B Modelling

This Appendix describes the approach, assumptions, and data sources used in the revised modelling undertaken by the Commission's consultants (Frontier Economics or Frontier) of the various Rule change proposals submitted by participants in relation to the Snowy region of the NEM. The analysis considered several alternative proposals:

- The Abolition of Snowy region proposal (Abolition proposal) submitted by Snowy Hydro, in which Tumut generation is located in the NSW region and Murray and Guthega generation are located in the Victorian region;

- The Snowy Split Region proposal formally put forward by Macquarie Generation, in which the existing Snowy region is split into separate Tumut and Murray regions with the Murray regional reference node (RRN) located at Dederang; and

- The Congestion Pricing and Negative Residue Management Arrangements for the Snowy Region proposal put forward by the "Southern Generators" (Loy Yang Marketing Management Company Pty. Ltd., AGL Hydro Pty. Ltd., International Power (Hazelwood, Synergen, Pelican Point and Loy Yang B), TRUenergy Pty. Ltd., Flinders Power, and Hydro Tasmania) which is based on the existing arrangements of the Tumut CSP/CSC Trial and the Southern Generators Rule. This is referred to as the Southern Generators' Congestion Pricing or "SG" scenario.

Each of the above proposals was compared to a base case similar to that used in the Commission's quantitative modelling for the draft Rule determination on the Abolition proposal, published on 19 January 2007 (Abolition proposal draft Rule determination). The base case included the Abolition proposal draft Rule determination existing Snowy region boundaries with no Tumut CSP/CSC Trial mechanism and no Southern Generators Rule

To the maximum extent possible, Frontier sought to maintain consistency between the modelling approach adopted for this final Rule determination and the analysis presented in the Abolition proposal draft Rule determination. However, there have been several changes to the modelling assumptions and the scenarios considered from the Abolition proposal draft Rule determination. These changes are clearly highlighted in this Appendix.

The Appendix begins by discussing the Commission's consultation approach then outlines the modelling framework. It then discusses the methodology, assumptions, results, and conclusions for the forward-looking investment analysis, the dispatch and price modelling, and the risk modelling in turn.

B.1 Modelling framework and approach

The modelling framework is oriented towards the decision-making criteria to be applied by the Commission. These criteria, in turn, are guided by the nature of the issue the proposed Rule change is seeking to address and the NEM Objective. The modelling framework for these three Rule change proposals aims to answer the following key questions:

- How do the proposals affect the **economic efficiency of dispatch**? The economic efficiency of dispatch is concerned with the costs of producing electricity to meet customer demand. The economic efficiency of dispatch will be *maximised* where the generation resource costs of supplying customer load are *minimised* over a given time period. In particular, the Commission is interested in testing whether the avoidable generation costs of meeting load are likely to be reduced by any of the Rule change proposals being considered, and if so, by what degree. As hydro plant have insignificant variable fuel and operating costs, from a dispatch efficiency perspective, they should be run at those times when they can displace the plant with the highest avoidable costs. By considering the pattern of dispatch under each of these Rule change proposals, it is possible to assess changes to the efficiency of dispatch; and

- How do the proposals affect the **risk associated with inter-regional trade**? This is a function of both the price differences between regions and the firmness of IRSR units that can be used to hedge inter-regional price differences. In particular, we are interested in testing whether inter-regional price differences converge and/or IRSR units are "firmed up" by the three Rule change proposals, which will have the implications for inter-regional trade. This is important since the functionality of the hedging market potentially affects both future wholesale and retail prices and participants' future investment decisions. In the medium to longer term, these impacts could affect the achievement of the NEM Objective.

These three Rule change proposals potentially give rise to complex behavioural changes in the market, which means that it is not possible to draw conclusions as to their likely effect purely from analysis of historical data or by reference to a conceptual model. Forward-looking empirical modelling was therefore undertaken to test the effect of each of the proposals on the economic efficiency of dispatch and the firmness of IRSRs. There are three key parts to the forward-looking modelling analysis:

- **Investment modelling** to determine a sensible pattern of new plant entry in the NEM. New investment needs to meet both reliability requirements and the range of greenhouse gas abatement schemes active in the NEM;

- **Dispatch/price modelling** to examine market outcomes in terms of generator output and revenues and spot market prices, which involves participants being allowed to engage in strategic bidding to maximise their operating margins under different market conditions. This modelling aims to test the behavioural changes to market participants resulting from implementation of each of the proposals and the differences in dispatch, price and revenue outcomes relative to the base case; and

- **Risk modelling** to consider the risk management implications for market participants. In particular, this aims to examine whether any of the proposals are likely to increase or decrease the risk of inter-regional trading, either by making prices more volatile and hence more difficult and costly to hedge, and/or by making inter-regional hedging more or less valuable.

The investment modelling was undertaken to determine an optimal investment profile, and a pattern of dispatch for non-strategic hydro plant (this terminology is discussed in more detail below), which was then used as an input to the dispatch/price modelling.

Both the forward-looking dispatch and the risk modelling analysis were undertaken for four key scenarios:

- **A business-as-usual scenario (Base)**. In this case, it was assumed that NEMMCO managed counter price flows on all interconnectors by clamping, with the exception of southward flows on the Victoria-Snowy interconnector where negative residues were managed by re-orientating relevant Snowy constraints to Dederang. Neither the Tumut CSP/CSC instrument nor Southern Generators Rule arrangements were assumed to be in place. This case is referred to as the "Base" scenario;

- **The Abolition of Snowy Region proposal scenario (Abolition)**. This scenario, referred to as the "Abolition" scenario, reflected the Snowy Hydro Rule change proposal.[132] In this case, Murray was included in the Victorian region while Tumut was included in NSW. The existing Victoria-Snowy and Snowy-NSW interconnectors are replaced with a single Victoria-NSW interconnector. Unlike in the analysis for the Abolition proposal draft Rule determination, in this analysis, bi-directional flows on all interconnectors are restricted (i.e. "clamped") to manage the accumulation of negative settlement residues. Neither the Tumut CSP/CSC Trial nor the Southern Generators Rule arrangements are included;

- **The Split Snowy Region proposal scenario (SSR)**. This scenario reflected the revised proposal put forward by Macquarie Generation.[133] And is referred to as the "SSR" scenario. It involved splitting the Snowy region, with Murray and Tumut becoming standalone NEM regions. The new Murray region included Dederang as the RRN with the RRN for the Tumut region located at Lower Tumut. The existing Victoria-Snowy and Snowy-NSW interconnectors were replaced with three new interconnectors: Victoria-Murray, Murray-Tumut and Tumut-NSW. NEMMCO was assumed to clamp flows on all interconnectors to manage negative settlement residues. Neither the Tumut CSP/CSC Trial or Southern Generators Rule arrangements were assumed to be in place; and

- **The Southern Generators' Congestion Pricing proposal scenario (SG)**. This scenario was based on the Southern Generators' Congestion Pricing proposal.[134] This incorporated the existing Tumut CSP/CSC Trial arrangements for Tumut generation and the Southern Generators Rule, which requires the positive inter-regional settlement residues on the Snowy-NSW interconnector to offset negative inter-regional settlement residues on the Snowy-Victoria interconnector (after adjusting for CSP/CSC allocations). This case is referred to as "SG" scenario.

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132 Available on the AEMC website at: http://www.aemc.gov.au/electricity.php?cat=rc.

133 Macquarie Generation, Rule Change proposal to establish new Snowy regions, 5 March 2007.

134 Southern Generators, Rule change request: move Snowy CSP/CSC trial into Chapter 3, 15 March 2007.

The first three scenarios are reasonably consistent with those presented in the Abolition proposal draft Rule determination. The SG scenario was considered in light of the Southern Generators' Congestion Pricing proposal to inform this final Rule determination.

The approach to each of these types of modelling, including a brief description of the models used, is discussed in Sections B.2 and B.4 below. Those Sections also present the modelling assumptions, results, and conclusions for each of the scenarios.

B.2 Forward-looking investment and dispatch/price modelling

This Section discusses the approach, assumptions, results, and conclusions for the forward-looking investment and dispatch and price modelling analysis.

B.2.1 Approach

The investment modelling was undertaken using Frontier Economics' least cost investment model, *WHIRLYGIG*. Using this pattern of investment, the dispatch/price modelling was undertaken using Frontier Economics' game-theoretic wholesale market model, *SPARK*. It is worth describing some of the key features of these models before discussing the methodology used to calculate the dispatch and pricing implications of the Abolition and SSR proposals.

B.2.1.1 Key features of WHIRLYGIG

WHIRLYGIG incorporates a representation of the physical system and is purpose built to determine optimal, least-cost investment patterns in a wholesale electricity market subject to reliability constraints, greenhouse schemes and so on. The model contains the following features:

- A realistic treatment of plant characteristics, including for example minimum generation levels, variable operation costs, etc;
- A realistic treatment of the network and losses, including inter-regional quadratic loss curves, and constraints within and between regions;
- The ability to model systems from a single region down to full nodal pricing;
- The capability to optimise the operation of fuel constrained plant (e.g. hydro plant), and pumped storage plant over some period of time; and
- The ability to include a range of constraints that represent limitations on the market, such as capacity reserve constraints or greenhouse gas emissions schemes.

Given this representation of the market, the current stock of committed plant and a "menu" of new investment options, *WHIRLYGIG* determines the least cost optimal investment and dispatch pattern over the modelling period including the timing, type, location and size of new generating capacity. This capacity reflects the system reliability constraints that the market must meet and other policy factors that influence investment (predominantly greenhouse measures).

B.2.1.2 Key features of SPARK

Much like WHIRLYGIG, SPARK incorporates a representation of the physical system. Furthermore the model is purpose built to examine strategic behaviour in a wholesale electricity market. The model contains the following features:

- A realistic treatment of plant characteristics, including for example minimum generation levels, variable operation costs, etc;
- A realistic treatment of the network and losses, including inter-regional quadratic loss curves, and power system security constraints within and between regions;
- The ability to model systems from a single region down to full nodal pricing, including the incorporation of intra-regional constraints (such as the ANTS constraints); and
- The capability to optimise the operation of fuel constrained plant (e.g. hydro plant), and pumped storage plant over some period of time.

In addition, *SPARK* uses game theory to determine equilibrium generator bidding patterns in an environment of imperfect competition. Game theory provides a systematic tool for determining generator bids in such an environment, obviating the need for subjective judgements on bidding behaviour. This effectively makes generator bids an output of the model rather than an input. This allows an investigation of the changes in pricing and output behaviour resulting from changes in market rules or structure.

These features allow generator bidding strategies to be automatically reformulated in response to them facing different settlement prices when region boundaries are changed.

SPARK applies game-theoretic techniques by allowing selected strategic players to choose from a set of quantity change strategies (Cournot competition) and/or price change strategies (Bertrand competition) for each set of market conditions having regard to the market rules, power system conditions and the extent of intervention. In addition, *SPARK* is capable of modelling portfolios of generators within and across region boundaries, thereby allowing generators to test, create and exploit transmission constraints to their profit.

Once each participant is provided with a set of bidding choices, *SPARK* tests the potentially millions of bidding combinations for their sustainability. Sustainability in this context refers to the application of the Nash Equilibrium solution concept. A Nash Equilibrium is a set of strategies for all generators in which no individual generator has an incentive to unilaterally deviate from its bidding strategy. *SPARK* finds the Nash Equilibrium by assessing the "payoffs" of each generator in response to the bidding behaviour of every other generator in the NEM. The "payoff" relates to the difference between each generator's \$/MWh pool revenue and its assumed \$/MWh variable cost as well as any contract difference payments the generator may make or receive. If a generator can increase its payoff by changing its bids, that means that its original bid was not consistent with a Nash Equilibrium.

SPARK uses the Nash Equilibria bidding strategies to produce a range of results. The outputs produced by *SPARK* for each level of demand modelled include:

- Generator bids;
- Generator dispatch/outputs;
- Regional prices; and
- Interconnector directions and MW flows.

B.2.1.3 Methodology

WHIRLYGIG was used to determine an optimal investment pattern in new generating capacity which incorporates system reliability limits, greenhouse schemes and other factors that effect investment in the NEM. This pattern of investment is then used as an input to the dispatch/price modelling.

As noted above, *SPARK* can be used to determine optimal bids, market prices, and generator outputs under a given set of market assumptions. As these assumptions change, so too does the model-determined optimal set of bids and, hence, market prices and generator outputs. This enables *SPARK* to be used to calculate the dispatch and pricing impacts of changes to the market design such as an alteration to the region boundary structure of the NEM.

The first step in the dispatch/price modelling is to describe the base case scenario against which market design changes can be compared. This allows comparison of the Base scenario to the Abolition, SSR and SG proposals. Each of these scenarios is briefly outlined below. Detailed modelling assumptions are discussed in the following Section.

Base scenario:

Features of the Base scenario

- **Existing region boundary structure** – the structure of the NEM regions represented the current configuration;
- **Tumut CSP/CSC Trial excluded** – as the derogation in Part 8 of Chapter 8A of the National Electricity Rules (Rules) states that the Tumut CSP/CSC Trial is due to expire on: [insert date], before the period of interest.[135] The Tumut CSP/CSC Trial was therefore excluded from the Base, Abolition and SSR scenarios in the analysis;

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[135] The modelling focused on three financial years – 2007/08 to 2009/10 inclusive.

- **Southern Generators Rule excluded** – the Southern Generators Rule is also included in the Part 8 of Chapter 8A derogation, which ends prior to the modelling period considered in this analysis. It was therefore excluded from all scenarios except the SG scenario in the same way as the Tumut CSP/CSC Trial; and

- **NEMMCO clamping** – the effect of the introduction of a region boundary change in the presence of clamping was the focus of the modelling analysis. As such, clamping to manage negative settlement residues was assumed to occur bi-directionally on all interconnectors. The only exception was in the base case for southward flows on the Victoria-Snowy interconnector, where the re-orientation of the constraints to Dederang ensured that no negative residues arose. Unlike the case in the Abolition proposal draft Rule determination modelling, clamping was modelled assuming a $6000 per hour threshold for negative settlement residues and perfect foresight - That is, if a given combination of market participant bids and offers resulted in negative settlement residues in excess of the threshold arising on a particular interconnector then the set of bids was re-dispatched with flow on the interconnector constrained to zero. As noted above, the Abolition proposal draft Rule determination utilised a zero threshold for clamping on the basis that this was consistent with the wording of the Rules, although not with NEMMCO's actual practice. The use of a $6,000 per hour threshold was intended to better reflect NEMMCO's actual practice, even though NEMMCO applies a $6,000 threshold over the duration of a negative settlement residue event as determined by pre-dispatch modelling rather than on a "per hour" basis. As Frontiers modelling approach does not involve model outcomes across consecutive trading intervals, it was necessary to settle on a threshold that could be applied on an hourly basis. Another change in the modelling assumptions for the final Rule determination applied where two parallel regulated interconnectors exist (i.e., NSW-Queensland (QNI and DirectLink) and Victoria-South Australia (Heywood and MurrayLink)). In these cases clamping was only implemented in the case that the *net* negative residues across *both* interconnectors was greater than the threshold.[136]

Abolition of Snowy region proposal scenario

Features of the Abolition scenario:

- **Alternate region boundary structure** – Murray and Guthega were included in the Victorian region while Tumut was included in NSW. The existing Victoria-Snowy and Snowy-NSW interconnectors were replaced with a single Victoria-NSW interconnector;

- **Tumut CSP/CSC Trial excluded** – as for the Base scenario;

- **Southern Generators Rule excluded** – as for the Base scenario; and

136 For example, if negative settlement residues of $X arose on DirectLink and positive residues of $Y arose on QNI then DirectLink would not be clamped if X<Y and would be clamped if X > Y + threshold.

- **NEMMCO clamping** – clamping was effected on all interconnectors.

Split Snowy Region proposal scenario:

Features of the SSR scenario

- **Alternate region boundary structure** – the Snowy region was split with Murray and Tumut becoming standalone NEM regions. The new Murray region has Dederang as its RRN and Lower Tumut as the RRN for the Tumut region. The existing Victoria-Snowy and Snowy-NSW interconnectors were replaced with three new interconnectors: Victoria-Murray, Murray-Tumut and Tumut-NSW;

- **Tumut CSP/CSC Trial excluded** – as for the Base scenario;

- **Southern Generators Rule excluded** – as for the Base scenario; and

- **NEMMCO clamping** – clamping was effected on all interconnectors.

Southern Generators' Congestion Pricing proposal scenario

Features of the SG scenario:

- **Existing region boundary structure** – the structure of the NEM regions represented the current configuration;

- **Tumut CSP/CSC Trial included** – as this was part of the Southern Generators' Congestion Pricing proposal;

- **Southern Generators Rule included** – as this was part of the Southern Generators' Congestion Pricing proposal; and

- **NEMMCO clamping** – clamping was effected on all interconnectors except bi-directional flows on the Victoria-Snowy interconnector (as in the Base scenario). Negative residues on this interconnector would not accrue due to the implementation of the Southern Generators Rule. The SG scenario removes the requirement for clamping or re-orientation of constraints on the Victoria-Snowy interconnector. Clamping of bi-directional flows on the Snowy-NSW interconnector only occurs in the event that they are not triggered by a binding constraint that is included in the nominated set of constraints for the Tumut CSP/CSC Trial. If the negative residues on the Snowy-NSW interconnector relate to a constraint in the Tumut CSP/CSC trial there is no clamping and the negative residues are funded as part of the CSP/CSC arrangements.

Required steps

After establishing each of the scenarios for examination (Base, Abolition, SSR and SG scenarios), the dispatch modelling analysis was progressed in three main steps:

- First, *WHIRLYGIG* was used to model a short run marginal cost (SRMC) bidding scenario to determine the optimal pattern of dispatch for all *non-strategic hydro* *plant* (see the discussion of modelling assumptions below for a discussion of this terminology). In the SRMC scenario, all (non-run-of-river) hydro plant (e.g. McKay Creek) were dispatched at those times and in those quantities that minimised the variable dispatch cost of all thermal plant in the system. However, while strategic hydro plant (such as Snowy Hydro) were not restricted to this pattern of dispatch in future scenarios, the pattern of dispatch for all non-strategic hydro plant were not altered for the remainder of the analysis;

- Second, *SPARK* was used to model the dispatch and pricing outcomes of a strategic bidding scenario. Snowy Hydro and key thermal generators in other regions were allowed to bid strategically. The modelling focused on a number of key demand levels when significantly different market outcomes as a results of boundary change were most likely to occur – i.e. extreme peak demand times in summer and winter; and

- Finally, a number of demand levels representing the remainder of the year were modelled under the assumption of competitive dispatch, where the output of the strategic hydro generators was energy-constrained to ensure that their output over the year reflected assumed energy limitations.

The detailed assumptions and sensitivities used for the dispatch/pricing modelling are discussed in more detail below.

B.2.2 Modelling assumptions

As previously discussed, to the maximum extent possible, Frontier sought to maintain consistency between the assumptions adopted in the modelling for the final Rule determination and the analysis presented in the Abolition proposal draft Rule determination. Accordingly, the assumptions are the same as those presented in the Abolition proposal draft Rule determination with the exception of the change in clamping assumptions, as outlined above, changes to the static loss factors and dynamic loss equations for the Abolition and SSR scenarios and the addition of the SG scenario. (See Section B.3 for explanation of key differences). The specific modelling assumptions used for the analysis of the Abolition, SSR and SG proposals in comparison to the base case are set out below. We then discuss the differences from the assumptions used in the Abolition proposal draft Rule determination in more detail.

B.2.2.1 Generation capacity

Existing and committed[137] generation capacities for scheduled generators were taken from *NEMMCO, Statement of Opportunities for the National Electricity Market, October 2006* (the SOO). The portfolio structure of existing generation was based on *NEMMCO, List of Scheduled Generators and Loads, 21 February 2006* adjusted for those portfolios where dispatch rights have recently been transferred under contract or via sale.

[137] For example, Kogan Creek in Queensland from 2007/08.

B.2.2.2 Generator bids

Abolition proposal draft Rule determination.

Game theory analysis in a market such as the NEM with multiple pricing zones, transmission constraints and a significant number of players is computationally demanding. The number of combinations of bids to be evaluated increases exponentially with the number of strategic players, as well as the number of available bidding strategies available to each strategic player. There are an infinite number of bidding strategies and it is obviously not possible to model all of these.

Therefore, a number of methods can be adopted to ensure the modelling problem is manageable, including:

- The types and ranges of bidding strategies can be limited. In *SPARK*, bidding strategies can involve bidding the available capacity at different prices, or making more or less capacity available to the market, or a combination of both. Within these choices, the price range over which generators are allowed to bid, and the increments within this range, can be limited. Similarly, the extent of capacity withdrawal choices can be contained to a level that is plausible, and again the number of discrete choices within this range can be restricted to make the computational problem more tractable;

- The number of strategic players can be limited. Players can be categorised as either "strategic" or "non-strategic":

  – *Non-strategic* players are given fixed bids (i.e. their bids remain constant no matter how other players bid – fixed bids can be in any form or level, just as so long as they are fixed); and

  – *Strategic* players are given a set of potential bids to choose from and will respond to changes in other players' bids in order to maximise their payoff by choosing the most profitable bid from those available; and

- The set of potential bids available to strategic players can be limited to decrease the number of bidding combinations to be evaluated.

The strategic participants and their strategic power stations used in this analysis are shown in Table B.1. To limit the number of strategic participants, only the largest generation portfolios in each region of the NEM were assumed to behave strategically. They were given options to alter the *quantities* they offered into the market using a number of strategies (i.e. Cournot competition). For instance a strategy of 75% shown in the table corresponds to a participant bidding 75% of the combined capacity of its strategic power stations at or near SRMC and the remainder at VoLL.

Given the importance of understanding the effect of the proposals on the incentives for Snowy Hydro, Snowy Hydro was allowed a relatively large number of bidding strategies. Snowy Hydro was given options to offer from 0% to 100% of its capacity in 12.5% increments. Murray and Tumut Power Stations were assumed to be able to separately engage in these bidding strategies. This allowed for nine strategies for each of Murray and Tumut Power Stations, or a total of 81 combinations for Snowy Hydro. Snowy Hydro capacity that was offered into the market was bid at $1/MWh. This allowed Snowy Hydro to engage in behaviour that has been anecdotally observed, such as bidding Murray at close to $0/MWh. Note that Snowy Hydro *was not* energy constrained at times when it, and other participants, were allowed to bid strategically. The modelling was set up such that if Snowy Hydro generated at full capacity at these strategic times it would not exhaust its annual energy budget.[138]

Major generators in other regions of the NEM were assumed to be able to offer 80% or 90% of capacity at or close to SRMC (with the remainder at VoLL). The largest players in NSW and Victoria – Macquarie Generation and International Power, respectively – were also given the option to offer only 70% of capacity at or close to SRMC.

Table B.1: Strategic Participants

Strategic participant	Strategic stations	Bidding strategies (proportion of capacity offered at or close to SRMC)
Snowy Hydro	Tumut (i.e. Lower Tumut, Upper Tumut), Murray (i.e. Murray 1 & 2 stations, plus Guthega)	0%, 12.5%, 25%, 37.5%, 50%, 62.5%, 75%, 87.5%, 100% (Murray and Tumut given flexibility to bid separately)
Delta	Mt. Piper, Munmorah, Vales Pt, Wallerawang C	90%, 80%
International Power	Hazelwood, Loy Yang B	90%, 80%, 70%
LYMMCO	Loy Yang A	90%, 80%
Macquarie Generation	Liddell, Bayswater, Hunter Valley GT	90%, 80%, 70%
QPTC (Enertrade)	Gladstone, Collinsville, Mt Stuart GT	90%, 70%
TRU Energy	Yallourn	90%, 80%

Hydro Tasmania was not modelled as a strategic player due to its present high level of vesting and other contract cover. This level of contract cover is expected to remain relatively high throughout the modelling period. All of Hydro Tasmania's discretionary capacity was bid into the market during high demand times (the summer and winter peak times when other players were allowed to bid strategically) at an SRMC of $1/MWh to reflect this high contract level and the fact that the plant would not be energy constrained at such times. For the remainder of the year, Hydro Tasmania was energy constrained such that its assumed annual energy

138 An annual energy budget is the volume of electricity, in MWh, that a generation plant can produce in a year if it utilised all of its available fuel. In the case of a hydro-storage plant, the annual available "fuel" (ie stored water) has been based on typical annual hydrological conditions rather than the recent drought conditions that have prevailed. See Section B.2.2.12.

budget was met. This ensured that Tasmanian spot prices reflected the opportunity cost of Hydro Tasmania's water across the year correctly.

