- Reviewing the grid and providing advice on its development and matters that can affect it; and
- Providing a national strategic perspective for transmission planning and coordination.

The first NTNDP will be published in December 2010. One of the main benefits of the NTNDP will be how it is presented by TNSPs in their revenue cap proposals and how it is taken into account by the AER.

Material Inter-network impact assessments are supposed to ensure that the effects of a transmission augmentation in one region are taken into account in another. It is a self-governing mechanism that requires the TNSP to assess the impact of proposed augmentations on another network.

3.5 Transmission revenue regulation

Notwithstanding the transmission planning framework set out above, the most important planning is undertaken at the time of the revenue resets. Transmission development is therefore driven more by the revenue regulation and incentive framework set out in Chapter 6A of the NER than by the transmission planning regime in Chapter 5. The regime allows for the development of three types of transmission services, prescribed, negotiated and non-regulated transmission services.

Each of these is discussed in turn below.

3.5.1 Prescribed transmission services

Under the prescribed services regime each TNSP is required to submit its forecast revenue requirement for the regulatory period which in some cases can be for a period of 6 to 7 years in advance of when commitment to the expenditure will occur. Most projects which are submitted to the regulator are unlikely to have been assessed against the RIT-T processes or consulted on with the market. Based on the information provided by the TNSP the AER establishes a maximum allowable annual aggregate revenue requirement. ..

Prescribed transmission services are services that are required to:

- Meet jurisdictional legislative requirements or schedule 5.1 or 5.1a;
- Delivers system wide benefits;
- Ensure the integrity of the transmission system – such as planning or operational requirements; or
- Provide connection services between NSPs.

Revenue regulation is intended to meet these prescribed services. However, the practice is that the framework is designed around ensuring that a TNSP has sufficient costs to meet its obligations. This is achieved through a periodic bottom up assessments of the needs of an individual transmission business using the Building Block methodology.

The major components of the building block are:

- Historical capital expenditure reflected in the asset base;
- Future capital expenditure, which considers both proposed augmentations to and replacements of the network
- A risk adjusted rate of return applied to historic and future capital expenditure requirements
- Operating expenditure, which accounts for network operation as well as the support the business costs, such as IT services and staff;
- A symmetric network availability and reliability scheme which places up to 1 per cent of a TNSP’s revenue at risk, and a move towards an asymmetric 2 per cent scheme based on the market impact of transmission congestion measure.

Nevertheless, the building block methodology explicitly focuses on the costs required by individual transmission business and does not enable the TNSP or the regulator to consider how the investments could better be met through investments in another TNSPs network. In doing this, it prevents the Australian Energy Regulator from conducting a more holistic assessment of the needs of the market.

The design of the regime also encourages transmission businesses to invest in transmission assets over potentially more cost effective and efficient non-network alternatives, particularly for grid-support arrangements which are treated as a cost pass through for the TNSPs and TNSPs are not adequately reward for actively pursuing non-network alternatives.

3.5.2 Negotiated services

Negotiated services are largely designed for those services that exceed state based legislative requirements or schedule 5.1 or 5.1a of the NER. Negotiated services are subject to a negotiating framework which is approved by the AER and is designed around the premise that the negotiating party has some countervailing power to the monopoly TNSP. It is largely used for the connection of new generators to the transmission system.

The costs of negotiated services are directly charged to the party requesting those services. This would normally be handled by a contract between the TNSP and the funding party. There are provisions in the NER which allow negotiated services to transfer classifications to prescribed services, however, the process is unclear and, as yet, untested.

There is evidence that the rates of return for providing these services are substantially above the regulated transmission returns available to TNSPs under the NER. This would suggest that TNSPs would be willing to forego construction of prescribed transmission services over prescribed transmission services.

It further reduces the incentives for identification and development of transmission services that provide ‘system wide benefits’.

3.5.3 Non-regulated services

Non regulated services are those services which are similar to negotiated services but for which asset provision is considered to be contestable. They are priced in a similar way to negotiated services however they are not subject to the NER’s negotiating framework. They are typically for services that are some distance away from the shared transmission network.

4. Network Operation

4.1 Capital and operational expenditure incentives

As noted previously the main driver for transmission investment in the NEM is jurisdictional reliability standards. On the whole these standards are typically met through a TNSPs capital expenditure program. It can either augment the network, in accordance with jurisdictional planning standards or economic planning boundaries, or adjust the operating parameters to improve network capability in the short-term.

Under the building block approach a TNSP is rewarded for delivering transmission assets with an ongoing payment stream for the life of the asset. Making short-term decisions which increase the network capability to minimise the impact on the market are not rewarded The approach provides the incentive for the TNSPs to rely less on improving operational practices and focus on delivering network assets. This might add to a culture of rating network elements too conservatively in the first place and to de-rate them if the elements are deemed to be over-burdened.

4.2 Improving operational incentives

There are many operational activities a TNSP can implement to increase short-term system capability but the two most common ways are to set variable, short-term breach asset limits or ratings. The other is to bring back into service an element that is on a scheduled outage.

When determining ratings and limits for its network elements, a TNSP must trade-off the longevity of the network elements (which might be compromised by regularly or frequently exceeding ratings) against efficiency (maximising the element's performance without unduly decreasing its productive life). In addition, a TNSP can bring an element that is out-of-service for maintenance earlier than intended in anticipation of high demand

Under the current regulatory framework TNSPs are exposed to limited market or financial risks imposed by regulation for the way that they operate their network. There is no underlying link between market pricing and TNSPs' operations activities and there are no financial consequences to TNSPs for failing to make available potential spare capacity. Consequently networks do not respond to movements in the market and consequently generators and customers cannot gain the benefit of flexible operational response.

The benefits of temporarily increasing line ratings are twofold. They enable generators to get better access to the regional high price by relaxing a constraint, which as demonstrated in section 6 can be significant, and they defer the next transmission augmentation by meeting what would otherwise be excess peak demand.

In the absence of incentives that drive alternative behaviour, TNSPs will operate conservatively within boundaries designed to maximise the life of those assets. It is open for TNSPs to alter their limit equations in response to changes in system configuration and increase system capability at critical times. It is also open for them to install low cost schemes that allow the existing network to better cope with changing generation and load patterns. However, they need to be rewarded for their actions.

5 Network charging, access and connection

5.1 Connections regime

The NEM's connection regime is designed around the bilateral negotiation of fair and reasonable arrangements between a connecting party and a TNSP. The NER contains a number of processes that a connection applicant and NSP must follow when a new connection, or modification of an existing connection, is sought.

However, a negotiation with a TNSP in any jurisdiction is a negotiation with a monopoly provider of a service. Connection applicants have no alternative service provider to negotiate with to enable its connection. The standards that a new connection must meet are invariably around the performance standards of a new generator or a new load. These standards are set out in schedules 5.2 and 5.3. There are, however, no commensurate standards imposed on a TNSP to give effect to that connection. Neither with respect to timing, which is subject to negotiation between the parties, nor the costs of facilitating the connection, which is invariably charged back to the connecting party.

5.2 Augmentations to facilitate new connections

The size, scope, timing and location of a new connection will determine the extent to which a new connection will require augmentation to the shared transmission network. The augmentation works required for efficient connection will often not only include the interface work to physically give effect to the connection but the more challenging augmentation of the shared network to manage subsequent congestion. The latter types of augmentations are not addressed appropriately in the current framework, and are sufficiently substantial to confer consequential benefits on other network users, not just to the funding connecting party.

However, there is no express provision in the NER which compels a TNSP to augment the network to facilitate a new connection. As a result, all network augmentations required to enable a connection to the transmission network has been paid for by the Connecting party.

It is appropriate for a connection applicant to face locational investment signals however, it is questionable whether the bilateral approach to negotiations will result in an efficient locational signal being imposed on any particular party.

It is also important that all prospective connections are treated equitably as far as possible. In this regard, questions arise as to whether it is appropriate for a new connection applicant to bear all augmentation costs, especially if that connection is the "straw that breaks the camel's back".

For example, in Victoria, the connection of multiple generators in the South-West Corner of the State are likely to impose significant augmentation costs on connecting parties over time. The current capacity of those transmission lines is around 3,000 MW with over 4,500 MW of connection enquiries on that line. While not all of those connection enquiries will proceed to full scale development in the time horizon outlined in their connection enquiry, it raises the question of what costs AEMO, as the Victorian Transmission Planner should impose on each connecting party, particularly as the capacity of the network reaches its capability.

These issues will continue to become more problematic with the increasing number of large-scale wind farm developments and gas turbine connections in areas that are not traditionally well served by the transmission network.

5.3 Coordinated Connections

As noted, the connections process involves bilateral rather than multi lateral negotiations. As a result, the current connections process adequately deals with sequential connection processes and was designed with a sequential process in mind. Under this process subsequent connecting parties are able to negotiate with the TNSP for use of the first connection party's assets.

This has the potential to lead to inefficient investments because connection applicants will seek to minimise costs by specifying "right sized" connection assets, whereas efficiency gains can be realised if the connection assets were "sized-up" to accommodate other connection proponents. Consequently, it can be beneficial to coordinate connection applications and even build in capability for unrealised or unexpressed generation and connection applications and accommodate them concurrently.

The AEMC recognised in the Climate Change review the challenges posed by multiple connections to a similar point of the network in a similar timeframe. Its solution, Scale Efficient Network Extensions (SENE) is an attempt to address some of the challenges of ensuring appropriate coordination. However, it suffers from an efficiency compromise in that the justification for a SENE is based on an estimate by the TNSP of being able to recover the costs of the project rather than being based on the RIT-T. Another shortcoming is that a SENE introduces a new asset classification into an already complicated transmission classification framework.

AEMO's Hubs regime is also an attempt to utilise the economies of scale arising from transmission assets. However, it too has limitations in that it only addresses the connection at the point on the shared transmission network and is less able to deal with efficient 'spur' lines to the transmission grid. The potential efficiency gains of the Hub concept[3] also suffers from lack of a clear right to compel a generator to connect to the Hub should it wish to connect elsewhere.

Lastly, the NER contains rules that constrain TNSPs from taking a coordinated approach. The main constraint is contained in the information disclosure provisions which prevent TNSPs from revealing connection information such as size, type, when, where or how the proponent is proposing to connect. Although information on land and easement acquisition is generally available from the relevant government departments[4] and when a generator becomes a committed project, it is too late by this time for other potential connection

3 The efficiency gains arise from aggregating known and potential future generation at a connection point and building the "right sized" asset to deliver the generation to the network.

4 Where environmental impact statements and analyses of a generation project are required under legislation, information relating to the size, type and specification can often be obtain through environmental planning channels.

applicants to become involved in concurrent connection negotiations at the common connection point.

5.4 Service classification and reclassification

When negotiating a connection, TNSP and connection applicants must agree a connection point. This point becomes the dividing line between the connection assets and the shared network. From an efficiency point of view, if there is an under-utilised connection asset, for example an over-sized transmission line of considerable length, it is inefficient to prohibit a third party access to that piece of equipment even if it were classified as a connection asset.

Over time the utilisation of the transmission service may change and there will be a need to classify negotiated services as prescribed services. It is important to note that such a re-classification effectively transfers some of the costs of that service away from the initial investor and imposes it on network customers.

If the initial augmentation investment is treated as providing a negotiated service on the basis that it did not initially yield social benefits (but presumably was privately optimal from the perspective of the investor), and where the subsequent connection then results in the original investment yielding social benefits, we believe that the investment should be re-classified as a prescribed transmission service. On the other hand, if the investment still does not pass the RIT-T following the connection of the second generator, it makes sense to impose a form of cost sharing between the first and second generators.

However, the practicalities of re-running the RIT-T under this approach involve the resolution of numerous issues:

- treatment of sunk costs – sunk costs incurred in the original investment cannot simply be ignored when the RIT-T is re-run at a later stage. If sunk costs were ignored, any subsequent RIT-T would prove trivial, since the cost of the ‘augmentation’ would effectively be nil while the benefits deriving from the new connection would presumably be positive. Rather, it would be necessary to somehow include the sunk costs of the augmentation; and
- assumptions regarding the future life of original assets – if the RIT-T is re-run, appropriate assumptions regarding the time stream of future benefits derived from the original asset must be made; and
- dispute process – one of the main risks of running a RIT-T is the risk of a dispute. The process for the reclassification of assets would need to consider whether a more limited dispute process is required.

5.5 Access Rights

The shared transmission network is a common carriage network in that no participant has any preferential right of access to, through or across the network in any circumstance, including at times of constraint (whether system normal or otherwise). This means that in a dynamically changing transmission network the connection of new generators causes existing generators to face constraints that they had not faced before such connection. An important set of circumstances that causes an existing generation unit to be constrained off occurs when a new entrant locates a generation unit near an existing generation unit and there is insufficient transmission capacity to allow each unit to operate at the output level on its offer curve consistent with the regional price in the NEM.

The generator compensation provisions, contained in clause 5.4A of the NER, contemplate some form of compensation to be negotiated. However, the compensation scheme is predicated on compensation being paid between generators, rather than from the TNSP to the generator. As a result, no compensation provisions have yet been agreed. To increase the likelihood of a compensation scheme being accepted by both connection applicants and TNSPs alike, the NER can be altered to introduce a framework for a multi-lateral negotiation process that allows all connecting parties to participate in the scheme but not be compelled to enter it.

The inability for new generators to negotiate such rights has the potential to deter them entering into the market or potentially inefficiently altering the position at which they locate on the network. This will increase the risks to the generators as well as entry costs. It is also likely to subdue existing generator's expansion plans if they have no certainty about their entitlements for the additional capacity they are seeking to provide to the market.

5.6 Transmission Pricing

Currently, all of the transmission costs are allocated to customers, with no costs allocated to generators. For customers, the locational component is supposed to reflect an efficient signal based on their location. As such, half the sunk cost of historical assets is meant to be a proxy to the cost of maintaining services to customers into the future. Because of the nominal nature of the split, the Rules also provide for an alternative method of determining the split between the locational and adjusted non-locational TUOS prices based on a reasonable estimate of future network utilisation that intends to provide more efficient location signals to existing and intending network users. This is intended to further refine the efficient allocation of transmission costs to individual connection points.

The lack of a locational signal to generators through transmission pricing means that the cost of connection and marginal loss factors are the only drivers on location from a network point of view. Efficient outcomes in terms of generation are important as we move into a period of greater change in the mix and location of generation and require greater consideration if we link new connection to efficient augmentation of the broader shared network.

5.7 Connection requirements differ by jurisdiction

Within a broad framework adopted, the NER lacks clear direction on connection requirements, preferring instead to leave TNSPs to develop their own standards in response to local needs and jurisdictional requirements. This results in local variations that may be of benefit to network users but it creates uncertainty for investors who wish to connect. It was noted by ERIG that "numerous state derogations from the national rules and regulations covering energy exist, creating a different legal and regulatory framework for the energy market in each state. These differences are compounded by different state regulatory arrangements, different licensing regimes, guidelines, codes of practice and other regulatory requirements".[5] These inconsistencies and differences between the jurisdictions create uncertainty for generators who must decide which region to connect to. It also makes it difficult for organisations that engage in the business of connecting in many jurisdictions to cost effectively do so because they face different requirements in each jurisdiction.

5 "Energy Reform, The way forward for Australia, A report to the Council of Australian Governments by the Energy Reform Implementation Group" January 2007, p. 46.

6 Network Congestion

The previous three sections detailed some of the shortcomings of the transmission planning, connection and operation framework and the inefficiencies that arise from the current design. However, this review must consider how the transmission framework interacts with the wholesale market and the deficiencies that arise there namely, conceptual mispricing, dispatch risk and 'disorderly bidding'. In a number of cases, the incentives on generators through the market arrangements can be to inefficiently use the network and increase congestion rather than to maximise the use of the available network capacity.

Our analysis suggests that the NEM is not managing dispatch congestion efficiently and that improvements to the current design are required. This evidence is contained in the appendices to this submission with:

- Selected incident analysis, where unfolding events over several hours are described in some detail to demonstrate how these inefficient outcomes materialise in practice, and
- Trend analysis, where some important measures of market performance are showing material shortcomings in performance that are deteriorating over time.

