ESTIMATION OF ECONOMIC HARM

Electricity Market Economic Modelling for the AER

30 June 2010

Final Report

Intelligent Energy Systems

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1 Introduction

The Australian Energy Regulator (AER) and the Australian Competition and Consumer Commission (ACCC) contracted Intelligent Energy Systems (IES) to provide electricity market modeling with respect to short term economic harm resulting from suspected instances of uncompetitive bidding in the National Electricity Market (NEM).

This report outlines IES's approach to estimating the short term economic harm and the results for a sample of eleven days that the AER selected. The AER's terms of reference for this project are outlined in the following section.

1.1 AER's Terms of Reference

Broadly, the Australian Energy Regulator (AER) is seeking to commission a paper which uses economic modelling to estimate the short term economic harm resulting from suspected instances of uncompetitive bidding in the National Electricity Market for a specified set of days, with a specific focus on:

a) the costs arising from production inefficiencies; and

b) the costs arising from dead weight loss - having regard to demand side response.

The paper should:

1) Set out its working definition of production inefficiency and dead weight loss as it relates to generation dispatch and demand side response in the NEM.
2) Explain the methodology and assumptions (in plain English) that have been made in order to estimate the costs of a) and b), supported by worked examples.
3) Provide a breakdown of the estimated costs for a) and b) on each of the 10 days, set out on a daily and half hourly basis.
4) Provide a short written commentary on the cost estimates.
5) Describe the strengths and weaknesses of the chosen methodologies and assumptions, with reference to alternatives that could have also been used.
6) Provide the supporting data and analysis used to determine the costs in 3) in an excel file and as an appendix to the paper, where practical. Ensure that data is set out in a way so that calculations can be easily replicated.
7) Be written in a manner which is appropriate for circulation to a wide regulatory audience as part of a discussion and policy development process carried out by the AER.

1.2 Outline of Report

The structure of the report is as follows:

- Section 2 Describes the approach which IES adopted to determining the dispatch costs for the alternative bidding scenarios and some of the issues associated with this approach;
- Section 3 Outlines the results; and
- Section 4 Describes the conclusions

2 Approach, Methodology and Issues

2.1 Overview of the Economic Modelling Process

The modelling process was essentially undertaken as follows:

1. AER provided IES with a sample of eleven days during which suspected instances of uncompetitive bidding had occurred in the National Electricity Market. For these days AER identified particular generators which they suspected of uncompetitive bidding.
2. IES reviewed the sample of days and sometimes identified one or two additional generators who also appeared to have made uncompetitive offers for periods during the days of interest. These generators were sometimes in other regions, such as Victorian generators when the main uncompetitive bidding was suspected to have occurred in South Australia. It is not clear whether these other uncompetitive bids were a response to the behaviours of the main generators of interest or other generators seizing on the same opportunity.
3. For the generators hypothesised with uncompetitive behaviour IES, in consultation with AER, determined alternative offers to substitute for the uncompetitive offers during the day. This was done by selecting an offer on the day which looked more competitive and was more like the typical or normal offers of the generator.
4. IES used its own generic dispatch engine (GEDIE) to estimate new dispatches and prices for the revised offers. This was done using a tool which we call NEMLAB. NEMLAB provides an environment for storing and managing the inputs and outputs to and from the NEM's dispatch engine (NEMDE), alternate demand forecasts, alternate offers etc. NEMLAB constructs the input data and executes GEDIE.
5. GEDIE provides a superset of dispatch engine capabilities for the NEM and other electricity markets such as those in Singapore and the Philippines. The NEMLAB and GEDIE dispatch and pricing process was checked for all eleven days using exactly the same inputs as for NEMDE. The results of this test were that GEDIE produced dispatch and pricing results exactly the same as NEMDE for most dispatch intervals and very slightly different for the other dispatch intervals. There were no material differences.
6. The alternative scenarios were developed using all the same inputs as NEMDE used for the historic dispatches, except the identified "uncompetitive offers" were replaced by more normal or typical offers on the day. These runs provided alternative dispatches and prices.
7. For both the historic and alternative dispatch scenarios the dispatch costs were calculated using ACIL Tasman's short run marginal costs for 2007-08, 2008-09 and 2009-10.

8. The costs arising from production inefficiencies were estimated from the dispatch costs for the historic scenario minus the dispatch costs for the alternative scenario.
9. The costs arising from inefficiencies in load curtailment were not estimated
10. An estimate of the economic harm caused by uncompetitive bidding was determined by just the costs of the production inefficiencies. The costs associated with inefficient load curtailment were not included.

2.2 Sample Days and Power Stations with "Uncompetitive Offers"

Table 1 presents the sample days chosen by the AER and the suggested power stations whose offers at some time during the day appeared to be uncompetitive.

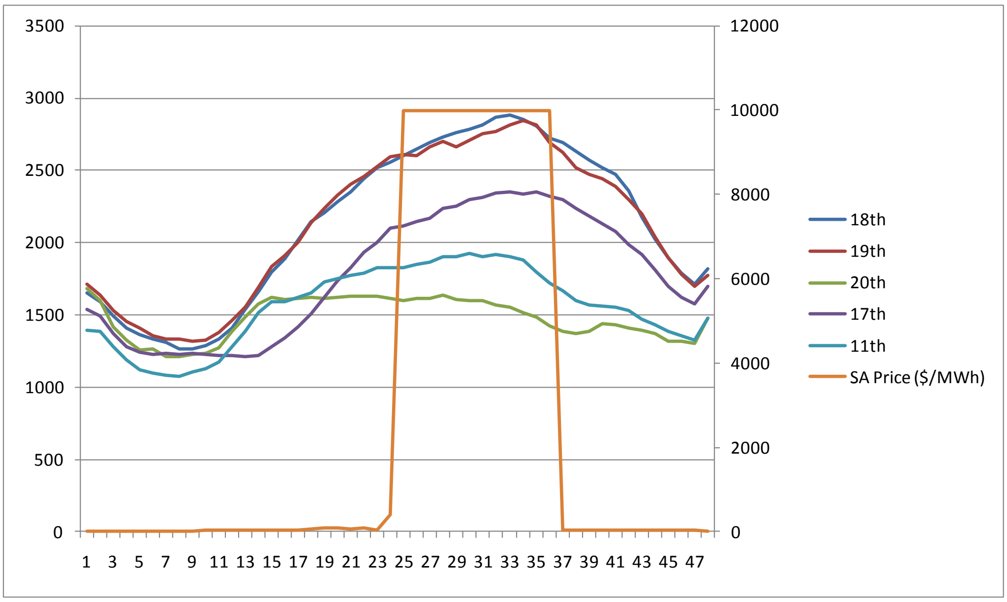
Table 1 Sample Days and Generators with "Uncompetitive Offers"

Date	Region	AER Identified Power Stations
10-Jan-08	SA	Torrens Island Power Station (TIPS) and Angaston
18-Feb-08	SA	TIPS, Loy Yang A and Loy Yang B
15-Jan-09	NSW	Eraring and Mt Piper
19-Jan-09	SA	TIPS
19-Nov-09	SA	TIPS and Loy Yang A
7-Dec-09	NSW	Eraring, Millmerran, Tarong, Swanbank B, Munmorah, Vales Pt and Wallerawang
11-Jan-10	SA	TIPS and Loy Yang A
18-Jan-10	QLD	Swanbank, Callide and Tarong
22-Jan-10	NSW	Eraring, Mt Piper Vales Pt, Wallerawang and Swanbank B
9-Feb-10	SA,VIC	TIPS, Loy Yang A & B
15-Feb-10	QLD	Swanbank, Millmerran Callide, Tarong, Tarong North and Gladstone

2.3 Selection of Alternative Offers

To illustrate the process of identifying "uncompetitive offers" and the process of selecting alternative offers we will take an example. In this case we will look at Monday 18th February 2008. On the day, South Australian spot prices were $9999.72/MWh from 12:30 to 18:00, see Figure 1. These prices were just a fraction under the market price cap of $10.000/MWh.

Figure 1 Spot Prices in SA 18th February 2008 and Regional Demands for the 11th, 17th, 18th, 19th and 20th February 2008



The offers made for Torrens Island B are presented in Figure 2. What is noticeable is the amount of capacity that has been offered at very high prices between 12:30 and 18:30. On the other hand a more typical offer structure for Torrens Island B is presented in Figure 3.

Figure 2 Offers Made for Torrens Island B for the 18th February 2008

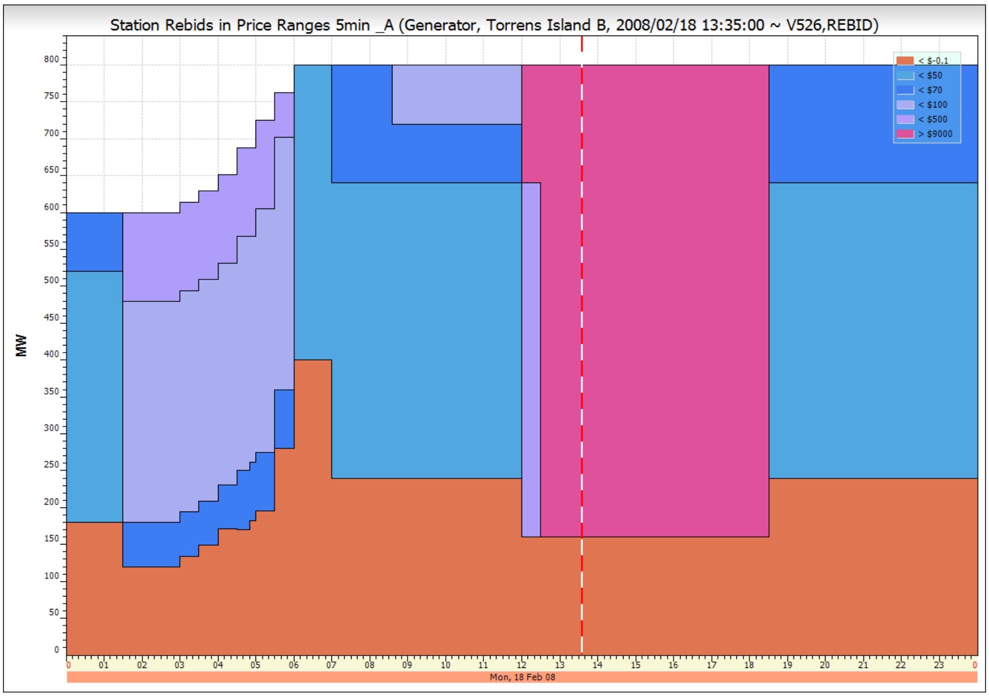
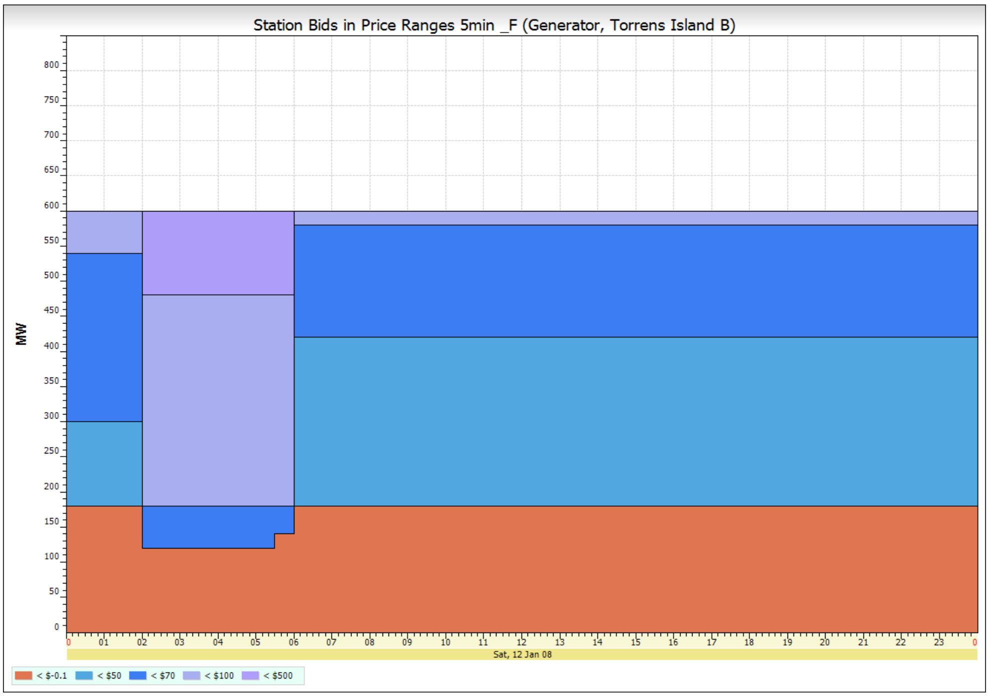


Figure 3 More Usual Offer Structure for Torrens Island B



The offer made for Torrens Island B for the half hour ending 8:30 on the 18th of February 2008 (Figure 2) looks more like the standard Torrens Island pattern, though more capacity has been offered than normal, probably due to an extra unit being online. On the other hand the 8:30 offer may not fully reflect the situation regarding gas supply and the plant capability at 12:30, immediately prior to large amounts of capacity being offered at near 10,000 $/MWh prices. So a more conservative approach was taken for Torrens Island, in this case the offer immediately before the high priced offers from 12:30 onwards would appear to be a reasonable indication of prices that Torrens Island would be prepared to generate at during the high demand periods. Thus for this case the offer ending at 12:30 was used as the basis for the alternative offers and was substituted for the offers between 12:30 and 18:30 inclusive. This is an example of the general process that IES adopted for creating alternate offers. The alternate offers are presented in Table 2, below.

Table 2 Schedule of Offers Which Were Substituted

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[1]	To[1]	With[1]
Day 01	10/01/08	12:30	17:30	Torrens Island A	SA	14:00	17:30	14:00
				Torrens Island B	SA	14:00	17:30	14:00
				Angaston	SA	12:30	17:30	12:30
Day 02	18/02/08	12:30	18:30	Torrens Island A	SA	12:30	18:30	12:30
				Torrens Island B	SA	12:30	18:30	12:30
				Loy Yang A	VIC	13:00	17:00	13:00
				Loy Yang B	VIC	13:00	17:00	13:00
Day 03	15/01/09	8:30	22:30	Eraring	NSW	11:30	17:00	11:30
				Mt Piper	NSW	8:30	22:30	8:30
Day 04	19/01/09	13:30	16:00	Torrens Island A	SA	13:30	16:00	13:30
				Torrens Island B	SA	13:30	16:00	13:30
Day 05	19/11/09	12:30	19:30	Torrens Island A	SA	12:30	19:30	12:30
				Torrens Island B	SA	12:30	19:30	12:30
				Loy Yang A	VIC	12:00	17:00	12:00
Day 06	7/12/09	0:30	0:00	Eraring	NSW	0:30	0:00	0:30
				Munmorah	NSW	12:00	20:00	12:00
				Vales Pt	NSW	12:00	17:00	12:00
				Wallerawang	NSW	12:00	18:00	12:00
				Millmerran	QLD	10:00	23:30	10:00
				Tarong	QLD	9:00	17:00	9:00
				Swanbank B	QLD	8:00	17:00	9:00
				Callide B	QLD	7:30	18:00	7:30
Day 07	11/01/10	13:00	19:00	Torrens Island A	SA	13:00	19:00	13:00
				Torrens Island B	SA	13:00	19:00	13:00
				Loy Yang A	VIC	14:00	18:00	14:00
Day 08	18/01/10	6:30	23:30	Swanbank B	QLD	6:30	23:00	23:00
				Swanbank E	QLD	12:00	17:00	12:00
				Callide B	QLD	11:30	17:00	11:30
				Callide C	QLD	6:30	23:30	6:30

[1] Period ending trading interval

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[1]	To[1]	With[1]
				Tarong	QLD	12:00	22:00	12:00
				Tarong North	QLD	12:00	17:00	12:00
Day 09	22/01/10	0:30	0:00	Eraring	NSW	0:30	0:00	7:00
				Mt Piper	NSW	7:30	19:00	7:30
				Vales Pt	NSW	9:30	23:30	19:00
				Wallerawang	NSW	4:00	0:00	4:00
				Swanbank B	QLD	6:00	22:30	6:00
Day 10	9/02/10	10:00	18:30	Torrens Island A	SA	12:00	18:30	12:00
				Torrens Island B	SA	12:00	18:30	12:00
				Loy Yang A	VIC	10:00	17:00	17:00
				Loy Yang B	VIC	13:30	17:30	13:30
Day 11	15/02/10	4:30	0:00	Swanbank B	QLD	6:00	22:30	6:00
				Swanbank E	QLD	12:00	0:00	12:00
				Tarong	QLD	4:30	19:00	19:00
				Tarong North	QLD	9:30	0:00	9:30
				Callide C	QLD	10:30	18:30	10:30
				Millmerran	QLD	10:00	21:00	10:00
				Gladstone	QLD	9:00	19:30	9:00

2.4 NEMLAB, GEDIE and Alternative Dispatch Scenarios

The historic and alternative bidding scenarios were run with IES's proprietary generic dispatch engine (GEDIE). GEDIE is a data driven generic dispatch engine that is a superset of NEMDE. GEDIE was configured to reproduce NEMDE's dispatches and this configuration was tested on the NEM's historical data for the 11 days of interest. Results given by GEDIE were either exactly the same as or very close to the historical NEMDE outcomes on all 3168 (11 * 288) dispatch intervals.

For the alternative bidding scenarios, NEMDE's market clearing mechanisms were matched as closely as possible. However, the following approximations were adopted.

2.4.1 Initial Conditions

Some of the constraints included in the clearing model for each dispatch interval represent the state of the network at the beginning of the interval. These initial conditions include generation levels, transmission flows on interconnectors and operating modes for fast start units electing to be centrally committed.

In the NEM, initial conditions come from SCADA measurements and are passed on to the dispatch engine through NEMDE's input files.

For the study, initial conditions for each dispatch interval were taken from the previous interval's solution except for the first interval modelled in each day (where historical SCADA measurements were used).

2.4.2 Generic Constraints

Some of the generic constraint right hand sides used in the actual market dispatch clearing are a function of the current state of the network. To compute these constraints' right hand sides, SCADA measurements of generators output levels, transmission lines flows etc are fed into NEMDE. The calculated right hand sides are then used in the clearing algorithm and reported in NEMDE's output files. For this study, generic constraints' right hand sides were not dynamically calculated. Values calculated by NEMDE were used instead and may not be strictly correct when the revised dispatches deviate significantly from NEMDE's historical dispatches.

2.4.3 Regional Demand

The NEM regional demands are demand figures based on generator outputs not load consumption. As such, they include intra-regional losses. Thus for the same actual demands by regional loads (consumers), a NEM regional demand would appear lower for a generation dispatch which used more local generation compared to an alternative dispatch which used more remote generation

The projected regional load against which the NEM generation is cleared is calculated for each region and each dispatch interval by NEMDE with the following elements:

- Initial demand: initial metered demand (measured at the beginning of the interval) passed into NEMDE from SCADA. In the SCADA system, this is calculated as the sum of metered MW generation from all dispatchable generation in the region plus the metered net generation import into the region from other regions measured at the inter-regional notional boundaries.
- Aggregated dispatch error: region demand correction computed in and transferred from the SCADA system.
- Forecast demand change: projected region demand change five minutes into the future (end of the interval) based on the sum of current metered generations, computed in and transferred from the SCADA system.