All non-strategic thermal generators were assumed to bid into the market at SRMC. For the demand levels where generators were allowed to behave strategically, non-strategic thermal baseload units were bid in at SRMC for 100% of capacity and peaking units were bid in at five times marginal cost, resulting in bids of $100-1500/MWh. The demand levels comprising the rest of the year were dispatched with all plant (strategic and non-strategic) bid in at SRMC. For strategic and peaking plant, only 90% of capacity was bid at SRMC, with the remainder at VoLL.

Given these bidding choices, over all demand points modelled, SPARK computed regional reference prices, generator outputs, interconnector flows, and so on for nearly 500,000 bidding combinations for each year modelled. The Nash Equilibria were found from the results of these model runs.

Thermal generation SRMC and new entrant plant SRMC and fixed costs were drawn from the ACIL document: *SRMC and LRMC of Generators in the NEM, February 2005*. As noted above, non-strategic hydro plant were assumed to generate in the same manner as in the SRMC scenario.

B.2.2.3 Game theory and multiple equilibria

Using the Nash Equilibrium solution concept of game theory, it is possible for more than one equilibrium set of bids to be found for a representative demand point. In theory, each equilibrium is just as likely as another. Given that an equilibrium outcome is more likely than an outcome that is not an equilibrium, it is possible to think of the collection of multiple equilibria as a collection of "likely" outcomes. By assuming a weighting for each equilibrium, we allow for distributions of these equilibrium outcomes to be generated. Frontier explicitly assumed that a given Nash Equilibrium was as likely as any other – that is, all equilibria were assumed to be equally likely.

Presentation of modelling outcomes in the presence of multiple equilibria is challenging and a number of approaches are possible:

- Present the full distributions of results for all key variables;
- Present a simple summary statistic that embodies the distribution of underlying results (i.e. distribution means); and
- Select a specific equilibrium using some kind of heuristic selection process.

Ideally, the full distributions would be presented for the key variables of interest in the analysis. However, due to the sheer volume of information involved, this was not practical. In practice, given the number of different scenarios and cases that needed to be compared against each other, presentation of the full distributions would actually hinder interpretation of the results.

Using a heuristic selection criterion, for example selecting the equilibrium with the lowest production cost for each demand point and ignoring all other sustainable outcomes, was also deemed an unsuitable approach to the analysis. The major benefit of using a framework like game theory to analyse incentives is that it is systematic and objective. Selecting one outcome in preference to all others would weaken the analysis and ignore the remainder of the distribution of likely outcomes.

As a compromise, Frontier presented the results using the average values of the distributions for all key variables assuming that all equilibria are equally likely. Additional analysis was undertaken by Frontier to ensure that these average values did not misrepresent the outcomes of the modelling.[139]

B.2.2.4 Contract levels and sensitivities

The level of contract cover can be an important determinant of bidding behaviour because some generators manage the risks of unfunded difference payments by bidding their contracted capacity at their SRMC. This approach to risk management can dampen spot prices in the short term.

Therefore, a number of different assumptions on contracting levels were modelled for each of the scenarios. In constructing the various contracting cases, four key aspects of contracting in the NEM were considered:

1. **Overall levels of contracts in the market** – strategic players were assumed to sell contracts equal to "high" and "low" percentages of their installed capacity (see Table B.2 below). These were similar to the levels used in assessing the Southern Generators Rule change;[140]

2. **Volume of IRSR units Snowy Hydro holds with respect to the contracts it has struck in Victoria and NSW** – Snowy Hydro was assumed to hold IRSRs *equal* to its inter-regional contracting volume;

3. **Split of Snowy Hydro's aggregate contract volume between the Victorian and NSW nodes** – Snowy Hydro was assumed to split the total volume of inter-regional contracts it sold between the Victorian and NSW nodes. Only the case where contracts were split equally between the Victorian and NSW nodes is presented. This 50/50 split was the base case used in the modelling for the Southern Generators Rule change[141]. The increased complexity and size of the modelling problem in this analysis meant that some limit on the number of scenarios and sensitivities had to be observed. As such, only this 50/50 split was considered; and

[139] The additional analysis found that the relativities between the averaged outcomes of the modelling were consistent with the relativities at other points on the distributions. That is, the distributions were generally smooth.

[140] AEMC, Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006, Appendix C, pp.C20-C21.

[141] AEMC, Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006, Appendix C, pp.C20-C21.

4. **Type of contracts held by Snowy Hydro** – Snowy Hydro was assumed to hold all cap contracts with $300/MWh strike prices. This reflects the fact Snowy Hydro essentially offers insurance products into the market.

Table B.2 summarises the combinations arising from the first two contracting cases considered. NSW strategic generators were assumed to contract to a lower level than players in other regions initially to account for the effect of the ETEF arrangement. These levels increased through the modelling period to reflect the ETEF roll-off. The percentage of NSW regulated retail load supported by ETEF is planned to reduce as follows:

- from September 2008 (100% to 80%);
- from March 2009 (80% to 60%);
- from September 2009 (60% to 40%);
- from March 2010 (40% to 20%); and
- from June 2010 (20% to 0%).[142]

Table B.2: Contracting cases

Contracting case	Snowy Hydro contract level	Snowy Hydro IRSR units	NSW players	Other players
High	60% of capacity	Equal to contract level	Initially 65% of capacity, rising to 75% by 2009/10 to account for ETEF roll-off	75% of capacity
Low	50% of capacity	Equal to contract level	Initially 55% of capacity, rising to 65% by 2009/10 to account for ETEF roll-off	65% of capacity

B.2.2.5 Modelling period

The modelling was conducted for the three financial years 2007/08 to 2009/10 inclusive.

142 See Office of Financial Management, Payment rules for the Electricity Tariff Equalisation Fund, April 2006, p.3.

B.2.2.6 Greenhouse schemes

Multiple greenhouse gas abatement schemes are active during the modelling period. The *WHIRLYGIG* modelling included the following schemes:

- NSW GGAS;[143]
- Queensland 13% gas;[144]
- Mandatory Renewable Energy Target (MRET);[145]
- Victorian Renewable Energy Target (VRET);[146] and
- The NSW Renewable Energy Target (NRET).[147]

These schemes ultimately affect the mix of plant present in the system and the way it is dispatched. The dispatch/price modelling incorporated these effects by assuming the determined investment pattern and the dispatch of "green" generators.

NEMMCO nets out the demand met by embedded generation from its demand forecasts. As a large component of these schemes is met by embedded generation, this demand was added back into the models and explicitly modelled. It should be noted that intermittent generation technologies, such as wind, only contribute a percentage of their capacity towards meeting the reliability constraints in the model (in the case of wind, this amounts to 8% of installed capacity being assumed operational at times of peak demand in line with NEMMCO's assumptions).[148]

B.2.2.7 Demand

To streamline the modelling, the analysis focused on 62 representative demand points per year rather than a chronological modelling of each half hour, or hour, in each year. The time saved by modelling fewer demand points allowed a larger number of strategic players and strategies to be modelled. Each demand point was weighted by its expected frequency of occurrence during the year (in hours) so that yearly average results could be determined by adding up the frequency-weighted outcomes for each demand point. This meant that points of low and average demand, which occur frequently throughout the year, received a higher weighting than the peak demand points, which occur infrequently.

The electricity demand in each year was based on the medium growth, 50% probability of exceedance (POE) forecasts from NEMMCO's 2006 Statement of

[143] Greenhouse Gas Reduction Scheme Administrator, Introduction To The Greenhouse Gas Reduction Scheme (GGAS), June 2006.

[144] See http://www.energy.qld.gov.au/13percentgas.cfm for details regarding the scheme.

[145] Office of the Renewable Energy Regulator, Mandatory Renewable Energy Target Overview, March 2006.

[146] See http://www.esc.vic.gov.au/public/VRET/Overview.htm for details regarding the scheme.

[147] NSW Government, NSW Renewable Energy Target Explanatory Paper, November 2006.

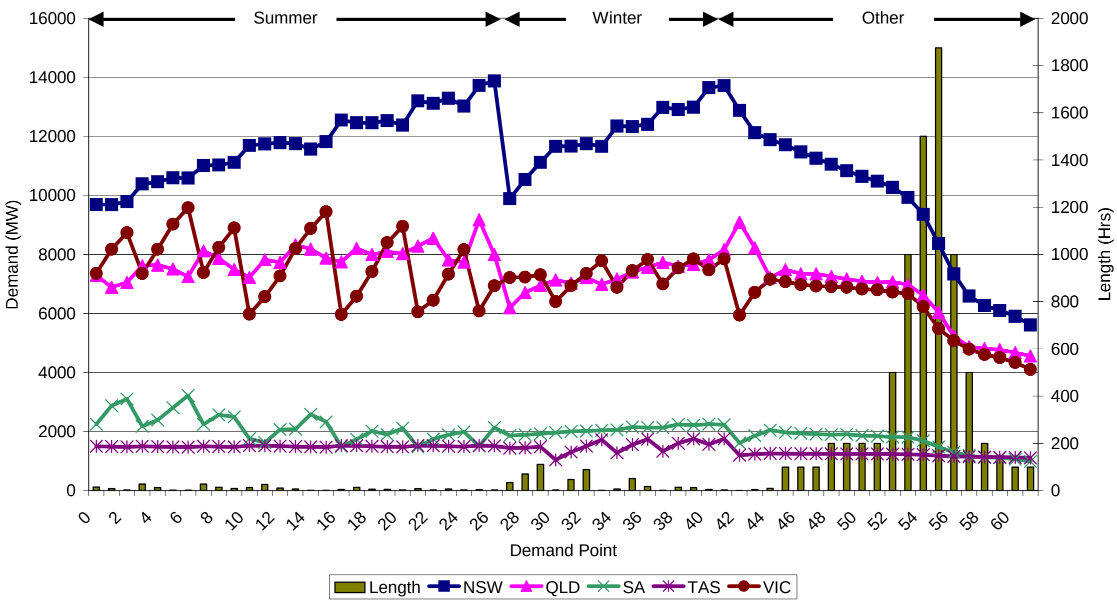
[148] NEMMCO, 2005 Energy and Demand Projections, July 2005, p.17.

Opportunities (SOO) and was characterised using the 62 representative demand points. The demand profile was based on the 2004/05 actual load profile.

The first 27 points focused on levels of NSW and Victorian demand that led to clamping (as informed by the previous Southern Generators Rule analysis) during *extreme* summer peak hours. These points accounted for 250 hours of the year. Another 15 points were allocated to *extreme* winter peak hours in a similar manner, corresponding to a further 470 hours. The remainder of the year, 8040 hours, was represented by a final 20 demand points. This is shown for 2007/08 in Figure B.1 below where the level of demand is shown on the left vertical axis and the length of each point is shown on the right vertical axis. It is important to note that the definition used here does not correspond to the summer and winter peak periods normally used in the NEM (e.g. AFMA summer and winter peaks).

Demand side bids were included, with the volume taken from the SOO at an assumed bid price of $500/MWh. No additional demand elasticity was assumed at any given demand point.

Figure B.1 Level and duration of demand points (2007/08)



B.2.2.8 Loss factors and equations

The modelling was conducted on a zonal pricing and settlements basis. Six regions (i.e. zones) were modelled: NSW, Queensland, Victoria, South Australia, Tasmania and Snowy (regions changed in the Abolition and SSR scenarios). Within each region static losses where accounted for by incorporating each generating unit's Static Loss Factor (SLF) as published by NEMMCO. Inter-regional losses where incorporated dynamically in the modelling using loss factor equations provided by NEMMCO. Static marginal loss factors and dynamic marginal loss factor equations were taken from a pre-release draft version of NEMMCO's document, List of

Regional Boundaries and Marginal Loss Factors for the 2006/07 Financial Year, March 2006.

The revised region boundary structures under the Abolition and SSR scenarios meant that new static loss factors were required for the new regions and new dynamic marginal loss factor equations were required for the new interconnectors. NEMMCO provided the specific static loss factors and dynamic marginal loss factor equations for each of these scenarios. For example, for the Abolition scenario a new Upper Tumut static loss factor relative to the NSW RRN and a dynamic loss equation for the new Victoria to NSW interconnector were provided.

B.2.2.9 Constraint equations

The constraints that are included in the Tumut CSP/CSC Trial for the Snowy region were taken from NEMMCO's document, *Constraint List for the Tumut CSP/CSC trial, March 2006*. This document lists the constraints for which Snowy Hydro receives CSP payments, including re-oriented formulations if applicable.

In the Base and SG scenarios, the constraint equations for all other constraints were taken from the Constraint Spreadsheet provided with the *Annual Transmission Statement (ANTS)* data attached to the NEMMCO 2005 SOO. The full list of system normal, national transmission flow path (NTFP) constraints was included in the modelling. These ANTS-zone constraints incorporate the principal transmission limits on the underlying physical network that affect power flows across the major transmission flow paths in the NEM. These flow limits incorporate:

1. Pure intra-regional limits;

2. Limits that impact on a combination of generators within a region and one or more interconnectors; and

3. Constraints that involve the interaction of flows on two (or more) interconnectors (e.g. QNI and DirectLink).

For the Abolition and SSR scenarios, NEMMCO provided altered versions of the 2005 ANTS constraint set which reflected the relevant change to region boundaries in each scenario. These constraints were implemented dynamically in the modelling for all scenarios in fully co-optimised form.

These constraint equations incorporated the effect of likely transmission network upgrades via changes in line ratings over time. The constraints also incorporate the impact of committed/likely new generation capacity by assigning each new generator a co-efficient in the constraint equations.

B.2.2.10 Interconnectors

For the Base and SG scenarios, the analysis used a six region representation of the NEM: Queensland, NSW, Snowy, Victoria, South Australia and Tasmania. As discussed earlier, boundaries between the Victorian, Snowy and NSW regions were altered under the Abolition and SSR scenarios and new interconnectors replaced the existing ones. The interconnector transfer capabilities were limited by the network constraints represented in the ANTS and the Snowy constraint list under system normal conditions. Basslink was assumed to be fully commissioned from the commencement of the modelling period, with limits of 590MW north or 300MW south, consistent with the detailed information provided with the 2006 SOO. MurrayLink, DirectLink and Basslink were dispatched as regulated interconnectors. For Basslink, this was justified on the basis that Hydro Tasmania was not nominated as a strategic generator for the reasons given above.

B.2.2.11 Outages

The modelling was conducted on a system normal basis, meaning it did not include any transmission outages (scheduled or random). This was done to increase flexibility for the gaming analysis and is consistent with the assumption that significant generator outages are unlikely to be scheduled during the peak summer and winter months, which were the focus of the modelling analysis. Random or forced generator outages were excluded from the analysis for simplicity. While this would tend to understate dispatch costs, the comparison between the Base scenario and the other scenarios should not have been significantly influenced by this simplification, as the pattern of outages should not be any different between the three scenarios.

B.2.2.12 Energy constrained plant

Hydro plant were modelled to reflect long-term average energy limitations, rather than the recent drought conditions that have become more apparent over the last 12-18 months. Run-of-river plants were assumed to operate at the same level across all demand periods and other hydro plant were assumed to run to meet annual energy budgets, based on the assumption that water would be used at times it was most valuable. The modelling also incorporated pumping units (Wivenhoe, Shoalhaven and Tumut), which were assumed to have a 70% pumping efficiency and be dispatched when optimal (i.e. most valuable).

Snowy Hydro had previously indicated that it had the ability to manage its water reserves between years.[149] To the extent that any of the proposals increased Snowy Hydro's output over the entire year relative to the Base scenario, we would observe higher production cost savings due to increased hydro output displacing thermal plant. However, for the purposes of this modelling exercise, Snowy Hydro was assumed to have an energy budget of 4.9 TWh p.a. as reported in NEMMCO's 2005 ANTS report. As discussed, Snowy Hydro was not assumed to be energy constrained during the "super-peak" times of the year when generators are assumed to bid strategically. The length of time represented by these strategic demand points meant that Snowy Hydro could not exhaust its energy budget even if it was fully dispatched at these super-peak times.

[149] See Snowy Hydro Limited, first round submission, Management of Negative Settlement Residues by re-orientation Rule change proposal, 7 July 2006, p.19.

B.2.2.13 Treatment of VoLL prices

Under some market conditions, *SPARK* finds it profitable for generators to set the spot price at the Value of Lost Load (VoLL = $10,000/MWh). In practice, the spot price occasionally rises to VoLL, but generally not as often as *SPARK* finds it is profitable to do so.

The key difference between the modelling results and actual behaviour is the observed tendency towards "self regulation" by generators. Typically, generators do not necessarily exploit every opportunity to set the market price at VoLL when they can. This self regulation could be due to generator concerns about the risk of not being able to meet contract payments triggered by high spot prices (the costs of which are taken into account in the *SPARK* modelling) or concerns that high spot prices will attract unwanted regulatory attention. Instead of setting VoLL prices under these circumstances, generators often set spot prices substantially less than the VoLL – but nevertheless at high levels compared to average prices.

It is difficult to conceive of a systematic approach for incorporating this self regulation into market modelling. There are two key choices for managing this issue: explain that this behaviour exists and take no account of its effects, or accept its reality and adjust for its effects. In the present modelling exercise, it was agreed to reflect the reality of self regulation through a systematic and consistent adjustment of VoLL pricing events across all scenarios. More specifically, prices were effectively capped by a notional generator with a bid equal to the recent historical average of high price events ($2,500/MWh), which were classified as any price over $300/MWh (the marginal costs of the most expensive generator).[150] The same adjustment approach was used for all modelling scenarios and therefore ought not significantly distort the comparison of the results.

B.3 Key assumption changes since Abolition proposal draft Rule determination in January 2007

Since the Abolition proposal draft Rule determination, several key assumption changes have been made with regards to how negative settlement residues on interconnectors are managed via clamping. These changes are summarised in Table B.3. Note that the Abolition proposal draft Rule determination work did not include a scenario analogous to the SG scenario.

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[150] This average price was derived from the Southern Generators' Determination: AEMC, Final Rule Determination, National Electricity Amendment (Management of Negative Settlement Residues in the Snowy Region) Rule 2006, Appendix C, p.C24-C25.

Table B.3: Key assumption changes since Abolition proposal draft Rule determination modelling

Assumption	Abolition proposal Draft Rule Determination	August Determination
Which interconnectors are subject to clamping	Snowy region interconnectors only except where V_SN is reoriented to Dederang for southward flows in the Base scenario	All interconnectors except where V_SN is reoriented for southward flows or for the V_SN interconnector in either direction in the SG scenario
Clamping threshold	$0	$6000/hour
Net clamping	N/A	Net clamping implemented for QNI/DirectLink and Heywood/MurrayLink ie flows only clamped if *net* residues across both interconnectors are negative in excess of the threshold.

As clamping can effectively segment the market, its effect on market outcomes is relatively large. The adoption of these assumptions brings the modelling of clamping closer to how it is implemented in practice. However some differences still remain:

- NEMMCO's threshold applies for the duration of the negative residue event as determined via pre-dispatch modelling; and
- NEMMCO implements clamping in a staged manner. That is, flows on the affected interconnector are stepped down over a number of dispatch periods eventually being constrained to zero flow if the negative residues persist.

Due to the demand point representation used in SPARK (rather than time sequential modelling of each half hour) and the partly discretionary nature of clamping implementation it is not possible to precisely capture these two features. Frontier believes that the current set of assumptions represent the closest practicable approximation to NEMMCO's actual implementation of clamping.

Static loss factors and interconnector dynamic loss factor equations for Abolition and SSR scenarios

In the modelling undertaken for the Abolition proposal draft Rule determination, revised static marginal loss factors for the Abolition scenario were derived by NEMMCO using the revised 2005 ANTS constraints for that scenario and made available for the analysis. For the (then) Split Region Option scenario, which is comparable to the current Split Snowy Region option, NEMMCO provided estimates of static loss factors that reflected the region boundary change and an approximate model of dynamic losses on the new interconnectors was assumed.

For the modelling undertaken for the final Rule determination, NEMMCO provided fully derived static loss factors and dynamic loss factor equations for the SSR scenario, which could be expected to improve the accuracy of the results. NEMMCO used the 2007 ANTS constraints to perform this derivation. The same data for the Abolition scenario has been used as was used in the Abolition draft Rule determination.

SG Scenario

The modelling for the final Rule determination considers the SG scenario as an additional scenario that was not considered in the Abolition proposal draft Rule determination.

B.3.1 Investment pattern results

As discussed above, the investment pattern results are derived under the assumption of competitive bidding, and are then applied to each of the scenarios considered in the dispatch/price modelling (Base, Abolition, SSR and SG).

Figure B.2 to B.5 show the new investment pattern for the NSW, Victoria, Queensland and SA regions respectively. In all regions, we observe a significant amount of “green” generating capacity being built, including technologies such as hydro, biomass and wind. This capacity was predicted to be built to meet the growing demand for low emissions generation brought about by the greenhouse gas abatement schemes active in the NEM as well as to ensure system reliability.

Beyond green investment, some additional peaking and mid-merit generation capacity was needed in each region for reliability purposes over the modelling period. The Tallawarra power station fulfilled this role in NSW, while generic new capacity was required in the other regions.

In NSW and Victoria, peaking capacity was the only additional capacity that was required. In South Australia, mid-merit capacity was the most cost effective way to meet load growth and reliability constraints. In Queensland, new mid-merit capacity was needed, predominantly to meet the Queensland 13% gas target. Note that the capacity shown in Figure B.4 for Queensland is in addition to the commissioning of projects listed as “committed” in the SOO, such as Kogan Creek from financial year 2007/08.