The efficient management of congestion not only impacts on generators in the operational timeframe, but also affects their financial contracting in the medium term and longer term investment.

6.1 The mechanisms by which inefficient dispatch eventuates

Notwithstanding improvements elsewhere in the transmission regime there will always remain a residual quantity of congestion between and within states. This will be driven by the need to optimise investment in relatively high cost transmission capacity. A good market design will resolve that congestion with the smallest possible detriment to efficiency, trading risk and customer price. Good design would also provide opportunities for parties to manage the commercial risk of congestion.

The analyses presented however demonstrate that the NEM's design can in fact greatly amplify the severity of relatively minor network congestion incidents.

The key features of the NEM's design which are relevant to these outcomes are:

- The dispatch risk suffered by generators when affected by congestion. They will suffer loss of market volume compared to their capacity. ;
- The incentive upon generators to generate is created by the regional settlement mechanism. This often means that a generator who is in a location of surplus energy whilst its regional reference node is in deficit, has a marginal incentive to generate opposite to its true circumstance; and
- Generators have a relatively unfettered ability to bid their marginal offer price and technical parameters.

The result is that where intra-regional congestion exists, generators do not present a marginal offer relevant to costs. Instead it will bid such that it optimises its own dispatch with respect to the regional reference price.

The failure of the auction process in those circumstances to discover costs in turn undermines the primary assumption in market dispatch, that the value of trade can be optimised by reference to the offers from generators.

As the examples show, small incidents of congestion that might have been expected to only impact a few generators by a few tens of MW, trigger a cascade of rebidding of many thousands of MW. This in turn provokes more dramatic impacts than might be expected from a market design that did not have the combination of features listed above.

6.2 Characteristics of "disorderly bidding"

This term was coined in the AEMC's Congestion Management Review to describe generator behaviour to maximise income when its settlement income is inconsistent with the conditions at the generator's connection point. It is a legal and rational individual response to the incentives created by the market design and the term is used without pejorative intent.

The following describe how generators disorderly bid in practice.

6.2.1 Market Floor price bidding

Generators avoid being constrained off by pricing capacity at the market floor price, which is -$1,000/MWh. The market allows negative prices to enable generators who intend to remain available at a later stage to continue generating in the short-term.

Whilst pricing bands are locked in from the day prior, rebidding of price is achieved by moving capacity from one band to another, which is permitted at any time. All large NEM generators maintain their first band at the market floor price (adjusted for the marginal loss factor) so that rebidding can access this price. Other negative prices are rare.

This tactic appears solely employed to reduce the impact of being constrained off. As the network's capacity is limited, when one generator employs it, others are consequentially more constrained and retaliate in kind. The ultimate result is often no individual gains, and less efficient overall dispatch.

If two such generators have equal impact in a constraint equation, then each will be dispatched to an equal fraction of its bid availability. This takes no account of actual marginal costs, and can result in gas turbines upstream of congestion starting.

Where a regulated interconnector and generators are affected by congestion, the interconnector is unable to retaliate. Thus in practice interconnectors receive lower priority in dispatch. Market Network Service Providers can however also bid at the market floor price. Appendix C will show it is possible for Tasmanian generation to be effectively presented at twice the market floor price.

Such incidents show the complexity of possibilities resulting from disorderly bidding. The outcomes are unlikely to provide stability and confidence for participants. It is difficult to envisage that, when planning or operating networks, a TNSP could anticipate such behaviours.

6.2.2 Market price cap bidding and reduced availability

Where generators are at risk of being constrained-on, they may take the course of bidding at high price levels to discourage dispatch, or more commonly, reducing availability below their true capability. This often occurs where a gas-turbine whose fuel cost exceeds the regional price receives a start signal. Where system insecurity would otherwise occur, a compensated AEMO direction usually results.

As will be shown in Appendix B, which considers the events of 7 December 2009, there are also situations where this kind of rebidding does not provoke insecurity, and therefore AEMO does not intervene, but causes inefficient dispatch as other generators or interconnectors are as a result constrained to a greater extent.

In that case, two generators with large coefficients in the constraint equation supplied bids that inhibited their being constrained. As a result the dispatch engine was forced to seek dispatchable variables with smaller coefficients, which had to be constrained several fold more. Interconnectors were severely constrained. In turn, this reduced the total supply to customers which raised price.

AEMO performed a detailed hypothetical recreation of the event which held the network constraint in place, but removed the rebidding of generators in response to it. The dispatch engine was able to find a far more optimal dispatch result, and the constraint had only a minor constraining effect on a few generators. More supply was available, and instead of prices approaching the market price cap, prices were around $100/MWh. Total customer settlement was at least $300m lower.

This result appears to suggest that substantial opportunities exist for improving dispatch inefficiency and reducing wealth transfers by discouraging this form of rebidding[6].

The particular constraint and similar bidding behaviours and high prices recurred on at least 7 more days in the following 8 months. These days were not re-run through the simulation, but graphs demonstrating the effects have been included in the appendix.

6.3 Ramp-rate limitations

Generators must enter a maximum Rate of Change (ROC) up and down which limits the amount a unit may be moved from one dispatch interval to the next. As this is considered to be a technical limit, it is given the highest priority of all constraints in the dispatch process.

To slow the impact of being constrained-off, generators often reduce their ROC. Until recently there were no rules relating to the use of this bidding term, and there were some incidents where very low ROCs threatened security. Recently rules were implemented that forced all large generators to maintain at least 3MW/min for non-technical issues. Since that time the bidding of 3MW/min ROCs has become common for constrained generators. This is still a very slow ROC for some large generators.

An example of this is evident from the analysis of the events of 21 and 22 April 2010. This incident demonstrates a generator behind a constraint increasing its output prior to the

[6] AEMO's re-run used its sophisticated combined dispatch and network simulation tool.

invocation of a constraint and then applying a 3MW/min ROC to delay being constrained off. The excess generation resulted in counter-price flows on the adjacent interconnector. Although AEMO attempted to stop these through its clamping procedure, this was made ineffectual by the generator's low ROC and $19m of negative residue accumulated which, as of July 2010, is recovered from the TNSP in the adjacent region. Further detail of this can be found in Appendix D.

6.4 The impacts of this inefficient dispatch

6.41 Inefficient use of plant

The market design intends to maximise the value of trade through minimising dispatch costs. It is expected that the impact of competition gives generators an incentive to reveal true costs to the dispatch engine through their bids. Clearly where the vast majority of generation in a large region is being bid at the market floor price (see Appendix B) then the process of optimisation has broken down.

Examples of this inefficiency are:

- Higher fuel cost plant operating whilst lower fuel cost plant is constrained from full output; and
- Gas turbine start cost.

6.4.2 Trading risks and competition

All customer load is settled at the regional reference price. A key enabler to competition is the ability for multiple generators to be able to be able to trade with retailers without basis risk. Within a large region this can occur to some extent because generators and customers are settled on the same price adjusted for predictable loss factors, although generators can be constrained off in unpredictable ways.

Where trading occurs between a generator in one region and a customer in another then the basis risk needs to be managed. For this the market relies upon the Settlement Residue Auction Instrument (SRA) that generates settlement residue that is intended to correlate to the basis risk.

However the SRA's performance, or "firmness" as discussed in Appendix A, is determined by the performance of the interconnector in the physical dispatch. As seen in Appendix B, D and E, real events result in the interconnector having low physical performance. Upgrading network assets at the regional boundary would not improve performance in these instances, because the actual constraints, amplified by disorderly bidding, were remote from the boundary.

Appendix A shows that on some interconnectors the performance of the SRA instrument to manage basis risk has been poor throughout the last 4 years. On some interconnectors it produced a reasonably stable level of hedge protection until 2009/10, albeit at a level well below the nominal capacity of the interconnector. During the summer of 2009/10, all interconnectors performed poorly and presumably inter-regional traders suffered financially.

The long-term impact of such performance is likely to be an unwillingness to trade inter-regionally and a reduction of competition within the NEM.

6.5 Inefficient customer pricing

The events described in the appendices include prices inconsistent with conditions. In some cases, such as Appendix E, this high price was the consequence of the constraint itself and not the rebidding: it occurred in the dispatch interval prior to the disorderly bidding. However in Appendix B, the re-run process showed that the high prices were actually a consequence of the disorderly bidding, and not of the constraint, which alone would have had minor impact. For that event, the re-run showed that absent the disorderly bidding, but inclusive of the constraint itself, the gross customer settlement total would have been at least $300m lower.

The disorderly bidding can also lead to inconsistent low customer prices. The bidding in Appendix C and E events resulted in negative prices in regions remote from the constraint.

6.6 Power System Security

AEMO creates network constraints with the intent of limiting the secure operating envelope. If the constraints do not violate and generators comply with their dispatch targets, then the dispatch engine should maintain the system in a secure pre-contingent state.

Generator technical constraints, such as ramp-rates and availability, have a higher priority than network constraints. This is because it is presumed to be physically impossible to operate outside generator limits so this approach models the real system.

However generators may adjust them for economic purposes, such as to avoid being constrained-off. If this causes network constraints to violate, the system will become insecure. Such an event occurred in October 2005, resulting in the AER successfully proposing a series of rules limiting the extent to which these parameters may be adjusted for non-physical reasons.[7]

Under that rule, large generators must now enter ROCs of at least 3MW/minute for economic purposes, which is nevertheless a very slow rate for some large generators. The appendices show no evidence of the power system becoming technically insecure due to low ROCs, however, as shown in Appendix B and D, it has extended the duration of inefficient dispatch and negative residues.

Another power system security concern relates to the sudden change in power system conditions when groups of generators simultaneously rebid following the application of a constraint. The incident of 10 August 2010 (App E) demonstrates how quickly a large volume of rebidding can occur when a constraint is applied unexpectedly. The rebidding in turn causes a rapid shift in power system conditions. In this case flows into a region were reversed by 2,550MW in about 30 minutes, with the majority in the first ten minutes. The rebidding also caused frequency disturbances, although the system remained technically secure.

[7] See AER rule change proposal: http://www.aemc.gov.au/Media/docs/Rule%20Change%20Proposal%20-%20AER-43e659d8-8c5f-461f-8201-777e231db023-0.pdf

Such rapid change moves the power system away from its most secure operating condition and increases its inherent vulnerability to contingencies. Even if the system remains secure in the strict technical sense, simultaneous sudden and large responses by a number of participants must increase the chance of multiple contingency events occurring during or immediately after such pricing events. The key question is whether it is acceptable for power system security to be allowed to become less secure, albeit not technically insecure, purely as a result of such rebidding.

6.7 The interaction between the planning regime and generator investment

Network congestion imposes significant risks on the dispatch of generators and the prospective output of new generators. As highlighted above, the inability for new and existing generators to negotiate access rights has the potential to deter or defer efficient expansions. The current arrangements therefore need to ensure that they link generator investment and bidding incentives with the transmission planning regime. Many of these challenges require a combination of changes to the market design, transmission planning, network connection and network operation framework. However, before implementing any, there are challenges that need to be better understood.

With respect to a market benefits analysis, a transmission planner must develop a view of the dispatch benefits that occur through the relief of a particular congestion. They will need to model a hypothetical dispatch environment. To do this, a view will be taken on the bidding of generators. For the most part this would presume generators bidding according to costs, and perhaps with some Nash-Cournot bidding to account for regional market power. It would seem impossible for a planner to predict the chaotic sequences of “disorderly bidding” with its cascading rebids at market floor prices and altered technical parameters. Thus these analyses will tend to value small pockets of congestion at a low level, unaware that the market design results in the amplification of the congestion.

With respect to customer reliability criteria, this takes no account of disorderly bidding. It will presume that the generation pattern is optimised from the point of view of supplying customers’ peak demand. This is accurate, because when the system is at the verge of shortfall the dispatch engine’s constraint priorities or even AEMO intervention will prevail over generator bidding to maintain reliability.

The demonstrated events show that inefficient outcomes can occur when there is more than adequate total supply to customers. The particular constraints responsible bear little direct threat to customer reliability and therefore a reliability criterion cannot address them.

7 Solutions to the framework problem

7.1 Framework principles

To guide the development of the optimal transmission framework we have identified a number of principles that need to be incorporated into the market design. The principles are:

- Service Provision – The role of network businesses should be focused on the provision of defined service levels, rather than the provision of assets. The rewards for providing these services should be commensurate with the risks faced in providing these services.
- Network Regulation – Regulation should be on a national, rather than regional, basis. Transmission infrastructure should remain regulated rather than rely fully on market prices for their financial returns. Regulated investments should be subject to 'ex-ante' assessment of their needs and not 'ex-post' reviews.
- Planning arrangements – Planning arrangements must be nationally based, but should be capable of accommodating individual needs of areas or jurisdictions. Planning information should be consistent across the NEM such that any generator or customer has access to the same information irrespective of their location.
- Integration of network planning and economic regulation – The regulatory arrangements need to be designed around the challenges faced in planning transmission network.
- Locational signals for connections – Generators and customers should be exposed to appropriate network related locational signals with either negotiated or legislated rights to receive a defined level of service. Negotiations with TNSPs should be around a defined minimum level set out in legislation and TNSPs should not have unfettered discretion during negotiation processes.
- Market pricing - Generators should face a price signal that reflects the value of their product to the market.
- Network congestion – It will always be efficient to have some level of congestion in the NEM. This does not mean that all current and forecast congestion should be 'built out' unless there is an economic case for doing so.

There are many ways in which these principles can be translated into market design approaches. However, to operate effectively they need to be integrated into an appropriate framework. We have outlined some potential solutions below.

7.2 Network Planning

7.2.1 Service Based Revenue Regulation

Given the deficiencies with the building block approach it can be removed in favour of allocating revenues where defined service levels are met. The service levels will be determined at the time of a RIT-T assessment and linked to guaranteeing a specified level of network capacity and capability under system normal and outage conditions. Alternatively, it could be linked to delivering services at a time most valued by the market.

Revenue regulation would also need to be undertaken on a national basis with the regulator considering all revenue needs at the same point in time. This would enable the regulator to make trade-offs between investments in different networks.

7.2.2 Negotiation Based Transmission Expansions

An alternative model, and one that is present to a degree in the current arrangements, is for all future expansions to be determined by the network users through voting rights. This model, currently applied to major expansions in Argentina, requires all of these projects to be subject to competitive tender with the users in the affected area, who ultimately pay for the expansion, determining what and how the expansion is constructed. All existing transmission infrastructure would continue to be regulated under the building block approach however it would exclude any, or at least major, augmentations going forward.

7.2.3 Economic Cost Benefit planning

To ensure that all decisions are economic a national cost-benefit planning approach could be instituted. This approach would incorporate reliability methods to deal with the uncertainty in future power system conditions and facilitate the most efficient solution to be implemented. The approach would involve the development of a range of market scenarios to allow for the uncertainty in customer demand profile and generation dispatch patterns.

Each scenario would then be assessed to determine the system actions, including the loss of supply to customers, that would occur to ensure NEM operational obligations are complied with. This assessment involves studies examining both normal and contingency conditions. The contingency studies may allow for assessments up to the 2nd, 3rd or even higher outage event.

The benefits of any investment option are determined from the difference between the system actions required following the investment option and the actions required without any investment. Probabilities are assigned to the market scenarios and the contingency condition such that the most-likely benefits resulting from any investment option are determined. Investments would then be made on the basis of those investments.

7.2.3.2 National Planner and Investor

The regional nature of the market inhibits the national consideration of options to address regional needs. The optimal solution would be to entrust responsibility for planning and investment decision making into a nationally focused body vested with the responsibility to address emerging network constraints. This model would still involve separate asset owners and operators providing services, either directly to customers or to the planner who would on-provide these services to the market. Private investment could still be accommodated under this model.