The values used in this study for regional initial demands, aggregated dispatch errors, and forecast demand changes were the historical data also used by NEMDE in the actual market clearing. This is not strictly correct and might impact on the study results when the revised dispatches (and associated intra-regional losses) deviate significantly from NEMDE's historical dispatches. For instance if more local generation were used in the alternative dispatch then its dispatch costs could be overestimated as the regional demand would not have been adjusted to account for reduced intra-regional losses.

2.5 Generator Dispatch Costs

For thermal generators' dispatch costs for 2009-10, IES used the short run marginal costs figures in ACIL Tasman's April 2009 report "Fuel resource, new entry and generation costs in the NEM". For the dispatch costs in earlier financial years, IES used the corresponding SRMC data developed by ACIL Tasman for the NEMMCO's ANTS consultation reports.

For wind farms we assumed dispatch costs of -$40/MWh (to include revenues from producing Renewable Energy Certificates). Nearly all the time the dispatch costs for wind farms are irrelevant because the dispatches for the historic and alternative scenarios are exactly the same.

The marginal cost of hydro generation is really the value of water used in generating. The marginal value of water in storage is its opportunity cost; as a consequence, determining suitable marginal costs to use for hydro generators when determining generation dispatch costs is not obvious or straight forward. To address the issue, IES looked at the prices in hydro generators' offers in the NEM. Generators will generally offer a very low price for the first price band in their offer, often very close to the market price floor of -$1000/MWh. In either their second or third price bands they will have a price that approximates their marginal costs of generation. Having one offer price near a generator's marginal cost allows the generator to offer a quantity of generation that the generator is somewhat indifferent about how much is dispatched. Generators will often have capacity offered at marginal cost around their contracted quantity for that half hour. For this study, IES found that hydro generators generally had a very low price for the first offer price band, a price near zero for the second offer price and a price that looked like it could be a reasonable approximation to their marginal generation costs based on an opportunity cost of water in storage. Thus IES used for each hydro generating unit the offered price in the third price band as an estimate of that unit's marginal cost. However, in the case of Snowy this may not always have been the most appropriate price band to use for Snowy generation as Snowy sometimes had a clustering of prices between bands three and six which meant that for some periods other price bands such as four and five could conceivably be better estimates of marginal costs (water opportunity costs).

2.6 Demand Side Response to High Prices

Assessing the amount of demand side response to high prices is quite difficult to do in general and on the eleven days in question. Potentially there are quite large amounts of loads that could respond to high prices. Some of these loads, such as a number of smelters and large customers, are already involved in load shedding schemes for network control or system security. Some of these may be part of general NEM network control ancillary service (NCAS) arrangements and others may be part of special schemes such as the Basslink system protection scheme. States such as QLD and NSW have quite large amounts of MWs of hot water heating that can be switched off using the capabilities of the distribution network. In QLD the amount of load reduction due to switching off hot water heating is around 100MW to 200MW. As well there is anecdotal evidence of regional demands dropping away when there are forecast high prices. Some of this would be due to customers who have unilaterally reduced their loads because they have some exposure to the spot market price, via such things as spot market pass through contracts.

AEMO is currently conducting a project which is looking at estimating the size of the possible demand side responses in the various NEM regions and how price sensitive this response is. This project is not yet complete. However, to get a rough idea of the economic harm that could be caused by having high spot prices which are unrelated to the real costs of supply, one could assume that a high priced event may consist of, say, six hours of prices above $2000/MWh in one or more regions and during this period 50MW of load is curtailed. If we assess the average opportunity cost of this forgone consumption of electricity at about $1000/MWh and the real cost of actually meeting this additional demand was about $100/MWh then such an episode would result in a short term lost economic benefit of about $ 6 x 50 x (1000 – 100) = $270,000.

3 Results

3.1 Introduction

The detailed results for each day are presented in the appendices. This section provides a summary of the results and uses one day, Monday, 18 February 2008, to outline and explain the results presented in the appendices.

3.2 Expected Results

The expected results for this study were:

- Lower regional reference prices in the regions where generators offers had been adjusted to reflect their more usual and lower priced offers (more capacity offered in the lower priced bands); and
- Reduced dispatch costs.

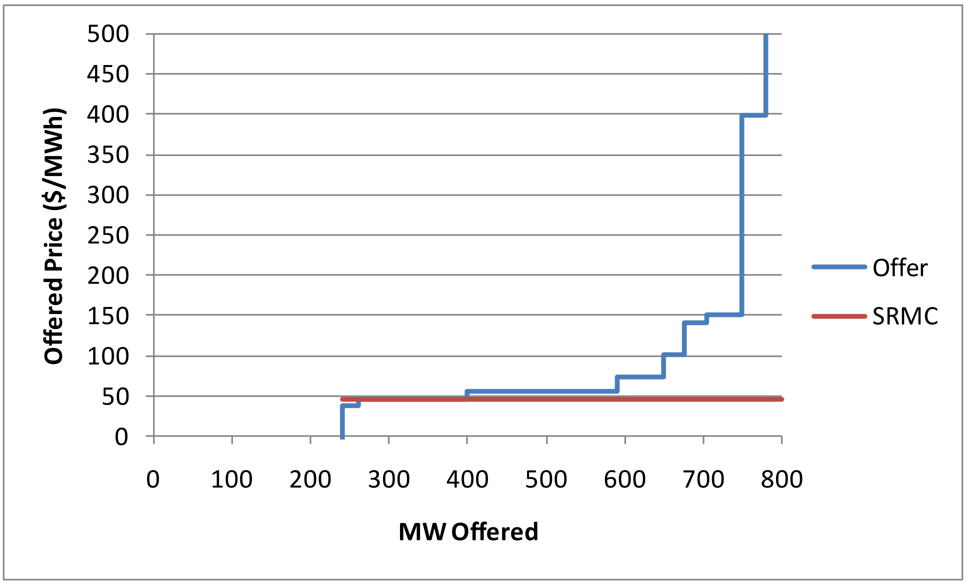
An expected reduction in dispatch costs is based on two implicit assumptions:

- That the prices and quantities that generators offer into the NEM roughly correlate with the underlying merit order of plant in the NEM and
- On the occasions when the capacities of some power stations have been offered at very high prices this has resulted in generators being dispatched out of merit order and thus increased the dispatch costs in the NEM relative to the more normal or usually offered supply curves.

However in practice even the lowest cost generators will often offer some of their capacity at prices well above their marginal costs and usually a small amount of capacity at prices near the market price cap. Slow start generators will tend to offer their capacity up to minimum loading levels at zero or negative prices, often just marginally above the market price floor. Next they may offer the swap contracted amounts at prices around the short run marginal costs often using their second and third price bands. If they have some cap contracts they may offer these quantities to the market around the cap exercise price. They will spread their remaining unallocated capacity around a range of other prices including some capacity offered near the price cap and the other quantities chosen in way that attempts to maximise the generator's profitability in the short or long term.

The offered supply curves invariable do not correspond to a generator's actual marginal costs of generation, for example see Figure 4 which shows an offered supply curve for a power station versus an estimated short run marginal cost of 46/MWh. Consequently, under normal circumstances the dispatch of generation in the NEM generally is not exactly in least cost merit order. Thus changing the offered supply curves for selected generators which are believed to have behaved in an uncompetitive way is not guaranteed to always reduce the NEM's total dispatch costs.

Figure 4 Example of Power Station Offered Supply Curve versus Short Run Marginal Cost of Generation



3.3 Spot Price Impacts

The alternative scenarios with the revised offers for a selected few generators always resulted in very substantial reductions in spot prices. The historical and alternative spot prices for 18 February 2008 are presented in the following figures for the regions which were substantially affected: South Australia, Victoria and Snowy.

Figure 5 South Australian Spot Prices for Historical and Alternative Dispatch 18/2/2008

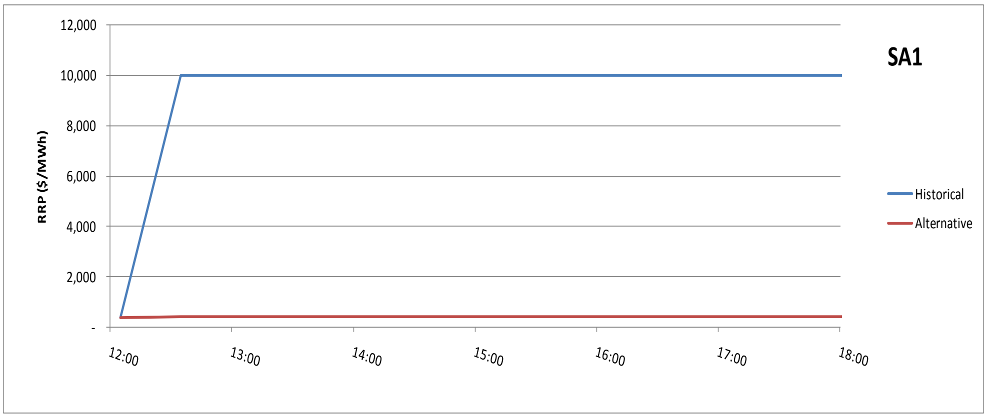


Figure 6 Victorian Spot Prices for Historical and Alternative Dispatch 18/2/2008

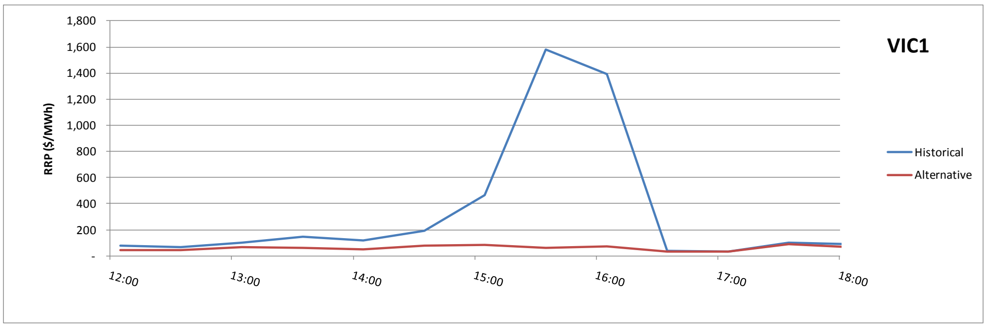
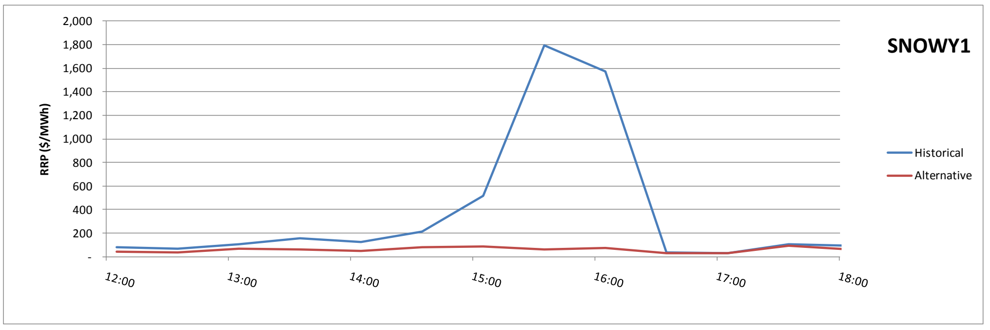


Figure 7 Snowy Spot Prices for Historical and Alternative Dispatch 18/2/2008



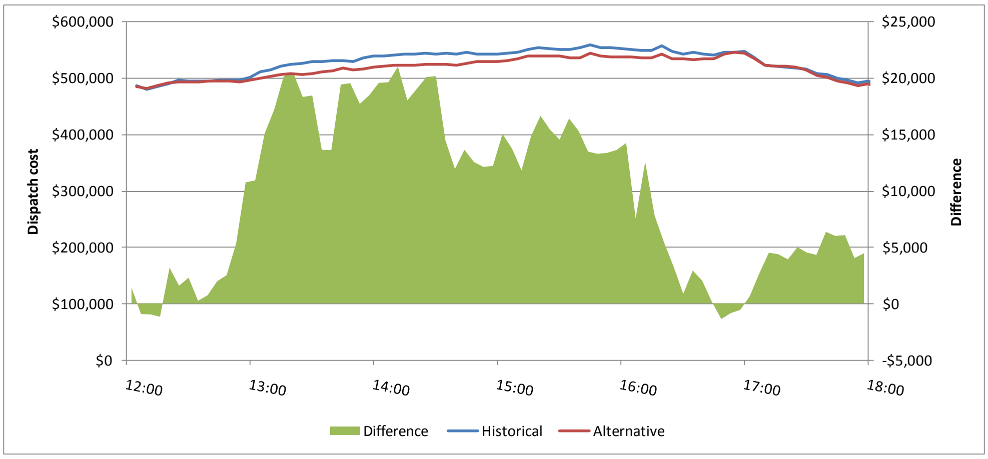
3.4 Dispatch Cost Impacts

The alternative scenarios with the revised offers for a few selected generators usually resulted in decreased dispatch costs, though there are some periods when this was not the case. For example Figure 8 shows some periods which had increased dispatch costs for the 18 February 2008.

Increased dispatch costs could occur for a number of reasons.

- Firstly, if the alternative dispatch uses local generators more than remote generators then the alternative dispatch costs could be overestimated slightly because the regional demands used in the modelling have not been adjusted for the reduction in intra-regional losses.
- Secondly, because the right hand sides of the generic constraints have not been adjusted for the alternative dispatch then some network constraints may be unnecessarily constraining the dispatch of some generators. The converse could also be the case as well, in that some constraints in the alternative dispatch should be constraining when they are not.
- Lastly, if the revised offers in the alternative scenario are for more expensive generators then there may be dispatch costs increases due to these more expensive generators replacing cheaper alternative generators.

Figure 8 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 18/2/2008



3.5 Dispatch Changes

The generators whose offers had been changed for the alternative scenarios always had increased amounts dispatched and hence increased dispatch costs. However, the other changes in dispatches and associated costs were not always so predictable. Quite often hydro generation was an important component of the changes. This is to be expected because much of the NEM's hydro generation plant operates in a peaking or mid merit mode. These points about changes in dispatches and dispatch costs are illustrated in the following table and figure for 18 February 2008. In this case the total dispatch costs for the 6 hour period modelled were estimated to be $40,952,581 with the alternate dispatch resulting in an estimated reduction in dispatch costs of $762,955 or about 1.9%.

Table 3 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 18/2/2008

Plant	Historical	Alternative	Difference
AGLHAL	626,917	602,949	23,968
AGLSOM	473,497	472,970	527
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	68,141	68,141	0
BARCALDN	165,810	162,722	3,088
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	167,190	110,431	56,759
BBTHREE1	89,175	89,175	0

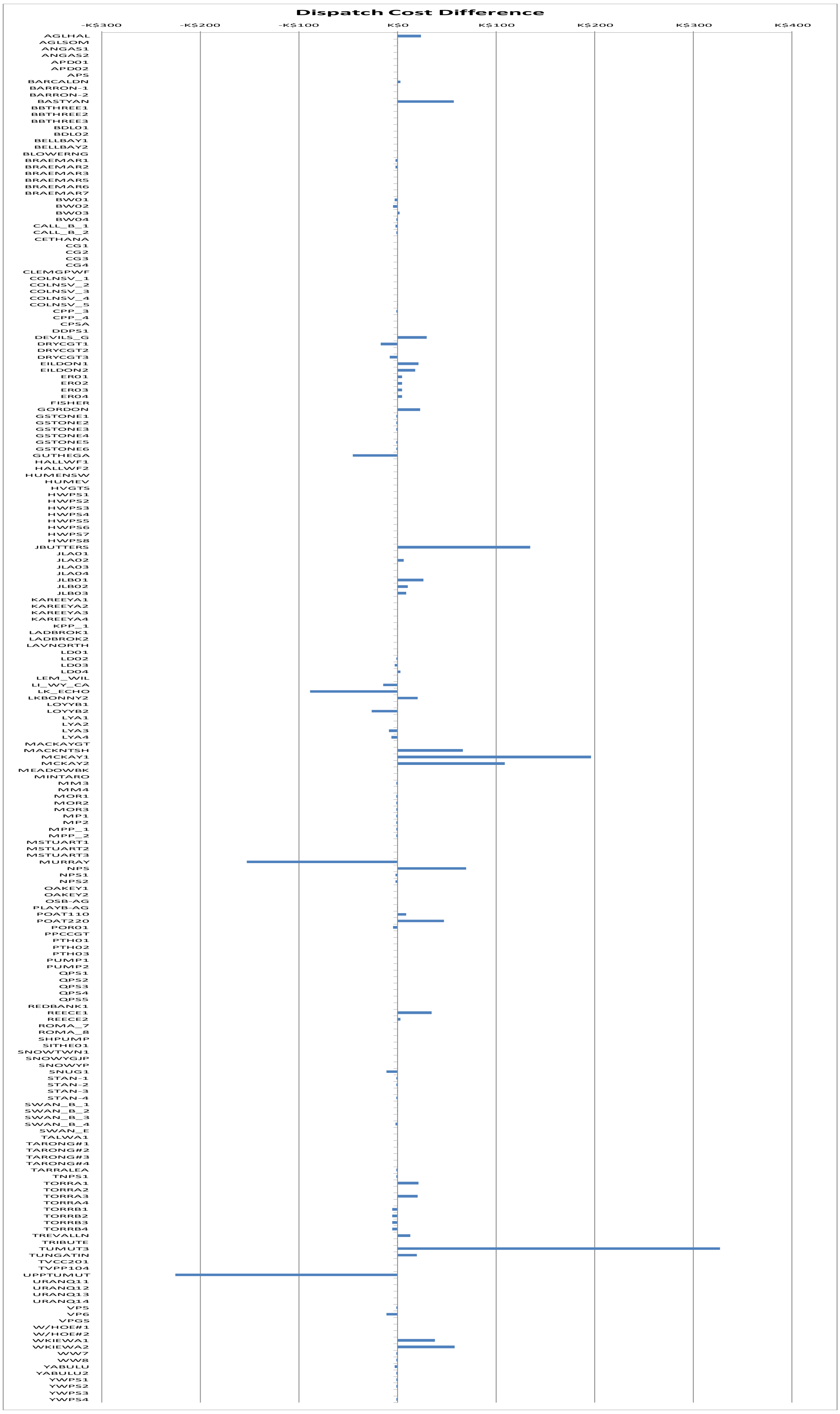
Plant	Historical	Alternative	Difference
BBTHREE2	0	0	0
BBTHREE3	125,172	125,172	0
BDL01	120,588	120,588	0
BDL02	25,459	25,459	0
BELLBAY1	472,699	472,699	0
BELLBAY2	394,154	394,154	0
BLOWERNG	5,460	5,460	0
BRAEMAR1	385,204	387,073	-1,869
BRAEMAR2	391,824	393,919	-2,095
BRAEMAR3	0	0	0
BRAEMAR5	0	0	0
BRAEMAR6	0	0	0
BRAEMAR7	0	0	0
BW01	386,493	389,012	-2,519
BW02	376,885	381,270	-4,385
BW03	365,931	364,036	1,895
BW04	363,545	363,920	-375
CALL_B_1	299,595	301,372	-1,777
CALL_B_2	306,389	307,239	-849
CETHANA	0	0	0
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	0	0	0
COLNSV_1	0	0	0
COLNSV_2	0	0	0
COLNSV_3	0	0	0
COLNSV_4	0	0	0
COLNSV_5	1,590	1,277	313
CPP_3	398,964	399,544	-580
CPP_4	384,232	384,232	0
CPSA	0	0	0
DDPS1	0	0	0
DEVILS_G	210,926	181,278	29,648
DRYCGT1	4,166	21,110	-16,943
DRYCGT2	219,986	219,986	0
DRYCGT3	144,921	152,907	-7,986
EILDON1	147,798	126,378	21,420
EILDON2	126,336	108,027	18,310
ER01	658,254	653,817	4,437
ER02	658,370	653,765	4,605
ER03	658,496	653,728	4,767
ER04	658,382	653,733	4,649
FISHER	0	0	0
GORDON	919,275	896,436	22,839
GSTONE1	182,178	182,414	-236
GSTONE2	233,417	235,018	-1,601
GSTONE3	234,318	235,896	-1,578
GSTONE4	0	0	0
GSTONE5	180,514	180,696	-182
GSTONE6	176,914	177,261	-347
GUTHEGA	56,289	101,400	-45,111