Figure B.2 NSW new investment

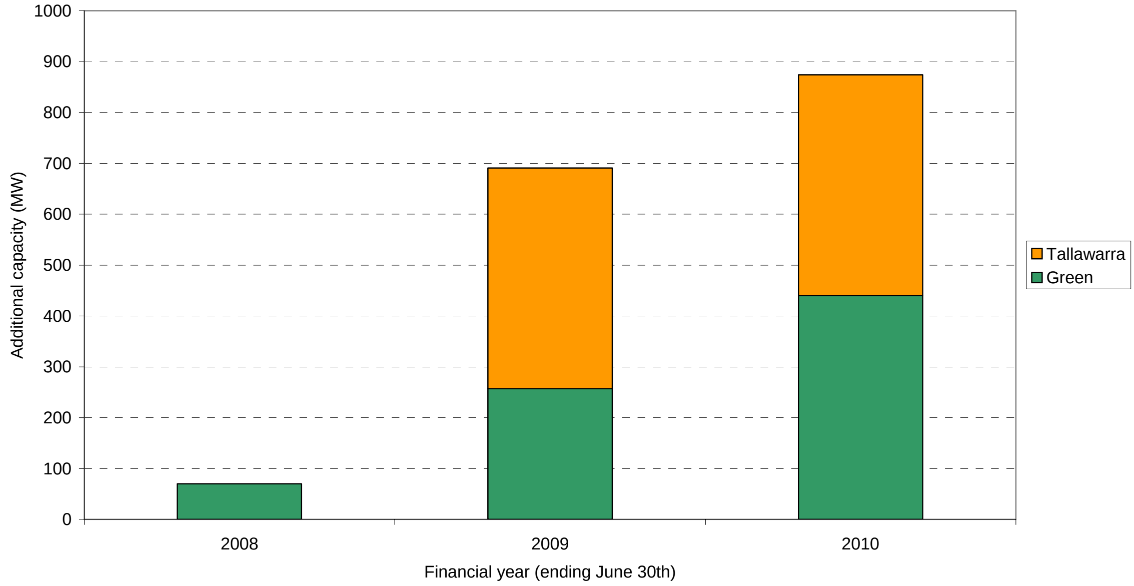


Figure B.3 Victoria new investment

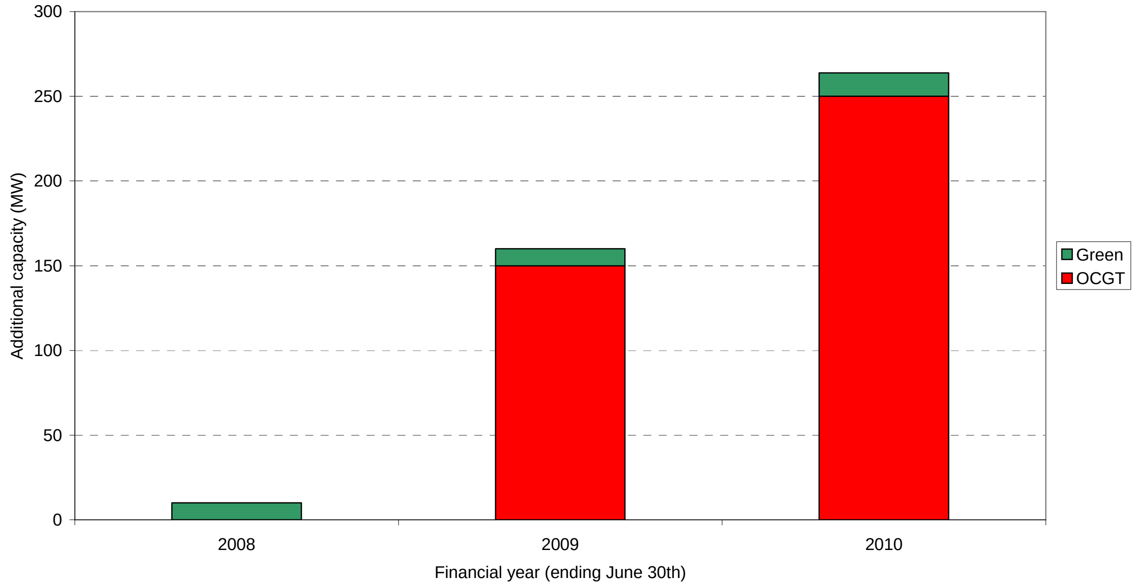


Figure B.4 Queensland new investment

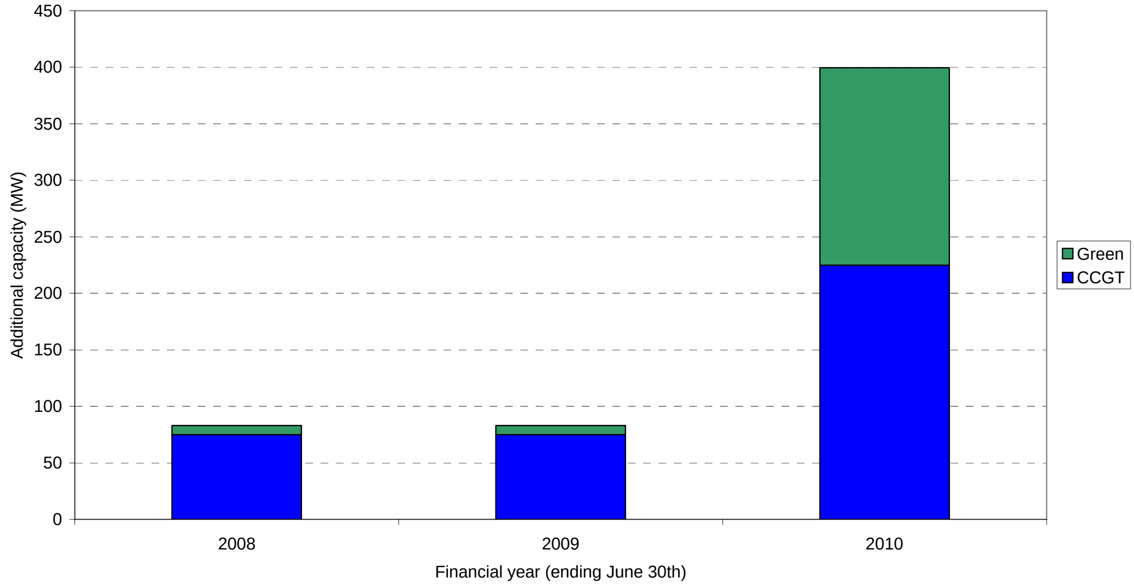
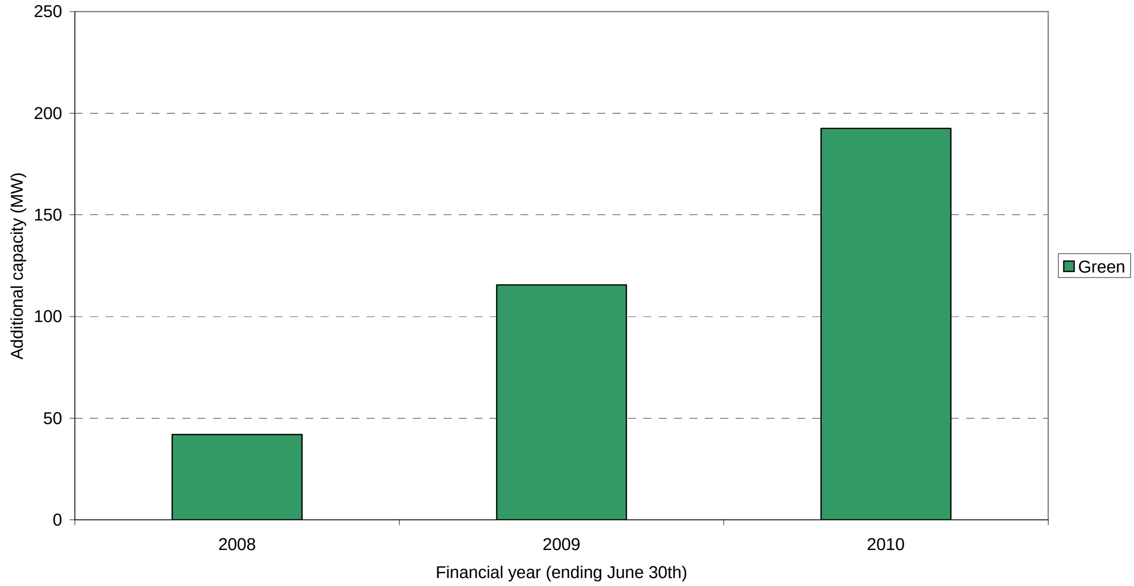


Figure B.5 SA new investment



The modelling approach assumed that the pattern of new generation investment as detailed above would not change under the different regional pricing and settlement arrangements modelled. This assumption was made to simplify comparisons between the scenarios and was considered to be, on balance, a conservative assumption to the extent that the modelling did not capture any dynamic efficiency gains due to an option leading to more efficient investment in the NEM. In any case, given that the modelling was only conducted over a three year period, any potential welfare gains due to more efficient investment would most likely have been small.

B.3.2 Dispatch/price modelling results

This Section discusses the dispatch and pricing modelling results obtained for each of the scenarios described above. The results of interest included:

- Production costs – annual NEM-wide variable electricity production costs in the summer peak period, winter peak period and remaining ("other") times of the year;
- The output of Snowy Hydro;
- Interconnector flows into NSW;
- Annual Regional (time-weighted) prices for Queensland, NSW, Snowy, Victoria, South Australian, and Tasmania;
- Instances of intra-regional constraint; and
- The frequency of clamping in the various scenarios.

Each of these results is discussed in turn below.

B.3.2.1 Broad conclusions of the modelling

In summary, both the Abolition and SSR proposals led to production cost savings and price reductions against the Base scenario, while the results for the SG scenario are less conclusive. The primary reason for the desirable outcomes from the boundary change proposals was an increased level of competition due to freer interconnector flows arising from the:

- New region boundary configuration and reformulated system constraints;
- Resultant change in network congestion between the scenarios, most prominently in a reduction of constraints around the Snowy region; and
- Altered incentives created for Snowy Hydro and other market participants under this new structure.

Specifically, the modelling shows that in the Abolition scenario, additional patterns of bidding that involved participants offering almost all their capacity into the market became sustainable (i.e. were Nash Equilibria). These "competitive" bidding equilibria were not sustainable (i.e. not Nash Equilibria) in the Base and SG scenarios due to altered patterns of congestion brought about by differences in region boundary reconfiguration, the implementation of clamping and the increased ability of participants to increase their profits by unilaterally withdrawing capacity. This was primarily due to a significantly different formulation of system constraints under the new region boundary configuration. This reformulation led to a reduction in system congestion and altered participants' incentives accordingly.

Savings in the SSR scenario arose for similar reasons as in the Abolition scenario. However, the magnitude of the savings was lower. Significant production cost *increases* (i.e. productive efficiency losses) at key demand points were also observed in the SSR scenario in certain years and contracting cases, which offset some of the production cost savings. These outcomes were fundamentally driven by Snowy Hydro being incentivised to withdraw large amounts of capacity in the SSR scenario compared to some other scenarios.

Results in the SG scenario followed a different pattern. The altered revenues received by Snowy Hydro changed its equilibrium bidding incentives. This meant that at certain times more capacity was offered into the market whilst at other times more was withdrawn relative to the Base scenario. The magnitude of the differences relative to the Base scenario was smaller than for the Abolition and SSR scenarios as would be expected given that the underlying set of system constraints was identical to that used in the Base scenario. Benefits in the SG scenario arise solely from the altered financial incentives of Snowy Hydro.. Conversely, in the Abolition and SSR scenarios, the reformulation of system constraints led to a significantly different and more efficient pattern of congestion across the NEM relative to the Base scenario.

These points are elaborated upon and supported by the modelling results presented below.

B.3.2.2 Caveats and limitations of the modelling

When interpreting the following results, it must be kept in mind that the modelling exercise was conducted to investigate the potential relative effects of different options for managing congestion in the Snowy region, with particular emphasis on the change in Snowy Hydro's bidding incentives. It was not the intention to predict actual market outcomes (particularly prices) for a given scenario, but rather, to investigate the relative changes that arise between the scenarios. For this reason, the results for a given scenario should not be considered as forecasts of actual market outcomes.

The key assumptions, which were constant across the scenarios, and which should be kept in mind when interpreting the results were as follows:

- The majority of the year was dispatched assuming competitive bidding in order to ensure Snowy Hydro does not exceed its energy budget. This resulted in lower pool price outcomes than may arise in reality, to the extent that strategic behaviour actually occurs at these times;

- Long term hydrology levels have been assumed contrary to actual drought conditions currently affecting the market. This led to lower price levels than are observed currently; and

- New entrant plant were assumed to be standalone and non-strategic in the absence of more accurate information. Again, this assumption would tend to depress pool prices towards the end of the modelling period, as greater amounts of capacity enter the market, to the extent that new entrant plant would be built by incumbent generators and/or withheld from the market more aggressively (or offered above SRMC).

B.3.2.3 Production costs

As discussed above, savings in variable production costs represent the dispatch efficiency benefits of a change in the market design. Figure B.6 shows the annual production cost savings for both the Abolition (red bars) SSR (blue bars) and SG (orange bars) scenarios. Savings are presented relative to the Base scenario for both the high and low contracting cases. Positive values denote a saving relative to the base scenario.

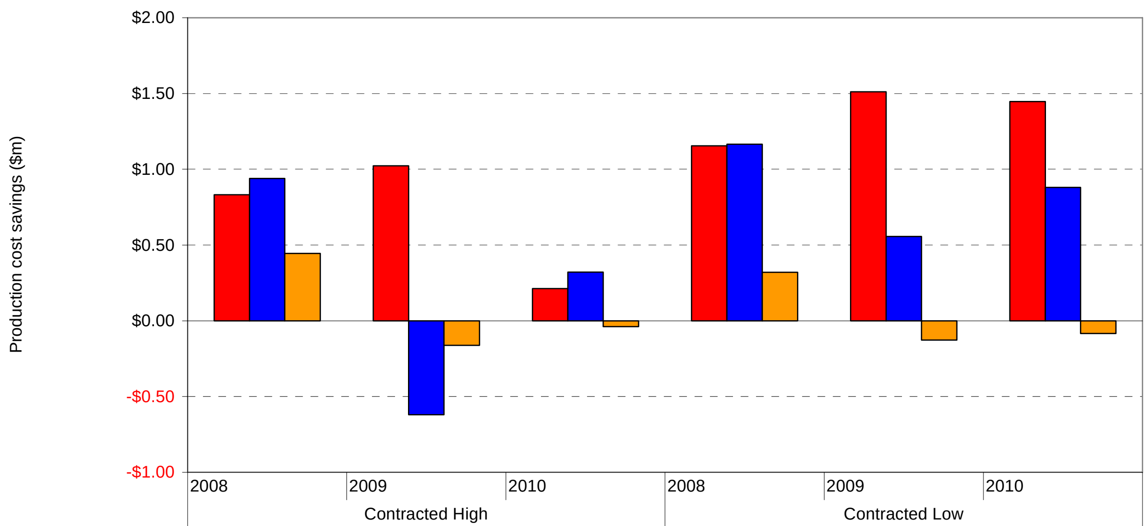
The Abolition proposal produced savings in all years and contract cases relative to the Base scenario. Savings peaked at $1.5m for the 2009, contracted low case. These savings were driven by the finding that the boundary change led to more competitive bidding strategies for Snowy Hydro and other participants being sustainable due to a reduction in the frequency of network constraint around the Snowy region. This led to greater levels of dispatch for Murray, Tumut, Victorian brown coal plant and cheaper NSW black coal plant displacing more expensive NSW and Queensland black coal and some mid merit gas plant across the NEM. The result was that production cost savings accrued (later results will also quantify the price effect this displacement causes). This effect was also observed in the analysis performed for the Abolition proposal draft Rule determination, the results of which are reproduced here in Figure B.7.

It should be noted that the modelling for the Abolition proposal draft Rule determination is not directly comparable to the results presented in this round of analysis due to the assumption of nonzero-threshold clamping on *all* interconnectors applied in that earlier work. Clamping in this manner, across all scenarios, significantly changed the incentives of market participants and had the net effect of dampening the magnitude of the production cost savings, particularly due to the assumption of a nonzero clamping threshold. This is consistent with the work performed for the Abolition proposal draft Rule determination, where the presence of clamping in only the Base scenario was identified as one of the drivers of the savings reported at that time. In the present modelling, given that less clamping occurs on the key Snowy region interconnectors occurs, differences (and source of production cost savings) between the scenarios have been reduced. This has resulted in reduced cost savings.

Production cost savings under the SSR scenario were generally positive and peaked at $1.2m relative to the SG scenario in the 2008, contracted low case. As with the Abolition scenario, these production cost savings arose due to the increased likelihood of more competitive bidding by Snowy Hydro and other participants due to reduced system constraint. The effect was not quite as great as that seen for the Abolition scenario and was also offset at certain demand levels where production cost losses were observed relative to the Base scenario. At these times, Snowy Hydro in particular was incentivised to pursue highly strategic bidding strategies in the SSR scenario that were not as profitable in either the Base or Abolition scenarios due to the different region configurations and constraint forms. Specifically, the fact that both Murray and Tumut generation were settled at their own respective regional prices tended to encourage greater withholding of capacity than under the Abolition or even the Base scenarios. Prices in the SSR scenario drove this outcome.[151] Specifically, the fact that the prices that were set in the Murray and Tumut regions incorporated the dynamic losses on the Victoria to Murray and Tumut to NSW interconnectors led to different pricing outcomes than in the Abolition case (even for the dispatch of identical bidding combinations). These different prices created different incentives for Snowy Hydro which, at times, led to production cost losses. This will be discussed in greater detail below.

Production cost savings in the SG scenario were either positive or very slightly negative (approaching the noise limits of the modelling), with the largest saving of $450K observed for the 2008, contracted high case. Production cost savings and losses in the SG scenario relative to the Base scenario were caused solely by the different incentives that Snowy Hydro had due under the SG arrangements. This lead to different bidding strategies being more profitable, coupled with the reaction of other participants to this change. This explanation is discussed in greater detail below. The differences between the SG and Base scenarios were less than those between the Abolition and Base and SSR and Base scenarios. This reflects the fact that the only difference between the Base and SG scenarios was Snowy Hydro's financial incentives rather than a fundamentally different constraint formulation, as was the case with the region boundary change scenarios.

Figure B.6 Annual production cost savings – current analysis ($m)

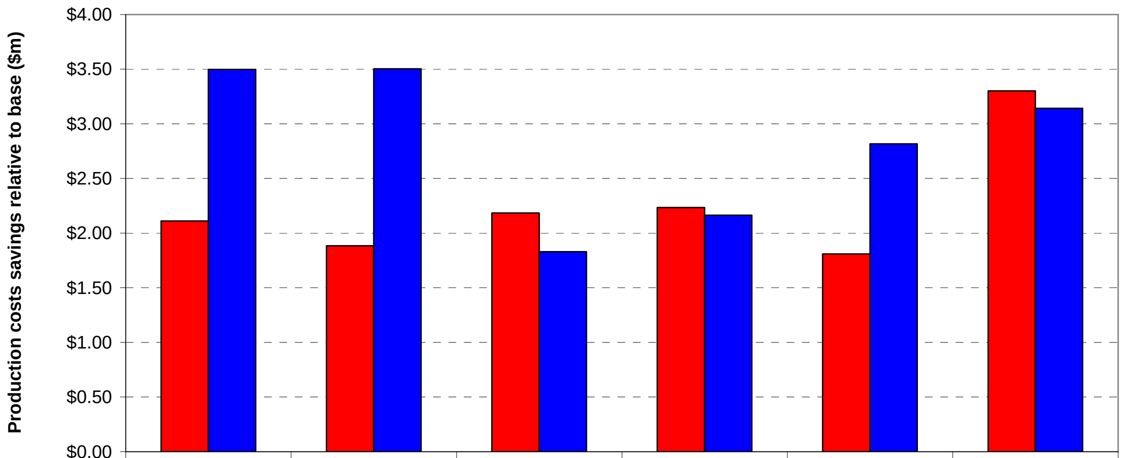


	2008	2009	2010	2008	2009	2010
Abolition vs Base	$0.83	$1.02	$0.21	$1.15	$1.51	$1.45
SSR vs Base	$0.94	-$0.62	$0.32	$1.16	$0.56	$0.88
SG vs Base	$0.45	-$0.16	-$0.04	$0.32	-$0.13	-$0.08

Contract case, financial year (ending June 30th)

151 The RRPs for Tumut and Murray generation are the nodal prices at Lower Tumut and Dederang. This means that nearly all generation in the Snowy Mountains area is settled at (or very close to) its nodal price, with the exceptions being Murray, Upper Tumut and Guthega power stations which are respectively settled at the Dederang, Lower Tumut and Dederang nodal prices.

Figure B.7 Annual production cost savings – from Abolition proposal draft Rule determination ($m)



	Contracted High			Contracted Low		
	2008	2009	2010	2008	2009	2010
Snowy	$2.11	$1.89	$2.19	$2.23	$1.81	$3.30
Split RO	$3.50	$3.50	$1.83	$2.16	$2.82	$3.14

Contracting case, financial year (ending June 30th)

B.3.2.4 Production cost savings under the assumption of competitive bidding by all participants

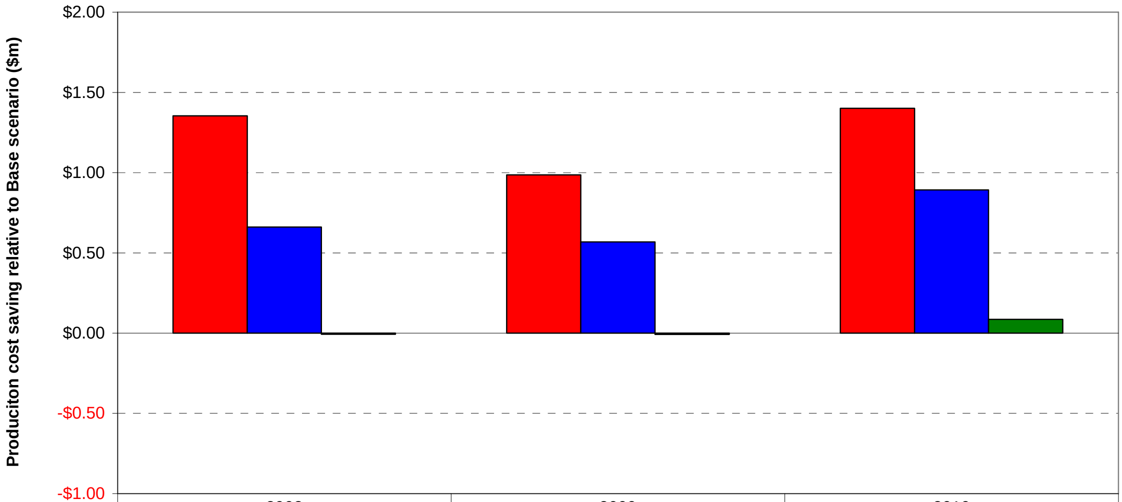
Figure B.8 shows the annual production cost savings if it is assumed that all market participants bid all capacity at SRMC (competitive bidding). Under this assumption, the level of contracting is immaterial. We observe that both the Abolition and SSR scenarios yielded annual production cost savings of between $0.5m and $1.5m. The savings were positive in all years for these two scenarios and the Abolition scenario delivered at least $0.5m of additional savings over the SSR scenario.

The SG scenario production costs were almost identical to the Base scenario outcomes in all three years. In the first two years, differences of less than $10,000 can be seen between the two scenarios (on an annual production cost of approximately $1.8bn). In the final year, a small saving of $90,000 can be observed, but this is potentially within the tolerance of the model and could comprise modelling "noise". The SG outcomes are not surprising given that:

- Under the assumption of competitive bidding, very little system constraint occurs across the NEM and both the SG and Base scenarios share the same constraint formulation; and

- The major difference between the scenarios – Snowy Hydro financial incentives – does not lead to a change in the assumed bidding pattern of Snowy Hydro (i.e. competitive).