7.3 Network connection, access and pricing

7.3.1 Centrally determined access levels

New entrants would be charged for network augmentations to ensure that network services meet, or continue to meet the service standards. Investment decisions would effectively be driven by the connecting party but against a generic access standard set out in the NER. Depending upon the form of the access standard, the standard may need to be changed to recognise the additional demands on the network arising from the connection of a new generator. If the standards were measured in terms of congestion levels, that may not be required.

7.3.2 Negotiated access levels

This would involve a bilateral negotiation of a service standard with any new connection. If the desired service standard exceeds existing network capability, the connecting party would need to pay for the augmentation, but would receive an entitlement to the service standard in return. The service standard might differ in some respects from that negotiated with others at the same connection point. Economies of scale would need to be pursued where appropriate, by extending the network more than is required by the new entrant. The new entrant would pay only for their portion of the capability.

7.3.3 Transmission Pricing

A national transmission pricing regime, established in the NER or administered by a single body, would ensure a nationally consistent approach. The pricing regime would also need to consider the implications of generators connection on a network. The planning regime would need to link better to the pricing regime such that investment decisions to alleviate congestion or which are predicated on an efficient dispatch pattern are transparent to current and new generators to enable the generator to be aware of the effects of its connection on the network.

7.4 Network Operation

7.4.1 Service based regulation

As noted earlier a service based regulatory approach would ensure consistent incentives apply to capital and operating expenditure.

7.4.3 Market Based Service Incentive Scheme Service targets performance incentives scheme

Developing a more powerful market based incentive could be achieved with the AER's proposed market impact parameters. However, the scheme would also need to be a symmetric scheme.

7.5 Network Congestion

7.5.1 Access rights regime

There are a number of proposals to provide a defined level of access to generators. If these are designed well, they should remove the incentive for disorderly rebidding and encourage the presentation of true costs to the dispatch engine. Any proposal in this regard should be considered with respect to their effectiveness of achieving these objectives. If it does achieve them, this should be included as an important benefit of such a proposal.

7.5.2 Direct regulatory controls on rebidding

As the concerns listed in section 4 result from generator bids rather than network performance, it is worth considering whether the bids that cause the problem can be prohibited. This is the form of control that was promoted with some success by the AER rule change upon the bidding of technical parameters[8].However such controls must be introduced cautiously, as they may be ineffectual, subverted or they may unintentionally restrict efficient behaviours.

Market design changes that align incentives with efficient dispatch are likely to be more effective and should be the preferred approach. However if the implementation of such design changes is prolonged, direct controls could be an appropriate transitional action.

7.5.3 Constrained compensation

Many electricity markets that employ zonal pricing also provide compensation to those generators who are constrained on or off from the zonal price. The compensation is paid according to the difference between the zonal price and the marginal cost of the generator. This marginal cost assessment usually requires some degree of regulatory audit.

If implemented well, e.g. there is no ability to misstate true costs, this can remove the benefits of bidding away from costs and thereby resolve the disorderly bidding problem.

One of the key challenges of such a scheme is the funding of the compensation. Presumably it would be funded by a broad levy on customers. Whilst this creates an additional cost to customers, it should be weighed against the benefits of avoiding high price events such as those described in Appendix B.

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[8] http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Ramp-Rates-Market-Ancillary-Service-Offers-and-Dispatch-Inflexibility.html

7.5.4 Localised constraint support contracting/constraint support pricing (CSC/CSP)

The AEMC's review of Market Frameworks in light of Climate Change Policy considered the application of the CSC/CSP scheme in localised pockets of congestion for limited periods. Such schemes in theory remove the incentive for disorderly bidding.

However the constraint events described in the Appendices could probably not be resolved by such an approach, as:

- They emerged with none or very little warning, with some of them being caused by network outages, and so it would not be possible to design and implement a specific CSC/CSP scheme in time;
- In cases such as Appendix B, the constraint affects numerous generators, so the narrowest implementation would still apply to the majority of a region.

7.5.5 Smaller Regions

In theory the incentive to disorderly bid is reduces with more granular settlement prices and so it is worth considering whether smaller regions would resolve the concerns. This is the case for the incident in Appendix D, which would not have occurred had the abolished snowy regional boundary been in place.

However for the other cases, more granular and/or frequently changing regional boundaries are unlikely to assist because:

- The congestion is unpredictable and transitory, so new regions cannot be implemented in time; and
- In events such as those in Appendix B, looped constraints are critical. To achieve accurate pricing would require a region for every different coefficient, i.e. individual generators.

7.5.6 Generalised CSC/CSP with rights allocated according to presented availability

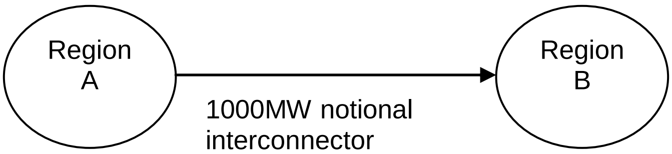
AEMO is aware of participant proposals to implement a generalised CSC/CSP arrangement where the CSC (constraint residue) is allocated according to the product of presented availability multiplied by the constraint coefficient. This appears, at a high level, to remove the incentive to disorderly bid and therefore should provide a more efficient dispatch. It requires more detailed analysis to confirm this view, and AEMO recommends the AEMC consider the costs and benefits of the proposal in detail. AEMO could assist by estimating its own costs to implement the settlement adjustments.

An allocation of residue rights according to availability presented to dispatch may however not provide the level of long-term predictability or locational signals to new generation that the AEMC is exploring elsewhere in the review. Like direct rebidding controls it could be considered as a useful transitional measure.

APPENDIX A: SRA FIRMNESS

1. Background to Settlement Residue Instrument (SRA)[1]

AEMO auctions quarterly the SRA instrument that can be used to manage price basis risk between regions. In a simplistic model of the NEM, purchasing SRA units should enable a generator in one region to sell a hedge to a retailer in another.



The SRA unit pays a $1/1000^{th}$ share of the settlement residue accumulating from flows across the interconnector. The residue each hour approximates:

(Region B Price – Region A Price)*Flow (net of losses)/1000

The promotion of national trade is one of the key objectives of the NEM. In turn, this is critically dependent upon the performance of the SRA unit.

SRA performance deteriorates when the residue does not correlate in the manner expected with the price difference. A participant purchasing a 100MW unit to remove the basis risk from a 100MW inter-regional hedge position, will find itself partially exposed to the price difference if the residue is smaller than expected during a large price difference. This occurs when the flow on the notional interconnector is smaller than expected. Causes of this include:

- The transmission capacity being lower than nominal, e.g. during network outages;
- The constrained dispatch solution results in a flow on the directional interconnector less than nominal, e.g. where the interconnector and a generator in region B compete for access to a constraint in Region B; and
- Reversals in system flows within a half-hour.

2. Counter-price flows

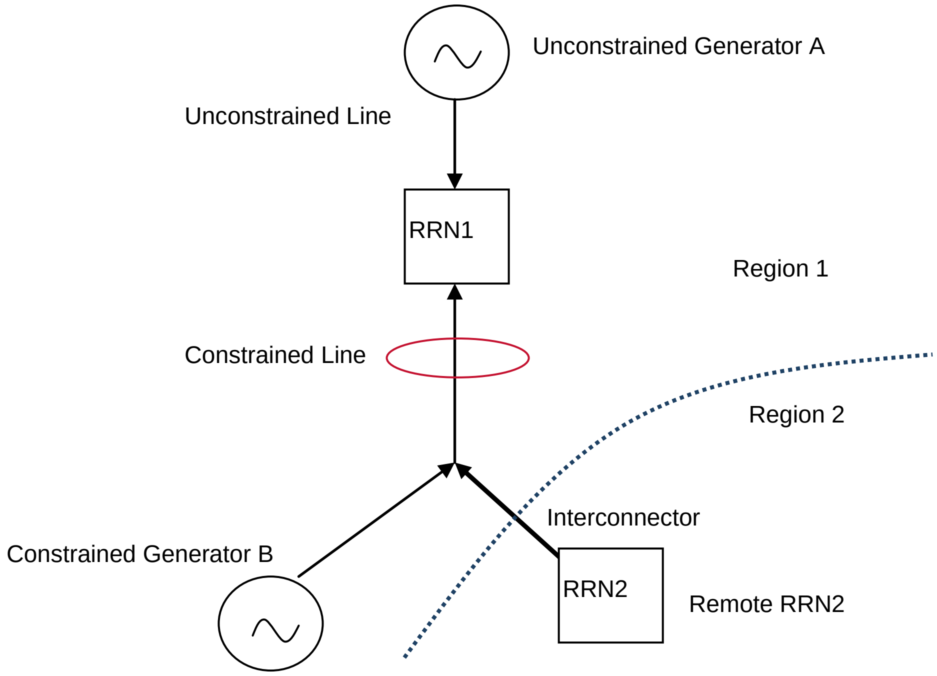
The interaction of constraints within a region can lead to counter-price flows. Consider the diagram below: Generator B and the interconnector compete for access to the constrained line. Generator B's settlement will be based on the price in Region 1.

If Generator B presents its capacity at the market floor price, then the dispatch engine will see this source as lower cost than generators in Region 2 and will dispatch Generator B in preference. As a result the interconnector will flow at less than nominal capacity into Region 1, and can even reverse towards Region 2, even though the price in this region is lower than Region 1.

Counter-price flows cause a market settlement deficit, as all generators and customers will be settled with reference to their regional prices. Effectively AEMO has purchased power at a high price in Region 1 and sold at a low price into Region 2.

[1] Detailed information about the SRA can be found at http://www.aemo.com.au/electricityops/sra.html

Diagram demonstrating intra-regional constraints and regional settlement



AEMO attempts to "clamp" these counter price flows to contain the settlement deficit[2]. However large negative residues can still accumulate where:

- Generators have non-price technical constraints, such as low Rates of Change that have a higher priority than AEMO's clamping constraint;
- Power system security would be jeopardised by the clamping; or
- FCAS constraints complicate the clamping.

3. Funding of Negative Residues

Since 1 July 2010, the importing TNSP is obliged to fund all settlement intervals that have accrued a negative residue[3], who will then recover this amount from customers. Thus customers in Region 2 will effectively fund part of the generation in Region 1 at the price of Region 1, even though there was spare generation in Region 2 not dispatched.

Prior to this time, negative residues would first offset positive residues accumulated during the current settlement week. If that failed to fund them, they would then be drawn from the next auction proceeds.

This intra-week offsetting tended to further reduce the value of the instrument for trade. Where there was a large negative and positive residue event in one week, then the positive residue would often be erased by an unrelated negative residue event.

For the purposes of a fair comparison of the effectiveness of the SRA over time, the following analysis was performed assuming the current funding of negative residue was in place, i.e. historical negative residues were not offset against positives.

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[2] See http://www.aemo.com.au/electricityops/soop3705v065.pdf section 19
[3] NER 3.6.5

4. Snowy Regional Boundary Change

Prior to 1 July 2008 the snowy region bisected the NSW-Victorian interconnector. When trading between the states it was necessary to purchase SRA's on both the Vic-Snowy and Snowy-NSW interconnectors. This could be achieved through the auction's "linked bid" facility where one bid can be made for multiple instruments and it should be possible to calculate the Vic-NSW hedging capability across the snowy region.

However prior to the snowy boundary abolition a CSC/CSP scheme was trialled which diverted some inter-regional residues in certain constraint situations. This complicates the analysis and presentation. Vic-NSW SRA firmness has not been assessed prior to 1 July 2008 for this submission. If it is seen to be of interest, AEMO could calculate an effective Vic-NSW trading capability prior to the snowy abolition.

5. Results

This approach intends to demonstrate the historical effectiveness of the SRA as an inter-regional hedging instrument. The first column "Payout per MW hedged" represents the accumulation of price differences for all half hours when the importing region had a higher price than the exporting region, divided by two to resolve to an hourly basis.

The "Total hedgeable MW" is the result of dividing the entire positive residues for that directional interconnector by the "Payout per MW hedged". This indicates what volume of inter-regional hedges that the total residue pool could have supported.

"Negative Residues" indicates the value that would have been recovered from the importing TNSP had the 3.6.5 rule been in place.

5.1. Qld-NSW

	To NSW (1200 nominal MW units auctioned)			To Qld (550 nominal MW units auctioned)		
Quarter	Payout per MW hedged	Total Hedgeable MW	Negative Residues	Payout per MW hedged	Total Hedgeable MW	Negative Residues
Q306	$23,645	977	$0	$3	NA**	$738
Q406	$9,378	881	$10,236	$1,093	NA**	$793
Q107	$13,473	763	$2,888,633	$19,107	77	$9,200
Q207	**$33,460**	**774**	$30,709	$2,089	NA**	$1,081
Q307	$7,975	615	$388,201	$3,608	63	$5,531
Q407	$12,968	491	$8,550,660	**$41,032**	**40**	$2,747
Q108	$7,681	643	$5,609,752	$86,174	132	$682
Q208	$10,875	689	$9,076	$2,551	NA**	$255
Q308	$10,411	729	$459,321	$940	NA**	$1,277
Q408	**$32,723**	**870**	$1,289,882	$13,678	152	$2,104
Q109	$13,894	735	$37,040	$7,401	146	$1,803
Q209	$7,605	739	$300	$95	NA**	$15
Q309	$5,683	751	$3,456	$1,049	NA**	$50,616
Q409	**$69,361**	**511**	$17,646	$2,216	170**	$440,360
Q110	**$42,195**	**223**	$318,829	**$33,897**	**100**	$1,926,470
Q210	$16,152	872	$517,050	$812	NA**	$212

5.2. NSW-Vic

	To Vic (1300MW nominal MW units auctioned)			To NSW (1500 nominal MW units auctioned)		
Quarter	Payout per MW hedged	Total Hedgeable MW	Negative Residues	Payout per MW hedged	Total Hedgeable MW	Negative Residues
Q308	$5,299	144	$7,884	$1,879	NA**	$18,535
Q408	$4,829	210	$4,372	**$34,607**	**617**	$20,539
Q109	**$70,445**	**398**	$1,500,533	$17,022	583	$63,833
Q209	$4,799	144	$57,460	$5,929	836	$6,468
Q309	$867	NA**	$5,407	$7,621	795	$1,427
Q409	$2,345	568	$335,938	**$113,010**	**514**	$954
Q110	**$55,754**	**200**	$5,666,238	**$41,968**	**270**	$1,957,720
Q210	**$40,030**	**43**	$1,321,018	$5,662	92	$18,900,547

5.3. Vic-SA

	To SA (700 nominal MW units auctioned)			To Vic (400 nominal MW units auctioned)		
Quarter	Payout per MW hedged	Total Hedgeable MW	Negative Residues	Payout per MW hedged	Total Hedgeable MW	Negative Residues
Q306	$9,625	274	$32,348	$3,010	276	$983
Q406	$17,723	321	$3,757	$1,735	NA**	$1,403
Q107	$10,172	122	$540,012	$28,677	148	$58,530
Q207	$4,108	76	$486,686	**$36,152**	**63**	$104,944
Q307	$4,146	130	$25,772	$5,248	179	$51,861
Q407	$6,567	276	$20,029	$6,643	184	$8,918
Q108	**$239,481**	**356**	$18,772	$1,351	NA**	$8,238
Q208	$2,583	107	$4,198	$4,841	221	$6,645
Q308	$2,495	NA**	$3,127	$5,578	208	$20,351
Q408	$2,917	163	$6,104	$6,046	213	$13,201
Q109	**$101,647**	**351**	$599,365	$16,574	30	$643,437
Q209	$4,560	194	$1,052	$3,172	222	$35,345
Q309	$4,887	161	$38,100	$1,890	NA**	$22,462
Q409	**$123,567**	**408**	$30,696	$2,898	239	$23,370
Q110	**$72,952**	**298**	$9,915	$2,225	NA**	$7,620
Q210	$5,882	202	$1,723,080	**$33,597**	**15**	$554,506

**As there were no significant price differences during this quarter (payout <$2,500), the hedgeable quantity calculation becomes materially affected by losses and has been ignored.

5.4. Interpreting the data

SRA firmness

The "Payout per MW hedged" gives an indication of the inter-regional basis risk during that quarter. Quarters with low payout values are not important for SRA firmness because this indicates that there was little price difference between the regions and therefore there was not much need for the SRA.