Plant	Historical	Alternative	Difference
HALLWF1	-2,560	-2,560	0
HALLWF2	0	0	0
HUMENSW	0	0	0
HUMEV	21,840	21,840	0
HVGTS	0	0	0
HWPS1	22,008	22,008	0
HWPS2	22,008	22,008	0
HWPS3	26,898	26,898	0
HWPS4	0	0	0
HWPS5	35,551	35,551	0
HWPS6	35,729	35,729	0
HWPS7	33,294	33,293	0
HWPS8	34,441	34,433	8
JBUTTERS	312,574	177,776	134,798
JLA01	0	0	0
JLA02	134,820	128,797	6,023
JLA03	0	0	0
JLA04	0	0	0
JLB01	117,208	90,992	26,216
JLB02	95,466	85,201	10,265
JLB03	128,224	119,531	8,693
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	224,880	224,540	340
LADBROK1	89,238	89,238	0
LADBROK2	89,238	89,238	0
LAVNORTH	1,124,707	1,124,707	0
LD01	432,287	432,169	118
LD02	431,943	433,445	-1,502
LD03	424,082	427,260	-3,177
LD04	380,088	376,988	3,099
LEM_WIL	92,739	91,953	786
LI_WY_CA	491,414	506,018	-14,604
LK_ECHO	80	89,211	-89,131
LKBONNY2	-126,463	-147,240	20,777
LOYYB1	221,235	221,130	105
LOYYB2	195,238	221,130	-25,892
LYA1	87,497	87,497	0
LYA2	78,636	78,636	0
LYA3	78,555	87,516	-8,961
LYA4	71,139	77,610	-6,471
MACKAYGT	0	0	0
MACKNTSH	183,915	117,453	66,462
MCKAY1	320,295	123,820	196,474
MCKAY2	141,863	33,459	108,403
MEADOWBK	88,355	87,509	846
MINTARO	363,703	363,703	0
MM3	314,856	315,319	-463
MM4	0	0	0
MOR1	32,960	33,603	-643
MOR2	18,829	19,031	-201

Plant	Historical	Alternative	Difference
MOR3	42,893	43,484	-592
MP1	830,056	830,651	-595
MP2	830,585	830,651	-66
MPP_1	188,830	188,910	-80
MPP_2	185,645	186,087	-442
MSTUART1	0	0	0
MSTUART2	0	0	0
MSTUART3	0	0	0
MURRAY	72,152	224,700	-152,548
NPS	1,209,985	1,140,070	69,915
NPS1	354,928	356,780	-1,851
NPS2	345,734	347,501	-1,767
OAKEY1	0	0	0
OAKEY2	0	0	0
OSB-AG	456,710	456,710	0
PLAYB-AG	312,332	312,182	149
POAT110	362,123	353,711	8,412
POAT220	528,056	480,695	47,361
POR01	943,477	947,661	-4,184
PPCCGT	1,138,017	1,138,017	0
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	70,746	70,746	0
QPS2	70,746	70,746	0
QPS3	70,746	70,746	0
QPS4	70,746	70,746	0
QPS5	0	0	0
REDBANK1	135,296	135,296	0
REECE1	201,623	167,388	34,235
REECE2	157,454	154,451	3,003
ROMA_7	0	0	0
ROMA_8	0	0	0
SHPUMP	0	0	0
SITHE01	460,042	460,042	0
SNOWTWN1	0	0	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	1,419,276	1,430,642	-11,367
STAN-1	286,785	287,381	-596
STAN-2	286,692	287,392	-700
STAN-3	333,520	333,230	289
STAN-4	286,671	287,341	-670
SWAN_B_1	111,278	110,935	344
SWAN_B_2	110,645	110,312	333
SWAN_B_3	0	0	0
SWAN_B_4	108,270	110,609	-2,339
SWAN_E	706,860	706,860	0
TALWA1	0	0	0
TARONG#1	115,085	114,503	582
TARONG#2	110,947	110,947	0

Plant	Historical	Alternative	Difference
TARONG#3	174,346	174,346	0
TARONG#4	110,947	110,947	0
TARRALEA	255,552	255,708	-157
TNPS1	376,002	376,639	-637
TORRA1	225,420	204,071	21,348
TORRA2	0	0	0
TORRA3	224,933	204,071	20,861
TORRA4	0	0	0
TORRB1	279,033	284,223	-5,189
TORRB2	279,081	284,243	-5,162
TORRB3	279,013	284,211	-5,198
TORRB4	279,043	284,211	-5,168
TREVALLN	149,849	136,490	13,359
TRIBUTE	228,816	228,339	477
TUMUT3	1,051,418	724,240	327,178
TUNGATIN	278,003	258,676	19,326
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	825,119	1,050,170	-225,052
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	0	0	0
URANQ14	0	0	0
VP5	788,876	789,703	-827
VP6	778,299	789,320	-11,020
VPGS	481,592	481,592	0
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	102,922	64,914	38,008
WKIEWA2	92,780	35,003	57,777
WW7	632,454	632,923	-469
WW8	632,527	632,923	-396
YABULU	349,874	352,872	-2,998
YABULU2	196,122	197,122	-999
YWPS1	58,301	58,308	-7
YWPS2	51,005	51,017	-11
YWPS3	62,626	62,626	0
YWPS4	59,419	59,491	-72
Total	**40,952,581**	**40,189,626**	**762,955**

Figure 9 Generator Dispatch Cost Changes



3.6 Estimates of Economic Harm Due to Dispatch Inefficiencies

A summary of the estimated dispatch cost inefficiencies (the historical dispatch costs – alternative dispatch costs) are presented in Table 4.

Table 4 Summary of Dispatch Cost Inefficiencies ($)

Scenario	Day	Primary Region(s) Affected	Primary Power Stations Involved	Economic Cost of Dispatch Inefficiency ($)
Day 01	10/01/2008	SA	Torrens Island	-55,726 (see discussion below)
Day 02	18/02/2008	SA and Vic	Torrens Island Loy Yang A & B	762,955
Day 03	15/01/2009	NSW	Eraring & Mt Piper	2,146,566
Day 04	19/01/2009	SA	Torrens Island	206,437
Day 05	19/11/2009	SA and Vic	Torrens Island Loy Yang A	530,730 (see discussion below)
Day 06	7/12/2009	NSW and QLD	NSW Power Stations and Southern QLD Power Stations	2,089,295
Day 07	11/01/2010	SA and Vic	Torrens Island Loy Yang A	353,644
Day 08	18/01/2010	QLD	Swanbank, Callide B & C, Tarong and Tarong North	4,829,793
Day 09	22/01/2010	NSW and QLD	Eraring, Mt Piper, Vales Pt, Wallerawang and Swanbank B	1,085,794
Day 10	9/02/2010	SA and Vic	Torrens Island Loy Yang A & B	1,376,971
Day 11	15/02/2010	QLD	Swanbank B & E, Callide C, Tarong, Tarong North, Millmerran and Gladstone	1,858,343
Total				15,184,802

For Day 01, the dispatch costs for the alternative dispatch were marginally higher than for the original dispatch costs. This result could have occurred for a number of reasons including the modelling issues discussed in 2.4 such as:

- Problems with initial conditions;
- Problems with generic constraints; and
- Problems with regional demands not adjusting to changes in local and remote generation.

For Day 05, the original estimate for the dispatch inefficiencies was a large negative value of -$539,845. The two most likely reasons for this were the following:

- The offered supply curves for the generators whose dispatches changed didn't reflect their position in the least cost merit order (under normal circumstances not all of the generation in the NEM is offered into the market according to the marginal cost merit order of the plant); or
- One or more of the marginal costs for the generators whose dispatches did change were materially wrong.

These options were investigated by AER and IES and it was found that the estimates of Snowy's marginal costs made a significant difference to the results. Snowy over the days investigated often had a number of price bands that could reasonably be construed as being somewhere around its marginal costs (marginal value of water). Price bands: three, four and five all appeared at times as though they could be reasonable approximations to Snowy's marginal costs. For Day 5 it was thought that the band five prices for Snowy were closer to Snowy's marginal costs. This resulted in an estimate of the dispatch inefficiency of $530,730.

4 Conclusion

Based on the analysis of the eleven days suggested by AER there does appear to be material economic costs incurred associated with inefficiencies in generator dispatches due to uncompetitive bidding.

Appendix A Day 01: 10/01/08

A.1 Introduction

This appendix provides the detailed results for Thursday, 10 January 2008, Day 01. The offers for this day were modified as follows.

Table 5 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[2]	To[1]	With[1]
Day 01	10/01/08	12:30	17:30	Torrens Island A	SA	14:00	17:30	14:00
				Torrens Island B	SA	14:00	17:30	14:00
				Angaston	SA	12:30	17:30	12:30

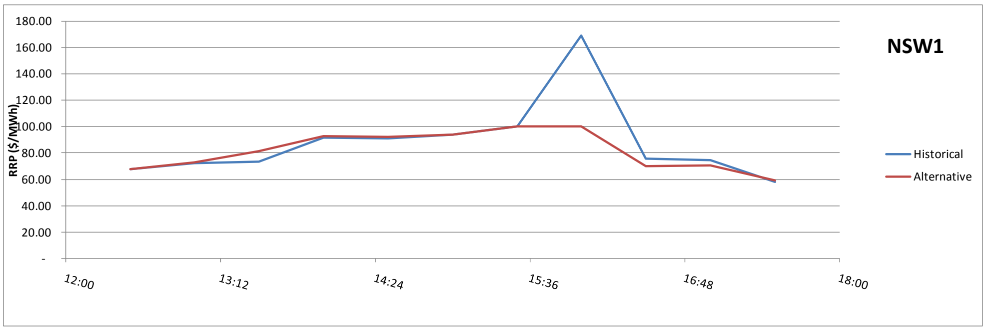
A.2 Overview and Discussion of Results

The alternative scenario resulted in slightly increased dispatch costs. This result was unexpected. The amounts involved are relatively small compared to the total dispatch costs hence could be the results of the limitations of the modelling as discussed in sections 2.4 and 3.2.

A.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices in the South Australian region and to a lesser extent the Victorian and Snowy regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 10 New South Wales Spot Prices for Historical and Alternative Dispatch 10/1/2008



[2] Period ending trading interval

Figure 11 Queensland Spot Prices for Historical and Alternative Dispatch 10/1/2008

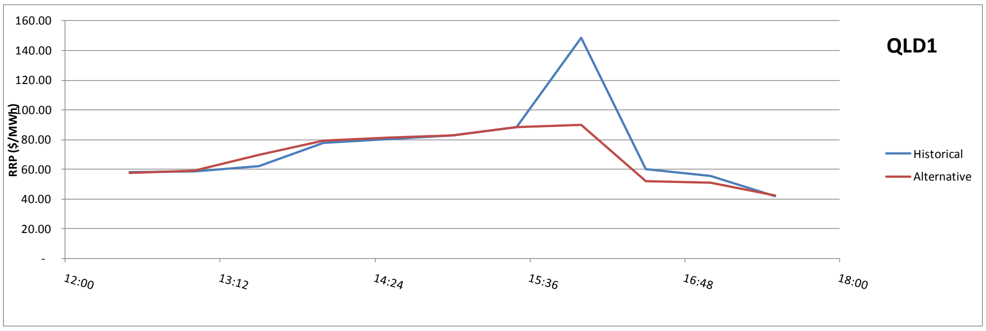


Figure 12 South Australian Spot Prices for Historical and Alternative Dispatch 10/1/2008

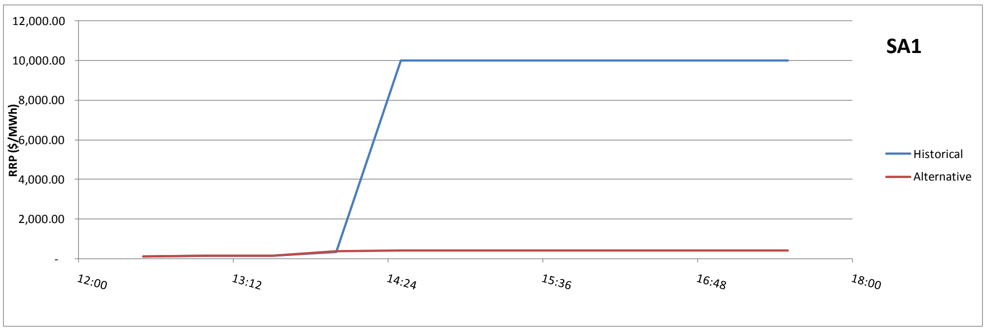


Figure 13 Snowy Spot Prices for Historical and Alternative Dispatch 10/1/2008

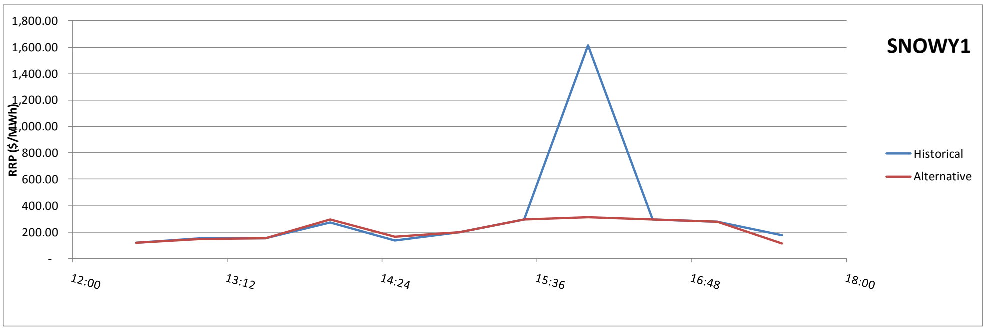


Figure 14 Tasmanian Spot Prices for Historical and Alternative Dispatch 10/1/2008

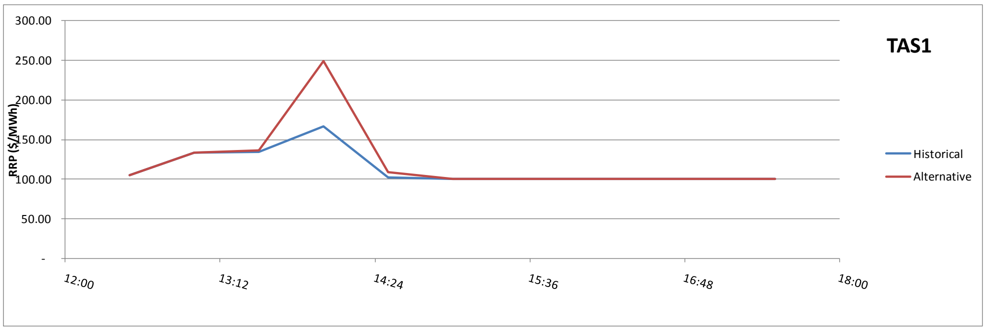
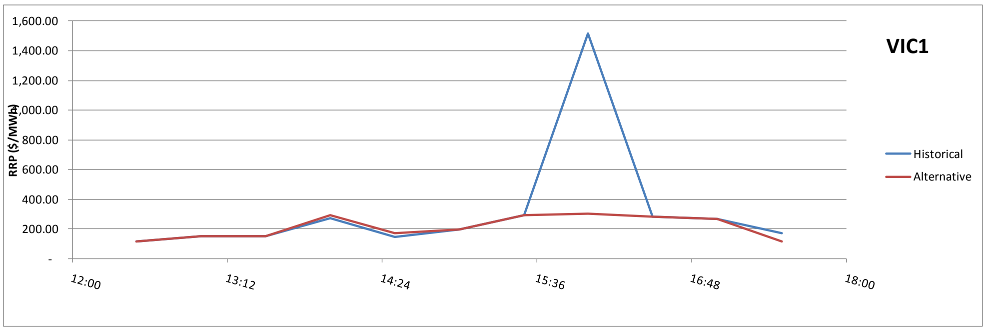


Figure 15 Victorian Spot Prices for Historical and Alternative Dispatch 10/1/2008



A.4 Dispatch Cost Impacts

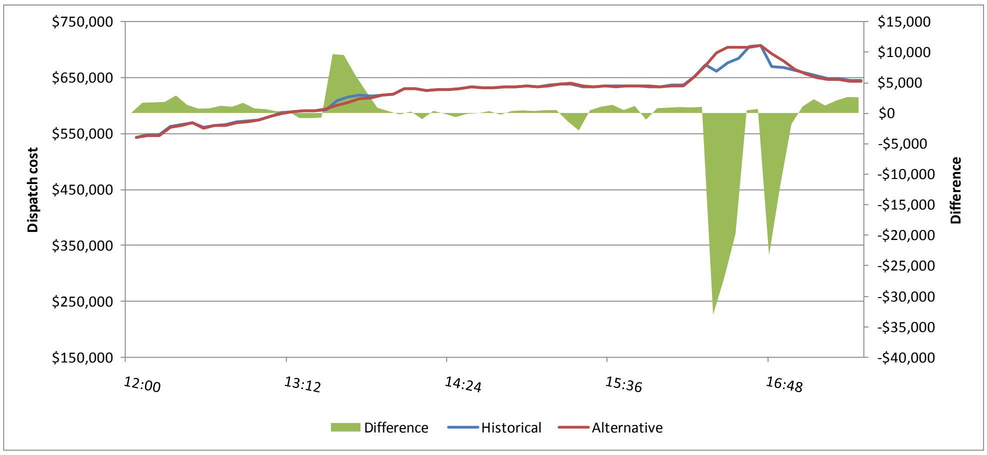
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 6 Historical and Alternative Dispatch Costs for 10/1/2008