Figure B.8 Annual production cost savings – assuming competitive, SRMC bidding by all participants ($m)



	2008	2009	2010
Abolition	$1.35	$0.99	$1.40
SSR	$0.66	$0.57	$0.89
SG	-$0.01	-$0.01	$0.09

Financial year

B.3.2.5 Timing of the production cost savings

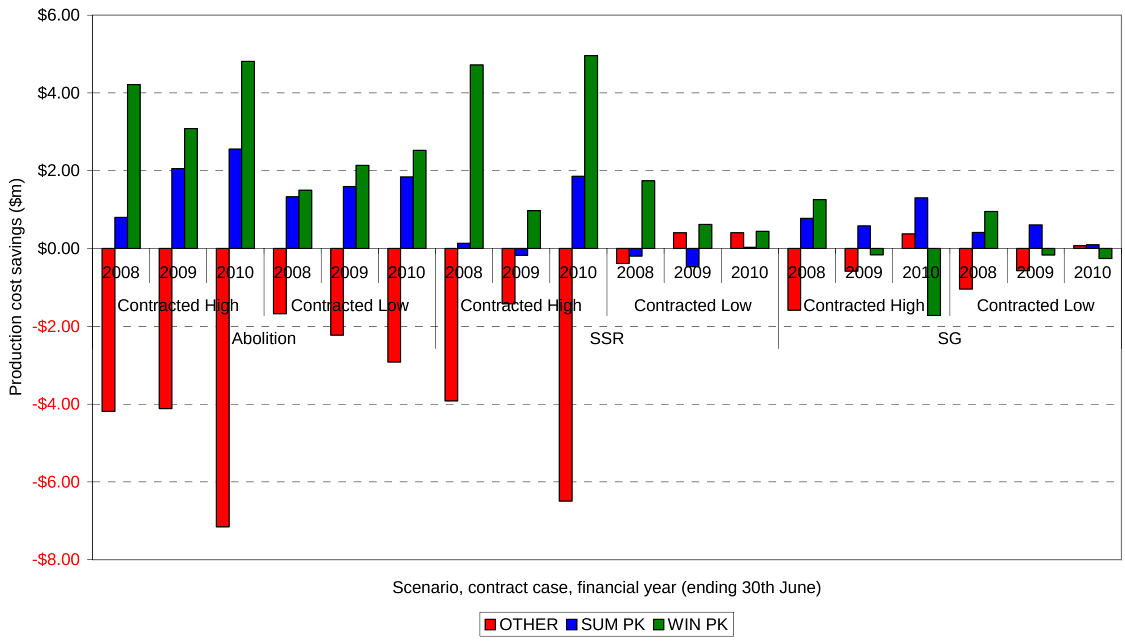
Figure B.9 shows the break down of the production cost by category - summer peak, winter peak and other times. Note that the summer and winter peak times do not correspond to conventional market definition of peak but rather the "super-peak" times noted above.

The production cost savings in the Abolition scenario occurred consistently during the extreme summer and winter peak times of the year when generators were allowed to bid strategically. During these periods, Snowy Hydro's hydro plant tended to run more than they did in the Base scenario. This caused a displacement of relatively expensive thermal generation in the Abolition case and hence a reduction in production costs at those times. However, due to Snowy Hydro's limited annual energy budget, it was forced to generate less at *other* times of the year in the Abolition scenario compared to the Base scenario. This meant that more relatively cheap thermal generation was required to run at those times in the Abolition case. Nevertheless, the net effect of the switching of timing of hydro production was lower overall costs in the Abolition case, as higher-cost thermal generation was displaced at peak times and more lower-cost thermal generation was required at other times.

With respect to the timing of production cost savings in the SSR scenario, we observe a similar pattern of savings to what was seen in the Abolition scenario in the contracted high case. Savings were not as consistent as in the Abolition scenario, particularly in the summer peak times. This reflected the occasions where production cost losses occurred in the SSR scenario relative to the Base scenario. For the contracted low case, a different pattern emerged. The magnitude of savings was far lower and generally occurred only during the winter peak times, with outcomes during the summer peak and other times following no clear pattern. In the contracted low case a greater range of equilibrium outcomes arose, with lower contracting levels making a greater range of bidding options feasible. On the average, this tended to produce similar outcomes for the SSR scenario as under the Base scenario, meaning that as such no significant savings (or losses) were observed. Note that this result differed from the Abolition scenario where greater number of equilibrium outcomes in the contracted low case resulted in production cost savings relative to the Base scenario.

Timing of the production cost changes in the SG scenario followed no obvious pattern. In addition, the magnitude of the savings was relatively low, as would be expected given the similarities between the SG and Base Case scenarios in terms of system constraint formulation. Having high or low levels of contracting in the SG scenario makes little difference to the production cost changes relative to the Base case.

Figure B.9 Annual production cost savings by time of year ($m)



B.3.2.6 Production cost changes by demand point

The drivers of the production cost results discussed above occurred to a greater or lesser extent across all of the demand points (29 and 30) modelled. Two demand points in particular serve well to illustrate exactly what lead to the differences in production cost outcomes-both in terms of savings and losses, between the scenarios. Both these points represent relatively high winter demand across the NEM, particularly in Victoria and SA. The levels of demand characterised by these points occur relatively frequently across the year (70.5 and 111.5 hours respectively) resulting in these demand points making up a large component of the annual production cost outcomes. Demand point 29 was given particular attention in the Abolition proposal draft Rule determination.

The impact of these points can be seen in Figure B.10 and Figure B.11. These figures show the production cost savings by scenario relative to the Base scenario by strategic demand point for the contract high and low cases respectively. It is clear that the greatest production cost savings and losses occurred for demand points 29 and 30 respectively. Further investigation of these two demand points, presented in detail below, serve to illustrate the driver of the differences across the scenarios for all demand points.

Figure B.10 Production cost savings relative to the Base scenario by strategic demand point, contracted high

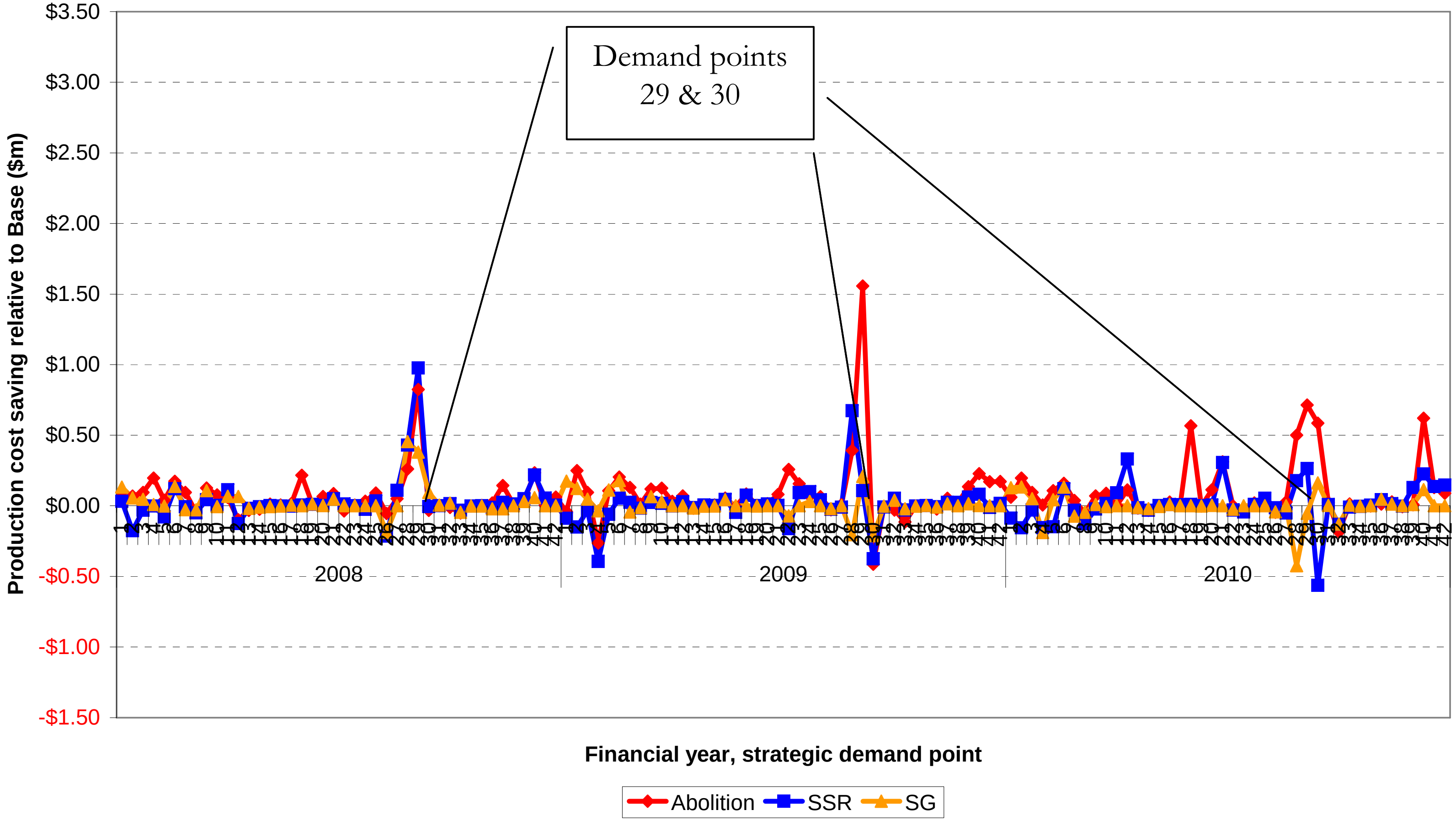
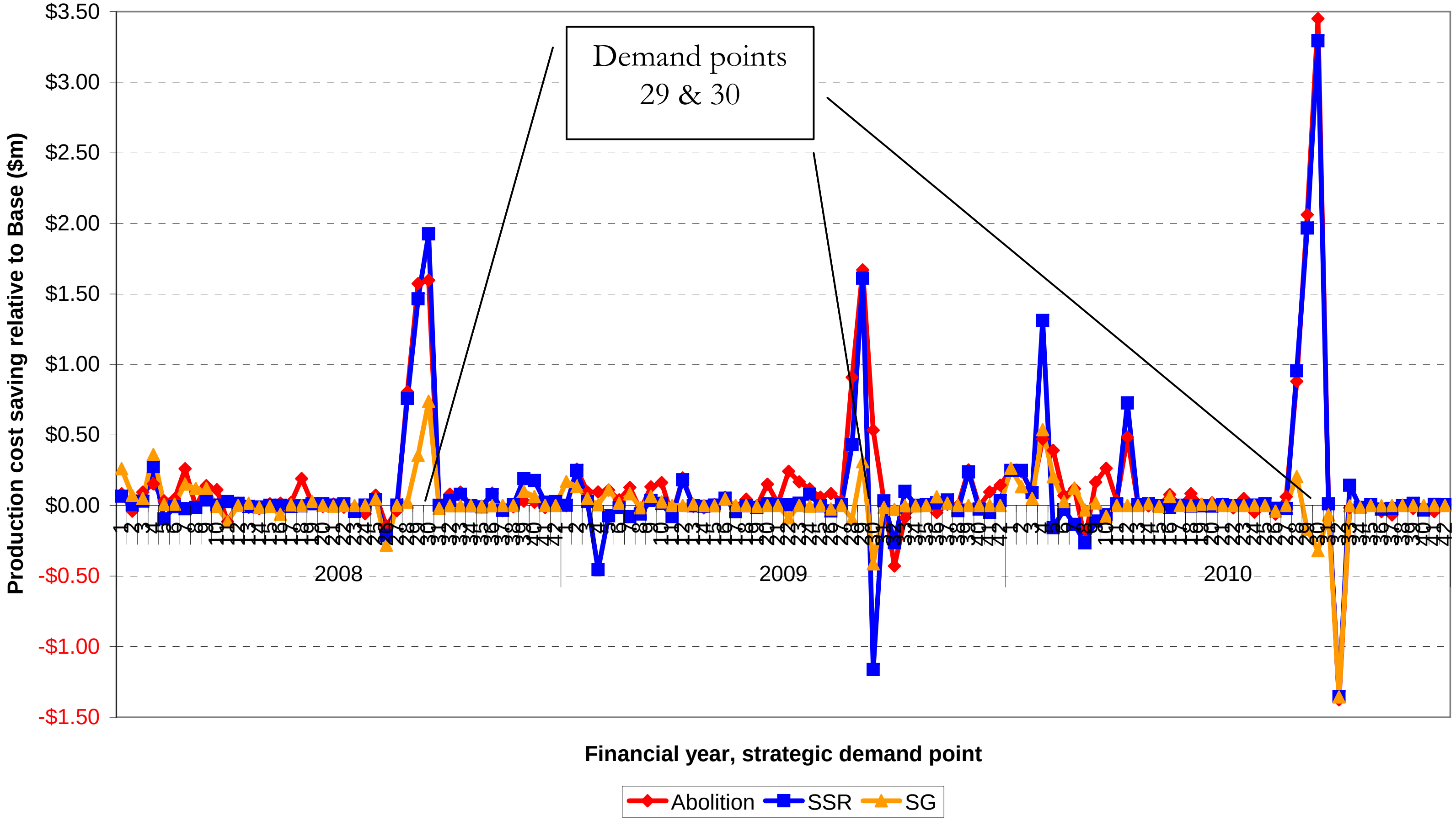


Figure B.11 Production cost savings relative to the Base scenario by strategic demand point, contracted low



B.3.2.7 Hourly production cost changes by demand point

Demand points 29 and 30 represent periods where significant production cost savings accrued. They serve well to illustrate the drivers of the different outcomes between the scenarios. This is partly due to these points representing a relatively large number of hours compared to the other strategic demand points that were modelled. This high weighting reflects the historical analysis undertaken by Frontier to identify levels of demand where constraint issues around the Snowy Region may arise. Before beginning a detailed discussion of the drivers behind these two demand points, it is valuable to present and discuss the production cost savings results on a per hour basis. These results are presented in Figure B.12 and Figure B.13 for the high and low contracting cases, respectively.

Whilst the largest contribution to annual production cost changes was made by points 29, 30 and several others, we see that on an hourly basis, other demand points dominated the results. This result is unsurprising for the following reason: The largest hourly production cost changes occurred for demand points that represented extreme market conditions in terms of high levels of demand. Based on Frontier's historical market analysis, it was observed that such events occurred relatively infrequently and hence, these points were given a correspondingly low weighting in the modelling. On the other hand, hourly outcomes for demand points 29 and 30 were not as extreme, but these levels of demand were observed much more frequently. Consequently, the outcomes relating to these points were given a larger weighting and their contribution to annual outcomes was highly significant.

Figure B.12 Hourly production cost savings relative to the Base scenario by strategic demand point, contracted high

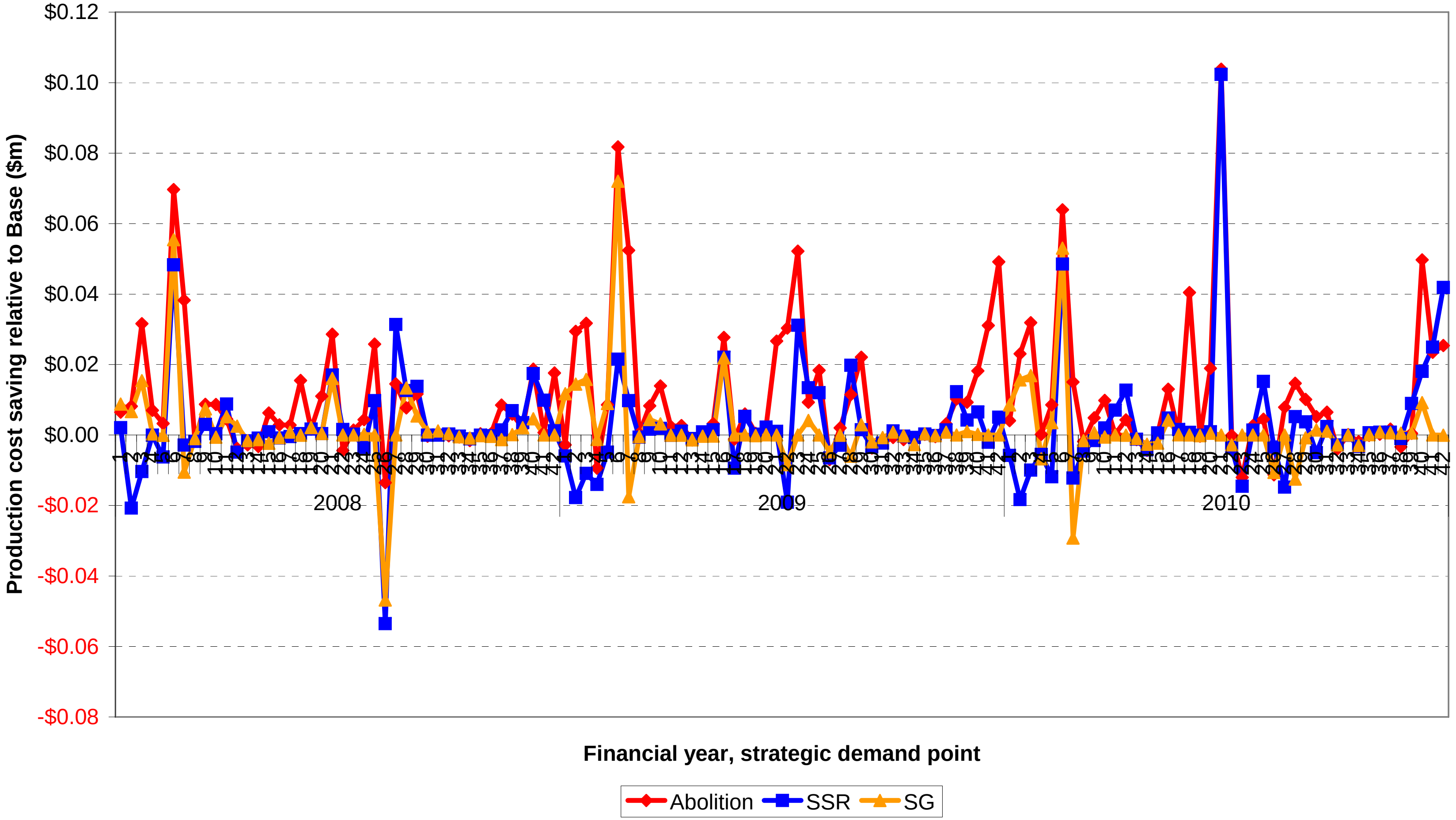
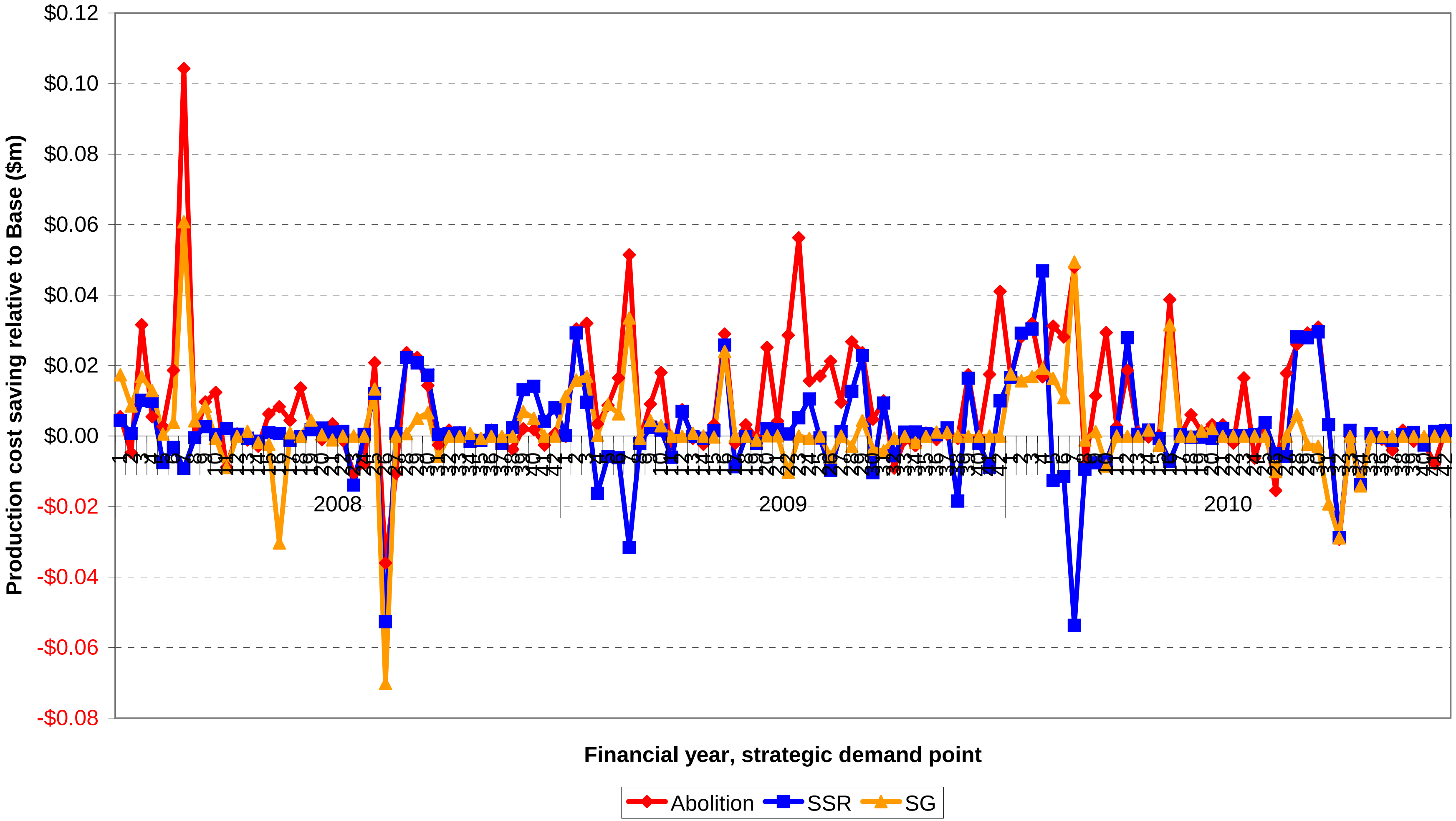


Figure B.13 Hourly production cost savings relative to the Base scenario by strategic demand point, contracted low



B.3.2.8 Drivers of the production cost savings

Figure B.14 shows a scatter plot of Nash Equilibrium outcomes for demand point 29 for the 2007/08, contracted high outcomes. The horizontal axis shows the combined amount of capacity offered into the market by Guthega, Murray and Tumut plant, while the vertical axis shows the payoff (profit) received by Snowy Hydro (including revenue from Laverton, Valley Power and Blowering and contract difference payments).

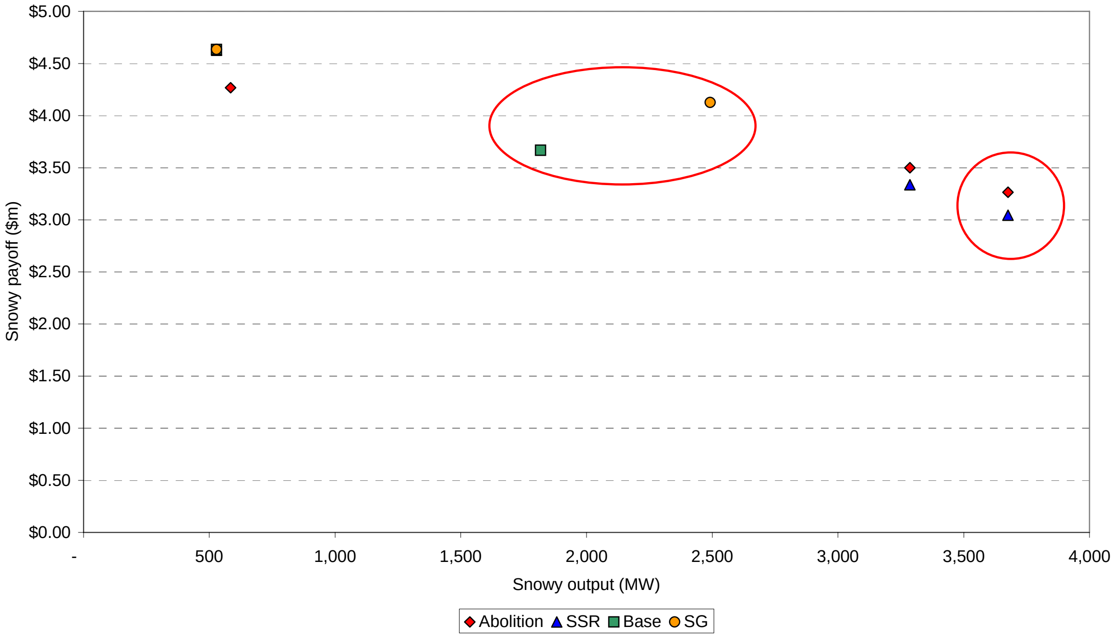
It can be observed that a single equilibrium in each scenario occurred on the left side of the graph where Snowy Hydro offered approximately 500MW into the market (note that the data point for the SSR scenario is partially obscured by the Base and SG data points). These equilibria also involved the withdrawal of capacity by other market participants. As similar outcomes occurred in all four scenarios the production cost differences relating to these four equilibria were small.