Quarters with high payout are the periods where the SRA is critical to support inter-regional hedging so those should be the focus. Examples of these have been **bolded**. If the "Total hedgeable quantity" is close to the nominal interconnector capacity, then this indicates the SRA has performed well as an inter-regional instrument.

Even if it fails to meet the nominal capacity, but is relatively stable, then it is useful to participants as they could still use it to offset basis risk by appropriately discounting the nominal value.

The hedgeable quantity shows that:

- Qld towards NSW was reasonably stable until the summer of 09/10, when it fell to only 223MW of 1200MW nominal units auctioned.
- NSW to Qld has performed poorly and unpredictably, never approaching the nominal capacity of 550MW.
- NSW to Vic has performed well below its nominal capacity of 1300MW, and was of negligible hedging value during high price events in Q2 2010.
- Vic to NSW performed stably at about one third of its nominal capacity until summer 09/10 when it performed at one half of that.
- Vic to SA has been the most stable, varying between 300 and 400MW out of a nominal capacity of 700.
- SA to Vic has performed poorly throughout.

We have not quantitatively analysed the specific causes for poor performance. We note anecdotedly that both flows into NSW during Q409 and Q110 were substantially affected by the recurring constraint incidents discussed in Appendix 2.

Negative Residues

As discussed previously, negative residues are no longer a detriment in themselves to the holder of SRA instruments. However they are symptomatic of a dispatch and settlement mismatch and must be funded, through TUOS, by customers of the importing region. As the imported power is more expensive than undispatched power from their own region, these value transfers are likely to be inefficient.

As can be seen, these can occasionally be large, especially Q210 into NSW which was mostly accrued on 22 April when constrained Victorian generation bid at low prices and reduced rates of change thereby avoiding being constrained off by AEMO's clamping procedure.

APPENDIX B: 7 DEC 2009

1. Looped constraints

This event was chosen as it is a good demonstration of how a constraint on a meshed network has different generator and interconnector coefficients, and how the incentive for "disorderly bidding" will result in a demonstrably inefficient dispatch. The constraint would not have greatly impacted dispatch were it not for the disorderly bidding that emerges from the market design. It was therefore not unreasonable for the a network planner to not anticipate these outcomes.

The particular constraint that triggered this event protects the short lines between Delta's Mt Piper and Wallerawang power stations, the 70/71 line constraint. This constraint emerged in late 2009 following some augmentations carried out by the network owner, and continued to affect dispatch until mid 2010. Subsequent operational actions, and ultimately further augmentations are expected to greatly reduce its incidence in future.

However the looped character of the constraint is consistent with numerous constraints protecting equipment in NSW and with many in Southern Qld. The unexpected emergence, and then relatively brief market impact of the constraint is consistent with previous constraint events in other locations. These two characteristics would seem to make pricing of such constraints through regional boundary change ineffectual.

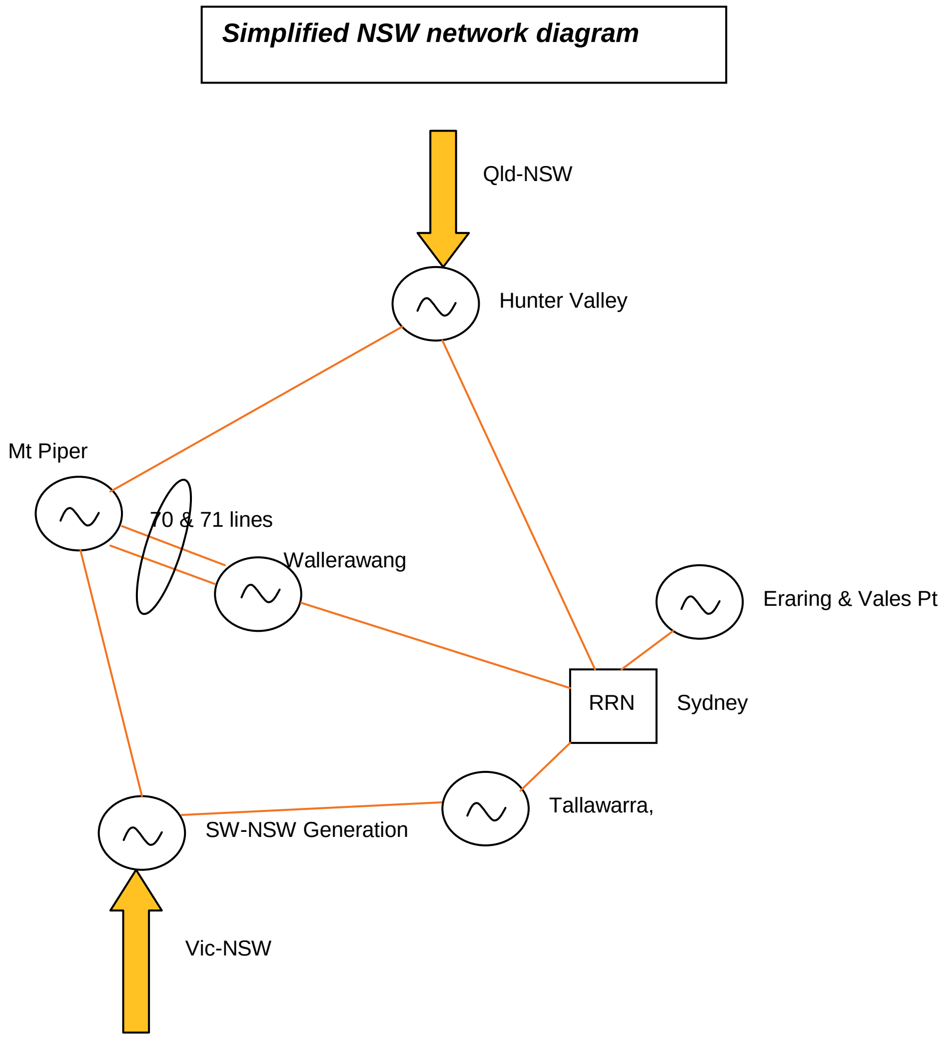
2. The Constraint

In NSW power generally flows towards Sydney from

- the West: Delta's generators west of the Blue Mountains;
- the North: Delta's, Macquarie's and Eraring's generators in the Hunter Valley area and from generators in Queensland; and
- the South West: Snowy's Tumut, Origin's Uranquinty, Eraring's Shoalhaven and TRUenergy's Tallawarra generators and from generators in Victoria.

Note that each path in the diagram below is a simplified representation of many parallel and meshed circuits, and also small load centres.

The network is meshed with multiple flow paths. Power will distribute itself along the paths in inverse proportion to their impedance, and will be influenced by the pattern of generation to load. An increase in the output of Mt Piper will flow mostly through the 70/71 lines. An increase in Wallerawang however will tend to offset this flow. Generation in the South West or the North West will split, with the majority flowing on other paths but also contributing to the flow through the 70/71 lines. An increase at Eraring or Vales Pt generation would have no effect on flows on the 70/71 lines.



The NSW network was managed securely throughout. On the 7 Dec the nearby network was in a 'system normal' condition (i.e. no network outages), although an outage on the Sydney West to Yass 330kV line until 1PM did slightly worsened the 70/71 line constraint. Otherwise the network was in a 'system normal' condition albeit the pattern of generation at the time emphasised this weak link. In particular, one of the two units at Wallerawang was out of service.

The constraint equation that manages the 70/71 lines under system normal conditions is named "N>>N-NIL_S". The following table provides the terms and coefficients in that equation. These coefficients can be thought of as indicating, if the generator were to increase output by 1 MW, what fraction of that MW would flow through the 70/71 lines.

Term	Coefficient	Term	Coefficient
Wallerawang (Delta)	-1.0	Uranquinty (Origin)	0.21
Mt Piper (Delta)	0.72	Tallawarra (TRUenergy)	0.10
Liddell (MacGen)	0.25	Shoalhaven (Eraring)	0.12
Bayswater 1,2,3 (Macgen)	0.26	NSW import from Qld	0.24
Bayswater 4 [500kV] (Macgen)	0.37	NSW import from Vic	0.21
Tumut Stations (Snowy)	0.21	Vales Pt, Munmorah, Colongra (Delta) Eraring (Eraring)	0.0 (ie, not constrained)

This constraint would act to primarily constrain on Wallerawang (as it has the effect of lowering flows on the critical lines) and to constrain off Mt Piper (which has the highest relative impact on increasing flows on these lines). It could also constrain off the other units and imports to NSW from Queensland and Victoria, but those generation sources have much lower coefficients and to have the same effect would require 3-4 times more volume to be constrained. In this case it is possible for Delta to offer a large negative price for Mt Piper to discourage it from being constrained off and a large positive price to discourage Wallerawang from being constrained on, and thereby inhibit the dispatch engine from exploring what would normally be the most effective and efficient to manage flows on these lines. It will also force the dispatch engine will to constrain off the other units to a much larger degree, resulting in loss of dispatch efficiency[4].

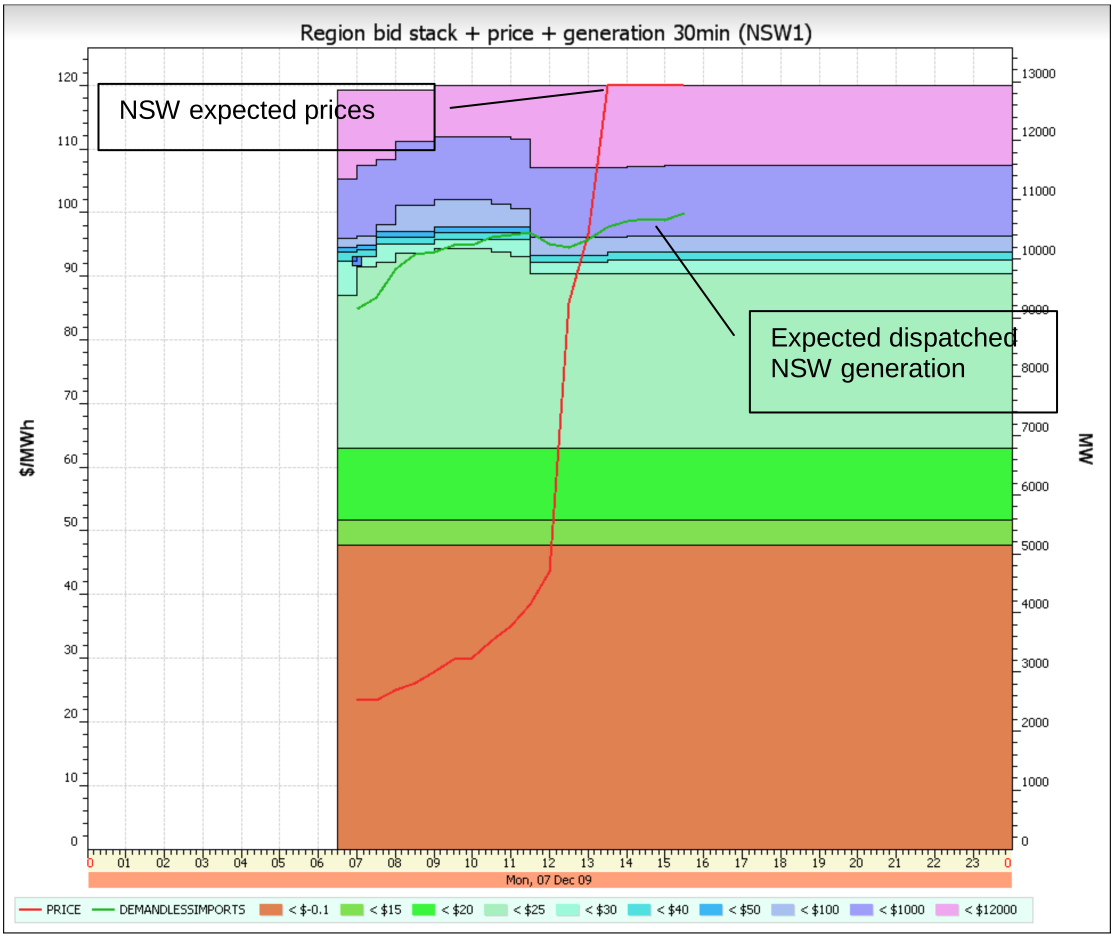
Because competition is limited by the constraint, the market power of unconstrained generators (that is, not constrained by the “N>>N-NIL_S” constraint), such as Vales Pt and Eraring is increased.

3. Rebidding

It appears that prior to 06:30AM, no generators were anticipating the impact of the constraint and bids were of a form typical for this day of moderately high NSW demand (approx 12,000MW) and high plant availability.

[4] Setting aside any other physical unit constraints such as ramp rate or maximum availability limitations.

NSW Generator bid stack prior to rebidding



This graph shows the bid supply curve as it was presented at 06:30AM for the rest of 7 Dec. About 5000MW of plant was bid at negative prices, presumably indicating minimum load levels of steam units. This generation would not be expected to be reduced in dispatch. A clear supply curve exists with up to 12,000MW of bids presented at levels below $1,000/MWh and a further 1000MW at prices above that. As notionally a further 2,000MW of moderately priced supply was available to NSW via interconnection, the highest priced bids would not be expected to be dispatched for a NSW demand of 12,000MW. As a result, prices were forecast to be below $1,000/MWh.

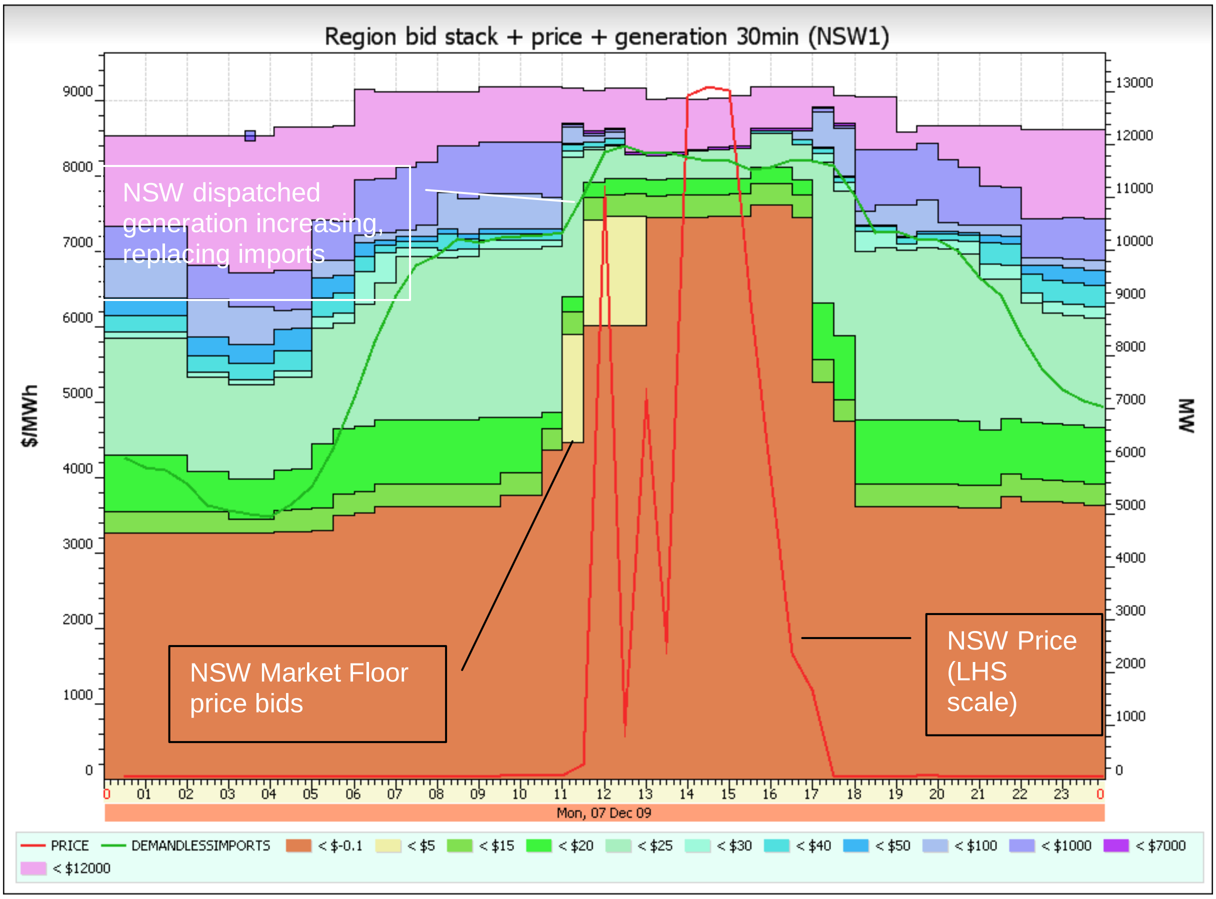
The constraint bound from 10.30AM to 5.30PM. During this time:

- The Wallerawang unit was bid such that output above 300MW was priced near the price cap, and from 1.30PM to 6.30PM the available capacity was reduced to 300MW.
- The full output of both Mt Piper units were offered at the Market Floor Price (MFP) of -$1,000/MWh.
- The maximum ramp-down rate on both Mt Piper units was reduced to the minimum permissible value of 3MW/Min, whilst the ramp-up rate was bid at 10MW/min.