	Historical	Alternative	Difference
Total generation cost ($)	41,111,459	41,167,185	-55,726

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 16 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 10/1/2008



A.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 7 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 10/1/2008

Plant	Historical	Alternative	Difference
AGLHAL	474,379	474,379	0
AGLSOM	380,433	380,433	0
ANGAS1	21,920	21,920	0
ANGAS2	15,117	15,117	0
APD01	0	0	0
APD02	0	0	0
APS	55,125	55,037	88
BARCALDN	157,663	157,663	0
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	275,083	272,003	3,081
BBTHREE1	78,474	78,474	0
BBTHREE2	0	0	0
BBTHREE3	137,330	137,330	0
BDL01	95,311	95,311	0
BDL02	19,535	19,535	0
BELLBAY1	403,484	403,484	0
BELLBAY2	0	0	0
BLOWERNG	11,220	11,220	0
BRAEMAR1	340,041	340,207	-167
BRAEMAR2	0	0	0
BRAEMAR3	338,569	338,633	-64
BRAEMAR5	0	0	0
BRAEMAR6	0	0	0
BRAEMAR7	0	0	0

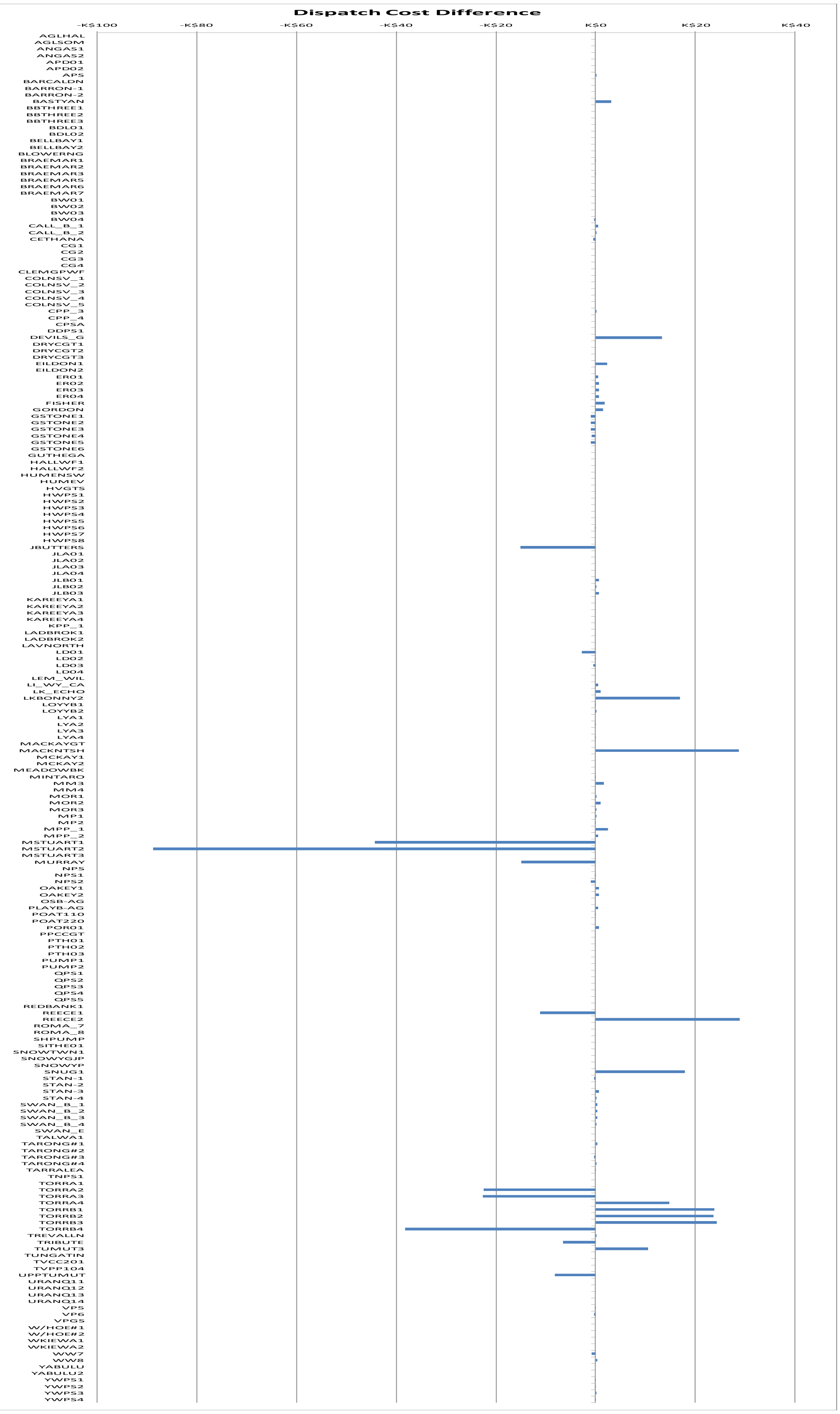
Plant	Historical	Alternative	Difference
BW01	0	0	0
BW02	504,425	504,425	0
BW03	504,425	504,425	0
BW04	503,893	504,253	-360
CALL_B_1	279,327	278,785	541
CALL_B_2	282,495	282,475	20
CETHANA	241,678	242,161	-484
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	0	0	0
COLNSV_1	18,157	18,157	0
COLNSV_2	16,860	16,860	0
COLNSV_3	18,157	18,157	0
COLNSV_4	16,860	16,860	0
COLNSV_5	36,313	36,313	0
CPP_3	269,048	268,832	217
CPP_4	325,119	325,119	0
CPSA	0	0	0
DDPS1	0	0	0
DEVILS_G	180,504	167,237	13,267
DRYCGT1	152,629	152,629	0
DRYCGT2	151,657	151,657	0
DRYCGT3	161,517	161,517	0
EILDON1	141,372	138,992	2,380
EILDON2	123,692	123,692	0
ER01	624,178	623,612	566
ER02	624,181	623,589	592
ER03	624,291	623,668	623
ER04	624,278	623,663	615
FISHER	55,725	53,912	1,813
GORDON	1,212,935	1,211,489	1,447
GSTONE1	186,721	187,727	-1,005
GSTONE2	186,768	187,727	-958
GSTONE3	186,768	187,727	-958
GSTONE4	186,330	187,078	-747
GSTONE5	186,721	187,727	-1,005
GSTONE6	0	0	0
GUTHEGA	63,360	63,360	0
HALLWF1	-1,480	-1,480	0
HALLWF2	0	0	0
HUMENSW	0	0	0
HUMEV	32,340	32,340	0
HVGTS	0	0	0
HWPS1	18,622	18,622	0
HWPS2	18,622	18,622	0
HWPS3	22,760	22,760	0
HWPS4	0	0	0
HWPS5	29,469	29,469	0
HWPS6	29,218	29,260	-42
HWPS7	28,905	28,905	0
HWPS8	27,515	27,515	0

Plant	Historical	Alternative	Difference
JBUTTERS	421,778	436,791	-15,013
JLA01	100,536	100,536	0
JLA02	141,260	141,260	0
JLA03	141,029	141,029	0
JLA04	129,446	129,446	0
JLB01	186,756	186,061	695
JLB02	176,147	176,104	43
JLB03	170,641	169,914	726
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	263,845	263,845	0
LADBROK1	73,412	73,412	0
LADBROK2	73,412	73,412	0
LAVNORTH	590,985	590,985	0
LD01	343,902	346,607	-2,705
LD02	407,519	407,547	-28
LD03	375,144	375,553	-410
LD04	0	0	0
LEM_WIL	101,450	101,450	0
LI_WY_CA	359,645	359,202	443
LK_ECHO	89,799	88,734	1,065
LKBONNY2	-60,648	-77,579	16,930
LOYYB1	180,828	180,931	-103
LOYYB2	180,861	180,830	31
LYA1	72,716	72,716	0
LYA2	65,926	65,947	-21
LYA3	71,370	71,370	0
LYA4	59,906	59,978	-72
MACKAYGT	0	0	0
MACKNTSH	283,979	255,255	28,724
MCKAY1	346,104	346,104	0
MCKAY2	174,174	174,174	0
MEADOWBK	89,821	89,821	0
MINTARO	280,989	281,023	-34
MM3	278,919	277,283	1,636
MM4	0	0	0
MOR1	37,395	37,134	261
MOR2	10,141	9,199	942
MOR3	35,794	35,782	12
MP1	730,540	730,320	220
MP2	728,403	728,456	-53
MPP_1	132,215	129,735	2,480
MPP_2	132,905	132,451	454
MSTUART1	516,141	560,373	-44,232
MSTUART2	171,816	260,547	-88,731
MSTUART3	0	0	0
MURRAY	222,779	237,633	-14,853
NPS	1,321,509	1,321,509	0
NPS1	301,951	301,953	-2
NPS2	293,281	294,182	-900
OAKEY1	35,111	34,394	716

Plant	Historical	Alternative	Difference
OAKEY2	56,018	55,385	633
OSB-AG	386,447	386,447	0
PLAYB-AG	263,272	262,795	477
POAT110	400,779	400,831	-52
POAT220	610,911	610,911	0
POR01	638,995	638,397	598
PPCCGT	958,769	958,769	0
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	59,862	59,862	0
QPS2	59,862	59,862	0
QPS3	59,862	59,862	0
QPS4	59,862	59,862	0
QPS5	0	0	0
REDBANK1	112,934	112,934	0
REECE1	326,420	337,592	-11,172
REECE2	385,544	356,590	28,954
ROMA_7	118,971	118,971	0
ROMA_8	118,971	118,971	0
SHPUMP	0	0	0
SITHE01	386,922	386,922	0
SNOWTWN1	0	0	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	707,160	689,185	17,975
STAN-1	287,806	288,127	-321
STAN-2	242,695	242,695	0
STAN-3	289,044	288,373	671
STAN-4	257,077	257,021	55
SWAN_B_1	83,355	83,072	283
SWAN_B_2	83,338	83,072	266
SWAN_B_3	89,422	89,157	264
SWAN_B_4	80,941	80,767	174
SWAN_E	608,685	608,685	0
TALWA1	0	0	0
TARONG#1	145,432	145,043	390
TARONG#2	93,878	93,878	0
TARONG#3	145,370	145,650	-280
TARONG#4	158,722	158,674	48
TARRALEA	255,217	255,255	-38
TNPS1	318,694	318,694	0
TORRA1	0	0	0
TORRA2	226,887	249,416	-22,529
TORRA3	226,710	249,415	-22,705
TORRA4	143,068	128,345	14,723
TORRB1	349,759	325,868	23,891
TORRB2	362,195	338,557	23,638
TORRB3	309,791	285,454	24,337
TORRB4	324,865	363,119	-38,254
TREVALLN	260,037	260,036	1

Plant	Historical	Alternative	Difference
TRIBUTE	140,395	146,936	-6,541
TUMUT3	3,163,741	3,153,298	10,443
TUNGATIN	0	0	0
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	411,552	419,706	-8,154
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	0	0	0
URANQ14	0	0	0
VP5	628,545	628,557	-11
VP6	648,770	649,112	-342
VPGS	597,650	597,650	0
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	96,151	96,151	0
WKIEWA2	97,260	97,260	0
WW7	542,456	543,181	-725
WW8	537,906	537,617	289
YABULU	298,584	298,584	0
YABULU2	166,795	166,795	0
YWPS1	48,065	48,076	-11
YWPS2	36,293	36,490	-197
YWPS3	52,084	52,080	4
YWPS4	48,996	49,181	-184
Total	41,111,459	41,167,185	-55,726

Figure 17 Dispatch Cost Changes



Appendix B Day 02: 18/02/08

B.1 Introduction

This appendix provides the detailed results for Monday, 18 February 2008, Day 02. The offers for this day were modified as follows.

Table 8 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[3]	To[1]	With[1]
Day 02	18/02/08	12:30	18:30	Torrens Island A	SA	12:30	18:30	12:30
				Torrens Island B	SA	12:30	18:30	12:30
				Loy Yang A	VIC	13:00	17:00	13:00
				Loy Yang B	VIC	13:00	17:00	13:00

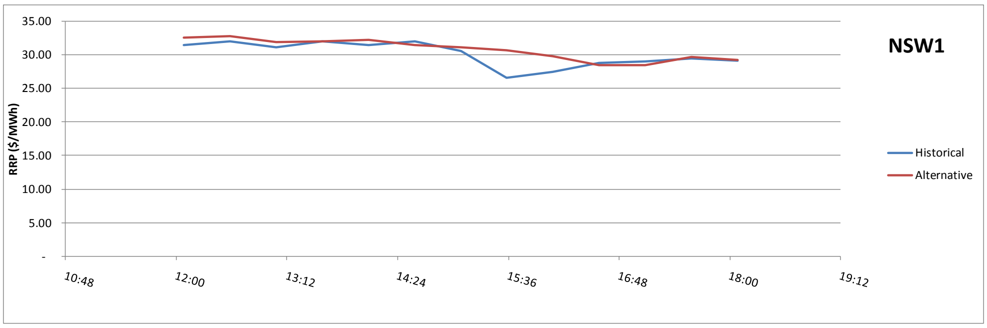
B.2 Overview and Discussion of Results

The alternative scenario resulted in a substantial reduction in dispatch costs, $762,000. This reduction was about 1.9% of the total dispatch costs of $40,952,581 for the ten hour period. The main sources of dispatch cost savings came from McKay and Tumut 3, though Murray and Upper Tumut increased their costs.

B.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 18 New South Wales Spot Prices for Historical and Alternative Dispatch 18/2/2008



[3] Period ending trading interval

Figure 19 Queensland Spot Prices for Historical and Alternative Dispatch 18/2/2008

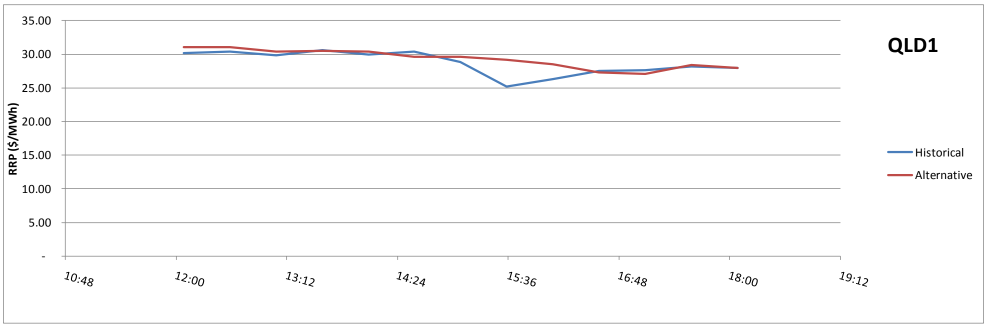


Figure 20 South Australian Spot Prices for Historical and Alternative Dispatch 18/2/2008

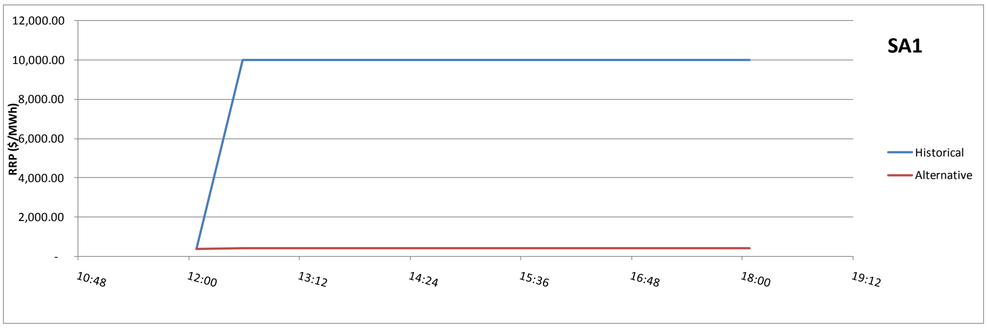


Figure 21 Snowy Spot Prices for Historical and Alternative Dispatch 18/2/2008

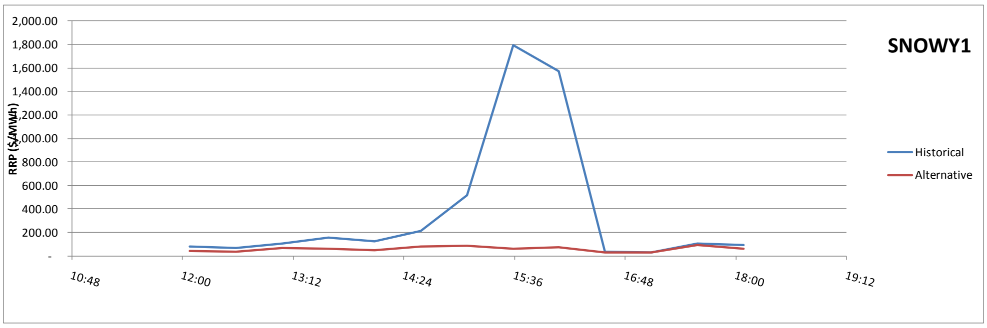


Figure 22 **Tasmanian Spot Prices for Historical and Alternative Dispatch 18/2/2008**

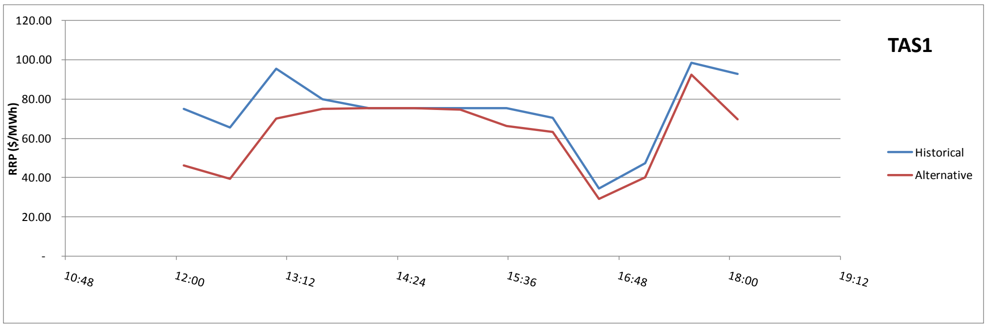
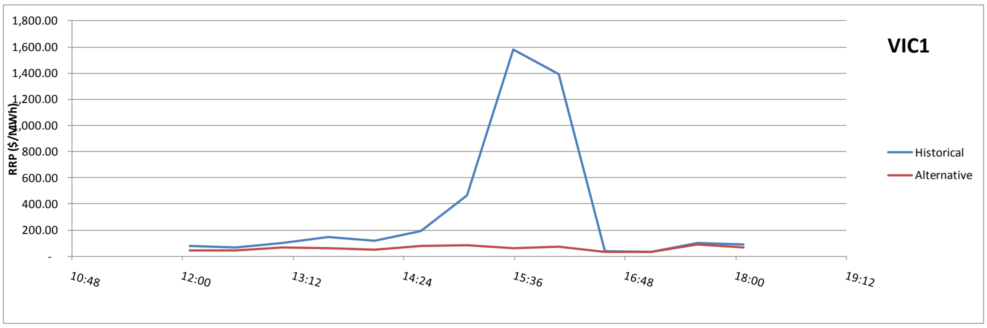


Figure 23 **Victorian Spot Prices for Historical and Alternative Dispatch 18/2/2008**



B.4 Dispatch Cost Impacts

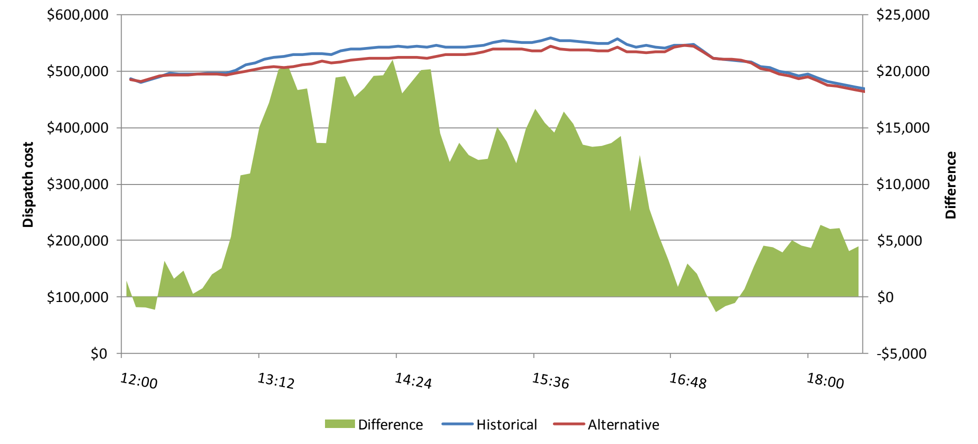
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 9 **Historical and Alternative Dispatch Costs for 18/2/2008**

	Historical	Alternative	Difference
Total generation cost ($)	40,952,581	40,189,626	762,955

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 24 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 18/2/2008



B.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below. All the generators whose offers were changed had increased generation and correspondingly increased generation costs. As a consequence some generators had reduced dispatches and correspondingly reduced generation costs.