In addition to these "strategic" equilibria (on the left side of the graph), a number of "competitive" equilibria (where more capacity was offered into the market) occurred under all scenarios. For the Base and SG scenarios a total of 1800MW and 2500MW respectively were offered into the market by Snowy Hydro's Tumut and Murray generation. This was still short of the Snowy region's full generating capacity (3126MW[152]). For the Abolition and SSR scenarios even more competitive equilibria arose, including outcomes where Snowy bid all of its capacity into the market (circled in red on the right-most side of the graph).

Because equilibria where Snowy Hydro offered a relatively large amount of capacity into the market dominated the outcomes in the Abolition and SSR scenarios we observed significant production cost savings for this demand point in both of these scenarios. While more capacity was offered in the SG scenario relative to the Base scenario, it was not as much as in the Abolition and SSR scenarios. This explains why the production cost savings, while significant for the SG scenario, were not as great as in the Abolition and SSR scenarios for this demand point.

[152] NEMMCO, List of Generators and Scheduled Loads in the National Electricity Market, NEMMCO, Brisbane, 6 August 2007.

Figure B.14 Snowy Hydro equilibrium outcomes, demand point 29, 2007/08 contracted high



Understanding exactly why these different Nash equilibrium outcomes were sustainable in the different scenarios requires an analysis of market participants bidding incentives, particularly Snowy Hydro's, and information about the level of system constraint that existed for the different bidding combinations. Four particular equilibria have been chosen to aid this analysis (circled in red in Figure B.14). These particular equilibria were chosen because they involved a fixed set of bids for all market participants other than Snowy hydro making diagrammatic comparison far easier.

Figure B.15 shows Snowy Hydro's payoff curve for four circled equilibria in Figure B.14. The modelling assumed 81 potential different combinations of capacity bids between Murray and Tumut. These are shown along the horizontal axis of Figure B.15, in increasing order of aggregate capacity (bid combination 1 corresponds to no capacity being offered into the market and bid 81 represents 100% of Murray and Tumut being offered into the market). The vertical axis shows the payoff received on the offered level of output. These curves represent a cross section through the strategic space considered in the modelling with other participants' bids held fixed at their equilibrium values. The "spikes" and "dips" in the payoff curves reflect the presence of system constraint or clamping in the market (which typically leads to price separation between regions, impacting on Snowy Hydro's payoffs).

In the Abolition and SSR scenarios, the highest payoff (in this case, Nash Equilibrium outcomes) occurred where Snowy Hydro offered all of its capacity into the market, as marked on the far right section of the payoff curves for these scenarios. The Base and SG equilibria occurred as shown. The higher payoffs received by Snowy Hydro for these bidding combinations were due to system constraints binding which led to large inter-regional price differentials and increased payoffs. The same constraints did not bind in the Abolition and SSR scenarios, enabling more competitive bidding strategies to be sustainable as Nash equilibria.

Figure B.15 Snowy Hydro payoff curve for demand point 29, 2007/08 contracted high

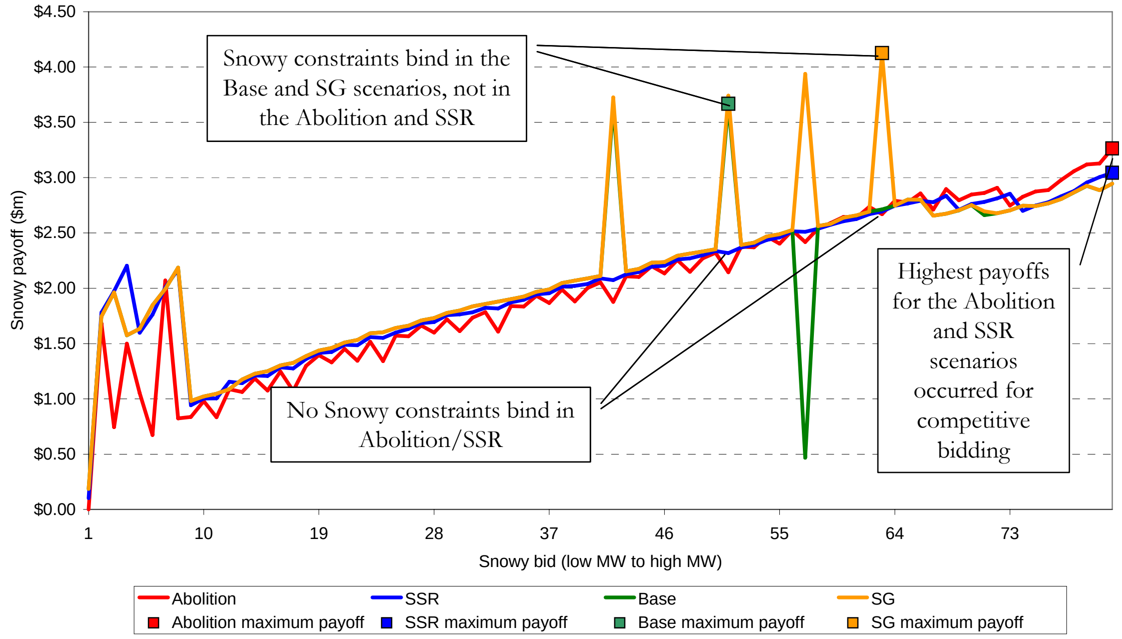


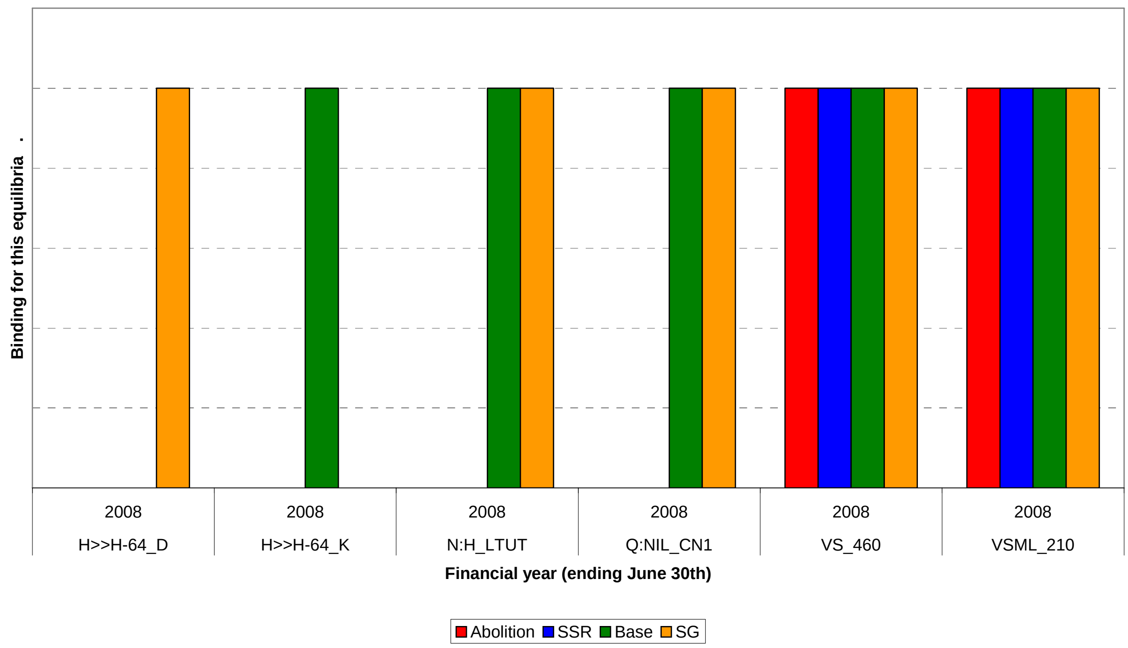
Figure B.16 depicts which constraints were binding in each of the four scenarios for demand point 29 when the equilibrium bidding combination for the Base scenario was dispatched in each scenario. The vertical axis is purely illustrative and indicates whether the constraint was binding for each of the equilibria chosen in the different scenarios. The "hard" limits on both the Heywood (VS_460) and MurrayLink (VSML_210) interconnectors bound in all four scenarios (the VS 460 and VSML 210 constraints shown in the Figure). In the Base and SG scenarios a handful of other constraints also bound:

- "H>>H" Snowy intra-regional constraints on the Murray to Tumut lines which were reformulated to reflect the altered region boundaries;
- "N:H_LTUT" Snowy to NSW inter-regional constraints which includes Snowy-NSW, NSW-Queensland and Victoria-SA interconnector flow terms and is also reformulated to reflect the altered region boundaries; and
- "Q:NIL_CN1" Queensland intra-regional constraint between the central and northern Queensland subregions which bound due to the above constraints binding which altered the amount of generation needed in Queensland.

The binding of these constraints was what makes certain, less competitive bidding strategies into Nash Equilibria in the Base and SG scenarios. When reformulated to reflect the altered region boundaries of the Abolition and SSR scenarios the constraints did not bind for the same set of market participant bids. The absence of any associated price spikes made it more profitable for Snowy Hydro to bid competitively, in these cases by offering all of its capacity into the market. This behaviour, in turn, drove the production cost savings in the Abolition and SSR scenarios relative to the Base scenario. These outcomes occurred for many of the modelled levels of demand and were most prominent for demand points 29 and 30.

For the SG scenario, Figure B.15 shows that the extra revenues that Snowy Hydro receives via the Tumut CSP/CSC Trial resulted in bidding strategies where more capacity was offered relative to the Base scenario. This led to production cost savings relative to the Base scenario. However, as the strategies were not as competitive as those seen in the Abolition and SSR scenarios, the magnitude of the savings was also less in the SG scenario.

Figure B.16 Binding constraints for equilibrium bidding combinations, for demand point 29, by region boundary scenario, 2007/08, contracted high case.



Similar outcomes can be observed in other years and contract cases. Figure B.17 to Figure B.20 show the equilibrium outcomes and payoff curves for demand point 29, in 2008/09 for the contracted high and low cases, respectively. Once again, specific equilibria where all other market participant bids were the same were selected, to aid comparison.

We observe that similar outcomes occurred in each of these cases. That is, the absence of binding constraints in the Abolition and SSR scenarios due to the new region boundary structure, led to more competitive equilibrium bidding strategies for Snowy Hydro and other participants. This resulted in production cost savings relative to the Base case. Similar effects can be seen for many other modelled demand levels.

Figure B.17 Snowy Hydro equilibrium outcomes, demand point 29, 2008/09 contracted high

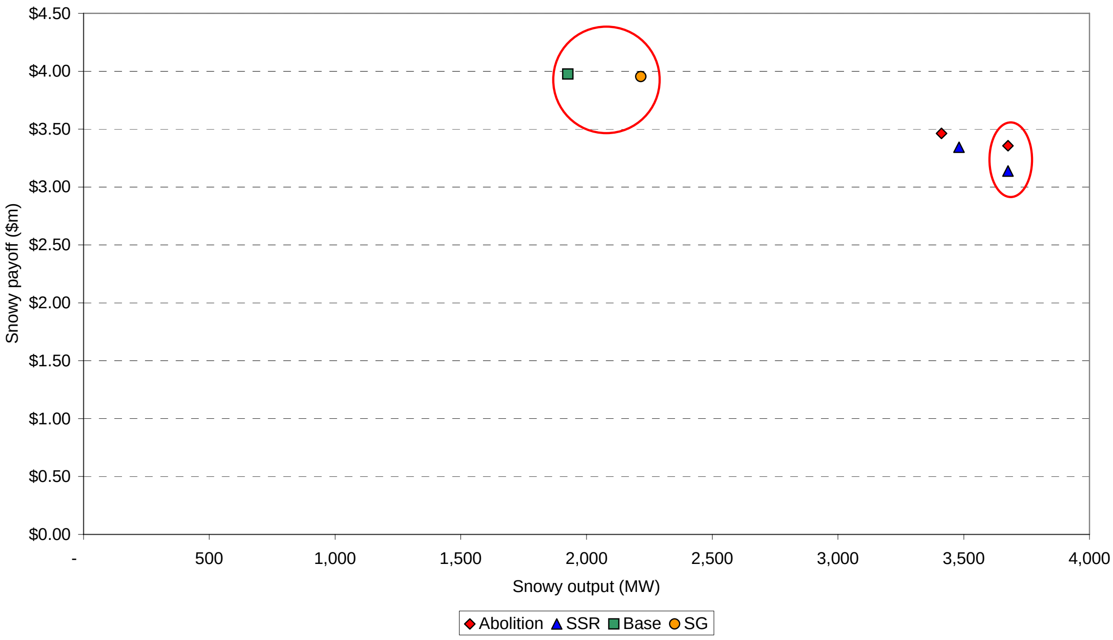


Figure B.18 Snowy Hydro payoff curve for demand point 29, 2008/09 contracted high

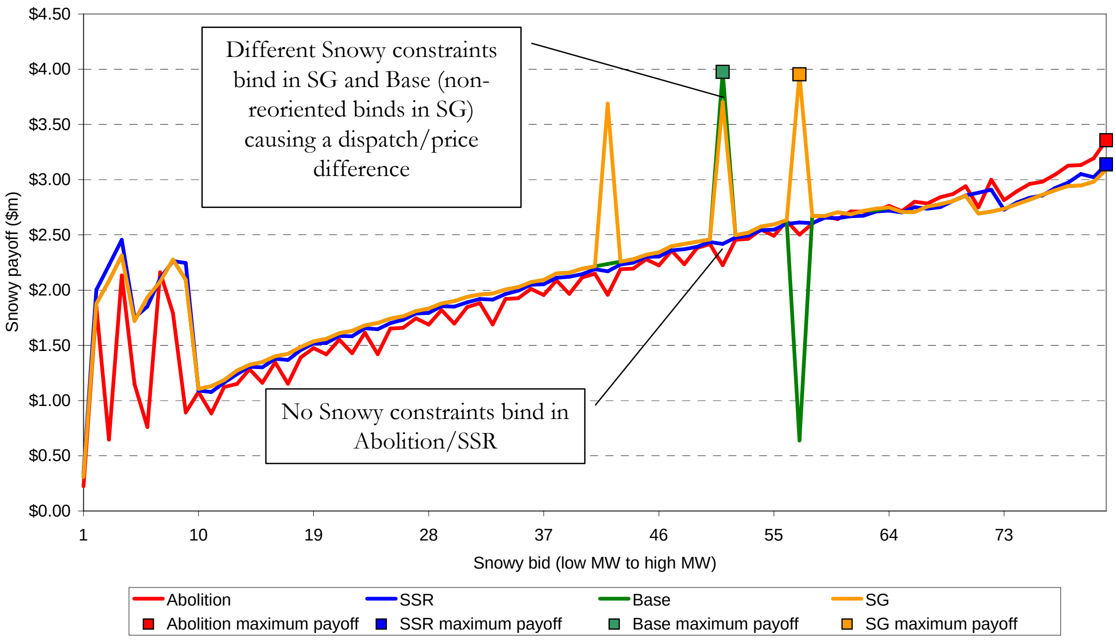


Figure B.19 Snowy Hydro equilibrium outcomes, demand point 29, 2008/09 contracted low

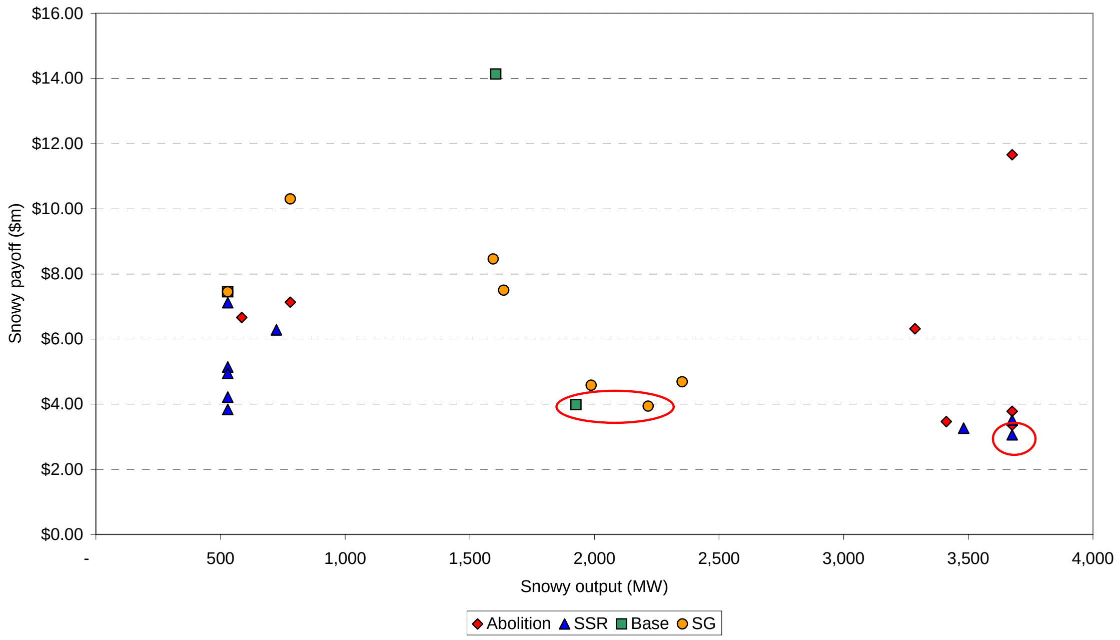
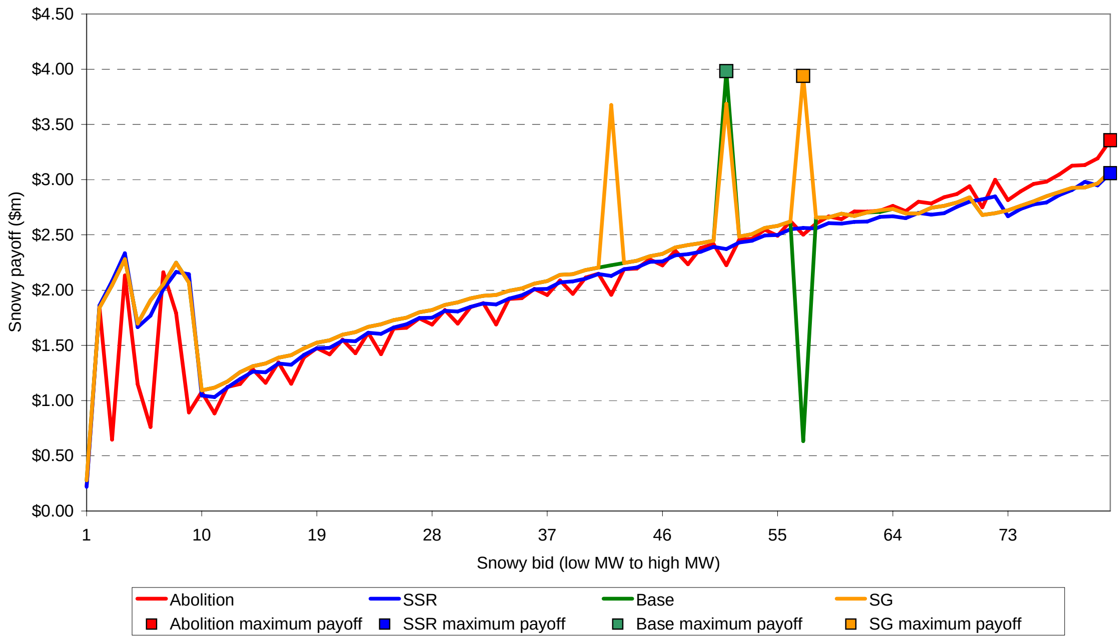


Figure B.20 Snowy Hydro payoff curve for demand point 29, 2008/09 contracted low



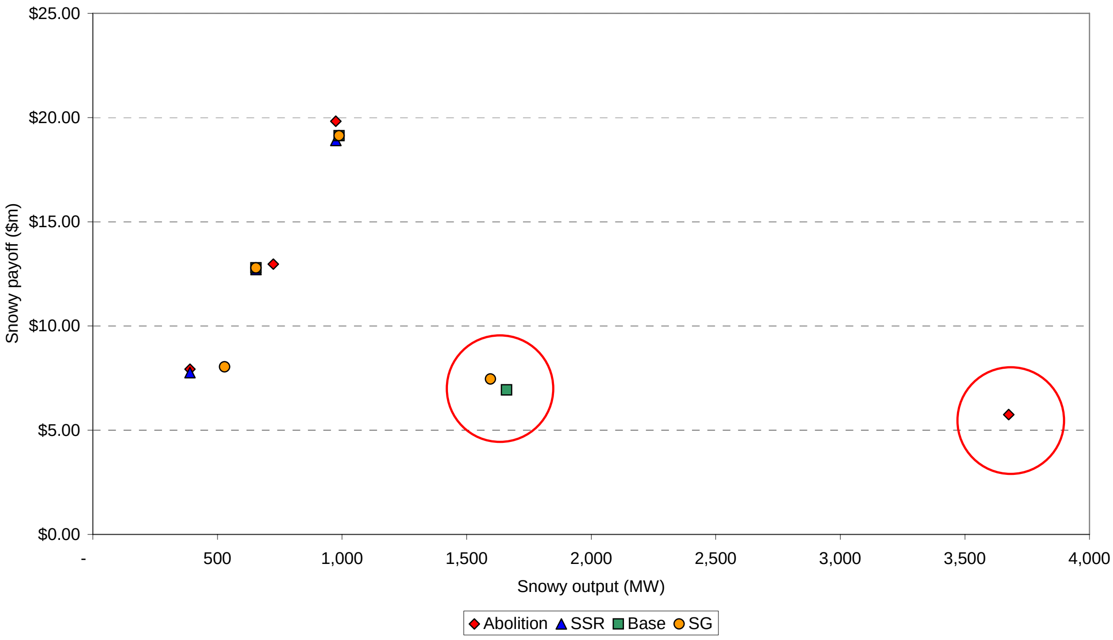
B.3.2.9 Drivers of the production cost losses

Net annual production cost losses relative to the Base scenario occurred for some years and contract cases in the SG and, more notably, SSR scenarios. For the SSR scenario this is most pronounced for the 2008/09 contracted high case. Examining Figure B.10 shows that the biggest single loss occurred for demand point 30, Figure B.21 shows the equilibrium level payoffs for this demand point.

We observe an equal number of strategies in all four scenarios where Snowy Hydro only offered 400MW to 1000MW into the market. However, in each of the Base and Southern Generators’ Congestion Pricing scenarios, an additional more competitive equilibrium per scenario arose in which Snowy Hydro offered approximately 1600MW into the market. As no corresponding competitive equilibrium arose in the SSR scenario, we found that, on average, the SSR scenario accrued production cost losses relative to the Base scenario. Conversely, a fully competitive equilibrium, in which Snowy Hydro offered all its capacity to the market, arose in the Abolition scenario. This resulted in production cost savings relative to the Base scenario. Such an outcome did not arise in the SSR scenario because such competitive strategies were dominated by strategies where Snowy Hydro withdrew significant amounts of capacity. This happened as a direct consequence of the different pricing outcomes that Snowy Hydro could achieve in the SSR regional configuration. This will be discussed in more detail below.

For demand point 30, we also observed production cost losses in the Southern Generators’ Congestion Pricing scenario, as less capacity was offered relative to the Base scenario. This arose due to a slightly different pattern of congestion and its effect on Snowy Hydro via the SG mechanism making it more profitable to withdraw slightly more capacity.

Figure B.21 Snowy Hydro equilibrium outcomes, demand point 30, 2008/09 contracted high



Once again, we considered Snowy Hydro's payoff curves to explain why these competitive equilibria did not arise in the SSR scenario. Note that in this instance, the circled equilibria *did not* involve the same bidding pattern for all market participants other than Snowy Hydro. In particular, the bidding pattern for the Base and Southern Generators' Congestion Pricing scenarios were the same whilst the Abolition equilibrium bidding combination was different.