These bids had the effect of inhibiting the dispatch engine from constraining the generators with the largest coefficients in the equation. As a result, other terms had to be constrained by 3-4 times the quantity.

Other NSW generators included in the constraint equation were therefore at risk of being constrained off. They reacted by also bidding at the MFP of -$1,000, and in some cases also reducing their ramp-down rates. These included all of Macquarie Generation's power stations, Snowy's Tumut units and Origin's Uranquinty.

Final NSW Generator bid stack after rebidding



As can be seen from this graph, nearly 11,000MW, or effectively all the NSW generation with a positive co-efficient in the constraint equation, was rebid to the MFP. Some of the residual units not in the equation transferred additional capacity into higher priced bands.

As the dispatch engine was inhibited from accessing a lower cost combination of generation, the NSW marginal price (i.e. the cost of supply an extra MW of demand in Sydney) became high, approaching the market price cap for several hours.

4. Impact on interconnectors

Generation in other regions are unlikely to rebid during this congestion because their settlement is correctly priced with respect to their role in the constraint and thus the lowering of their bids would reduce their settlement price. Thus the dispatch engine sees the NSW MFP offers as much more attractive than their output and dispatches them in preference.

Thus the interconnector flows into NSW were significantly reduced, from 1125MW at 11:00AM, to zero 30 minutes later. In fact, the dispatch engine attempted to reverse the flows and operate them in a counter-price direction. This however was clamped by AEMO under its intervention procedure[5].

During the period 11:30AM to 5:00PM, the NSW price averaged $5,071/MWh, whilst Queensland and Victoria averaged $172/MWh and $22/MWh respectively. During much of this period the interconnectors into NSW were restricted to very low levels of flow.

As the interconnectors were reduced to low flow levels due to the way the market responded to the congestion, so the settlement residue instrument had a very zero payout at a time the owner would have been requiring a high payout to manage the large price difference between the regions. The instrument was therefore effectively rendered worthless as an inter-regional hedge for the period of the event.

5. Re-Run

To understand the implications of the bidding, AEMO has performed a “what-if” analysis of the day’s events. This was carried out by re-running the dispatch engine for the same market and power system conditions, but using a bidding pattern based on the last bids that were submitted by the generators that morning before they became aware of the constraint[6]. Demands were held constant. No network constraints were adjusted, so this is an assessment only of a more efficient dispatch result, not of an increased network capacity.

As the constraint equation’s Right Hand Side value uses terms observed from the real power system, AEMO employed the use of its Dispatch Training Simulator (DTS) which includes a full power system simulation to re-create these values. The re-run was carried out from 06:30AM to 3:30PM.

It should be noted that any re-run must be based on a hypothetical assumption about market conditions and should therefore be treated with caution. In this case we are assuming continuation of the conditions expected at 06:30AM. In preparing this analysis, AEMO was unaware of any material change in conditions except those relating to the action of the 70/71 constraint.

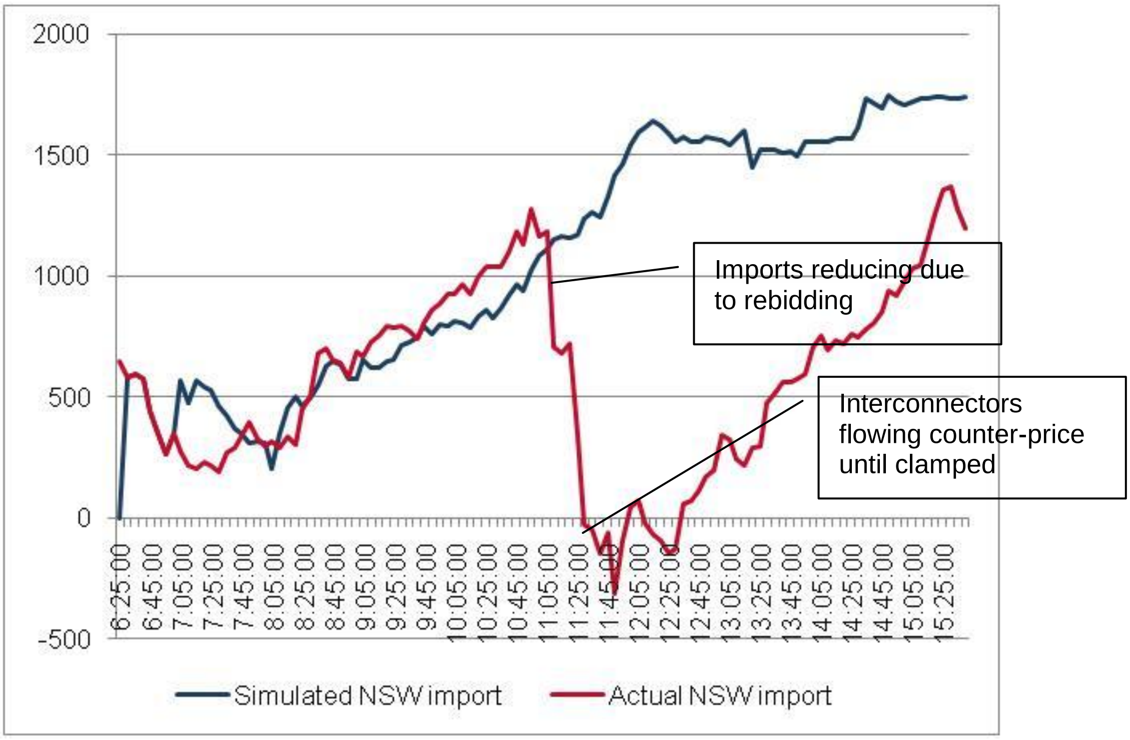
With the bids held constant, the dispatch engine was able to move units into a generation pattern that, whilst the constraint was still binding, utilised the remaining network much more efficiently and benign market conditions resulted. The outcome of that was more imported power into NSW and less NSW generation, especially peaking generation. NSW prices between 10:30AM and 3:30PM averaged $90/MWh in the re-run against the actual average of $4,917/MWh, which would have reduced pool settlement by about $300m.

The quantity of peaking generation in the NSW region greatly reduced. During this time, the combined output of the power stations: Tumut, Guthega, Uranquity, Colongra and Shoalhaven averaged 871MW in the re-run against 2307MW in the actual. None of the Uranquity or Colongra gas turbines started in the re-run, whereas most of these started on the actual day. The re-run therefore simulated a more operationally efficient dispatch.

[5] See http://www.aemo.com.au/electricityops/soop3705v065.pdf section 19

[6] One rebid resulting from the unexpected outage of a Uranquity unit at 12:00 was retained as it was presumably not affected by the constraint.

Re-run NSW imports vs Actual imports

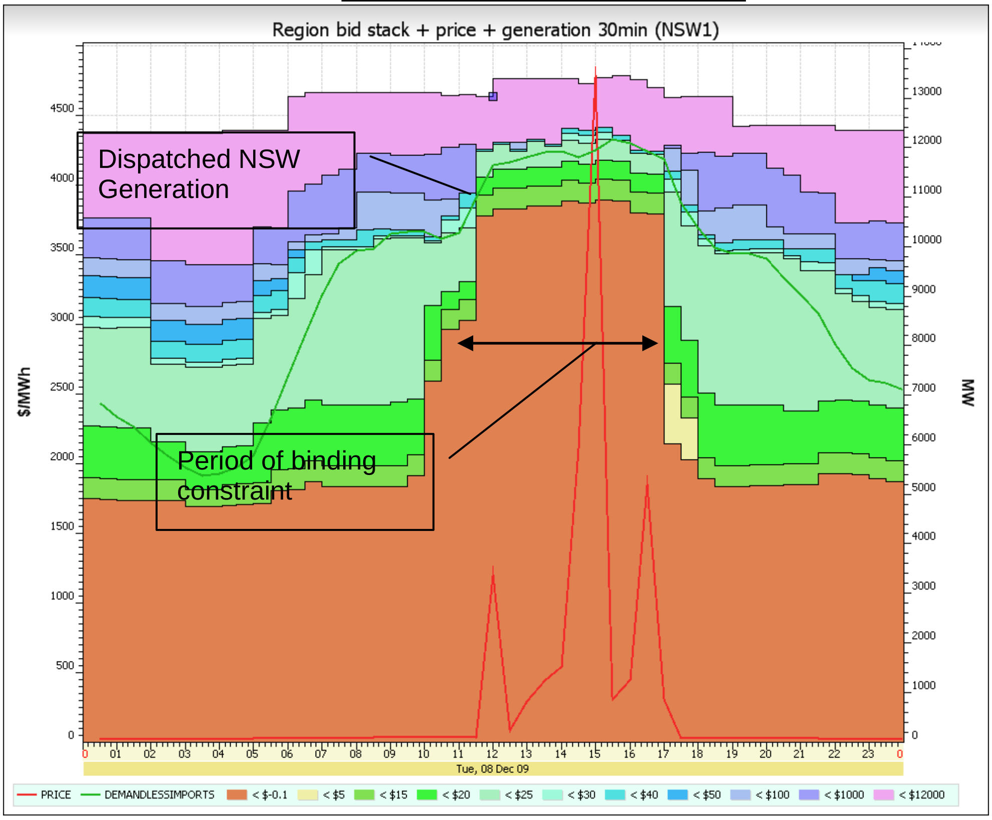


6. Similar events

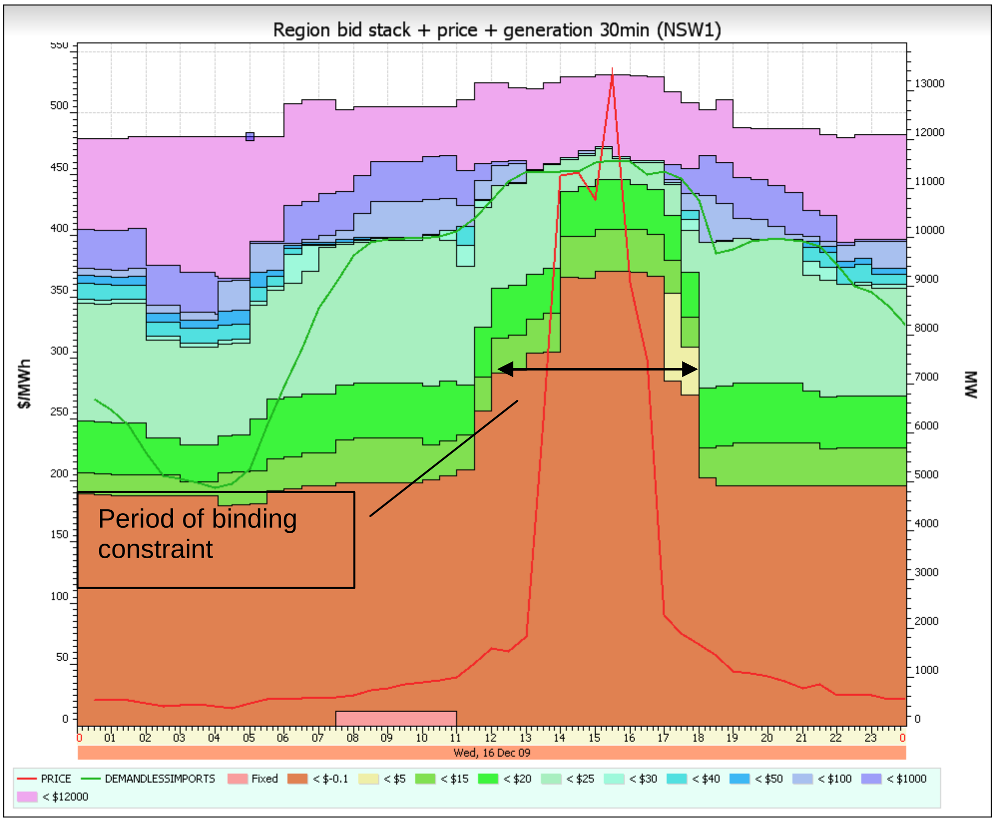
7 Dec 2009 was the first of a series of similar events over the subsequent months also triggered by the binding of this constraint. A pattern developed where the majority of NSW generation would rebid to the market floor price, maximum rates of change were reduced and in some cases output was bid at "fixed" levels. Resulting imports into NSW fell and NSW prices increased.

AEMO has not performed re-runs on these other events but suspects similar outcomes to the 7 Dec 2009 would result. The following plots show the final NSW bid prices on several of these days. The red lines are the resulting prices.