Table 10 Dispatch Cost Changes for Generators for Historic and Alternative Scenarios for 18/2/2008

Plant	Historical	Alternative	Difference
AGLHAL	626,917	602,949	23,968
AGLSOM	473,497	472,970	527
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	68,141	68,141	0
BARCALDN	165,810	162,722	3,088
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	167,190	110,431	56,759
BBTHREE1	89,175	89,175	0
BBTHREE2	0	0	0
BBTHREE3	125,172	125,172	0
BDL01	120,588	120,588	0
BDL02	25,459	25,459	0
BELLBAY1	472,699	472,699	0
BELLBAY2	394,154	394,154	0
BLOWERNG	5,460	5,460	0
BRAEMAR1	385,204	387,073	-1,869
BRAEMAR2	391,824	393,919	-2,095
BRAEMAR3	0	0	0

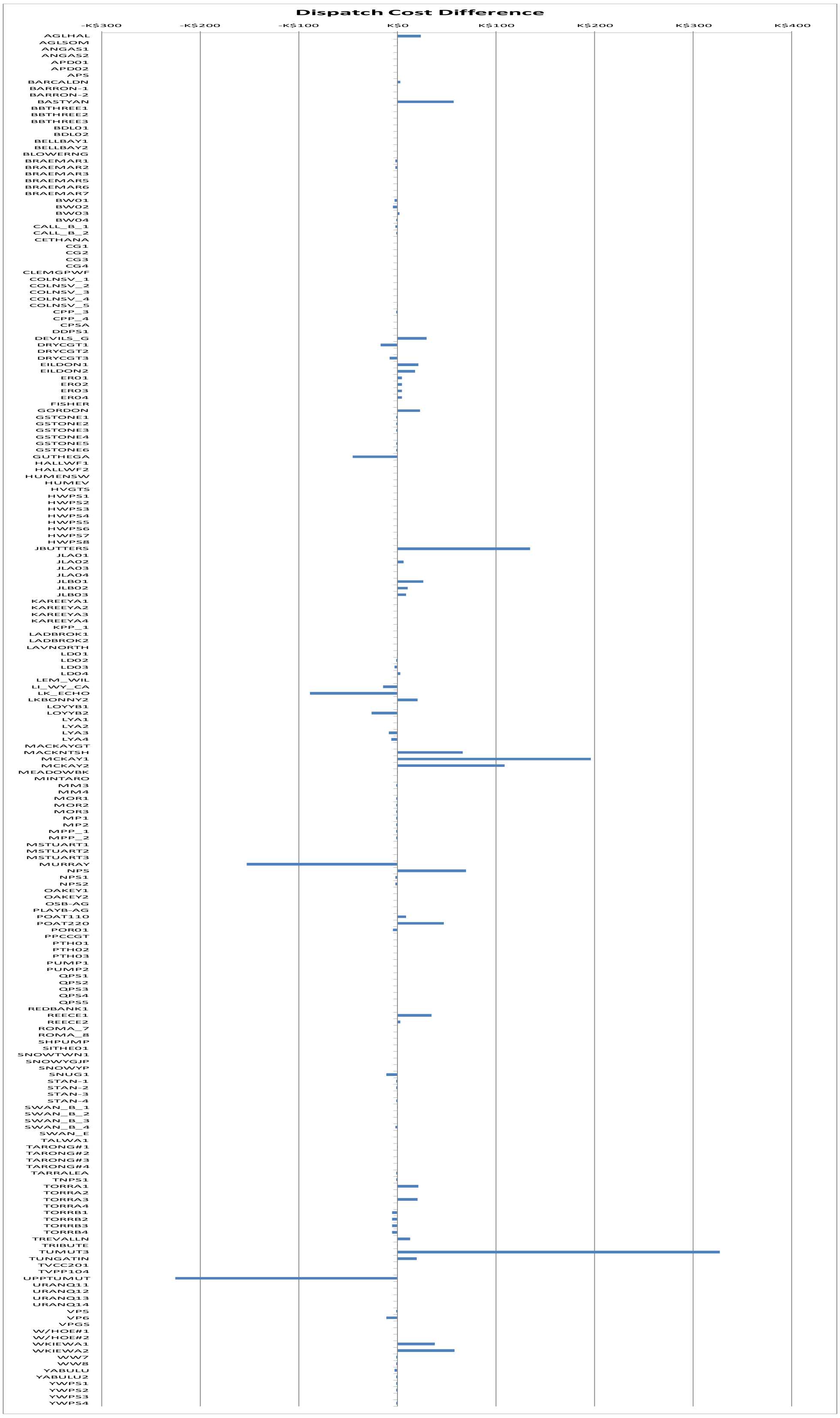
Plant	Historical	Alternative	Difference
BRAEMAR5	0	0	0
BRAEMAR6	0	0	0
BRAEMAR7	0	0	0
BW01	386,493	389,012	-2,519
BW02	376,885	381,270	-4,385
BW03	365,931	364,036	1,895
BW04	363,545	363,920	-375
CALL_B_1	299,595	301,372	-1,777
CALL_B_2	306,389	307,239	-849
CETHANA	0	0	0
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	0	0	0
COLNSV_1	0	0	0
COLNSV_2	0	0	0
COLNSV_3	0	0	0
COLNSV_4	0	0	0
COLNSV_5	1,590	1,277	313
CPP_3	398,964	399,544	-580
CPP_4	384,232	384,232	0
CPSA	0	0	0
DDPS1	0	0	0
DEVILS_G	210,926	181,278	29,648
DRYCGT1	4,166	21,110	-16,943
DRYCGT2	219,986	219,986	0
DRYCGT3	144,921	152,907	-7,986
EILDON1	147,798	126,378	21,420
EILDON2	126,336	108,027	18,310
ER01	658,254	653,817	4,437
ER02	658,370	653,765	4,605
ER03	658,496	653,728	4,767
ER04	658,382	653,733	4,649
FISHER	0	0	0
GORDON	919,275	896,436	22,839
GSTONE1	182,178	182,414	-236
GSTONE2	233,417	235,018	-1,601
GSTONE3	234,318	235,896	-1,578
GSTONE4	0	0	0
GSTONE5	180,514	180,696	-182
GSTONE6	176,914	177,261	-347
GUTHEGA	56,289	101,400	-45,111
HALLWF1	-2,560	-2,560	0
HALLWF2	0	0	0
HUMENSW	0	0	0
HUMEV	21,840	21,840	0
HVGTS	0	0	0
HWPS1	22,008	22,008	0
HWPS2	22,008	22,008	0
HWPS3	26,898	26,898	0
HWPS4	0	0	0
HWPS5	35,551	35,551	0

Plant	Historical	Alternative	Difference
HWPS6	35,729	35,729	0
HWPS7	33,294	33,293	0
HWPS8	34,441	34,433	8
JBUTTERS	312,574	177,776	134,798
JLA01	0	0	0
JLA02	134,820	128,797	6,023
JLA03	0	0	0
JLA04	0	0	0
JLB01	117,208	90,992	26,216
JLB02	95,466	85,201	10,265
JLB03	128,224	119,531	8,693
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	224,880	224,540	340
LADBROK1	89,238	89,238	0
LADBROK2	89,238	89,238	0
LAVNORTH	1,124,707	1,124,707	0
LD01	432,287	432,169	118
LD02	431,943	433,445	-1,502
LD03	424,082	427,260	-3,177
LD04	380,088	376,988	3,099
LEM_WIL	92,739	91,953	786
LI_WY_CA	491,414	506,018	-14,604
LK_ECHO	80	89,211	-89,131
LKBONNY2	-126,463	-147,240	20,777
LOYYB1	221,235	221,130	105
LOYYB2	195,238	221,130	-25,892
LYA1	87,497	87,497	0
LYA2	78,636	78,636	0
LYA3	78,555	87,516	-8,961
LYA4	71,139	77,610	-6,471
MACKAYGT	0	0	0
MACKNTSH	183,915	117,453	66,462
MCKAY1	320,295	123,820	196,474
MCKAY2	141,863	33,459	108,403
MEADOWBK	88,355	87,509	846
MINTARO	363,703	363,703	0
MM3	314,856	315,319	-463
MM4	0	0	0
MOR1	32,960	33,603	-643
MOR2	18,829	19,031	-201
MOR3	42,893	43,484	-592
MP1	830,056	830,651	-595
MP2	830,585	830,651	-66
MPP_1	188,830	188,910	-80
MPP_2	185,645	186,087	-442
MSTUART1	0	0	0
MSTUART2	0	0	0
MSTUART3	0	0	0
MURRAY	72,152	224,700	-152,548
NPS	1,209,985	1,140,070	69,915

Plant	Historical	Alternative	Difference
NPS1	354,928	356,780	-1,851
NPS2	345,734	347,501	-1,767
OAKEY1	0	0	0
OAKEY2	0	0	0
OSB-AG	456,710	456,710	0
PLAYB-AG	312,332	312,182	149
POAT110	362,123	353,711	8,412
POAT220	528,056	480,695	47,361
POR01	943,477	947,661	-4,184
PPCCGT	1,138,017	1,138,017	0
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	70,746	70,746	0
QPS2	70,746	70,746	0
QPS3	70,746	70,746	0
QPS4	70,746	70,746	0
QPS5	0	0	0
REDBANK1	135,296	135,296	0
REECE1	201,623	167,388	34,235
REECE2	157,454	154,451	3,003
ROMA_7	0	0	0
ROMA_8	0	0	0
SHPUMP	0	0	0
SITHE01	460,042	460,042	0
SNOWTWN1	0	0	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	1,419,276	1,430,642	-11,367
STAN-1	286,785	287,381	-596
STAN-2	286,692	287,392	-700
STAN-3	333,520	333,230	289
STAN-4	286,671	287,341	-670
SWAN_B_1	111,278	110,935	344
SWAN_B_2	110,645	110,312	333
SWAN_B_3	0	0	0
SWAN_B_4	108,270	110,609	-2,339
SWAN_E	706,860	706,860	0
TALWA1	0	0	0
TARONG#1	115,085	114,503	582
TARONG#2	110,947	110,947	0
TARONG#3	174,346	174,346	0
TARONG#4	110,947	110,947	0
TARRALEA	255,552	255,708	-157
TNPS1	376,002	376,639	-637
TORRA1	225,420	204,071	21,348
TORRA2	0	0	0
TORRA3	224,933	204,071	20,861
TORRA4	0	0	0
TORRB1	279,033	284,223	-5,189
TORRB2	279,081	284,243	-5,162

Plant	Historical	Alternative	Difference
TORRB3	279,013	284,211	-5,198
TORRB4	279,043	284,211	-5,168
TREVALLN	149,849	136,490	13,359
TRIBUTE	228,816	228,339	477
TUMUT3	1,051,418	724,240	327,178
TUNGATIN	278,003	258,676	19,326
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	825,119	1,050,170	-225,052
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	0	0	0
URANQ14	0	0	0
VP5	788,876	789,703	-827
VP6	778,299	789,320	-11,020
VPGS	481,592	481,592	0
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	102,922	64,914	38,008
WKIEWA2	92,780	35,003	57,777
WW7	632,454	632,923	-469
WW8	632,527	632,923	-396
YABULU	349,874	352,872	-2,998
YABULU2	196,122	197,122	-999
YWPS1	58,301	58,308	-7
YWPS2	51,005	51,017	-11
YWPS3	62,626	62,626	0
YWPS4	59,419	59,491	-72
Total	40,952,581	40,189,626	762,955

Figure 25 Generator Dispatch Cost Changes



Appendix C Day 03: 15/01/09

C.1 Introduction

This appendix provides the detailed results for Thursday, 15 January 2009 , Day 03. . The offers for this day were modified as follows.

Table 11 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[4]	To[1]	With[1]
				Loy Yang A	VIC	13:00	17:00	13:00
				Loy Yang B	VIC	13:00	17:00	13:00
Day 03	15/01/09	8:30	22:30	Eraring	NSW	11:30	17:00	11:30
				Mt Piper	NSW	8:30	22:30	8:30

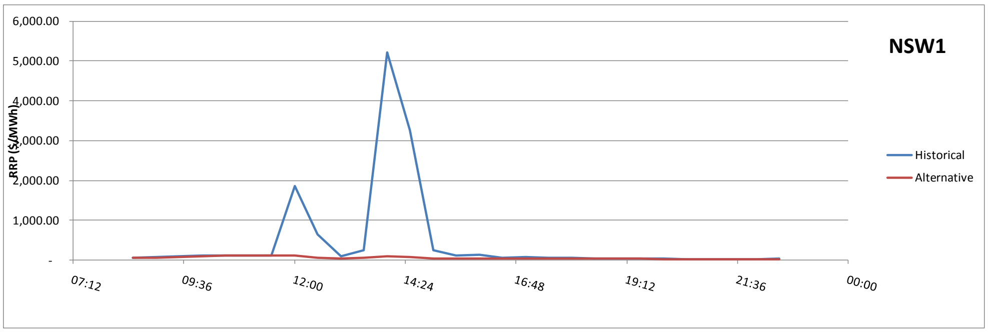
C.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $2,146,000 or 2.7% reduction. Reduced Mt Stuart costs and increased Mt Piper costs were the most substantial changes.

C.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 26 New South Wales Spot Prices for Historical and Alternative Dispatch 15/1/2009



[4] Period ending trading interval

Figure 27 Queensland Spot Prices for Historical and Alternative Dispatch 15/1/2009

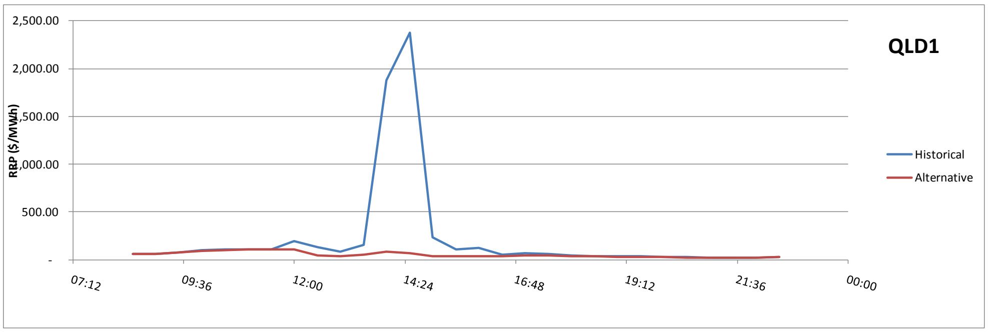


Figure 28 South Australian Spot Prices for Historical and Alternative Dispatch 15/1/2009

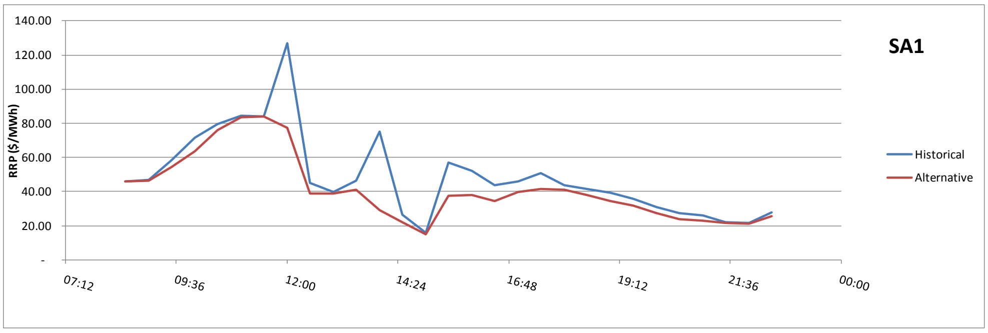


Figure 29 Tasmanian Spot Prices for Historical and Alternative Dispatch 15/1/2009

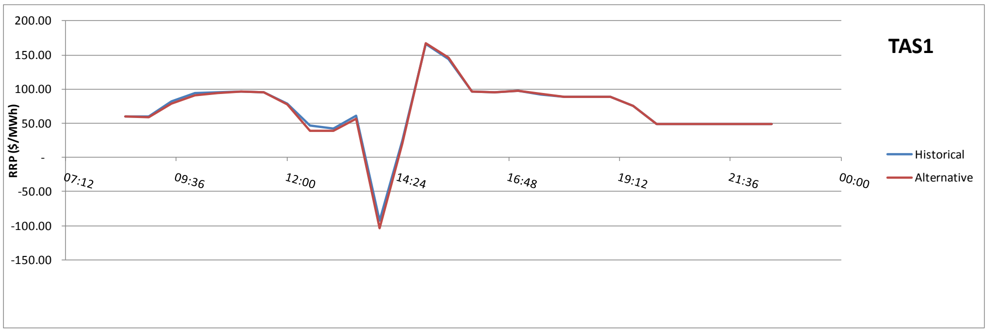
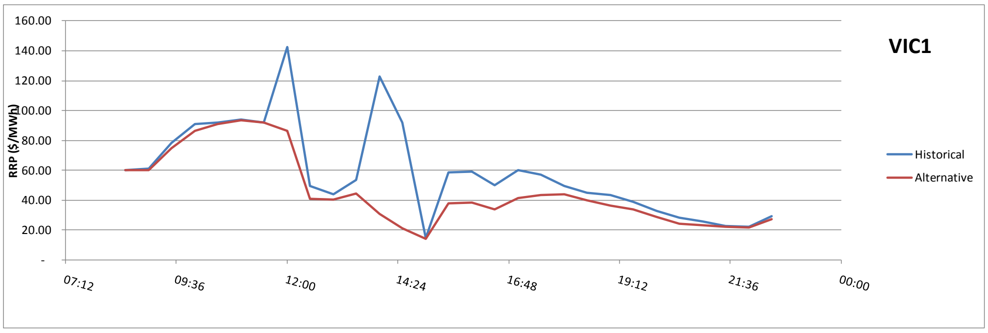