Figure B.22 shows the payoff curves corresponding to the Base and SG equilibrium strategies for all other players. Figure B.23 shows the payoff curves where all other participants were fixed with the Abolition equilibrium strategies. In both graphs the reason why a more competitive equilibria did not arise in the SSR scenario was that it was more profitable for Snowy Hydro to withdraw significant amounts of capacity and increase pool prices. This occurred for a number of key demand points in all years and contract cases for the SSR scenario and in some cases led to net annual production cost losses.

Two features of the payoff curves drive this outcome:

- When Snowy Hydro withdraws more capacity (left-most side of Figure B.23) it consistently earns an equivalent or greater payoff in the SSR scenario than it earns under the Abolition scenario – this made withdrawal strategies relatively more profitable in the SSR scenario; and

- When Snowy Hydro offers all or most of its capacity into the market (right-most side of Figure B.23) it consistently earns a lower payoff than that which arises under the Abolition scenario – this made competitive strategies relatively less profitable.

The effect of these two features was that at certain times and for certain demand levels, it was more profitable for Snowy Hydro to withdraw significant amounts of capacity in the SSR scenario. This was an effect that was not observed in the Abolition scenario. This result was purely driven by the different pricing implications of the two scenarios. In the Abolition case, Murray generation receives the Victorian price and generation at Tumut receives the NSW price. However, in the SSR scenario, both Murray and Tumut generation receive an imported price *that is adjusted for losses on the new interconnectors*. Also, slightly different amounts of dynamic losses occurred in the SSR scenario. Typically, greater losses occurred in the SSR scenario than in the Abolition scenario, as the dynamic losses were being calculated on a greater number of interconnectors. This resulted in additional overall generation in the SSR scenario to cover the shortfall.

These two factors resulted in non-trivial price differences in the SSR scenario compared to the other scenarios. This, in turn, resulted in the different payoff curve discussed above. For the more uncompetitive bidding combination that resulted in the maximum payoff in the SSR scenario (left side of Figure B.23), the additional losses required the dispatch of additional generation. The dispatch of this more expensive additional generation resulted higher prices across the entire NEM including the Murray and Tumut regions. The result was that significant withdrawal was the most profitable strategy in the SSR scenario.

Conversely, the fully competitive strategy, which yielded an equilibrium for the Abolition scenario (right-most side of Figure B.23), was not as profitable in the SSR scenario. For this bidding combination, power flowed from Murray to Victoria and Tumut to NSW. In the Abolition scenario, Snowy Hydro received the Victorian and NSW regional references prices, as discussed above. In the SSR scenario, Snowy Hydro received the lower, dynamically loss-adjusted Victorian price at Murray and the lower, dynamically loss-adjusted NSW price at Tumut. This made this bidding combination less profitable in the SSR scenario than in the Abolition case.

Figure B.22 Snowy Hydro payoff curve for demand point 30, 2008/09 contracted high – Base and SG equilibrium strategies for other market participants

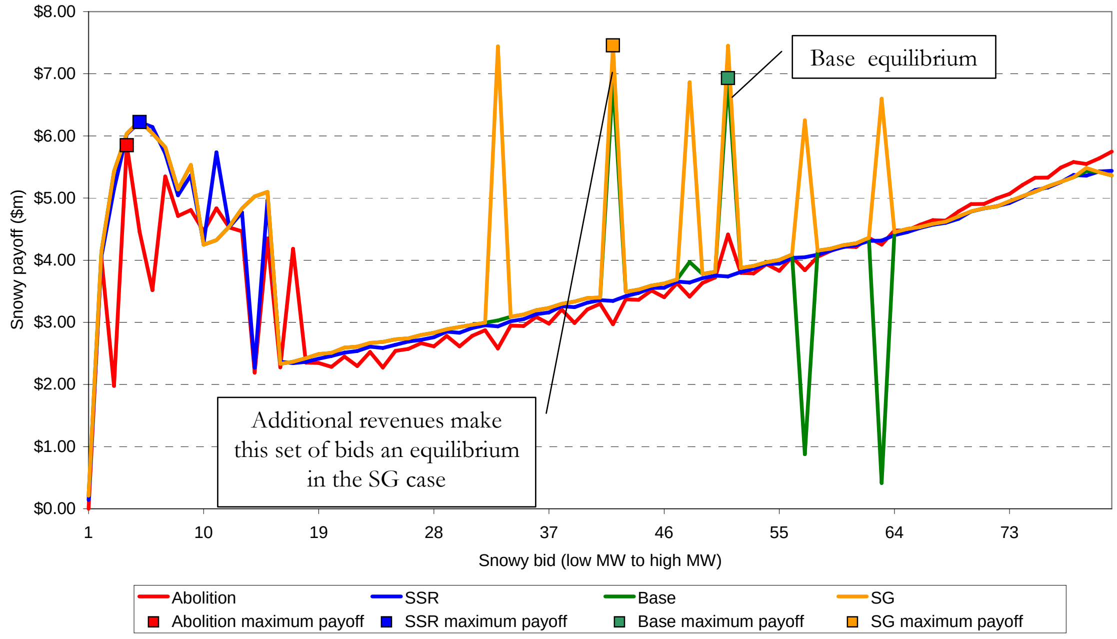
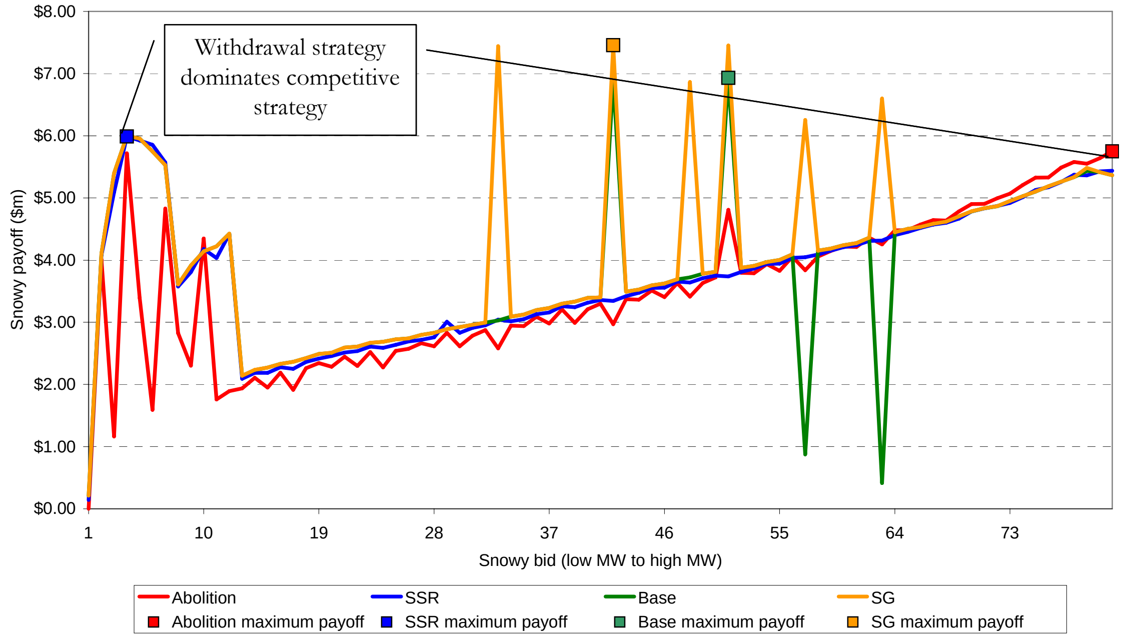


Figure B.23 Snowy Hydro payoff curve for demand point 30, 2008/09 contracted high – Abolition equilibrium strategies for other market participants



B.3.2.10 Production cost changes by plant type

The analysis presented above shows that production cost savings across the modelled scenarios arose when market participants, particularly Snowy Hydro, bid more competitively and when expensive generation was displaced by cheaper generation. Figure B.24 to Figure B.26 show the production cost savings by cost-band relative to the Base scenario for the Abolition, SSR and SG scenarios respectively. A positive value represents less generation, and hence a production cost savings, in any given cost band.

In the Abolition scenario we consistently saw production cost savings arise due to mid-merit and peaking plant being displaced by black coal. Mid-merit plant was also generally displaced in most years in the SSR scenario, particularly in those years in which the net annual production cost savings was positive. A similar, but dampened effect was observed in the SG scenario for those years where savings were positive.

Figure B.24 Production cost savings relative to Base by cost band - Abolition

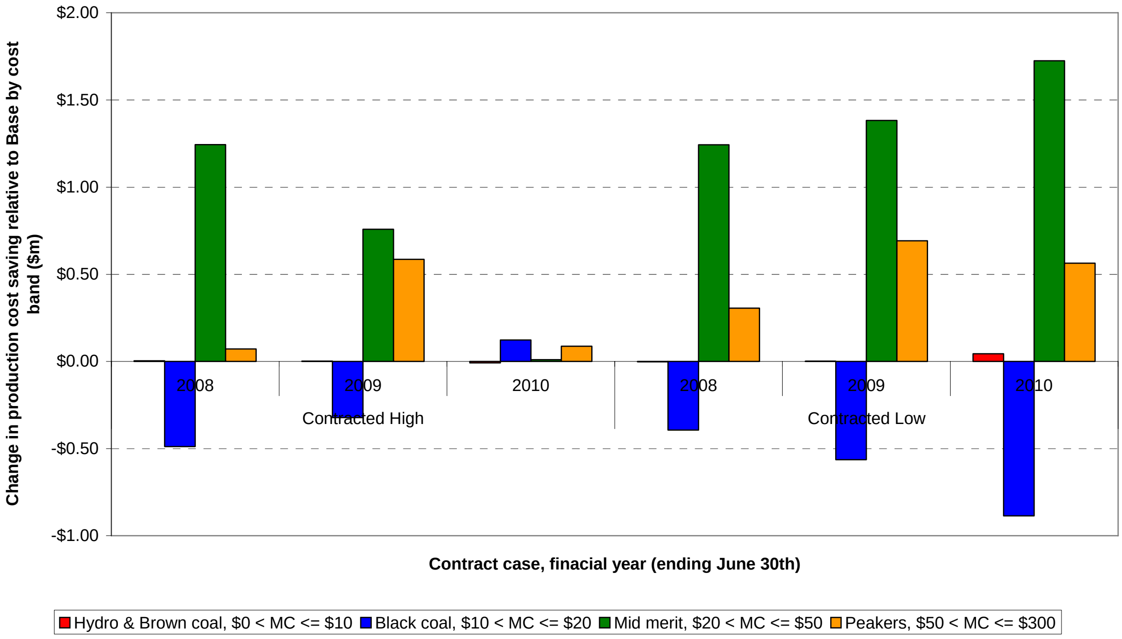


Figure B.25 Production cost savings relative to Base by cost band - SSR

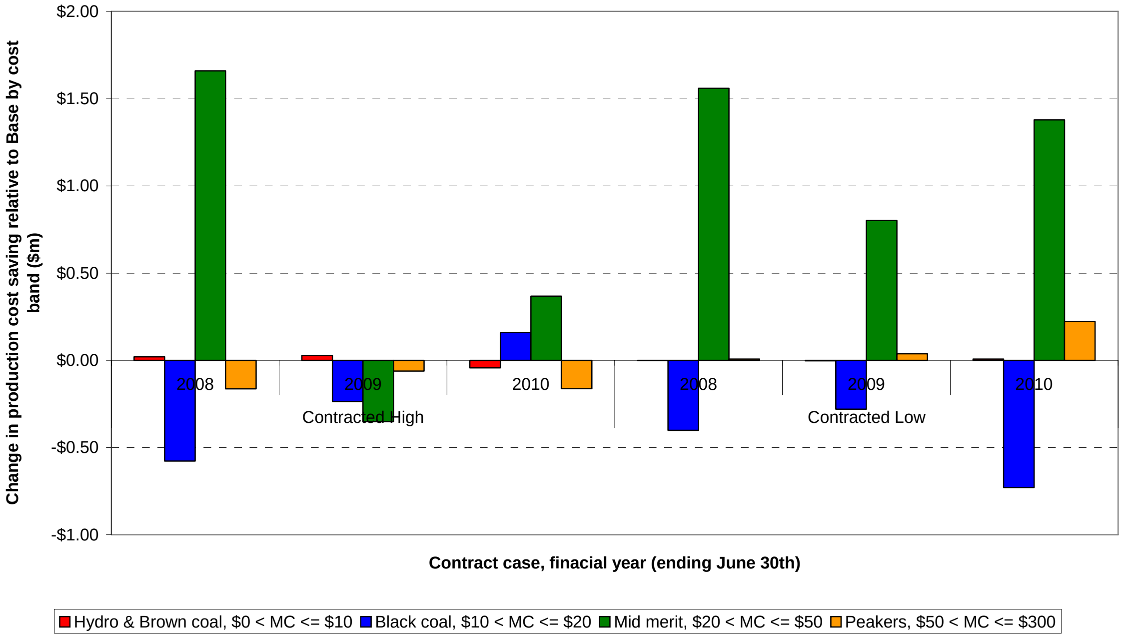
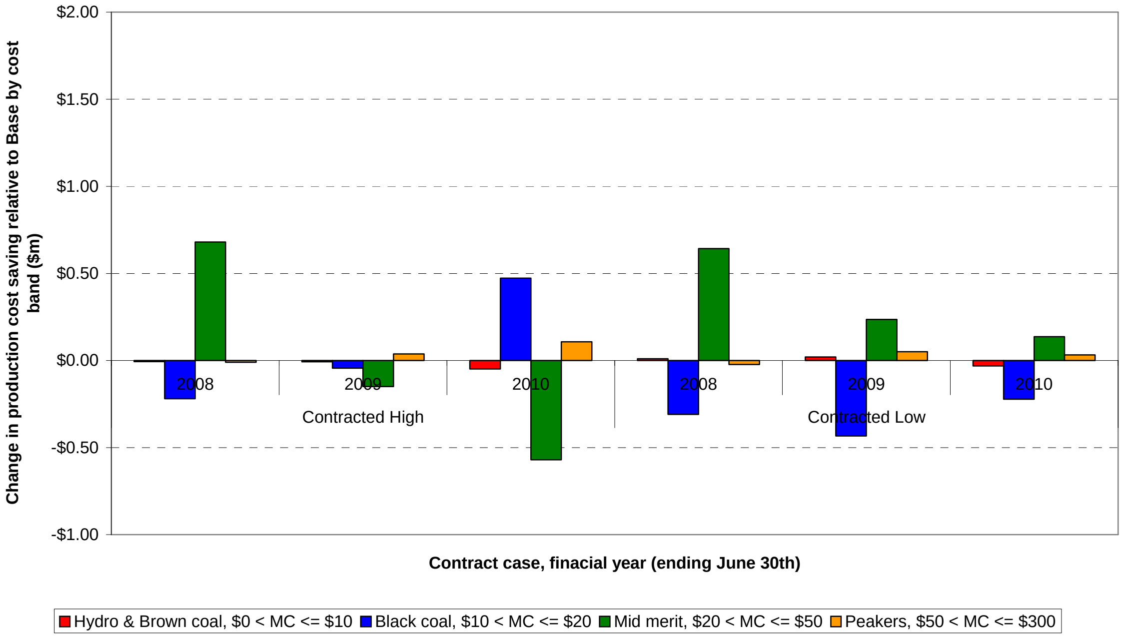


Figure B.26 Production cost savings relative to Base by cost band - SG



B.3.2.11 Changes in dispatch

Figure B.27 to Figure B.29 show the changes in output levels for Snowy Hydro at Murray and Tumut by time of year for the Abolition, SSR and SG scenarios respectively relative to the Base scenario. In the Abolition scenario (Figure B.27), Murray consistently generated more during peak times while Tumut generated less with the net effect being an increase in Snowy Hydro generation during peak times. This outcome was in keeping with the increased likelihood of more competitive bidding discussed above. Due to Snowy Hydro's annual energy budget, the increased output at peak times necessitated a reduction in output during the other times of the year.

Snowy output levels followed a similar pattern in the SSR scenario, particularly in the contracted high case as was seen for the production cost results. In the contracted low case, we observed a smaller increase in Murray generation during peak times and a larger reduction in Tumut generation. The overall effect was closer to a switching of Snowy Hydro generation from Tumut to Murray rather than a significant net increase in output at peak times. Again, this outcome is consistent with the production cost results and bidding analysis outlined for this contracting case.

Changes in output in the SG scenario relative to the Base scenario were of a smaller magnitude than in the other scenarios, as would be expected due to the identical constraint representation. In 2007/08, when production cost savings were positive for both the contracted high and low cases, we observe an increase in Tumut generation at peak times.

Figure B.27 Change in Murray and Tumut output relative to Base - Abolition

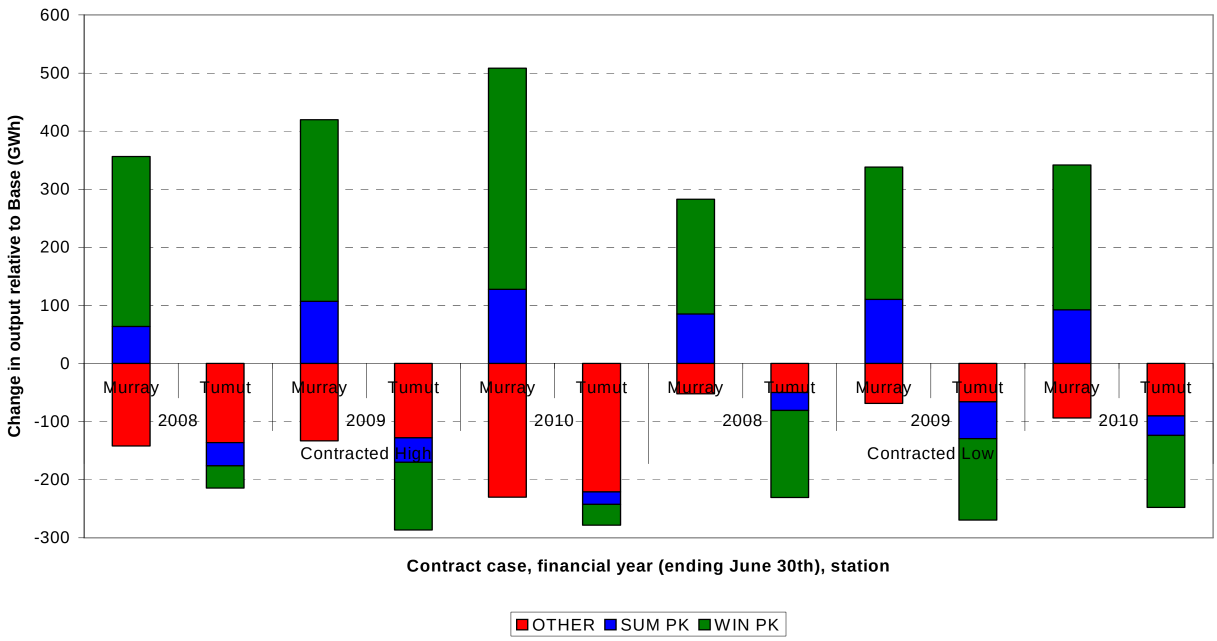


Figure B.28 Change in Murray and Tumut output relative to Base - SSR

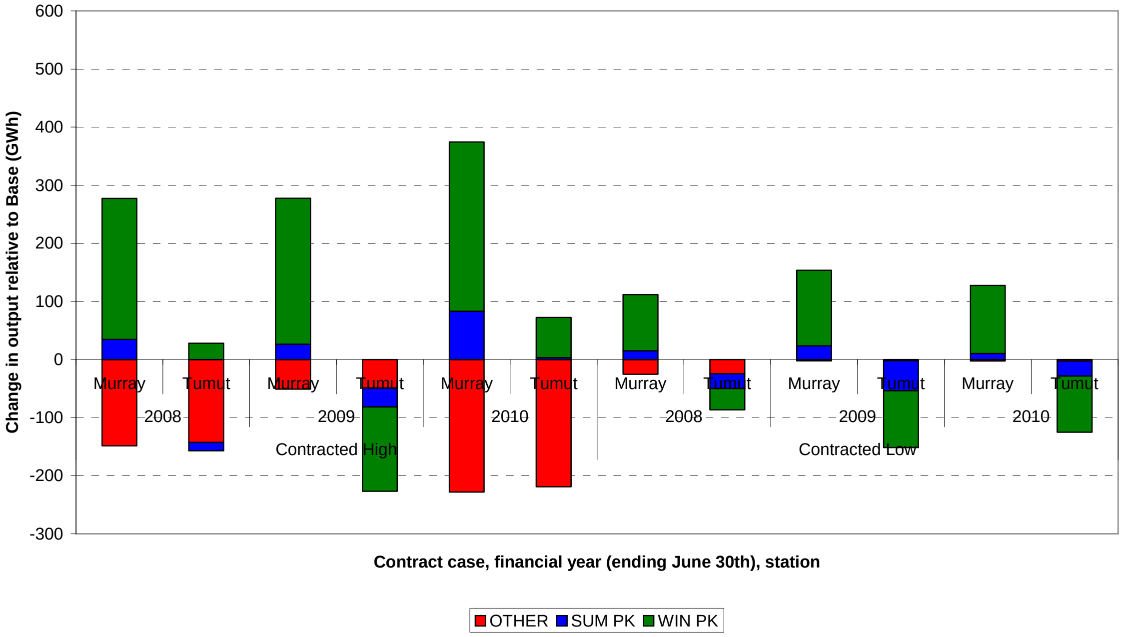
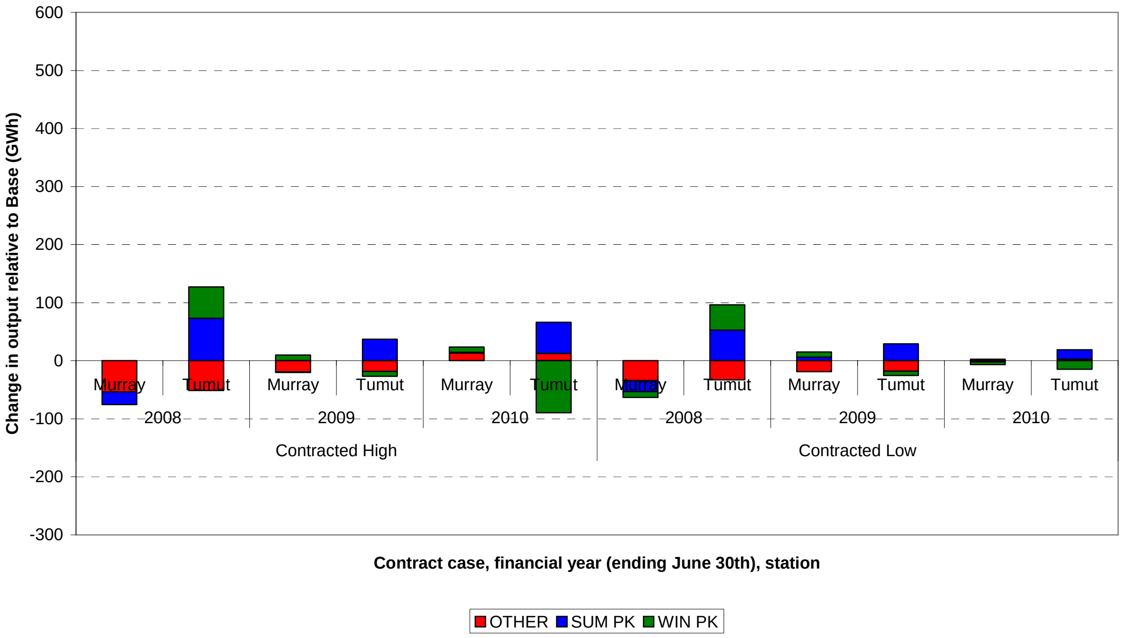


Figure B.29 Change in Murray and Tumut output relative to Base – SG scenario



Some slight changes in annual production between the Northern and Southern generators across the year were observed in the results. The differences between the Base scenario and a given proposal did not exceed roughly 50GWh across the year (out of an annual production level of at least 212TWh). These changes did not follow any particular pattern across the years and contract cases modelled.