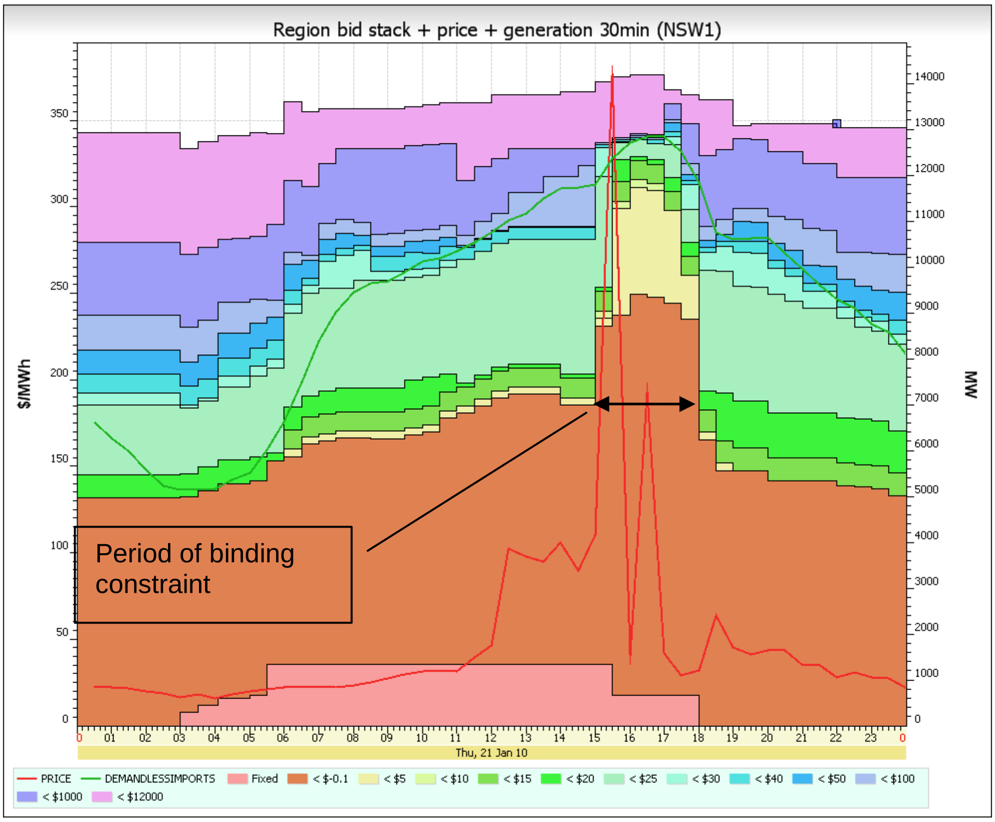
NSW Price stack 8 Dec 2009



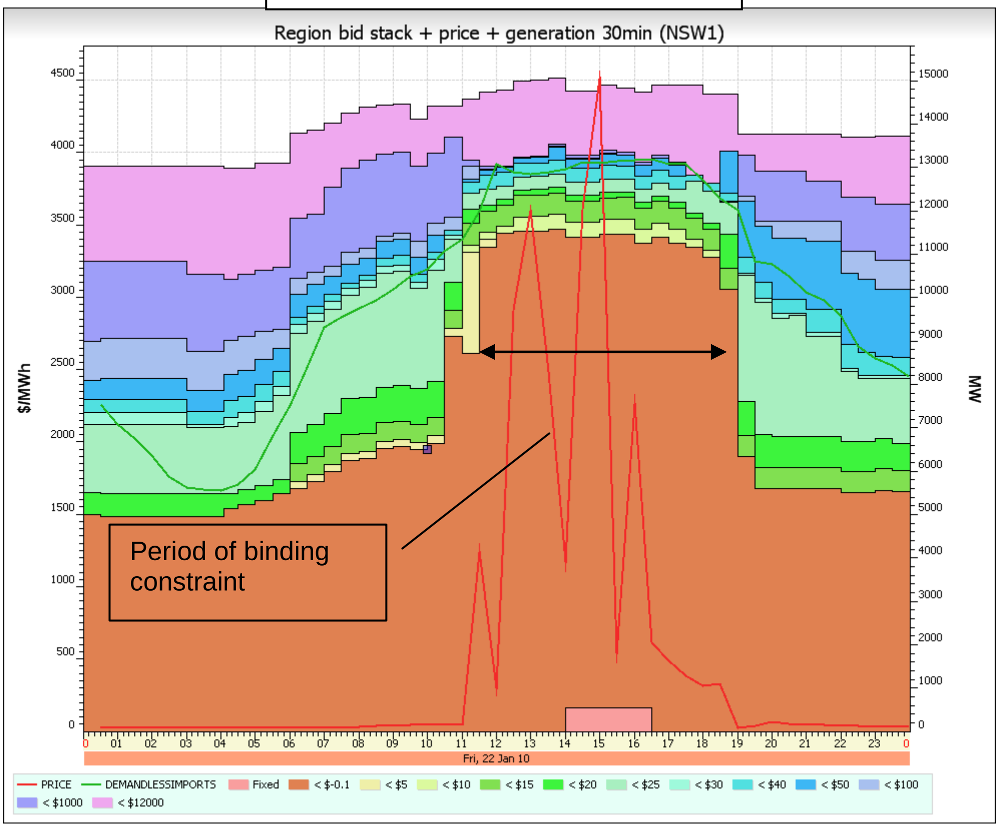
NSW Price stack 16 Dec 2009



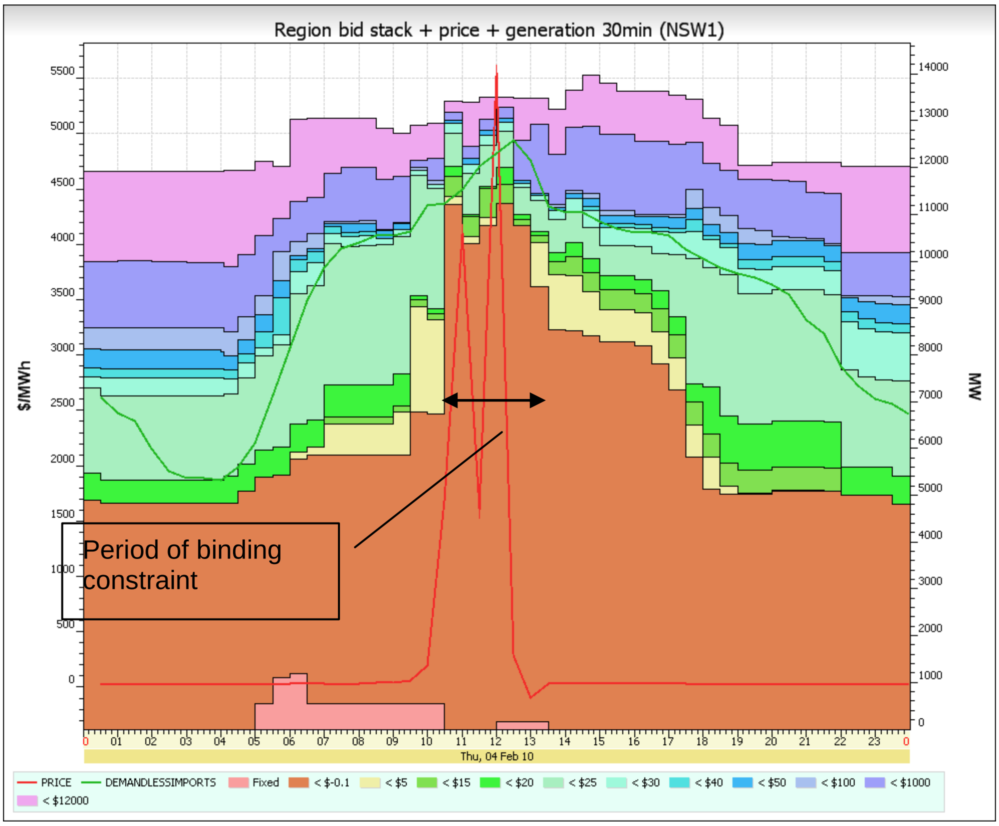
NSW Price stack 21 Jan 2010



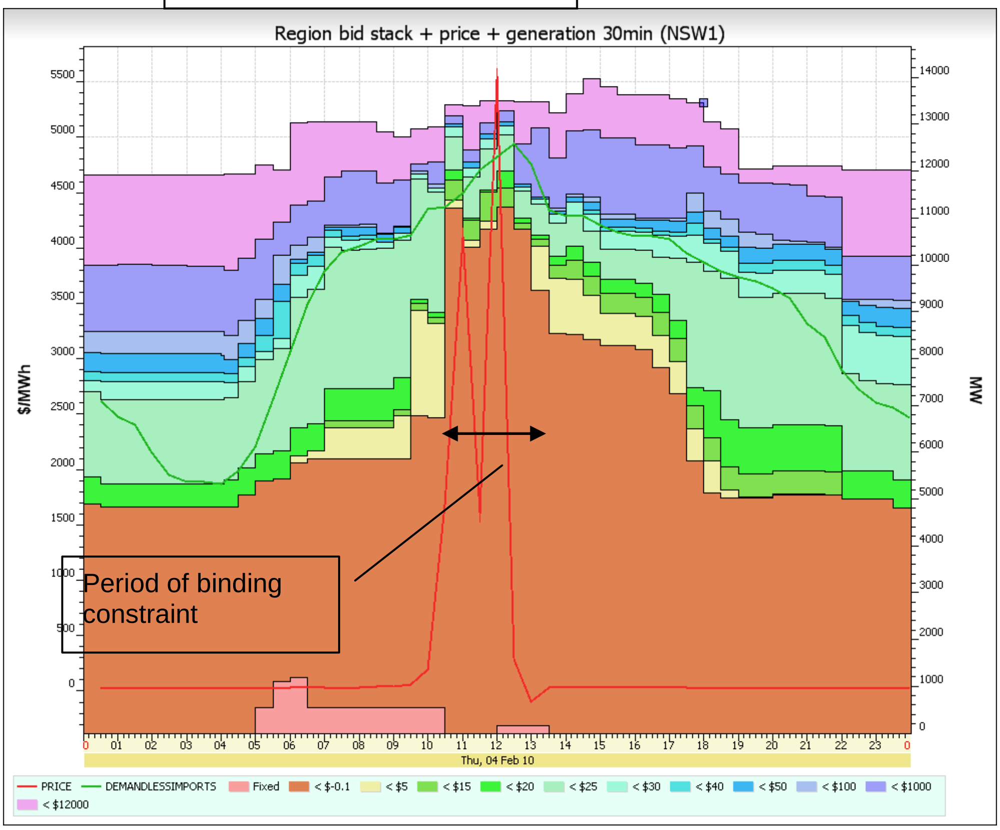
NSW Price stack 22 Jan 2010



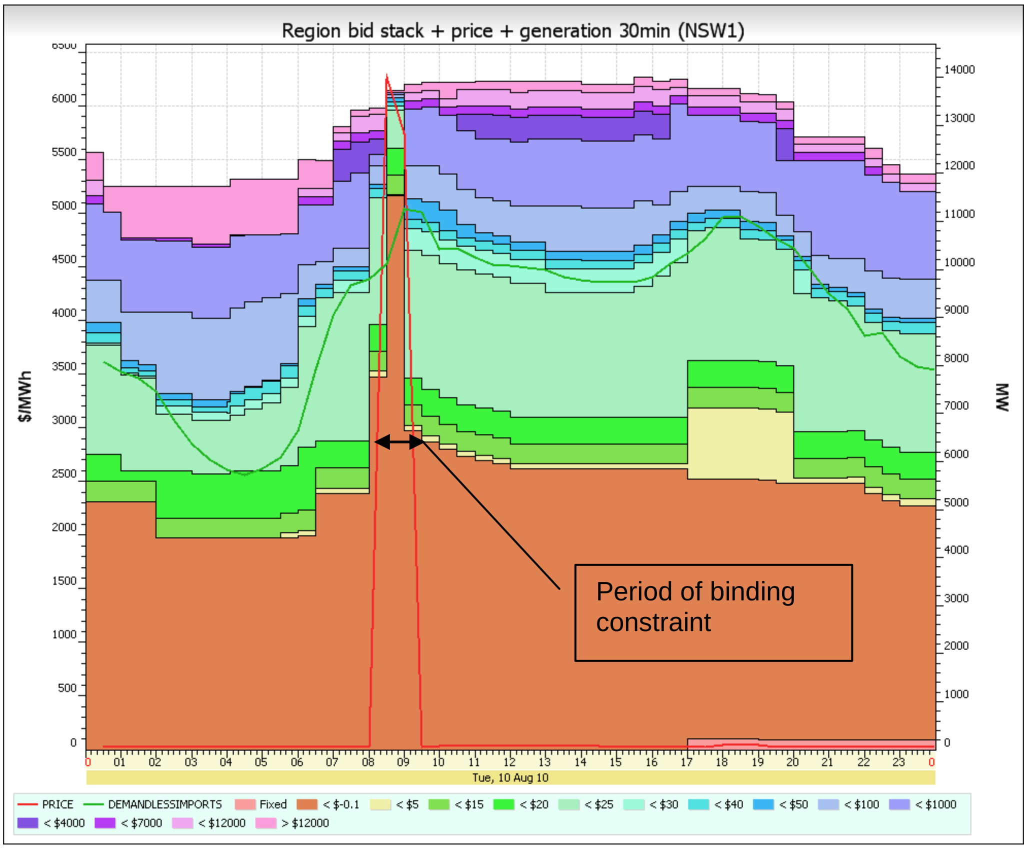
NSW Price stack 4 Feb 2010



NSW Price stack 22 Feb 2010



NSW Price stack 10 Aug 2010



APPENDIX C: 2ND & 3RD FEB 2010

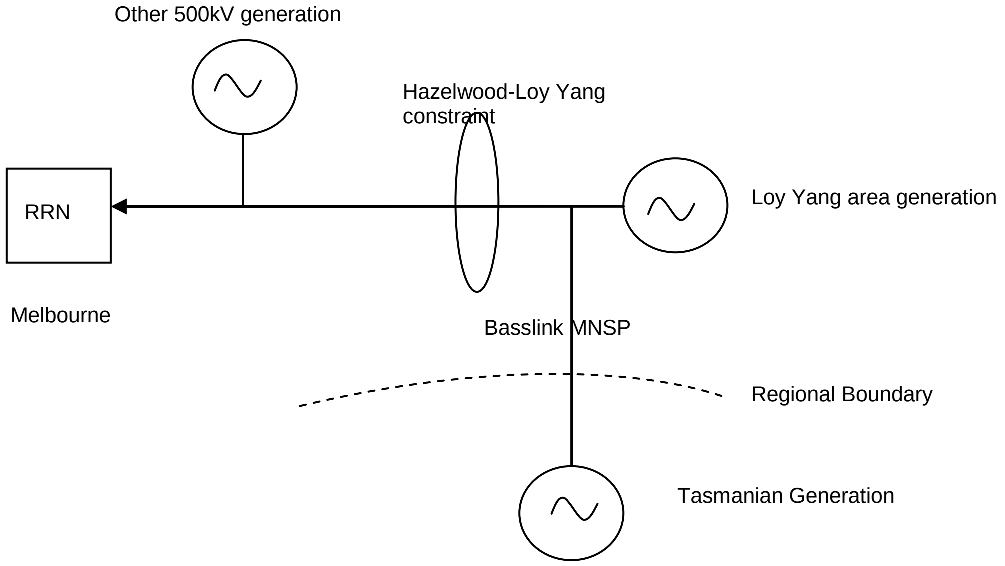
1. Circumstance

This event was chosen as an example of bidding behaviours when subject to a radial constraint, i.e. a constraint where all dispatchable variables have equal coefficients. In these cases, all constrained generators tend to rebid to the market floor price and may also use a combination of rate of change or fixed limitations to avert being constrained off. Where generators rebid to the floor price, the dispatch engine's tiebreaking constrains them off pro-rata according to capacity.

On these days a single line network outage constrained flow on part of the 500kV network from Latrobe Valley to Melbourne. The path is used by Loy Yang A and B power stations, Valley Power Gas Turbines and Basslink Market Network Service Provider (MNSP), a total of about 4000MW of capacity.

2. The Constraint

Simplified Network diagram: Hazelwood to Loy Yang



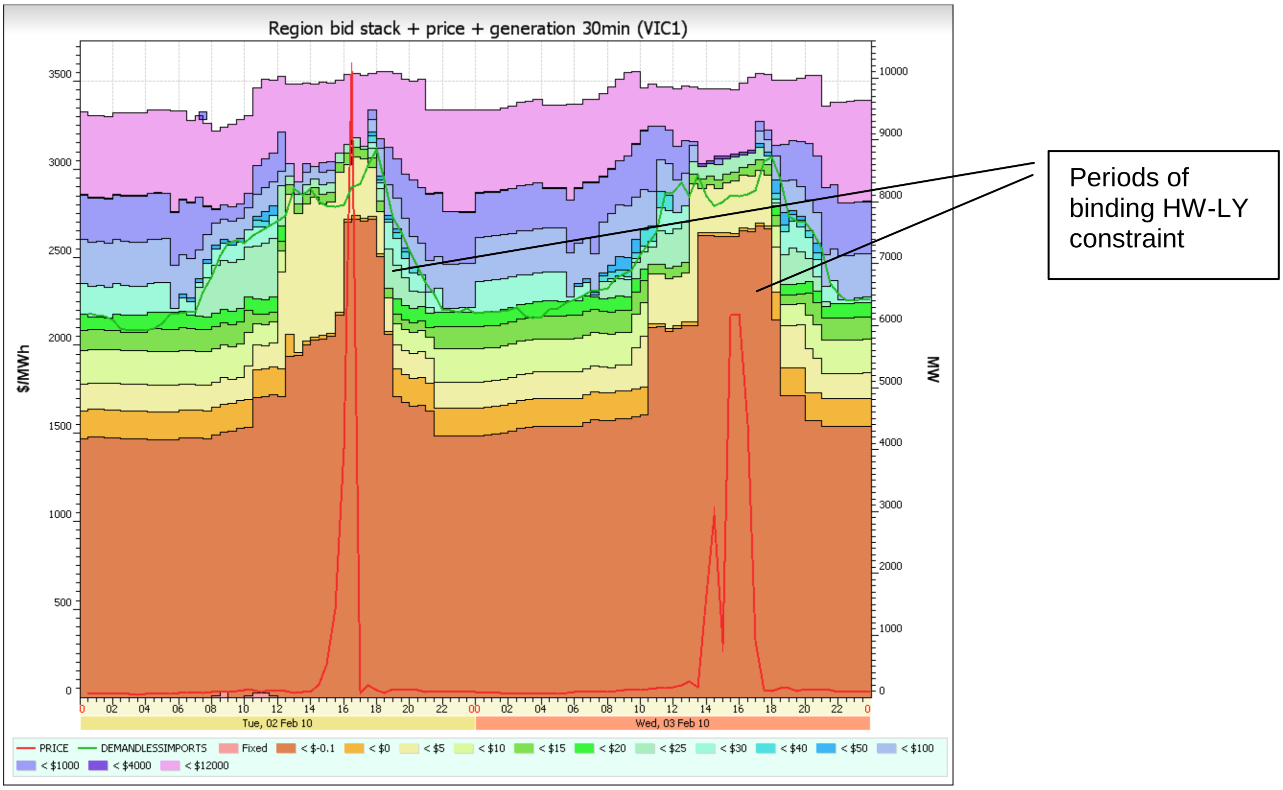
The constraint has a simple form with unity co-efficients:

Loy Yang A + Loy Yang B + Valley Power + Basslink ≤ Line capacity.