Figure 30 Victorian Spot Prices for Historical and Alternative Dispatch 15/1/2009



C.4 Dispatch Cost Impacts

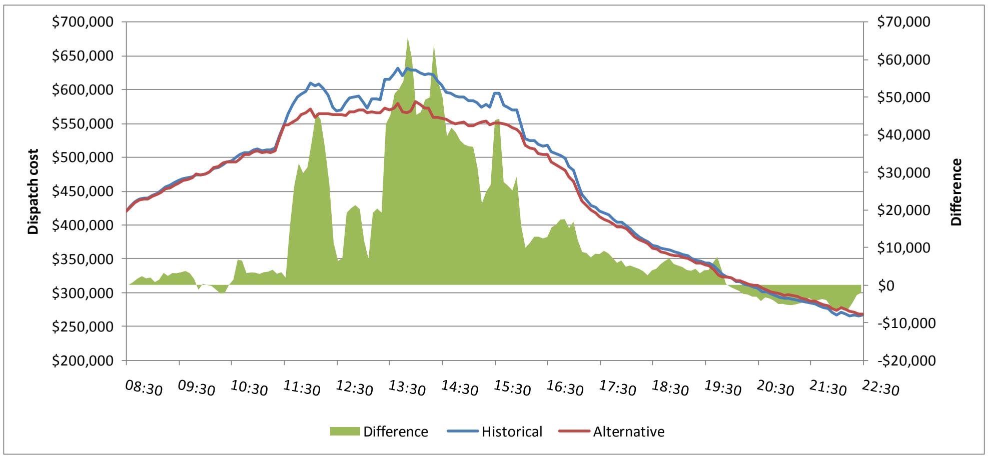
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 12 Historical and Alternative Dispatch Costs for 15/1/2009

	Historical	Alternative	Difference
Total generation cost ($)	78,184,994	76,038,428	2,146,566

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 31 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 15/1/2009



C.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 13 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 15/1/2009

Plant	Historical	Alternative	Difference
AGLHAL	0	0	0
AGLSOM	0	0	0
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	147,059	147,059	0
BARCALDN	63,297	62,938	359
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	210,246	211,482	-1,236
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	161,565	161,394	172
BDL02	12,584	12,615	-32
BELLBAY1	0	0	0
BELLBAY2	1,202,034	1,202,034	0
BLOWERNG	40,560	40,560	0
BRAEMAR1	661,606	661,056	550
BRAEMAR2	633,616	631,546	2,069
BRAEMAR3	593,479	588,040	5,439
BRAEMAR5	0	0	0
BRAEMAR6	0	0	0
BRAEMAR7	0	0	0
BW01	1,282,885	1,251,947	30,938
BW02	1,282,375	1,251,951	30,424
BW03	1,280,739	1,251,957	28,783
BW04	1,282,013	1,251,994	30,019
CALL_B_1	763,136	763,136	0
CALL_B_2	663,027	662,903	124
CETHANA	166,879	165,848	1,032
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	0	0	0
COLNSV_1	93,290	93,335	-45
COLNSV_2	98	98	0
COLNSV_3	65,040	65,769	-729
COLNSV_4	95,748	96,150	-401
COLNSV_5	132,469	138,319	-5,850
CPP_3	839,988	840,787	-799
CPP_4	831,383	831,603	-221
CPSA	0	0	0

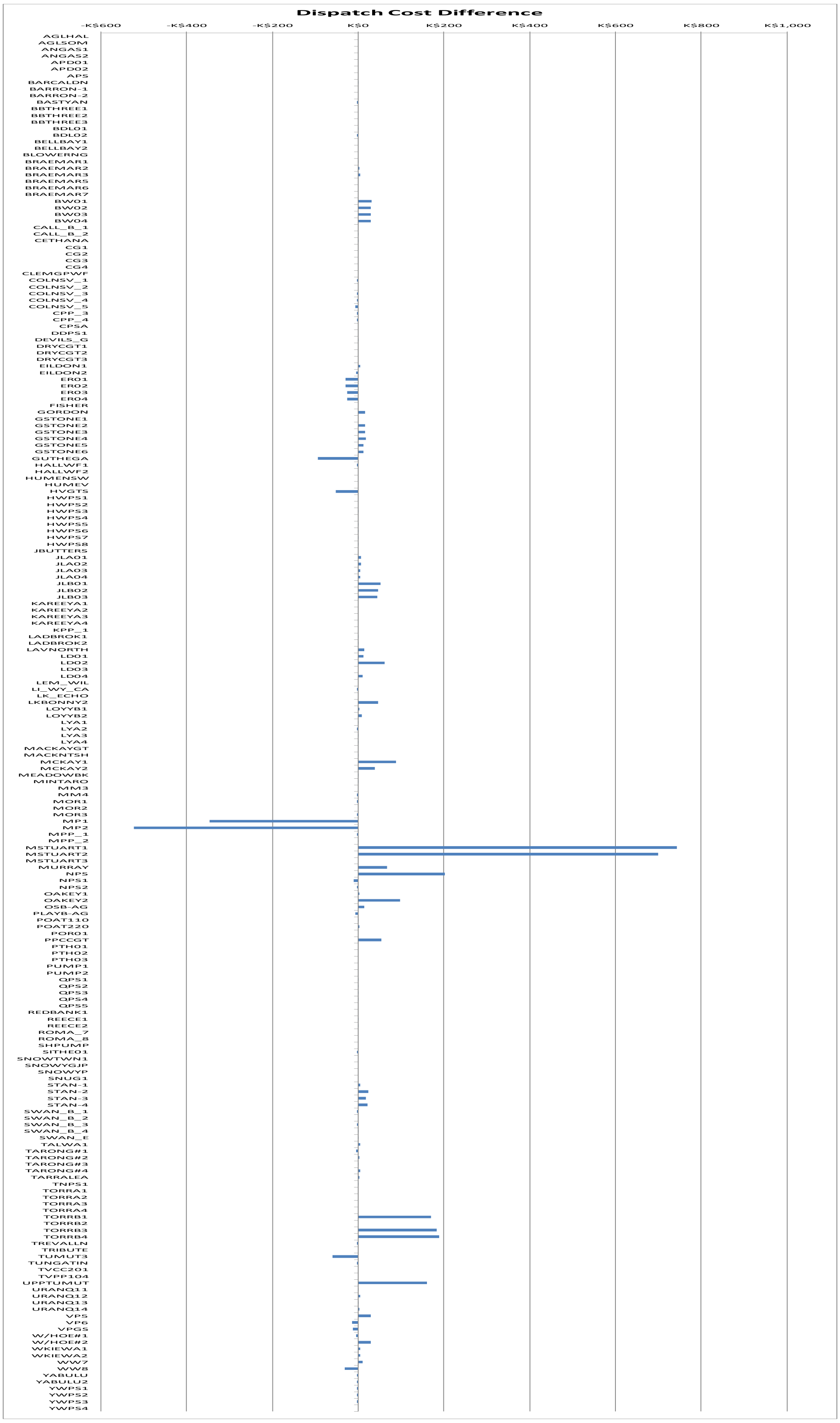
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	115,688	115,605	83
DRYCGT1	0	0	0
DRYCGT2	0	0	0
DRYCGT3	0	0	0
EILDON1	78,119	72,880	5,240
EILDON2	126,375	130,780	-4,405
ER01	1,414,836	1,444,175	-29,339
ER02	1,415,246	1,444,112	-28,866
ER03	1,431,250	1,455,910	-24,660
ER04	1,429,520	1,454,435	-24,914
FISHER	6,418	6,418	0
GORDON	716,282	699,153	17,128
GSTONE1	0	0	0
GSTONE2	577,736	562,227	15,510
GSTONE3	553,776	537,725	16,050
GSTONE4	564,256	546,578	17,678
GSTONE5	572,535	560,227	12,308
GSTONE6	572,264	560,289	11,975
GUTHEGA	78,514	172,502	-93,988
HALLWF1	-207,789	-204,781	-3,008
HALLWF2	0	0	0
HUMENSW	59,400	59,400	0
HUMEV	19,425	19,425	0
HVGTS	398,124	449,820	-51,696
HWPS1	0	0	0
HWPS2	58,374	58,374	0
HWPS3	77,706	77,605	102
HWPS4	77,706	77,706	0
HWPS5	75,198	75,094	105
HWPS6	75,372	75,303	70
HWPS7	64,727	64,696	31
HWPS8	71,929	71,896	33
JBUTTERS	0	0	0
JLA01	131,869	125,135	6,733
JLA02	187,102	180,357	6,746
JLA03	153,308	148,222	5,086
JLA04	153,775	148,922	4,853
JLB01	370,704	319,141	51,563
JLB02	403,846	357,682	46,164
JLB03	397,641	352,598	45,042
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	0	0	0
LADBROK1	176,366	176,308	58
LADBROK2	176,387	176,308	79
LAVNORTH	286,811	272,611	14,200
LD01	978,478	966,863	11,614
LD02	563,629	501,727	61,902
LD03	0	0	0
LD04	160,033	148,886	11,147

Plant	Historical	Alternative	Difference
LEM_WIL	115,011	115,011	0
LI_WY_CA	457,531	457,771	-241
LK_ECHO	0	0	0
LKBONNY2	-449,050	-494,756	45,706
LOYYB1	351,916	348,909	3,007
LOYYB2	356,707	348,974	7,732
LYA1	134,684	133,565	1,120
LYA2	132,105	132,133	-28
LYA3	132,947	132,894	53
LYA4	132,010	130,871	1,139
MACKAYGT	0	0	0
MACKNTSH	246,226	246,002	224
MCKAY1	90,587	2,726	87,861
MCKAY2	38,034	0	38,034
MEADOWBK	85,152	85,115	38
MINTARO	60,746	60,730	16
MM3	744,783	744,783	0
MM4	744,773	744,783	-10
MOR1	113,884	115,329	-1,445
MOR2	0	0	0
MOR3	93,871	95,264	-1,393
MP1	1,391,350	1,737,821	-346,471
MP2	1,214,171	1,737,996	-523,825
MPP_1	375,035	376,538	-1,504
MPP_2	375,484	374,658	826
MSTUART1	1,514,755	770,711	744,044
MSTUART2	1,574,047	873,704	700,342
MSTUART3	0	0	0
MURRAY	1,984,967	1,917,385	67,582
NPS	2,950,659	2,748,311	202,348
NPS1	758,754	768,240	-9,487
NPS2	750,370	753,721	-3,351
OAKEY1	284,729	282,520	2,209
OAKEY2	311,859	214,665	97,194
OSB-AG	816,749	802,411	14,338
PLAYB-AG	319,748	327,259	-7,511
POAT110	131,455	130,182	1,273
POAT220	506,704	503,570	3,135
POR01	0	0	0
PPCCGT	2,323,037	2,269,565	53,472
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	116,617	116,527	90
QPS2	144,261	144,185	77
QPS3	144,248	144,185	63
QPS4	116,577	116,527	50
QPS5	0	0	0
REDBANK1	286,954	286,954	0
REECE1	274,874	274,659	215
REECE2	326	0	326

Plant	Historical	Alternative	Difference
ROMA_7	288,733	288,733	0
ROMA_8	0	0	0
SHPUMP	0	0	0
SITHE01	945,175	948,558	-3,383
SNOWTWN1	-383,160	-383,160	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	0	0	0
STAN-1	554,171	549,244	4,927
STAN-2	694,168	669,838	24,330
STAN-3	705,811	687,121	18,690
STAN-4	601,623	578,957	22,666
SWAN_B_1	366,014	368,612	-2,598
SWAN_B_2	0	0	0
SWAN_B_3	188,524	189,908	-1,385
SWAN_B_4	352,789	352,093	696
SWAN_E	1,502,016	1,501,288	729
TALWA1	1,426,661	1,421,792	4,869
TARONG#1	359,613	364,379	-4,765
TARONG#2	486,982	483,959	3,023
TARONG#3	485,571	483,901	1,670
TARONG#4	383,477	378,081	5,397
TARRALEA	331,619	327,791	3,829
TNPS1	768,822	768,737	84
TORRA1	0	0	0
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	0	0	0
TORRB1	1,033,771	863,808	169,963
TORRB2	0	0	0
TORRB3	1,032,226	849,808	182,418
TORRB4	1,032,665	843,189	189,476
TREVALLN	69,407	69,485	-78
TRIBUTE	188,854	188,854	0
TUMUT3	2,712,072	2,771,855	-59,783
TUNGATIN	212,400	212,455	-55
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	2,331,027	2,170,673	160,354
URANQ11	653,867	652,121	1,745
URANQ12	764,297	760,213	4,083
URANQ13	544,303	542,839	1,464
URANQ14	553,945	551,495	2,450
VP5	638,521	608,832	29,689
VP6	1,576,967	1,590,344	-13,377
VPGS	924,167	935,715	-11,548
W/HOE#1	7,297	11,717	-4,420
W/HOE#2	542,740	513,785	28,955
WKIEWA1	133,363	128,529	4,833
WKIEWA2	133,353	128,477	4,877
WW7	1,142,556	1,132,851	9,705
WW8	1,125,313	1,156,096	-30,782
YABULU	671,497	671,687	-191

Plant	Historical	Alternative	Difference
YABULU2	387,422	387,631	-208
YWPS1	131,822	132,023	-201
YWPS2	132,011	132,023	-11
YWPS3	132,822	132,858	-36
YWPS4	0	0	0
Total	78,184,994	76,038,428	2,146,566

Figure 32 Dispatch Cost Changes



Appendix D Day 04: 19/01/09

D.1 Introduction

This appendix provides the detailed results for Monday, 19 January 2009, Day 04. The offers for this day were modified as follows.

Table 14 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[5]	To[1]	With[1]
Day 04	19/01/09	13:30	16:00	Torrens Island A	SA	13:30	16:00	13:30
				Torrens Island B	SA	13:30	16:00	13:30

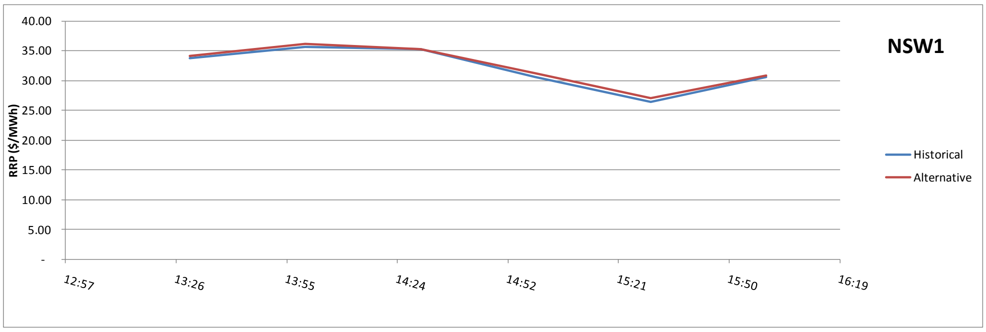
D.2 Overview and Discussion of Results

The alternative scenario resulted in reduced dispatch costs of $206,000. This result was due to only modest increases in Torrens Island costs but a substantial decrease in Port Lincoln Power Station's (POR01's) costs.

D.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 33 New South Wales Spot Prices for Historical and Alternative Dispatch 19/1/2009



[5] Period ending trading interval

Figure 34 Queensland Spot Prices for Historical and Alternative Dispatch 19/1/2009

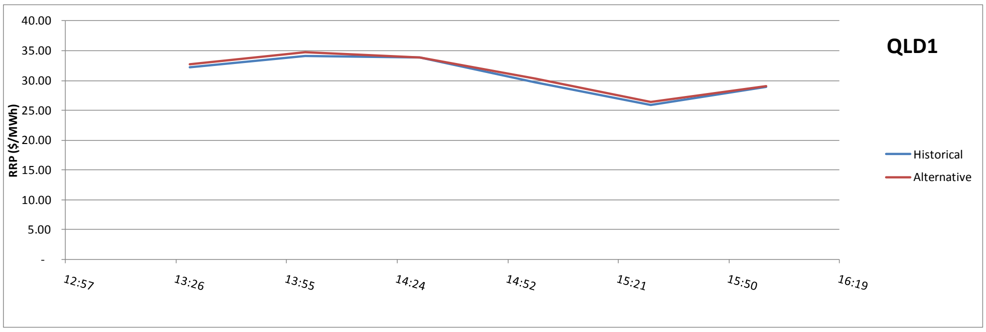


Figure 35 South Australian Spot Prices for Historical and Alternative Dispatch 19/1/2009

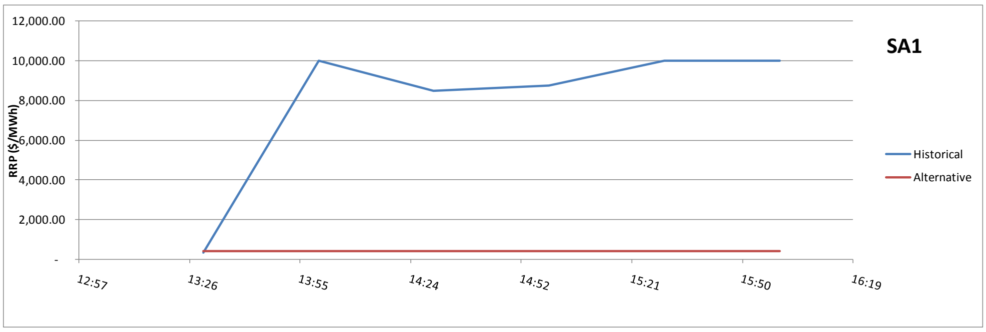


Figure 36 Tasmanian Spot Prices for Historical and Alternative Dispatch 19/1/2009