B.3.2.12 Changes in flows

Figure B.30 show the change in net energy transfers from Victoria to Murray and from Tumut to NSW, when the Abolition scenario is completed to the Base Case. The changes in net energy transfers are split into summer and winter "super peak" periods. Figure B.31 and Figure B.32 show the same figure for the SSR and SG scenarios respectively. In all figures, positive Murray to Victoria values represent an increase in power transferred in a southward direction under the relevant scenario, while positive Tumut to NSW values represent an increase in power transferred northwards.

Increases in flows out of the Snowy region can be observed for both the Abolition and SG scenarios, particularly during winter peak times (which represent a greater number of hours than the summer peak times). This was attributable to Snowy Hydro being incentivised to offer more capacity into the market as a result of reduced system congestion, resulting in greater levels of dispatch. Only minor variations in the SG scenario were observed, as would be expected given that there is no change in the constraint representations between the SG and Base scenarios.

Figure B.30 Changes in net flows relative to the Base scenario – Abolition scenario

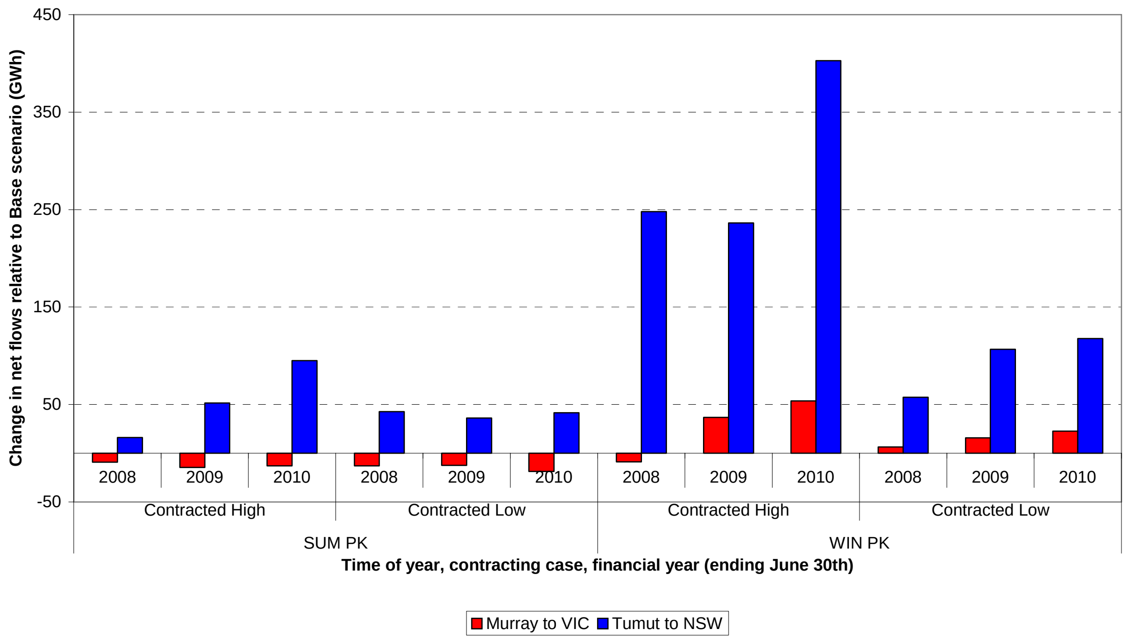


Figure B.31 Changes in net flows relative to the Base scenario – SSR scenario

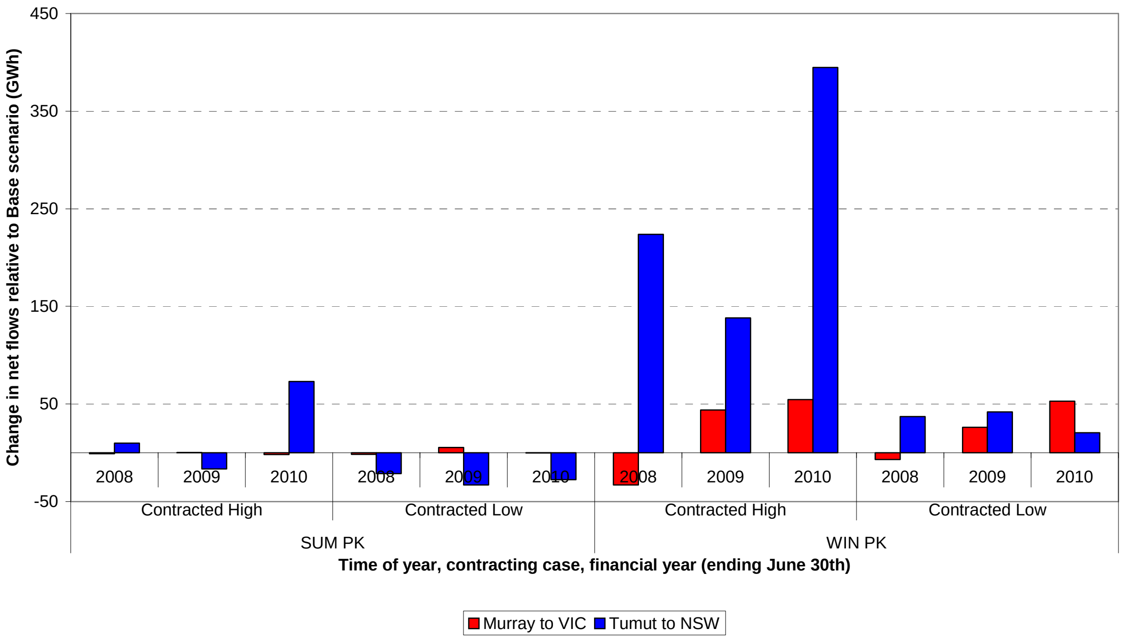
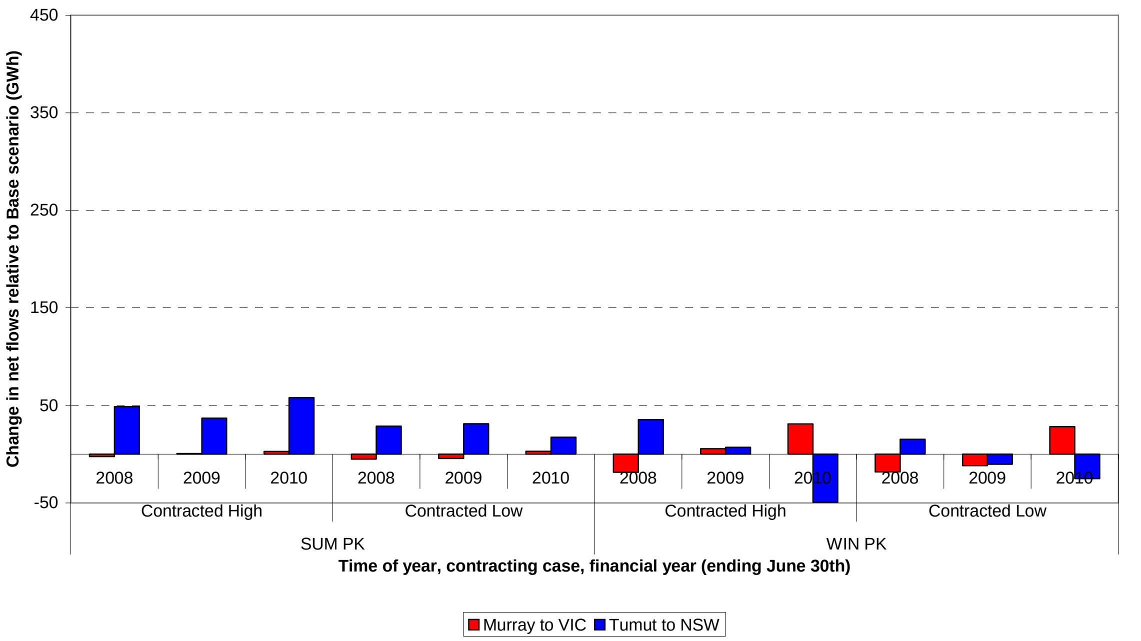


Figure B.32 Changes in net flows relative to the Base scenario – SG scenario



B.3.2.13 Price effects

Figure B.33 and Figure B.34 show the results for the time-weighted average annual prices for NSW and Victoria, respectively. The peak summer demand points (when high volatility is typically observed) predominantly drove differences in prices between the scenarios. Changes to region boundaries generally led to a reduction in prices due to baseload plant displacing relatively expensive plant, as discussed above. Small decreases were also observed in the SG scenario.

The Base scenario generally resulted in the highest prices of all four scenarios for each year and contract case in both NSW and Victoria. The Abolition scenario resulted in the lowest price outcomes for the majority of years and contract cases. This is consistent with the production cost savings results presented earlier, particularly where it was shown that significant amounts of mid merit and/or peaking generation is displaced by cheaper baseload generation.

The South Morang constraint[153] played a significant role in the price outcomes of the modelling. In all instances where a significantly reduced price was observed relative to the Base scenario we observed the South Morang constraint binding less frequently. This outcome conforms with observed market outcomes, which reveal a coincidence of the South Morang constraint binding and high regional prices. The results of the next Section show that this constraint bound least frequently in the Abolition scenario and the SSR scenario relative to the Base scenario. The majority of price changes occurred during the summer peak times, and to a lesser extent during the winter peak times. Differences in pricing outcomes during the other times of the year were immaterial between the scenarios. These outcomes were consistent with the modelling undertaken for the Abolition draft Rule determination.

153 In the 2005 ANTS the South Morang constraint on the F2 transformer was referred to as VH>V3NIL. In later years this constraint has also be referred to as V>>H_NIL_2_R, V>>H_NIL_3_R and V>>V_NIL_3B_R.

Figure B.33 Average annual prices – NSW

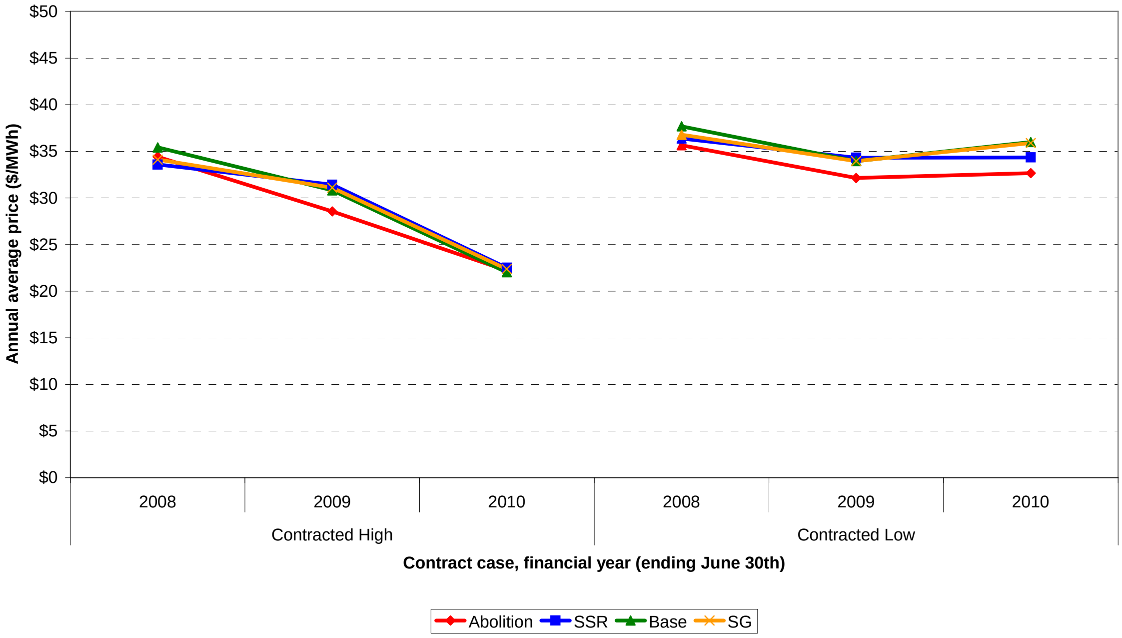
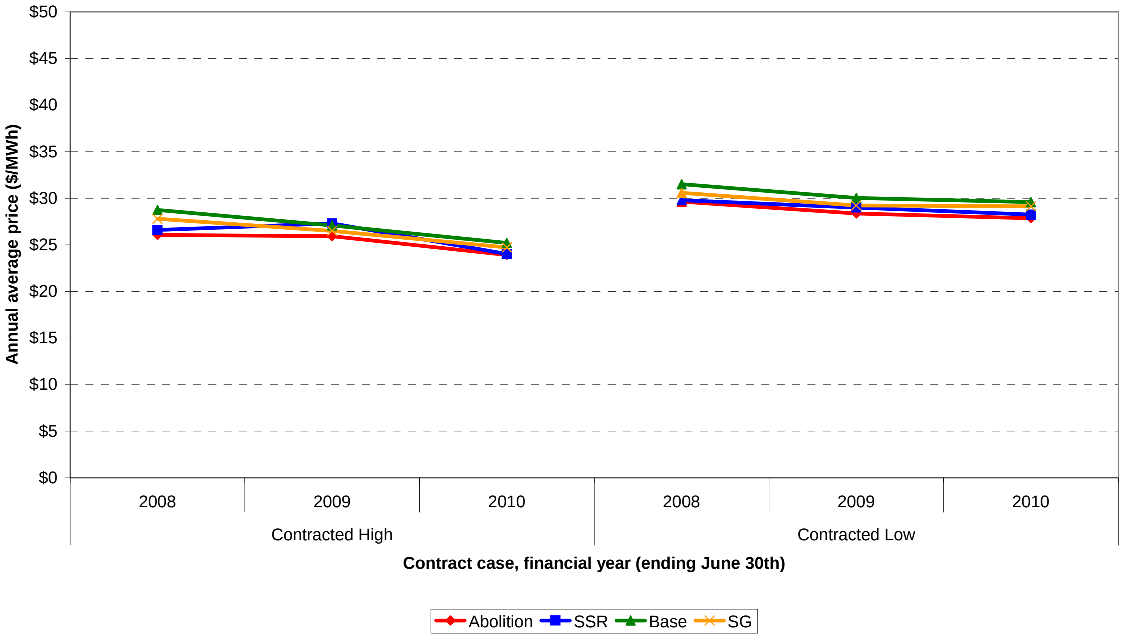


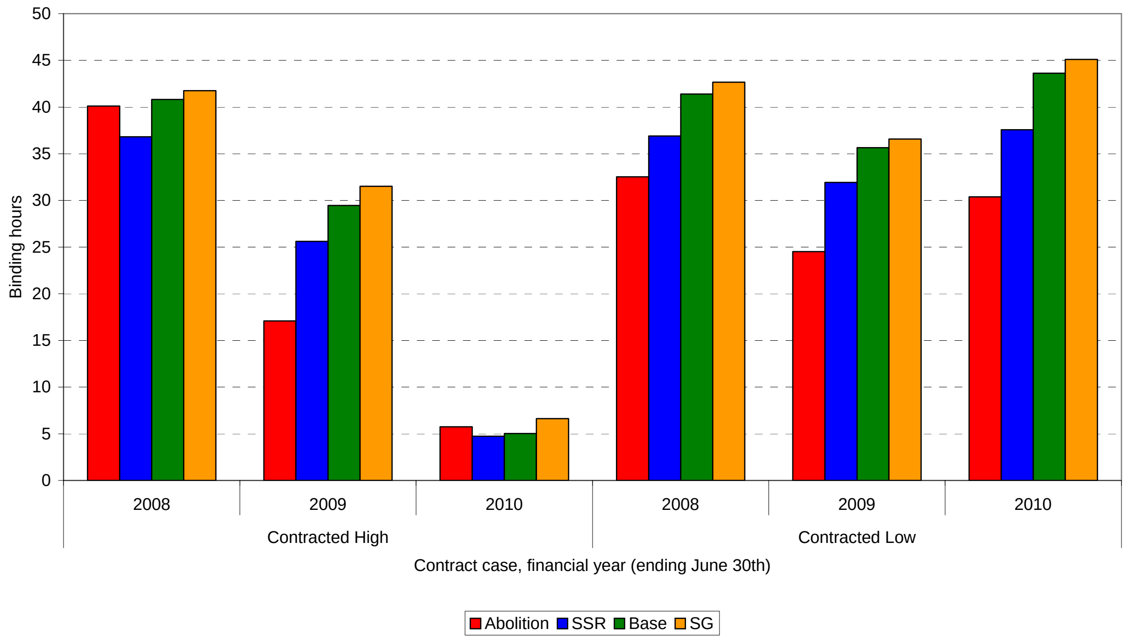
Figure B.34 Average annual prices - Victoria



B.3.2.14 Incidence of constraints

The previous Section noted the effect of the South Morang constraint on wholesale spot prices. The South Morang constraint is imposed to avoid overloading the F2 transformer at South Morang. Figure B.35 shows the frequency with which the South Morang constraint bound across the four scenarios. We observe that the Abolition scenario resulted in the lowest level of congestion on this constraint, followed by the SSR, Base and SG scenarios in increasing frequency of constrained hours for the majority of years and contracting cases.

Figure B.35 South Morang constraint – frequency of occurrence



Numerous other constraints also bound in the modelling across the various years and scenarios. Figure B.36 and Figure B.37 show the hours of binding constraint by category for the contracted high and low cases respectively. The categories have been chosen to reflect cutsets relevant to the analysis, with particular focus on the Snowy region and the immediately surrounding area. Data were also included for other regions of the NEM where congestion could arise as a follow-on effect of a Snowy region boundary change – Victoria NSW and transfers from NSW to Queensland. Voltage and stability constraints were also included, as was a discretionary constraint category. This category consisted of essentially the Victoria to Snowy interconnector 1900MW hard limit on southern flows. Data for northern Queensland and for flows from Victoria to South Australia are not shown in the figures. The northern Queensland data were not considered relevant to the analysis. Similarly, the constraints that set the hard flow limits on the Victoria to South Australia and MurrayLink interconnectors bound for almost all of the demand points that were modelled competitively (+8,000 hours). It should come as no surprise that bidding all Victorian brown coal into the market at SRMC at these times would result in significant flows of power from Victoria to South Australia.

The figures show that constraints were observed primarily around the NSW to Queensland border, internally throughout NSW, on the western ring[154] within NSW (grouped as "Liddell-Tom") and on the Murray-Tumut lines. Stability constraints also bound relatively frequently. Lesser congestion arose north of Tumut and around South Morang. The South Morang constraint, although it bound for a relatively small number of hours, was a significant driver of pricing outcomes in the modelling.

Relative to Base scenario, the two region boundary change proposals led to a substantial change to the location of congestion. Constraints on the Murray-Tumut lines effectively ceased to bind and there was a marked reduction in the frequency of stability constraints and NSW to Queensland transfer limit constraints binding. The South Morang constraint also bound less frequently, as discussed above. These reductions were offset, to some extent, by an increase in congestion elsewhere in the network. The internal NSW constraints reflected transfers of power from baseload generation in NSW to Queensland and could potentially lead to any of the NSW baseload generators being either constrained-on or -off. These constraints bound with greater frequency in the region boundary change scenarios relative to the Base case, in line with the fact that more power flowed northwards from Snowy. Similarly, we also observed a slight increase in congestion north of Tumut. An increase in the discretionary constraints (essentially the 1900MW hard limit on southward flows from Snowy to Victoria) bounds more frequently. Again, this reflected increased production at Snowy at certain times.

The SG scenario produced outcomes that were generally similar to those seen in the Base scenario given that the constraint formulation between the scenarios was essentially identical. The major difference was in the incidence of Murray-Tumut congestion, where lower levels were observed in the SG scenario. This reflected Snowy's altered incentives and the resultant sustainable bidding patterns.

In terms of production cost drivers, the most significant change in the pattern of congestion was that the Murray-Tumut constraints ceased to bind in the Abolition and SSR scenarios (as discussed in detail above). The reduction in the frequency of the South Morang constraint binding was the primary driver of the observed price effects in the modelling.

[154] The "western ring" constraint is discussed in Appendix D.

Figure B.36 Binding constraints by category – contracted high

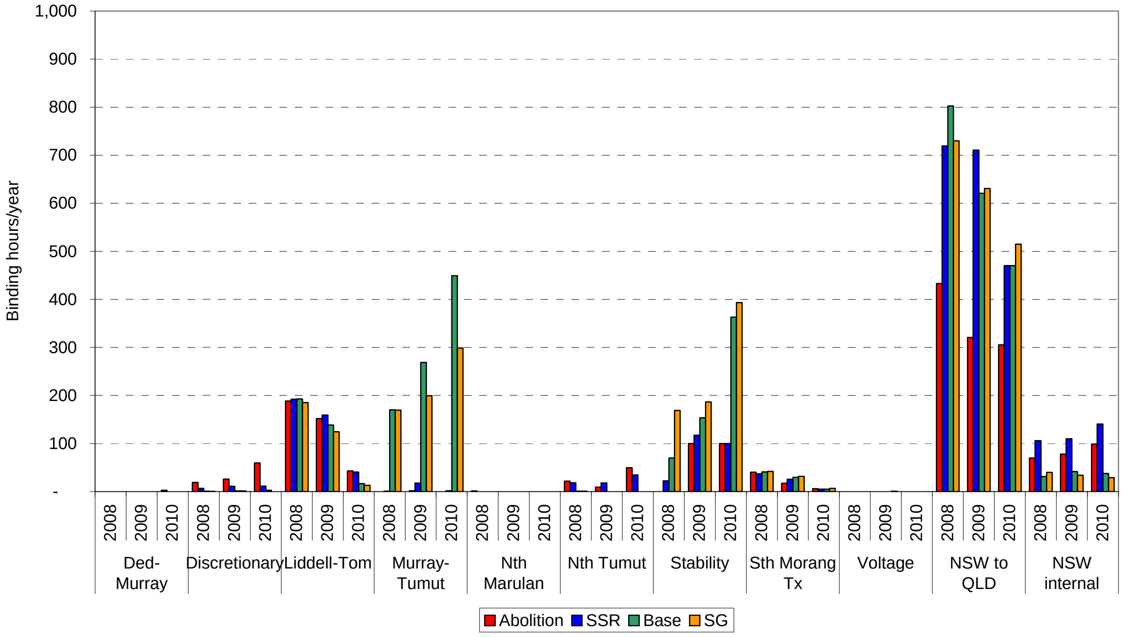


Figure B.37 Binding constraints by category – contracted low

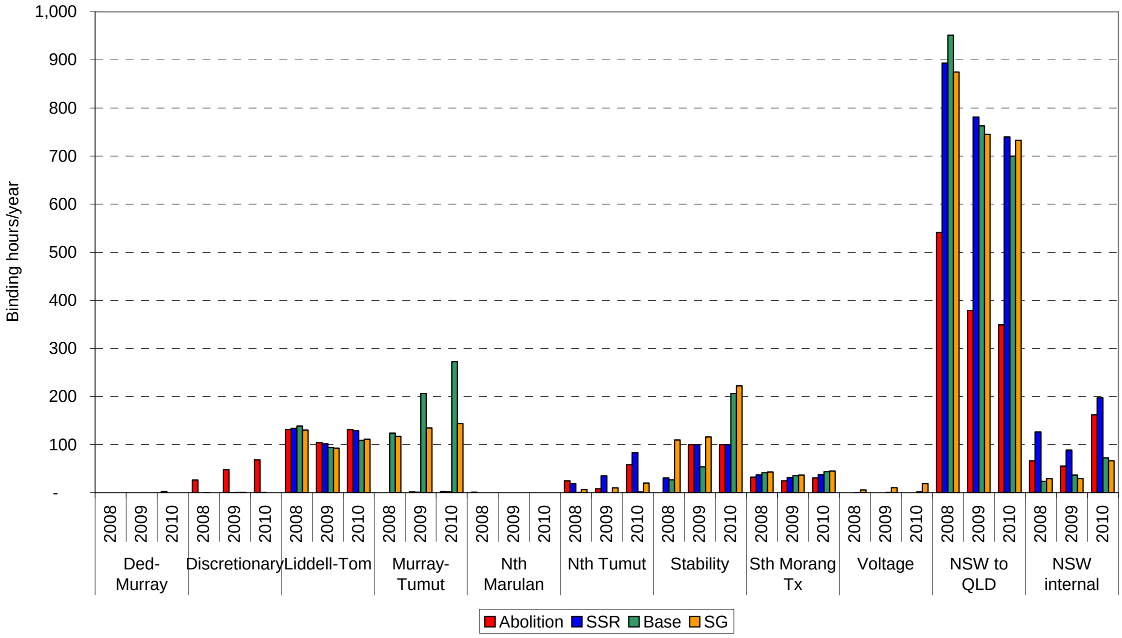


Figure B.38 and Figure B.39 show the average dual price when particular groups of constraints bound. The dual price of a constraint in an optimisation problem for the dispatch of an electricity market reflects the change in total system cost if the right hand side of the constraint were increased by one unit. For example, the dispatch problem includes a constraint stating that supply must equal demand. By increasing the value of demand by one unit and looking the change in the total system cost (objective function), the dual price of the constraint can be determined. In the case of a supply must equal demand constraint, this dual is usually identified as the system marginal price, as it reflects the marginal cost of meeting an extra unit of demand.