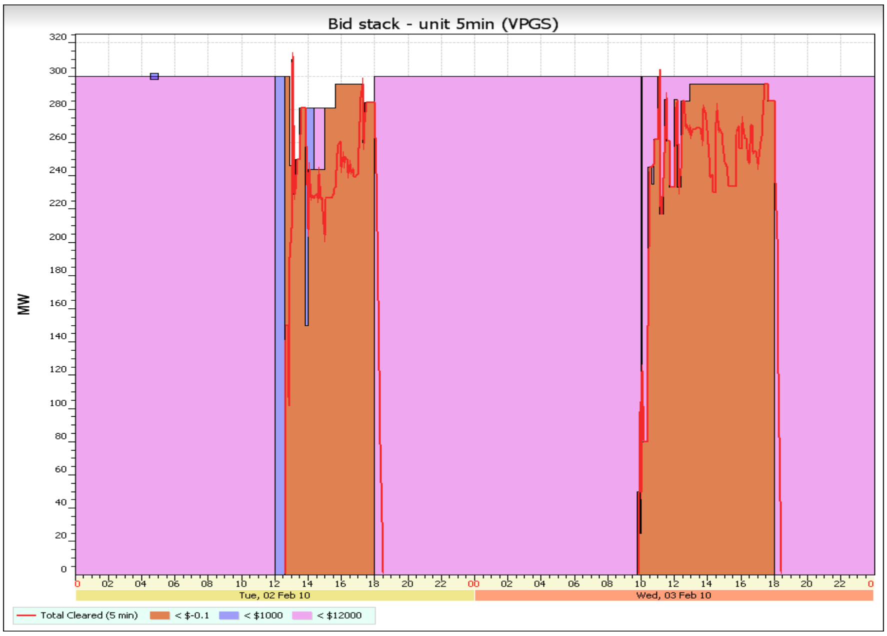
3. Victorian generators

As the constraint bound in the middle of the day on 2nd and 3rd February, all the Victorian generation in this equation rebid at the market floor price (the burnt orange colour below).

Vic Generator bid stack 2 & 3 Feb 10



Valley Power Gas Turbines bid stack 2 & 3 Feb 10



The red line indicates Valley Power's dispatch. As a peaking station, Valley Power was not operating when prices were low. However as the constraint bound, prices became high, and

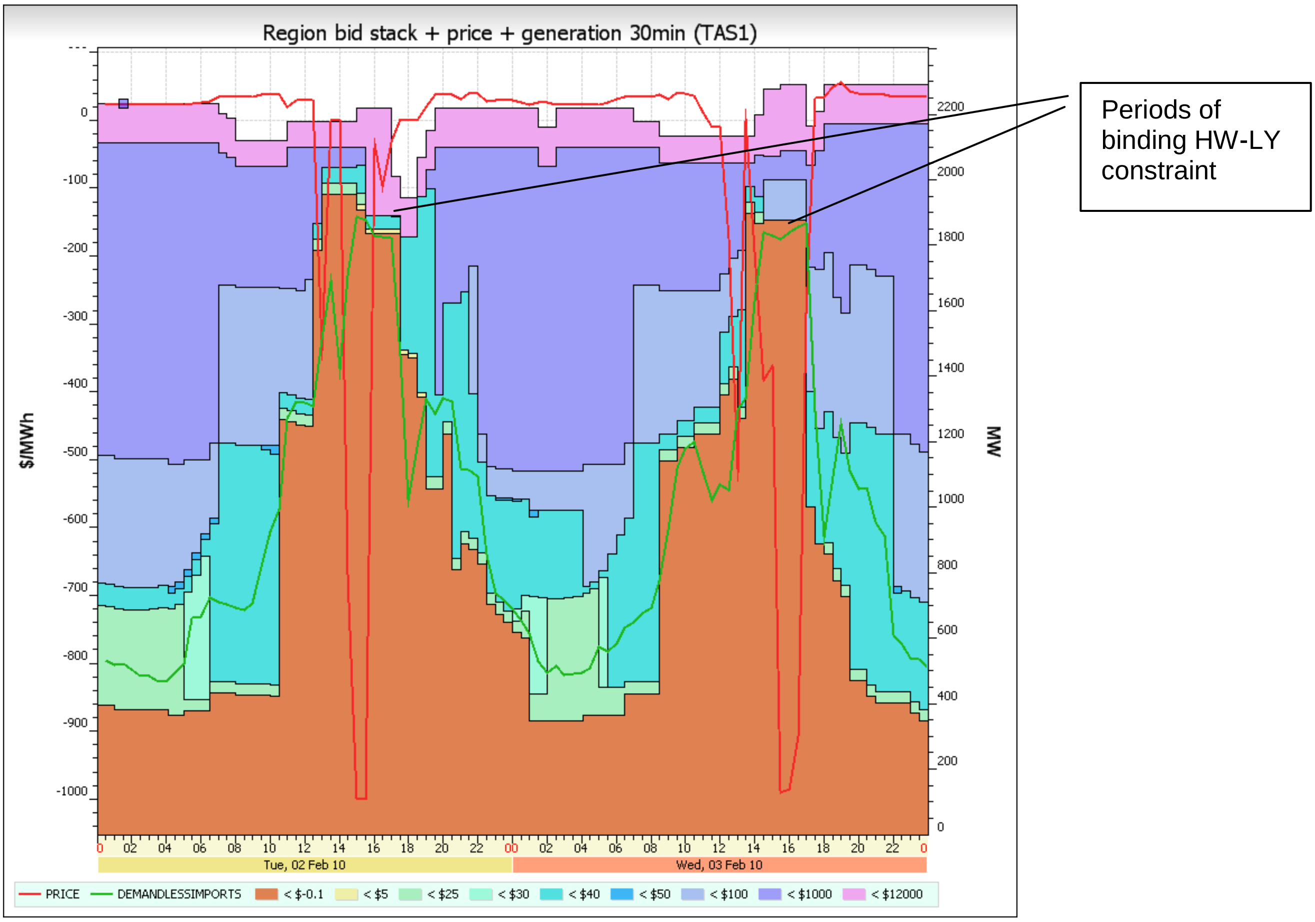
Valley Power ensured its own dispatch by bidding its entire capacity at the market floor price. Not it was nevertheless constrained somewhat below its capacity. Similar behaviours occurred with the other generators.

This outcome, whilst predictable within the market incentives, is paradoxical because this was the period when the network desired less generation upstream of the constraint, not more, and yet peaking gas turbines were started in a congested location.

4. Tasmanian generators

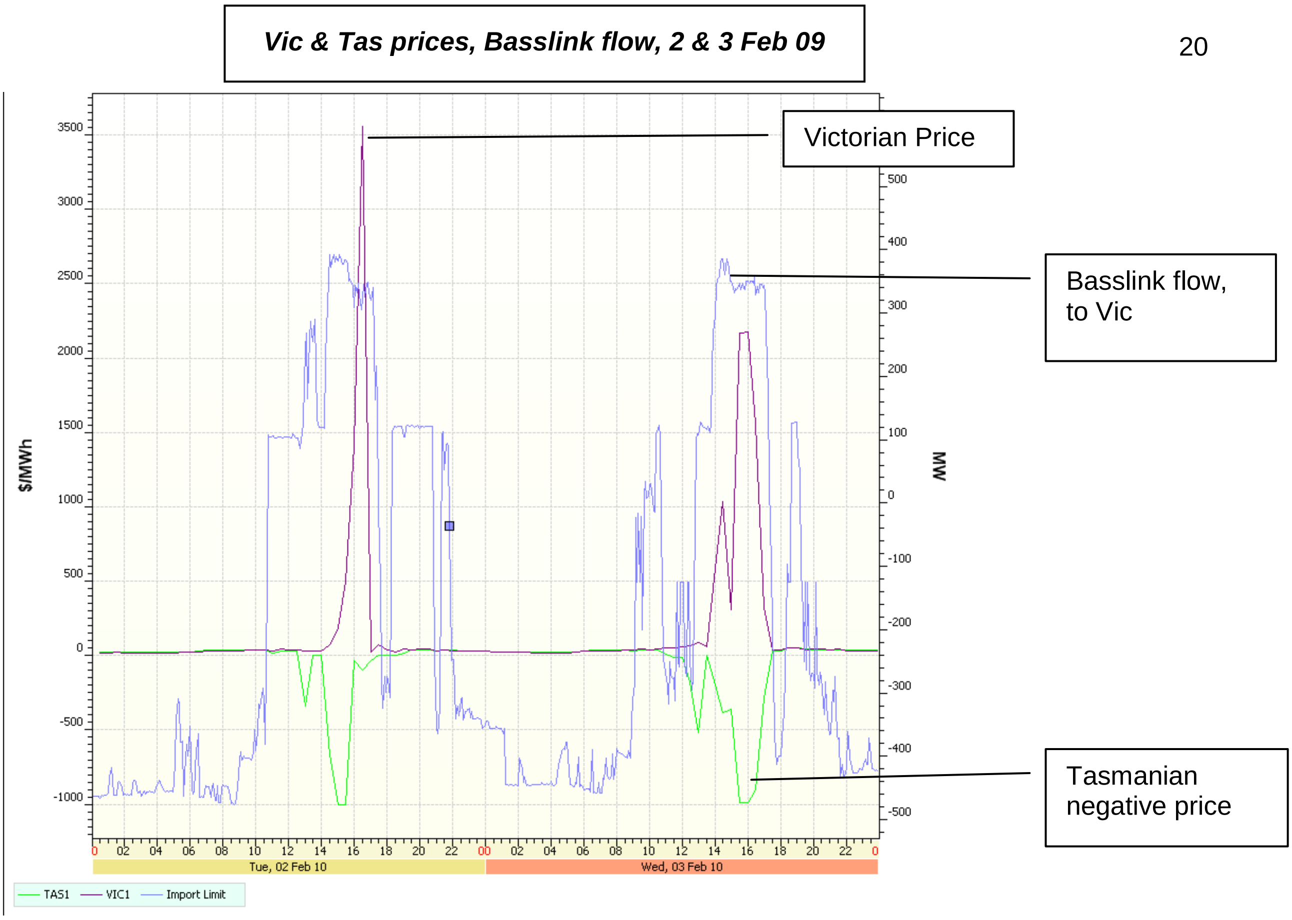
Tasmanian generators also rebid to the market floor price during the period of the constraint, presumably to maximise the opportunity of Basslink to gain access into the constraint.

Tasmanian Generator bid stack 2 & 3 Feb 10



However by bidding at the market price floor across the unconstrained Tasmanian region, the Tasmanian price was set to a negative level.

As a result of the negative prices, Tasmanian generator spot market settlement was debited $4.8m. Presumably Tasmanian hedging may have offset their exposures to these settlements. At the same time, Basslink residues from exporting into Victoria during the negative prices totalled about $5m.



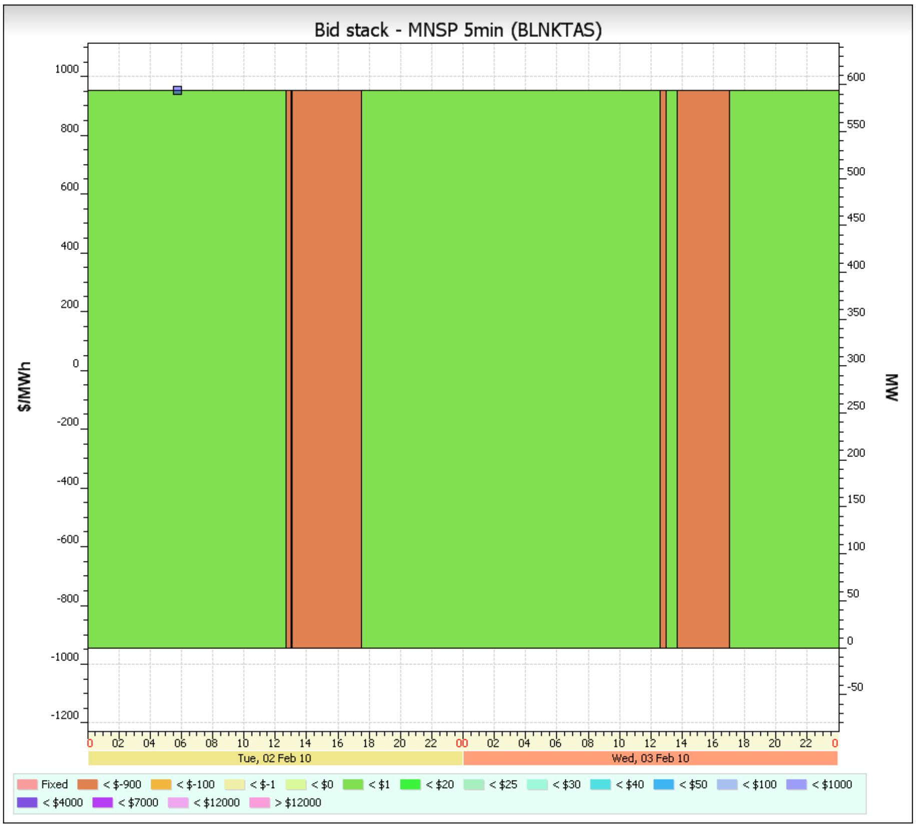
5. Basslink bidding

As an MNSP, Basslink enters a bid against its transfer capacity. If it wishes to flow whenever there is a price difference (allowing for losses), then an MNSP simply enters all its capacity at a zero price level. If however an MNSP wishes to only flow above a trading profit threshold, then it may enter a positive bid of the minimum profit requirement. If marginal, this bid can contribute to price setting in the adjacent regions.

Basslink typically bids with a zero price in both directions at all times.

During the constraint period of 2nd and 3rd February however Basslink transfers into Victoria were bid at the market floor price. This combined with the market floor price offers in Tasmania to be effectively twice the market floor price in Victoria. This gained Basslink preference in the Latrobe Valley to Melbourne constraint.