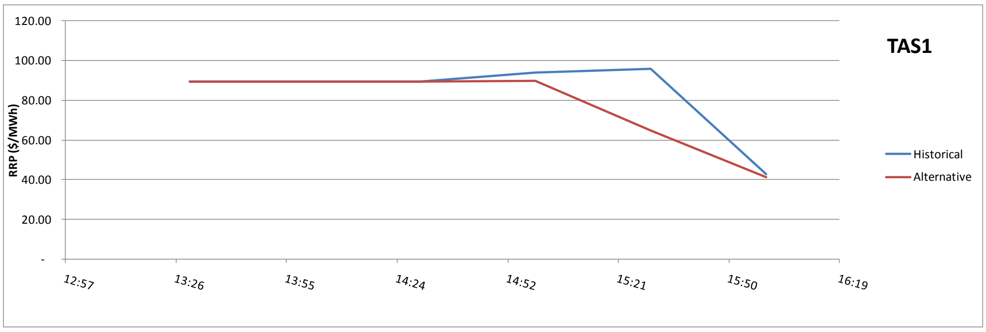
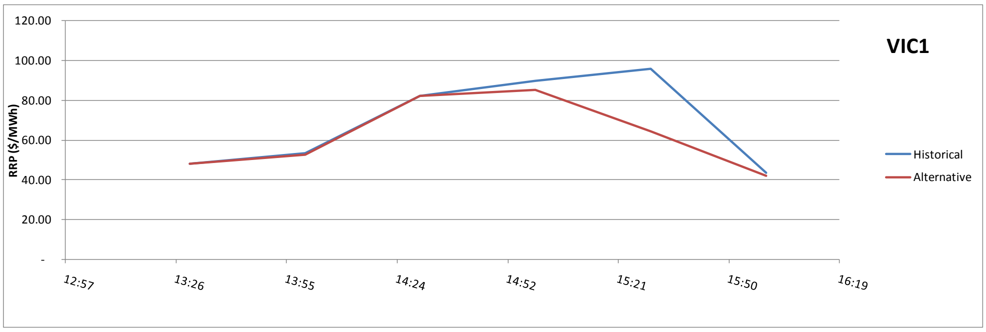


Figure 37 Victorian Spot Prices for Historical and Alternative Dispatch 19/1/2009



D.4 Dispatch Cost Impacts

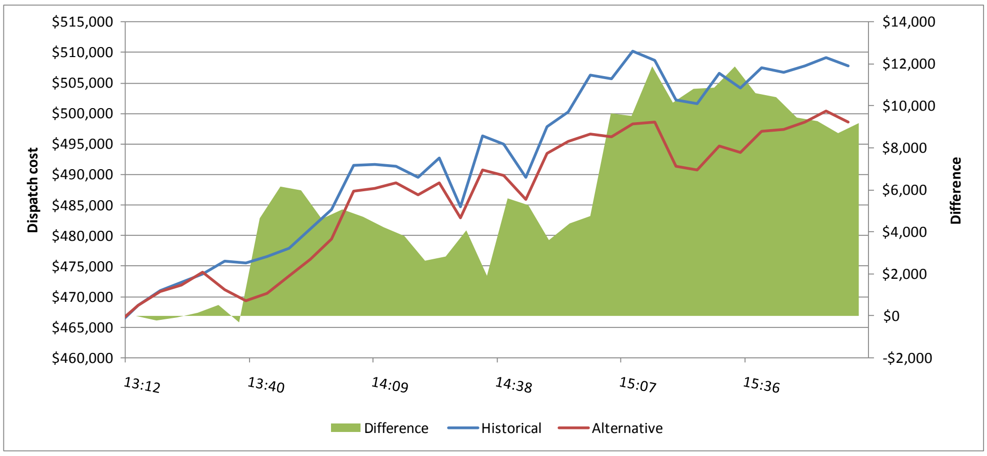
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 15 Historical and Alternative Dispatch Costs for 19/1/2009

	Historical	Alternative	Difference
Total generation cost ($)	17,692,899	17,486,462	206,437

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 38 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 19/1/2009



D.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 16 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 19/1/2009

Plant	Historical	Alternative	Difference
AGLHAL	285,312	258,890	26,422
AGLSOM	13,043	12,906	137
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	32,016	32,016	0
BARCALDN	0	0	0
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	9,360	9,500	-140
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	58,802	58,802	0
BDL02	12,338	12,338	0
BELLBAY1	0	0	0
BELLBAY2	256,055	256,055	0
BLOWERNG	7,200	7,200	0
BRAEMAR1	178,099	178,099	0
BRAEMAR2	179,578	179,578	0
BRAEMAR3	176,520	176,520	0
BRAEMAR5	0	0	0
BRAEMAR6	0	0	0
BRAEMAR7	0	0	0
BW01	271,458	270,740	717
BW02	269,525	268,793	732
BW03	269,087	268,720	368
BW04	266,585	267,023	-438
CALL_B_1	123,158	123,156	2
CALL_B_2	114,480	114,480	0
CETHANA	79,607	79,607	0
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	0	0	0
COLNSV_1	15,547	15,547	0
COLNSV_2	15,547	15,547	0
COLNSV_3	0	0	0
COLNSV_4	9,187	9,187	0
COLNSV_5	18,374	18,374	0
CPP_3	172,773	172,773	0
CPP_4	172,773	172,773	0
CPSA	0	0	0

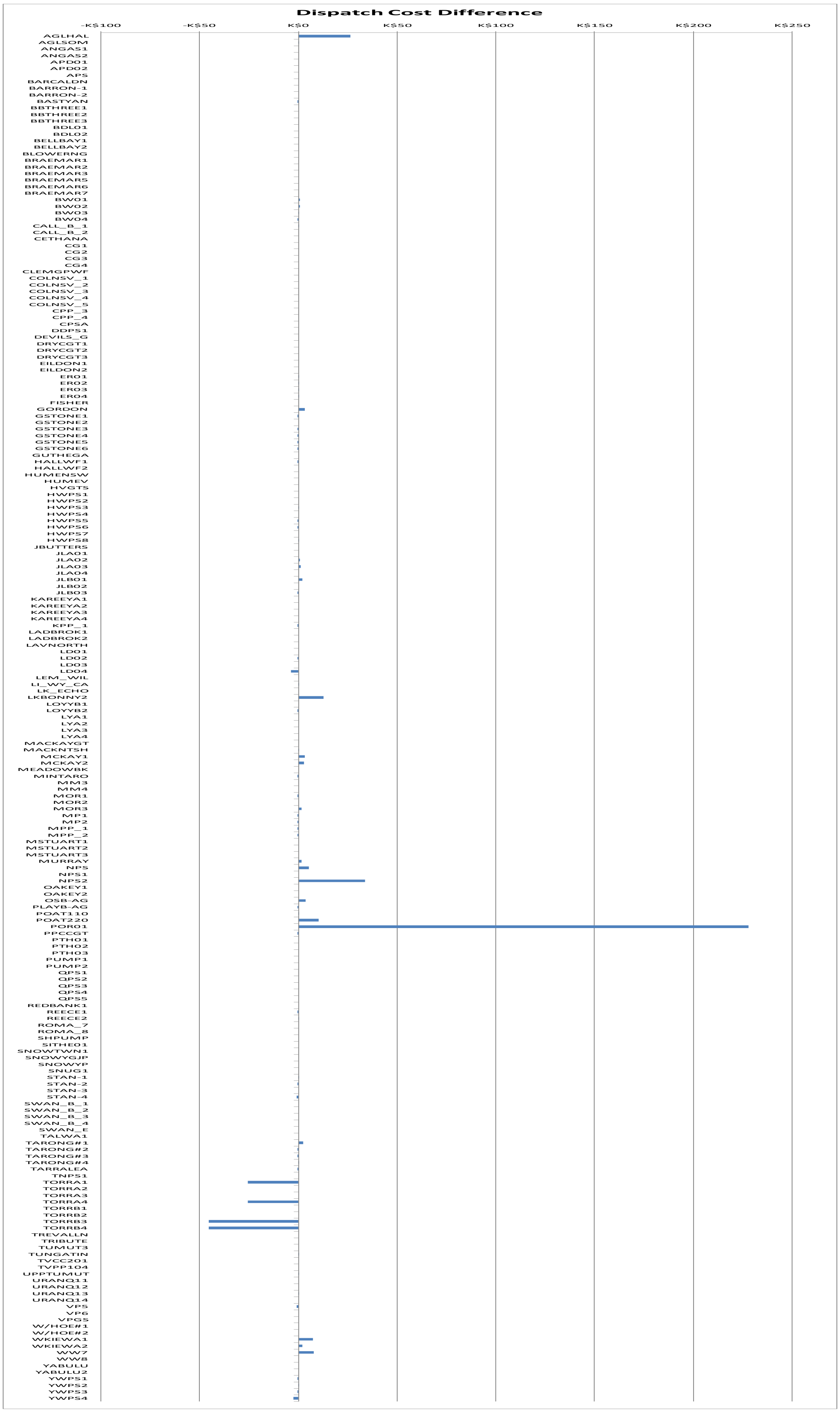
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	14,369	14,369	0
DRYCGT1	100,277	100,277	0
DRYCGT2	101,802	101,802	0
DRYCGT3	114,276	114,276	0
EILDON1	68,314	68,314	0
EILDON2	58,395	58,395	0
ER01	318,932	318,468	464
ER02	318,932	318,453	479
ER03	319,289	319,202	86
ER04	319,289	319,202	86
FISHER	33,005	33,005	0
GORDON	178,916	175,510	3,406
GSTONE1	85,230	85,340	-110
GSTONE2	0	0	0
GSTONE3	102,088	102,256	-168
GSTONE4	102,099	102,256	-157
GSTONE5	101,955	102,256	-301
GSTONE6	102,151	102,256	-105
GUTHEGA	0	0	0
HALLWF1	-6,107	-5,520	-587
HALLWF2	0	0	0
HUMENSW	0	0	0
HUMEV	20,160	20,160	0
HVGTS	0	0	0
HWPS1	12,415	12,415	0
HWPS2	12,791	12,791	0
HWPS3	16,534	16,532	2
HWPS4	16,553	16,553	0
HWPS5	15,884	15,886	-2
HWPS6	15,512	15,518	-6
HWPS7	14,296	14,296	0
HWPS8	14,883	14,860	23
JBUTTERS	0	0	0
JLA01	13,619	13,619	0
JLA02	39,691	38,991	700
JLA03	39,781	38,665	1,116
JLA04	13,619	13,619	0
JLB01	111,736	109,769	1,968
JLB02	0	0	0
JLB03	111,091	111,470	-379
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	119,611	119,644	-34
LADBROK1	44,521	44,521	0
LADBROK2	44,521	44,521	0
LAVNORTH	0	0	0
LD01	211,162	211,162	0
LD02	170,949	171,059	-110
LD03	211,162	211,162	0
LD04	186,276	190,070	-3,794

Plant	Historical	Alternative	Difference
LEM_WIL	74,819	74,819	0
LI_WY_CA	78,011	77,997	14
LK_ECHO	0	0	0
LKBONNY2	-22,126	-34,726	12,601
LOYYB1	101,520	101,520	0
LOYYB2	100,747	100,786	-38
LYA1	38,396	38,396	0
LYA2	35,802	35,802	0
LYA3	40,014	40,014	0
LYA4	40,014	40,014	0
MACKAYGT	0	0	0
MACKNTSH	49,620	49,565	55
MCKAY1	73,670	70,200	3,470
MCKAY2	30,704	27,999	2,705
MEADOWBK	12,472	12,472	0
MINTARO	169,315	169,320	-5
MM3	146,448	146,448	0
MM4	0	0	0
MOR1	21,973	22,351	-378
MOR2	0	0	0
MOR3	19,763	18,331	1,432
MP1	367,126	367,180	-54
MP2	367,126	367,180	-54
MPP_1	87,356	87,383	-27
MPP_2	87,249	87,379	-130
MSTUART1	0	0	0
MSTUART2	0	0	0
MSTUART3	0	0	0
MURRAY	1,060,472	1,058,795	1,677
NPS	764,651	759,349	5,302
NPS1	164,701	164,701	0
NPS2	128,817	94,977	33,840
OAKEY1	0	0	0
OAKEY2	0	0	0
OSB-AG	210,613	206,978	3,635
PLAYB-AG	86,301	86,634	-333
POAT110	628	514	114
POAT220	77,066	66,757	10,309
POR01	480,458	252,678	227,780
PPCCGT	522,671	522,728	-57
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	32,472	32,472	0
QPS2	30,848	30,848	0
QPS3	30,848	30,848	0
QPS4	32,472	32,472	0
QPS5	0	0	0
REDBANK1	61,126	61,126	0
REECE1	14,122	14,250	-128
REECE2	20,435	20,158	277

Plant	Historical	Alternative	Difference
ROMA_7	64,212	64,212	0
ROMA_8	0	0	0
SHPUMP	0	0	0
SITHE01	212,028	212,028	0
SNOWTWN1	-12,440	-12,440	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	446,666	446,666	0
STAN-1	115,161	114,948	213
STAN-2	120,167	120,418	-251
STAN-3	155,736	155,736	0
STAN-4	125,073	125,998	-925
SWAN_B_1	36,472	36,472	0
SWAN_B_2	36,472	36,472	0
SWAN_B_3	39,787	39,787	0
SWAN_B_4	36,472	36,472	0
SWAN_E	316,039	316,039	0
TALWA1	0	0	0
TARONG#1	86,293	83,981	2,312
TARONG#2	108,542	108,583	-41
TARONG#3	104,888	104,929	-41
TARONG#4	84,907	84,757	150
TARRALEA	71,725	71,748	-22
TNPS1	157,469	157,469	0
TORRA1	104,991	130,768	-25,777
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	105,045	130,768	-25,724
TORRB1	0	0	0
TORRB2	0	0	0
TORRB3	133,914	179,190	-45,276
TORRB4	133,832	179,012	-45,180
TREVALLN	26,919	26,919	0
TRIBUTE	69,527	69,527	0
TUMUT3	0	0	0
TUNGATIN	5,100	4,963	137
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	364,226	363,849	376
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	255,460	255,298	162
URANQ14	0	0	0
VP5	361,992	362,691	-699
VP6	352,973	352,973	0
VPGS	0	0	0
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	43,058	35,538	7,520
WKIEWA2	39,267	37,167	2,100
WW7	266,087	258,324	7,763
WW8	217,854	217,854	0
YABULU	176,060	176,060	0

Plant	Historical	Alternative	Difference
YABULU2	89,712	89,712	0
YWPS1	26,862	27,136	-274
YWPS2	28,129	28,123	5
YWPS3	27,090	27,113	-23
YWPS4	24,008	26,463	-2,455
Total	17,692,899	17,486,462	206,437

Figure 39 Generation Dispatch Cost Changes



Appendix E Day 05: 19/11/09

E.1 Introduction

This appendix provides the detailed results for Thursday, 19 November 2009, Day 05. The offers for this day were modified as follows.

Table 17 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[6]	To[1]	With[1]
Day 05	19/11/09	12:30	19:30	Torrens Island A	SA	12:30	19:30	12:30
				Torrens Island B	SA	12:30	19:30	12:30
				Angaston	SA	12:00	17:00	12:00

E.2 Overview and Discussion of Results

The alternative scenario resulted in substantially increased dispatch costs of about $540,000. These unexpected increases in costs appear to be largely due to Torrens Island substituting for cheaper Murray and Tumut 3 generation.

In section 2.4 it was discussed that the dispatch costs for the alternative dispatch could be slightly higher than the original historical dispatch costs for a number of modelling reasons including:

- Problems with initial conditions;
- Problems with generic constraints; and
- Problems with regional demands not adjusting to changes in local and remote generation.

However, the large negative value on Day 5 of -$539,845 for the dispatch inefficiencies is likely to be caused by other reasons. The two most likely reasons are the following:

- The offered supply curves for the generators whose dispatches have changed don't reflect their position in the least cost merit order (under normal circumstances not all of the generation in the NEM is offered into the market according to the marginal cost merit order of the plant); or
- One or more of the marginal costs for the generators whose dispatches have changed are materially wrong. For instance, if band five prices for Snowy were closer to Snowy's marginal costs on Day 5 then the negative dispatch efficiency changes to a positive dispatch efficiency of $530,730.

[6] Period ending trading interval

E.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 40 New South Wales Spot Prices for Historical and Alternative Dispatch 19/11/2009

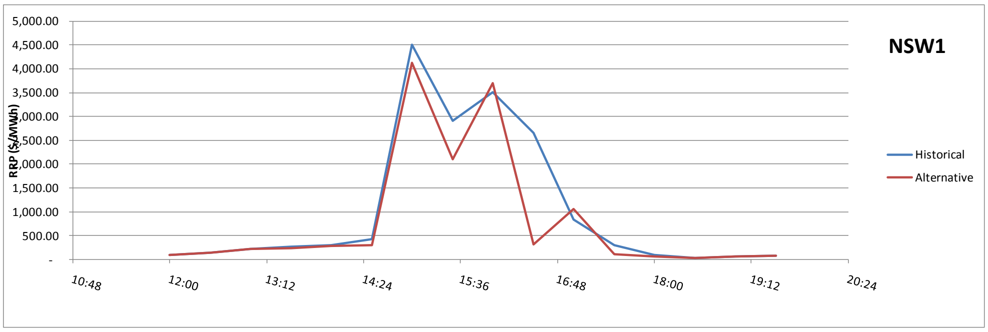


Figure 41 Queensland Spot Prices for Historical and Alternative Dispatch 19/11/2009

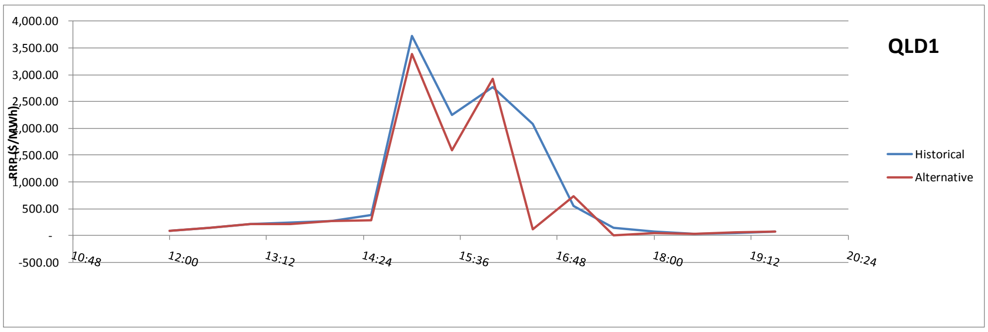


Figure 42 South Australian Spot Prices for Historical and Alternative Dispatch 19/11/2009

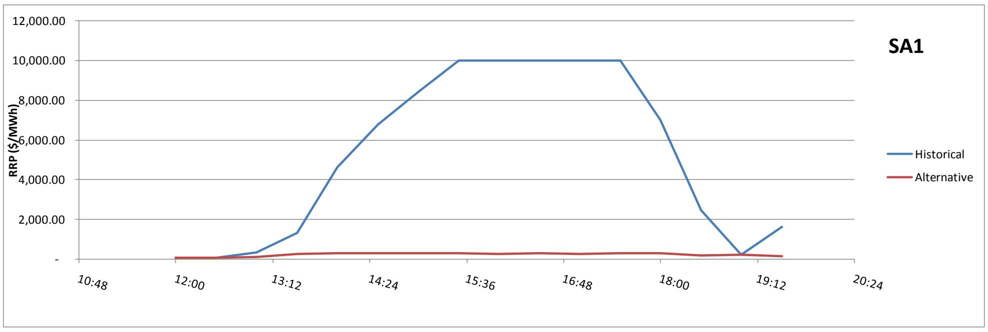


Figure 43 Tasmanian Spot Prices for Historical and Alternative Dispatch 19/11/2009