For the grouped constraints represented below, the averaged dual prices *do not* have an obvious economic interpretation. This mostly reflects the fact that the constraints were not normalised relative to each other – the right hand sides of the constraints reflect line ratings on different lines. Effectively, we averaged over "apples and oranges". They do, however, reflect the extent to which the given set of constraints would alter dispatch patterns when they bound. As such, the results presented in Figure B.38 and Figure B.39 should be used as an indicative measure of the severity of constraint in NEM, rather than as an absolute measure.

Using these duals as an indicator of the severity of constraints, the greatest effect by far was for the internal NSW constraints, followed by the NSW to Queensland transfer constraints. Both of these groupings involve terms for the large NSW baseload generators and set flow limits on DirectLink and QNI. When these constraints bind, they lead to price separation between NSW and Queensland and also potentially between NSW and the Southern regions (to the extent that changes in baseload output across NSW can bind the southern interconnectors). The result is that when these constraints bind, the duals associated with them are relatively high reflecting interregional price separation.

The Western ring (Liddell-Tom) and South Morang constraints also have non-trivial constraint duals, reflecting their impact on dispatch.

Figure B.38 Average dual prices by category – contracted high

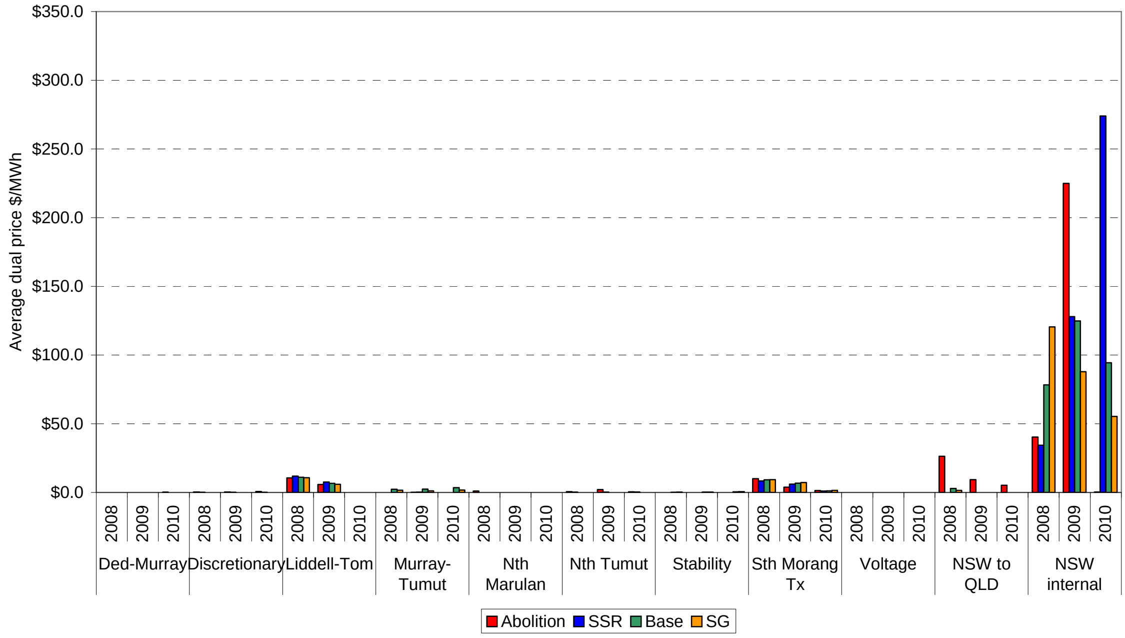
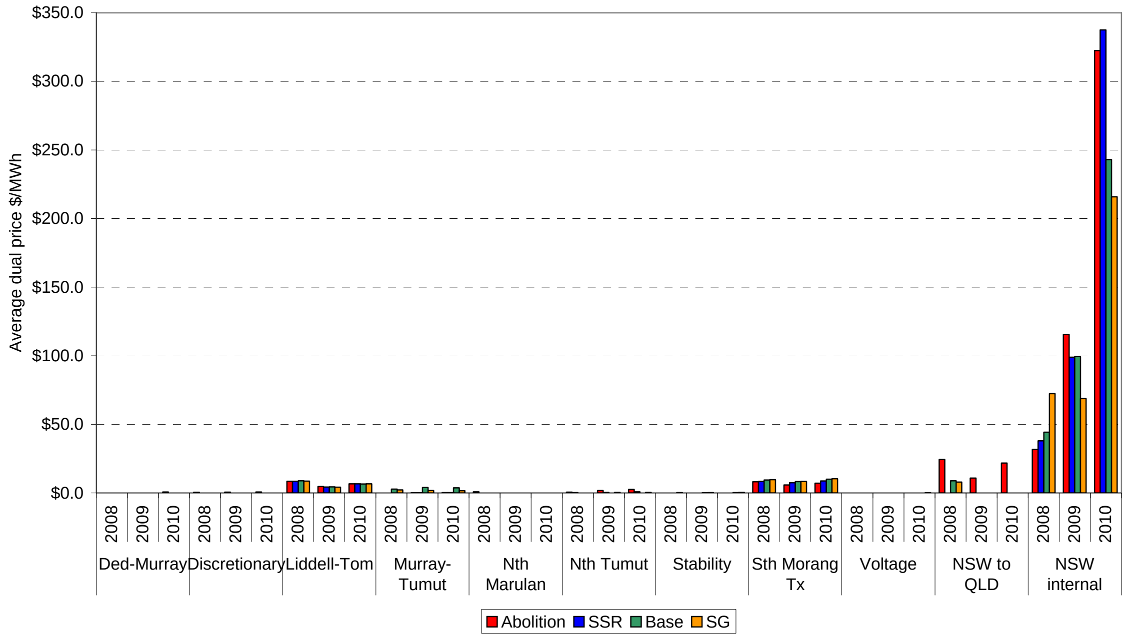


Figure B.39 Average dual prices by category – contracted low



B.3.2.15 Incidence of clamping to manage negative settlement residues

As discussed previously in this Appendix, for this modelling undertaken to inform the final Rule determination, NEMMCO was assumed to manage negative settlement residues on all interconnectors, except southward flows on the Victoria to Snowy interconnector in the Base scenario and Victoria to Snowy interconnector flows in either direction in the SG scenarios. Clamping was assumed to be activated with a $6000/per hour threshold, meaning that the flow on a given interconnector would be set to zero if the residue would otherwise exceed this threshold. Clamping on QNI/DirectLink and Heywood/MurrayLink only occurred when the *net* residue across both interconnectors was less than the clamping threshold, in line with NEMMCO's implementation for these interconnectors.[155] Although a greater number of interconnectors were subject to clamping in the modelling for this final Rule determination, the assumption of a $6000 threshold and the use of a net clamping approach on some interconnectors resulted in a reduced incidence of clamping relative to the Abolition proposal draft Rule determination results. This approach more accurately reflects the policy towards clamping that NEMMCO currently applies than the approach previously modelled.

Figure B.40 and Figure B.41 show hours of clamping on the Snowy Region and other inter-regional interconnectors, respectively. Where a given interconnector is not shown on the graph, e.g. the Victoria to NSW or Murray to Tumut interconnectors in Figure B.40, it should be inferred that no clamping was observed. Of the two interconnectors that connect to the Snowy region, in the Base scenario the greatest incidence of clamping was for the Snowy-NSW interconnector. Clamping on this interconnector was in the order of 1% of the year. Some minor clamping also occurred on the Victoria-Murray and Tumut-NSW interconnectors in the SSR scenario. No clamping was observed in the Abolition and SG scenarios for the relevant interconnectors around the Snowy region.

Figure B.41 shows the incidence of clamping on other interconnectors in the system. Relatively low levels of clamping (less than 0.1% of the year) were observed on these interconnectors.

[155] See NEMMCO, *Operating Procedure, Dispatch*, doc no: SO_OP3705, Rev 46, 16/03/07.

Figure B.40 Hours of clamping, Snowy region interconnectors

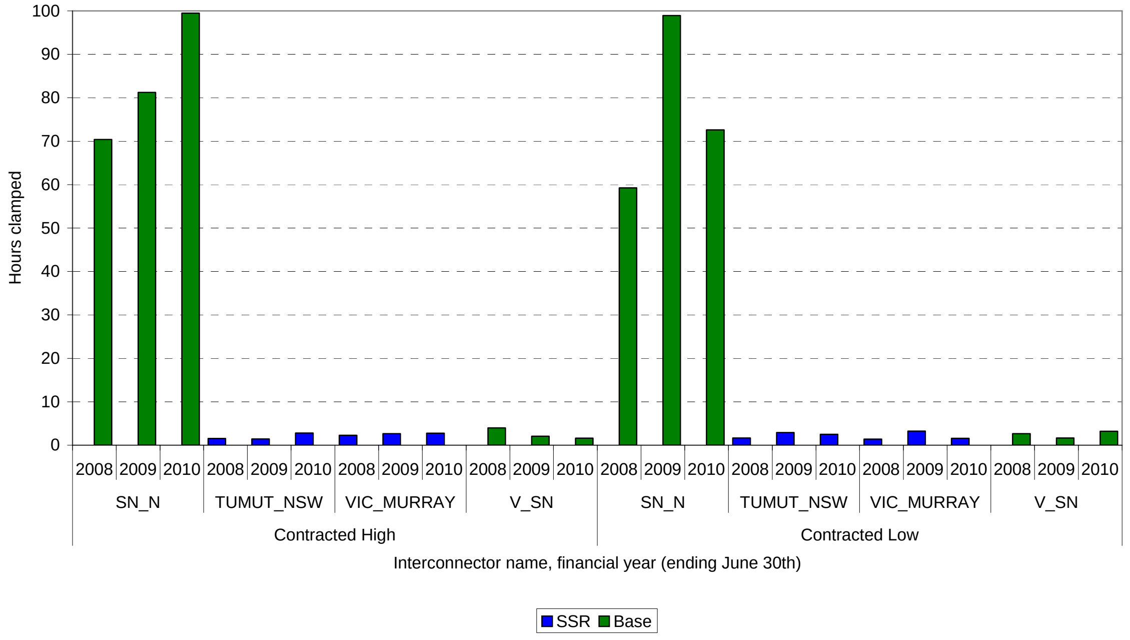
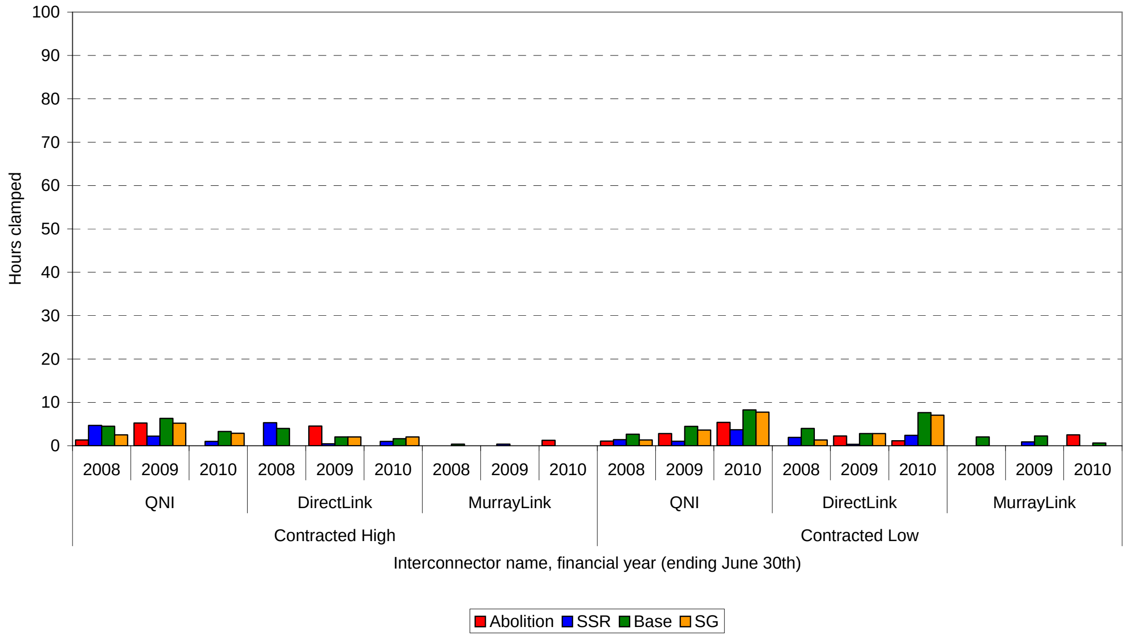


Figure B.41 Hours of clamping, other interconnectors



B.4 Risk modelling

This Section discusses the approach, assumptions, results, and conclusions for the forward-looking risk modelling analysis.

B.4.1 Approach

The risk modelling was undertaken using Frontier Economics' portfolio optimisation model, *STRIKE*. This discussion begins by describing some of the key features of this model before discussing the methodology used to calculate the risk implications of the Abolition case, the SSR case, the SG case and the Base scenario.

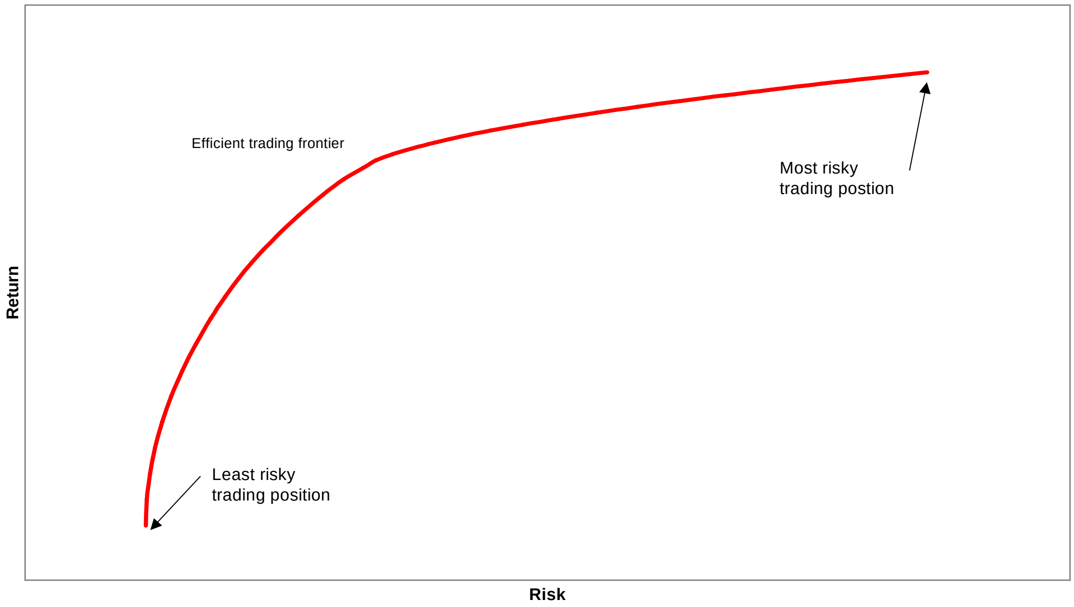
B.4.1.1 Key features of *STRIKE*

The *STRIKE* financial model uses portfolio theory to determine an efficient mix of energy purchasing instruments from a suite of options (spot, physical and financial) for a range of risk levels. Each efficient combination of instruments is represented as a point on a frontier, against which other portfolios can be compared.

Portfolio theory sets out how rational investors would use diversification to optimise their portfolios and how an asset should be priced given its risk relative to the market as a whole. More specifically, portfolio theory estimates the return of an asset as a random variable and a portfolio as a weighted combination of assets. The return of a portfolio is therefore a random variable and consequently has an expected value and a variance. Risk in this economic model is usually identified with the standard deviation of portfolio return (although other measures of risk can be used). For a given expected return, a rational investor would choose the least risk portfolio. In portfolio theory this relationship between risk and reward is represented by an efficient frontier (see Figure B.42).

The efficient frontier describes the outer edge of every possible portfolio of assets that could be plotted in risk-return space. Portfolios of assets along this line deliver lowest risk for a given level of expected return. Conversely, for a given amount of risk, the portfolio lying on the efficient frontier represents the combination of assets offering the best possible expected return. Any portfolio that lies below and/or to the right of the efficient frontier is sub-optimal, delivering either a lower expected return and/or higher level of risk than a portfolio lying on the frontier. It is not possible to construct a portfolio that lies above and/or to the left of the efficient frontier. The model calculates the outer edge (frontier) of every possible portfolio using an advanced quadratic mixed integer programming technique.

Figure B.42 A generalised efficient frontier for hedging energy trading risks



B.4.1.2 Methodology

As market conditions change, so does the efficient frontier. This enables the impact of changes in spot price volatility and IRSR firmness arising from the various options to be compared.

The risk modelling was undertaken for several key scenarios:

- A Victorian generator hedging at the NSW node;
- A NSW generator hedging at the Victorian node; and
- A Snowy Hydro generator hedging at both the Victorian and NSW nodes concurrently.

Each of the options affect the existence and/or magnitude of settlement residues accruing between Victoria, Murray, Tumut and NSW. The above cases cover the range of likely risk-management applications using combinations of the relevant residues.

In each case, *STRIKE* was run to calculate the efficient frontier for the given set of price duration curves and IRSR units.

The precise effect of a region boundary change on risk will depend on where participants choose to locate on the efficient frontier – that is, their risk preferences. Given that the analysis is primarily concerned with the *relative* effects of the alternative proposals, for simplicity the results are presented for the most conservative risk position on the efficient frontier (that is, the bottom left point of the efficient frontier).

The analysis assumes a generator in a given region has a fixed inter-regional position and determines the minimum risk (measured in $/MWh standard deviation in return) associated with that same position under each of the Base case, SG, SSR and Abolition proposals. It is the level of risk associated with the minimum risk position for each scenario that is presented in the results Section below.

B.4.1.3 Assumptions

The risk modelling was based on the spot prices and IRSRs produced by the dispatch modelling for the Base case, SG, SSR and Abolition proposals described above.

For each of the spot price series and associated IRSR units, the analysis compared the efficient frontiers for each of the following hypothetical generators with an inter-regional position using the relevant IRSR units between Victoria, Murray, Tumut and NSW:

- Victoria into NSW: A 100MW Victorian generator with a 100MW position in NSW and able to purchase a mix of relevant northward IRSR units;
- NSW into Victoria: A 100MW NSW generator with a 100MW position in Victoria and able to purchase a mix of relevant southward IRSR units; and
- Murray/Tumut into Victoria/NSW: A 100MW Snowy Hydro generator (50MW at Murray and 50MW at Tumut) with a 50MW position in Victoria and a 50MW position in NSW and able to purchase a mix of relevant IRSR units.

For the purposes of comparison, the generation and inter-regional position were assumed to be consistent in each case. IRSR units were assumed to be available to the generator at actuarily fair cost (i.e. the cost of the unit was equal to the expected return of the residues[156]).

B.4.1.4 Results

The *STRIKE* results are presented below in Figure B.43 and show the level of risk associated with the risk-minimising inter-regional position (including a risk-minimising mix of relevant IRSR units). Risk is expressed in terms of the standard deviation of returns for the optimised portfolio, in terms of $ per MWh covered by the inter-regional position.

The minimum risk results are a combination of two key factors, the underlying level of basis risk (uncertainty of price differentials between regions) and the effectiveness of the various IRSR units in offsetting that basis risk. The underlying basis risk may differ between the region boundary options modelled due to the impact that changes in the regional structure and constraints have on prices and hence price differentials,

[156] Note that the assumed cost of the IRSR units is inconsequential to this particular analysis. This is because the analysis focuses on determining the portfolio with minimum risk, and hence has no regard to cost. The minimum risk portfolio would be the same no matter what the assumed cost of the IRSR units.

but also due the behavioural effects the various change options have on participant bids. Similarly, the effectiveness if IRSR units to offset the basis risk may change between the options for similar reasons.

For inter-regional positions from NSW into Victoria and Murray/Tumut into Victoria/NSW, the analysis found that the Abolition scenario produced the lowest levels of risk, over all years and contracting cases, except for contracted high 2010 that exhibits significantly lower levels of underlying basis risk compared to earlier years. The Base case tended to produce the highest levels of risk, followed closely by the SG scenario and then the SSR proposal. For hedging from Murray/Tumut into Victoria/NSW, the analysis indicated that the Snowy Hydro proposal produces the lowest risk outcome. This is intuitively obvious, as there is no inter-regional price risk for Snowy Hydro's generators under its proposal – Murray earns the Victorian price and Tumut earns the NSW price. These results were driven by the changes in underlying basis risk between the options, which happen to follow the level of prices in NSW and Victoria under each option. The implications is that lower prices correspond to lower inter-regional price risk. Whilst the effectiveness of relevant IRSR units may differ between the cases, the impact of this is not material enough to alter the ranking of options based on the underlying basis-risk.

For inter-regional positions from Victoria into NSW, the results differed somewhat. The SG scenario generally produced the lowest levels of risk, which is not surprising given that the SG rules act to firm up the Victoria to NSW IRSRs. The SG risk results were followed fairly closely by the Abolition proposal. Again, this is not surprising as the Abolition option produced the lowest, and hence least volatile, prices. It is important to note that the impact on contract competition in NSW at these times is somewhat ambiguous, because lower hedging by Victorian generators at the NSW RRN may be (more than) offset by greater hedging by Tumut at the NSW RRN. The Base case and SSR option produced the highest levels of risk, interchanging between years and contracting cases with SSR generally worse in risk terms than the Base case.

Importantly, the STRIKE modelling makes several assumptions that may not be borne out in reality – it assumes that:

- Participants can obtain as many IRSR units on whichever directional interconnectors they wish – that is, they bear no execution risk;
- Participants incur no material transactions costs in determining how many and what kind of IRSR units they need to best hedge their contract positions.

To the extent that these assumptions depart from reality, the STRIKE results may not provide an accurate reflection of the risk impacts of changes to the market structure. Note also that the STRIKE modelling does not consider the risks faced by generators within a given region contracting at their own RRN.

Figure B.43 Inter-regional risk results