Basslink Bid stack, 2 & 3 Feb 10



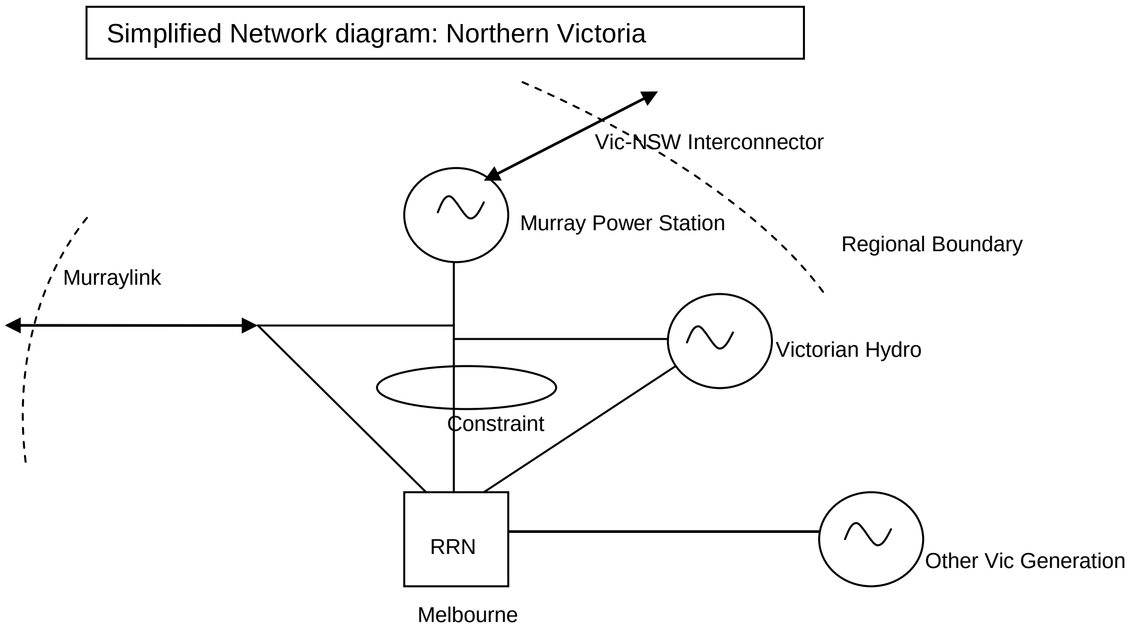
APPENDIX D: 21ST & 22ND APR 2010

1. Circumstance

This event was chosen as an example of how disorderly bidding in the presence of congestion, especially the use of non-price parameters such as low rates of change, can result in large negative residues. A network outage in Victoria caused reductions in the capacity of lines between Melbourne and the generators in the north of the state and Murraylink.

The event occurred for several hours on both days, but as the impact was more severe on the 22nd, only those results are shown here.

2. The Constraint



The constraint has loops, so it has varying coefficients:

0.995Murray + 0.984NSW-Vic + 0.286Murraylink + 0.090Vic Hydro ≤ limit.

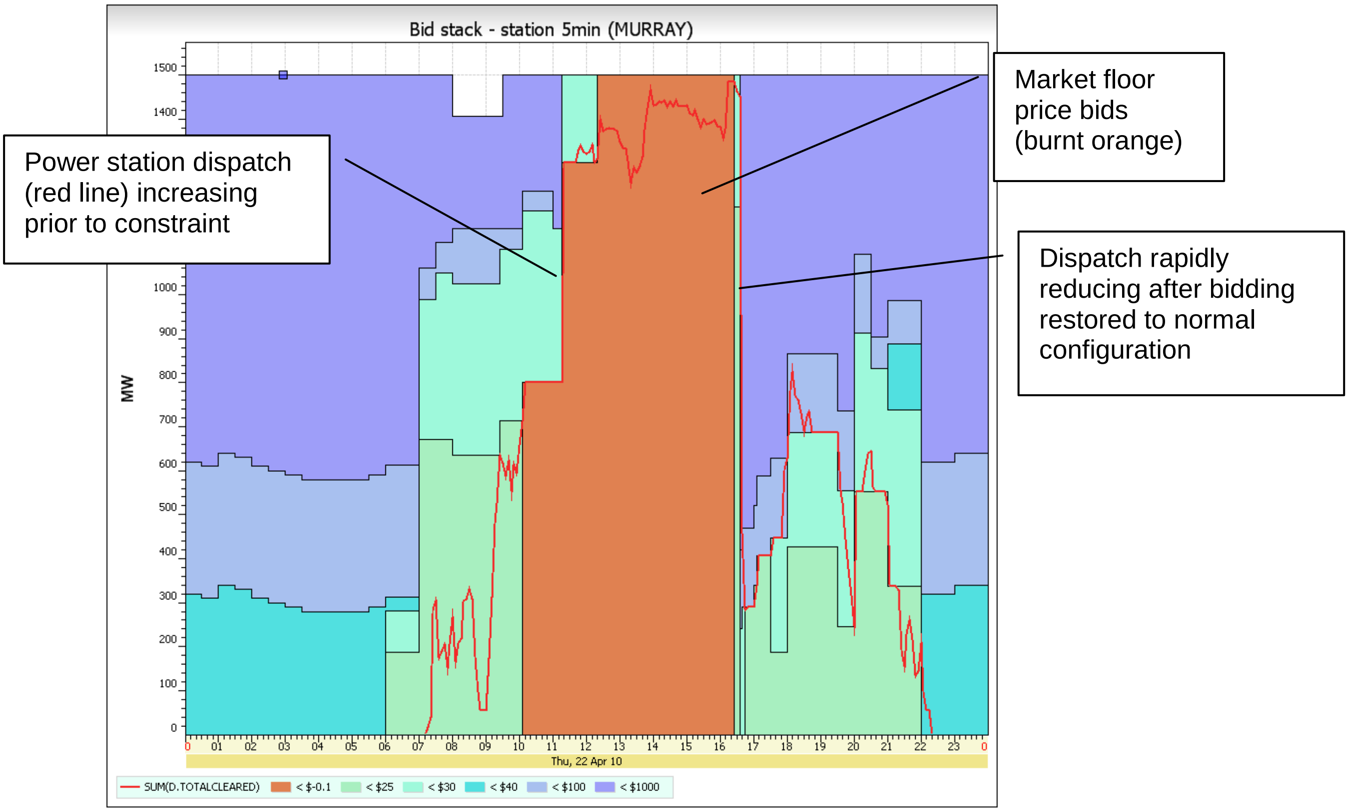
The most important terms therefore are Snowy's 1500MW Murray Power station and the interconnector flow from NSW.

3. Murray Generation

As the outage was planned, there was an expectation that this constraint would bind during the daytime. Murray generation was bid at the market floor price such that it was generating near full output before the constraint materially impacted dispatch at 12:20PM.

From that time, Victorian prices went very high whilst NSW and SA prices were low. The constraint, combined with Murray's bids, forced flow out of Victoria into NSW and SA, i.e. counter-price, accruing a large negative residue. AEMO then acted to clamp the counter-price flows under its normal procedure using a network constraint upon these interconnectors.

Murray Power station bid stack 22 Apr 10



However, along with the market floor price bid, Murray's maximum Rate of Change (ROC) down had been reduced from its normal level of 200MW/min to the minimum permissible of 3MW/min. The maximum ROC up remained at 200MW/min. ROC has a higher priority than AEMO's clamping constraint. As the constraints conflicted the ROC prevailed and Murray's output could only be very gradually reduced.

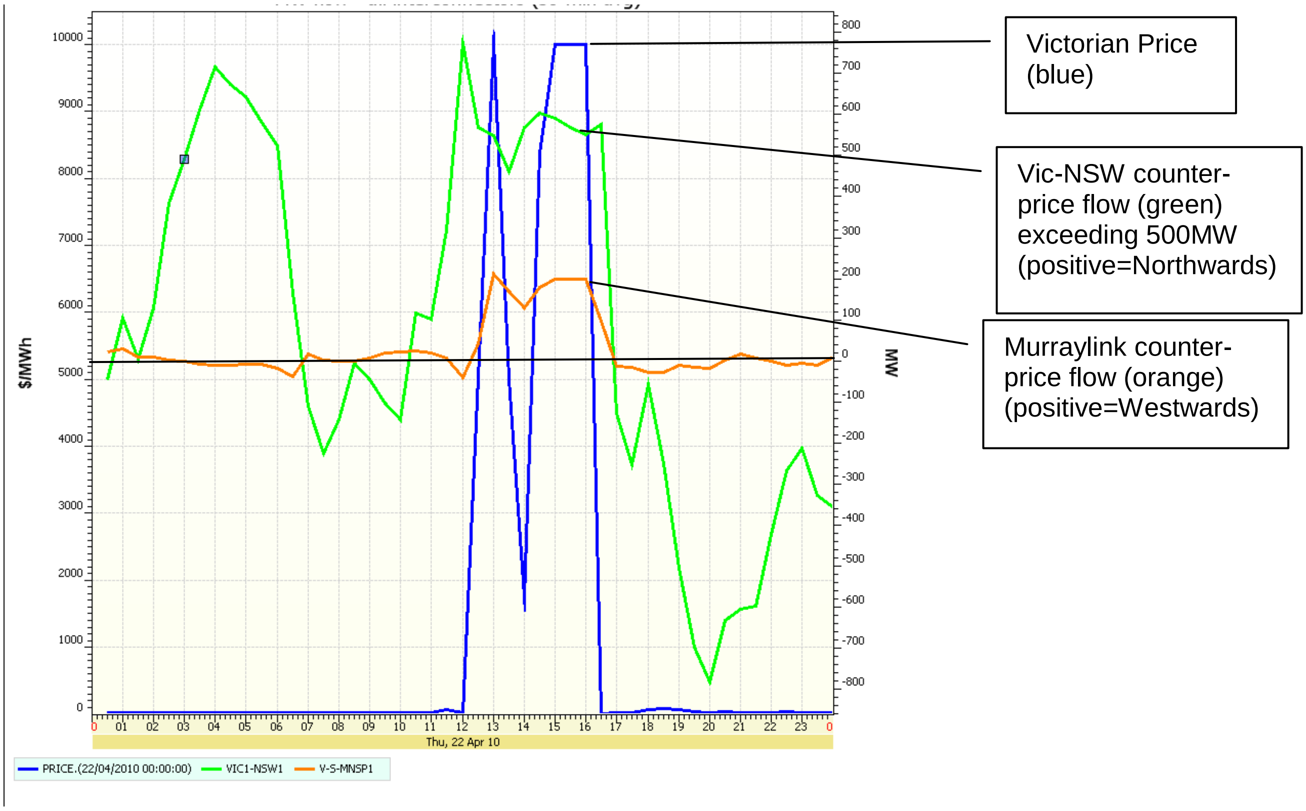
However, when the constraint event concluded and bids returned to a more typical pattern, Murray's generation reduced rapidly, achieving an actual ROC down of 200MW/min down in one dispatch interval.

4. Negative Residues

Because the clamping was ineffectual, large negative residues accrued on both interconnectors, totalling approximately $19m.

As no positive residue accumulated for the relevant SRA instruments, they had no value as a supporter of inter-regional hedging into the Victorian region at a time when inter-regional price differences approached $10,000MWh.

Vic Price, Murraylink and Vic-NSW flow 22 Apr 09



APPENDIX E: 10TH AUG 2010

1. Circumstance

This event was chosen as an example of how rapidly large volumes of rebidding to the market floor price can occur when a network constraint binds unexpectedly. Along with the dispatch inefficiency and trading risks discussed previously, events such as these create risks associated with the rapidity of power system transition.

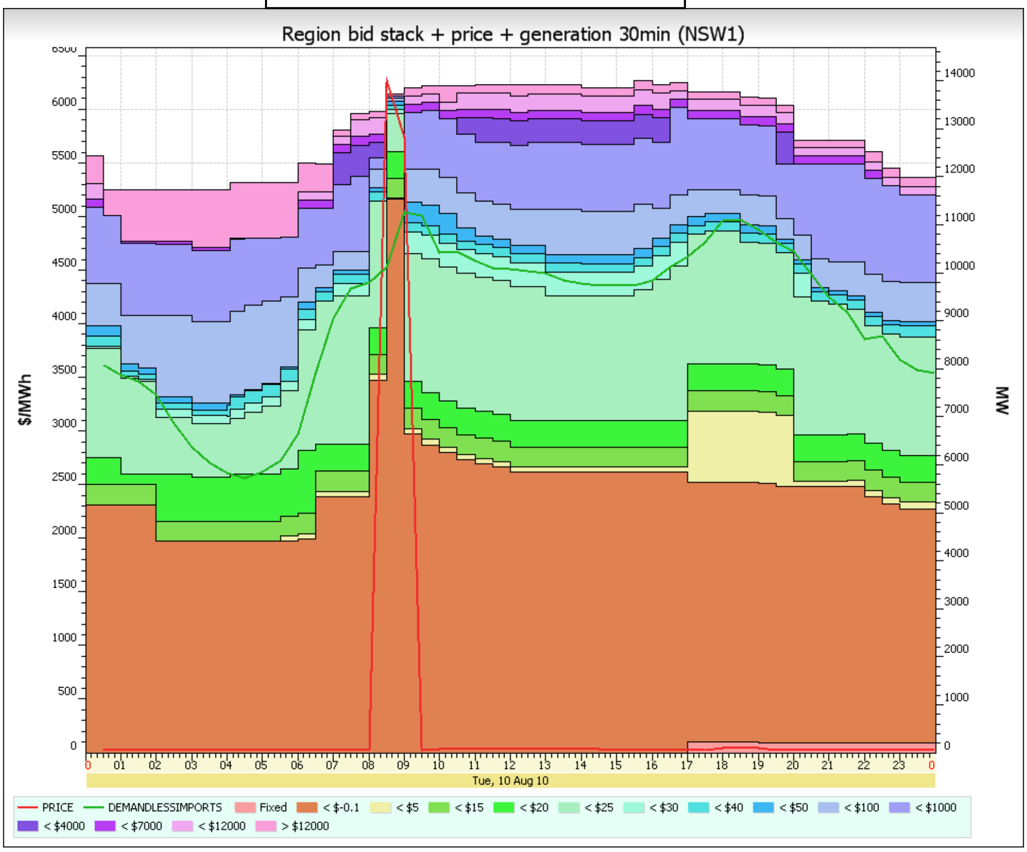
The event was triggered by a network reconfiguration that unexpectedly, and briefly, invoked a lower rating on the Mt Piper-Wallerawang constraint discussed in detail in Appendix B.

Some network events are by their nature unpredictable. This appendix will not discuss the circumstance that lead to this constraint being invoked, instead focussing upon the rebidding reaction and resulting power system impacts.

2. Rebidding

When this constraint binds, it is common for most NSW generation to rebid to the market floor price and to reduce Rates of Change (ROC) down to the minimum permissible of 3MW/min. The floor price rebidding (burnt orange) can clearly be seen on the graph after the constraint was invoked at 08:15AM until it was removed at 09:00AM.

NSW price stack 10 Aug 2010



The invocation of the constraint at 08:15AM was immediately followed by major rebidding activity of this form.

Plant	Approx Capacity[7]	First floor-price rebid time[8]
Tallawarra	400MW	08:17:11
Lower Tumut and Upper Tumut	2100MW	08:17:51
Uranquinty	600MW	08:23:04
Bayswater	2640MW	08:26:34
Liddell	2000MW	08:26:34
Colongra	724MW	08:45:56

3. Power system flows

The sudden and large re-pricing of capacity resulted in dramatic reversals of transmission flows as demonstrated by the graph below.

- NSW had been previously importing 1050MW from Qld via QNI, and within 10 minutes this changed by some 1450MW to a 400MW export. Such a sudden change to the Qld supply resulted in a period of negative pricing as Qld generators had to ramp down to accommodate the additional supply.
- NSW had been exporting 100MW to Victoria, and over 40 minutes this increased to 1200MW.

Thus NSW flows to the other states increased by 2550MW during the event. As NSW prices were high, this incurred a negative residue of approx $1m. No positive residue accumulated so the SRA could not support inter-regional hedging into NSW.

The dispatch equation is constrained with the intent of keeping the power system secure, on the presumption that generators comply with their dispatch targets. This mostly occurred and the system remained generally secure. However the dramatic and sudden changes to generator outputs did disturb power system conditions. For example, system frequency rose to 50.085Hz as the floor-price bids were dispatched, then fell to 49.86Hz shortly at 9:10AM as bids were restored to normal.

[7] This is the nominal capacity of the entire station.
[8] This appears to be the first rebid that attempted to lower prices. In some cases, several units were rebid slightly later.

NSW interconnector flows and prices: 6AM-11AM 10 Aug 2010