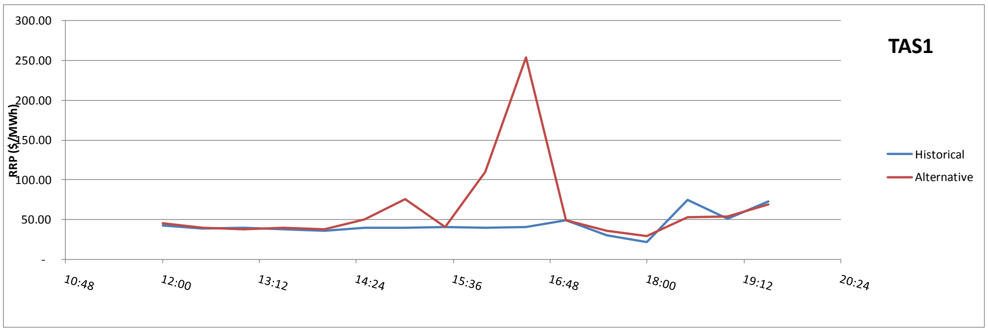
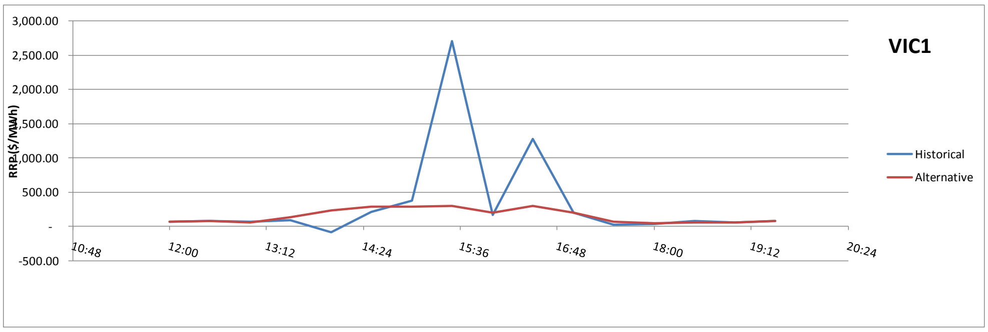


Figure 44 Victorian Spot Prices for Historical and Alternative Dispatch 19/11/2009



E.4 Dispatch Cost Impacts

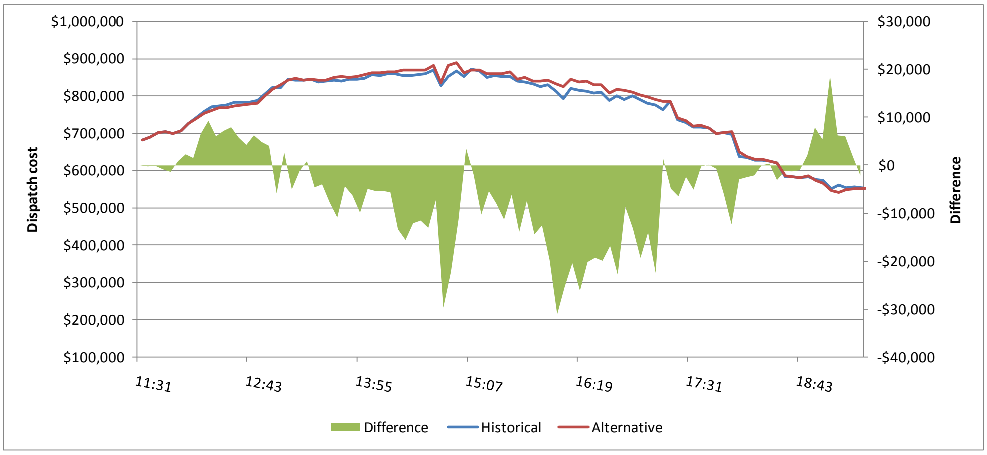
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 18 Historical and Alternative Dispatch Costs for 19/11/2009

	Historical	Alternative	Difference
Total generation cost ($)	73,090,877	73,630,722	-539,845

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 45 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 19/11/2009



E.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 19 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 19/11/2009

Plant	Historical	Alternative	Difference
AGLHAL	1,241,770	1,241,432	338
AGLSOM	830,317	843,235	-12,918
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	82,422	82,496	-74
BARCALDN	92,215	75,105	17,110
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	63,698	63,698	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	156,619	157,605	-986
BDL02	28,312	28,489	-177
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	31,680	31,680	0
BRAEMAR1	545,025	544,557	468
BRAEMAR2	541,633	541,166	468
BRAEMAR3	512,715	520,308	-7,593
BRAEMAR5	613,664	612,625	1,038
BRAEMAR6	610,258	609,220	1,038
BRAEMAR7	608,638	607,185	1,454

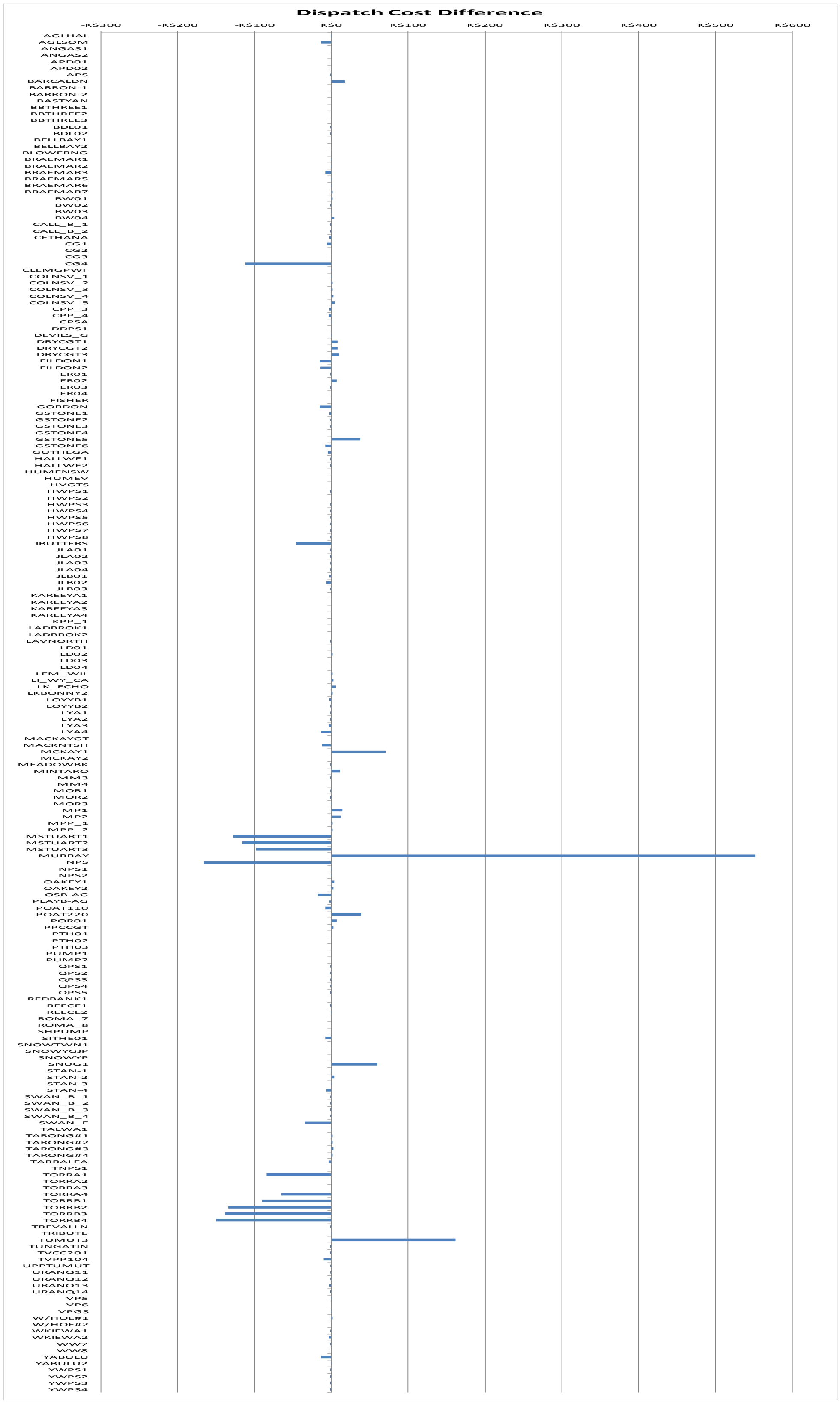
Plant	Historical	Alternative	Difference
BW01	772,773	770,972	1,801
BW02	774,667	775,440	-773
BW03	776,097	776,017	79
BW04	779,035	775,089	3,946
CALL_B_1	452,495	454,057	-1,562
CALL_B_2	398,640	399,715	-1,075
CETHANA	173,935	176,340	-2,405
CG1	216,033	221,482	-5,448
CG2	0	0	0
CG3	0	0	0
CG4	1,204,116	1,315,825	-111,710
CLEMGPWF	-126,326	-126,326	0
COLNSV_1	2,401	2,343	58
COLNSV_2	35,734	34,232	1,502
COLNSV_3	43,731	41,606	2,125
COLNSV_4	44,148	41,394	2,754
COLNSV_5	96,044	91,595	4,449
CPP_3	459,915	462,477	-2,561
CPP_4	490,948	494,743	-3,795
CPSA	38,784	38,745	39
DDPS1	0	0	0
DEVILS_G	132,085	131,666	419
DRYCGT1	259,996	252,366	7,630
DRYCGT2	254,638	246,218	8,420
DRYCGT3	267,848	257,232	10,616
EILDON1	139,272	154,940	-15,669
EILDON2	136,889	151,508	-14,619
ER01	903,322	903,571	-249
ER02	450,313	443,096	7,217
ER03	903,645	903,868	-222
ER04	0	0	0
FISHER	98,257	98,257	0
GORDON	429,364	444,212	-14,848
GSTONE1	348,343	351,457	-3,114
GSTONE2	353,763	355,458	-1,695
GSTONE3	330,306	332,261	-1,955
GSTONE4	0	0	0
GSTONE5	360,309	322,539	37,770
GSTONE6	338,719	346,368	-7,648
GUTHEGA	111,593	116,296	-4,703
HALLWF1	-147,923	-147,473	-450
HALLWF2	-109,694	-109,063	-631
HUMENSW	23,400	23,400	0
HUMEV	60,060	60,060	0
HVGTS	0	0	0
HWPS1	35,255	35,275	-19
HWPS2	0	0	0
HWPS3	46,421	47,029	-608
HWPS4	48,246	48,402	-156
HWPS5	43,259	43,617	-358
HWPS6	45,760	45,969	-209
HWPS7	40,764	41,104	-340
HWPS8	44,719	44,764	-46

Plant	Historical	Alternative	Difference
JBUTTERS	162,936	209,069	-46,134
JLA01	128,850	129,702	-852
JLA02	141,752	142,604	-852
JLA03	129,529	130,381	-852
JLA04	141,752	142,604	-852
JLB01	234,459	236,723	-2,264
JLB02	224,800	231,698	-6,899
JLB03	230,932	232,677	-1,746
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	332,000	332,000	0
LADBROK1	220,995	220,995	0
LADBROK2	220,995	220,995	0
LAVNORTH	1,452,365	1,453,624	-1,259
LD01	661,909	660,989	921
LD02	617,641	615,854	1,787
LD03	0	0	0
LD04	557,019	557,019	0
LEM_WIL	174,898	173,086	1,812
LI_WY_CA	362,702	360,166	2,536
LK_ECHO	62,750	57,131	5,619
LKBONNY2	-34,656	-36,080	1,424
LOYYB1	284,196	286,602	-2,406
LOYYB2	283,831	285,710	-1,879
LYA1	112,461	114,369	-1,908
LYA2	103,264	103,693	-429
LYA3	110,799	114,906	-4,107
LYA4	94,672	108,358	-13,686
MACKAYGT	9,956	9,956	0
MACKNTSH	321	12,813	-12,493
MCKAY1	653,408	582,613	70,795
MCKAY2	0	0	0
MEADOWBK	80,444	81,888	-1,444
MINTARO	518,581	506,972	11,609
MM3	474,515	475,471	-956
MM4	0	0	0
MOR1	42,287	42,711	-424
MOR2	22,927	24,437	-1,510
MOR3	56,073	55,884	189
MP1	1,038,930	1,024,954	13,976
MP2	1,147,166	1,135,116	12,050
MPP_1	340,545	339,171	1,374
MPP_2	226,720	225,098	1,622
MSTUART1	2,372,435	2,500,302	-127,867
MSTUART2	3,308,416	3,424,719	-116,302
MSTUART3	2,734,299	2,832,845	-98,546
MURRAY	2,079,931	1,528,446	551,485
NPS	1,942,440	2,108,023	-165,583
NPS1	377,772	377,755	16
NPS2	416,526	416,302	225
OAKEY1	338,791	335,510	3,282

Plant	Historical	Alternative	Difference
OAKEY2	536,485	533,404	3,081
OSB-AG	648,987	666,835	-17,848
PLAYB-AG	380,490	382,923	-2,433
POAT110	114,963	122,575	-7,611
POAT220	249,957	211,559	38,398
POR01	741,459	734,687	6,772
PPCCGT	1,310,144	1,307,502	2,642
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	125,879	126,205	-326
QPS2	140,285	140,666	-381
QPS3	133,292	133,655	-363
QPS4	133,730	134,093	-363
QPS5	765,949	767,236	-1,288
REDBANK1	0	0	0
REECE1	239,240	240,395	-1,155
REECE2	237,971	237,606	366
ROMA_7	173,574	173,574	0
ROMA_8	184,711	184,711	0
SHPUMP	0	0	0
SITHE01	585,475	593,084	-7,609
SNOWTWN1	-265,000	-265,000	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	1,895,941	1,836,019	59,922
STAN-1	385,555	384,983	572
STAN-2	471,746	467,487	4,259
STAN-3	466,813	466,716	98
STAN-4	313,193	320,217	-7,024
SWAN_B_1	158,445	158,478	-32
SWAN_B_2	175,227	177,011	-1,784
SWAN_B_3	190,582	191,153	-571
SWAN_B_4	182,524	183,422	-898
SWAN_E	700,208	734,270	-34,062
TALWA1	1,093,911	1,093,649	263
TARONG#1	317,767	316,343	1,424
TARONG#2	321,620	319,567	2,054
TARONG#3	316,213	313,823	2,390
TARONG#4	320,211	318,992	1,219
TARRALEA	176,577	180,288	-3,711
TNPS1	0	0	0
TORRA1	278,860	362,841	-83,981
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	276,120	340,861	-64,741
TORRB1	355,890	446,053	-90,163
TORRB2	341,199	474,871	-133,672
TORRB3	347,380	485,636	-138,255
TORRB4	347,683	497,484	-149,800
TREVALLN	157,518	158,646	-1,128

Plant	Historical	Alternative	Difference
TRIBUTE	178,031	177,411	619
TUMUT3	2,427,289	2,265,381	161,908
TUNGATIN	225,587	226,632	-1,045
TVCC201	795,877	797,673	-1,796
TVPP104	189,060	199,594	-10,534
UPPTUMUT	1,230,730	1,232,481	-1,751
URANQ11	988,128	989,188	-1,060
URANQ12	1,016,306	1,017,140	-834
URANQ13	986,238	989,188	-2,950
URANQ14	1,016,164	1,017,140	-976
VP5	849,890	849,258	631
VP6	0	0	0
VPGS	710,480	710,205	275
W/HOE#1	2,041	0	2,041
W/HOE#2	0	0	0
WKIEWA1	120,023	121,834	-1,811
WKIEWA2	127,907	131,702	-3,796
WW7	750,069	751,756	-1,686
WW8	668,490	668,490	0
YABULU	464,104	476,945	-12,840
YABULU2	249,784	249,640	143
YWPS1	82,889	82,925	-36
YWPS2	81,374	81,439	-65
YWPS3	78,581	78,648	-67
YWPS4	86,657	86,728	-71
Total	73,090,877	73,630,722	-539,845

Figure 46 Dispatch Cost Changes



Appendix F Day 06: 7/12/09

F.1 Introduction

This appendix provides the detailed results for Monday, 7 December 2009, Day 06. The offers for this day were modified as follows.

Table 20 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[7]	To[1]	With[1]
Day 06	7/12/09	0:30	0:00	Eraring	NSW	0:30	0:00	0:30
				Munmorah	NSW	12:00	20:00	12:00
				Vales Pt	NSW	12:00	17:00	12:00
				Wallerawang	NSW	12:00	18:00	12:00
				Millmerran	QLD	10:00	23:30	10:00
				Tarong	QLD	9:00	17:00	9:00
				Swanbank B	QLD	8:00	17:00	9:00
				Callide B	QLD	7:30	18:00	7:30

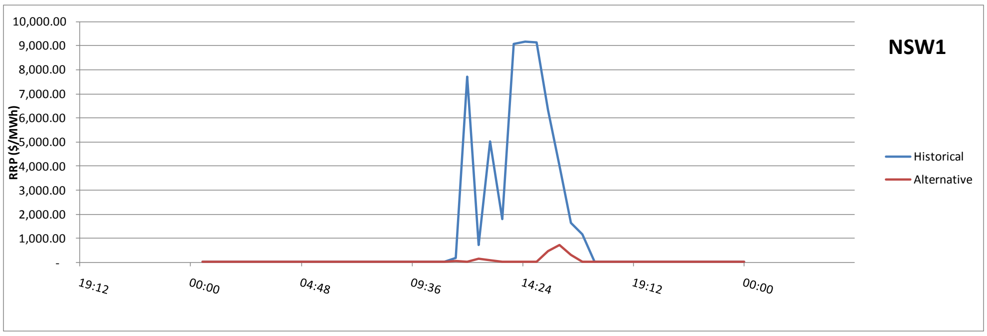
F.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $2,089,000. This was largely due to significant reductions in Mt Stuart costs.

F.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 47 New South Wales Spot Prices for Historical and Alternative Dispatch 7/12/2009



[7] Period ending trading interval

Figure 48 Queensland Spot Prices for Historical and Alternative Dispatch 7/12/2009

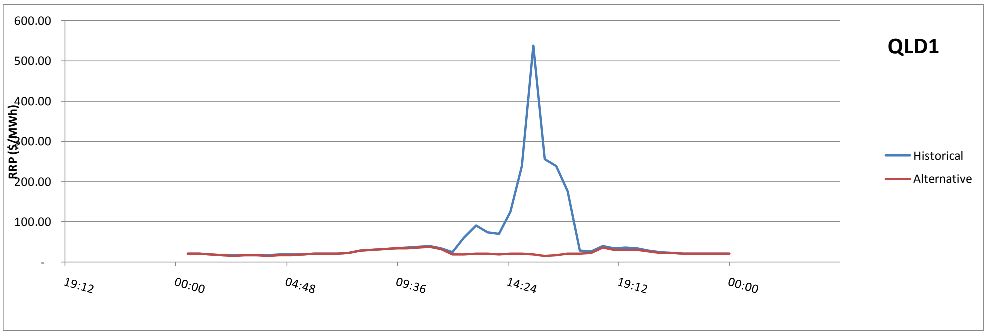


Figure 49 South Australian Spot Prices for Historical and Alternative Dispatch 7/12/2009

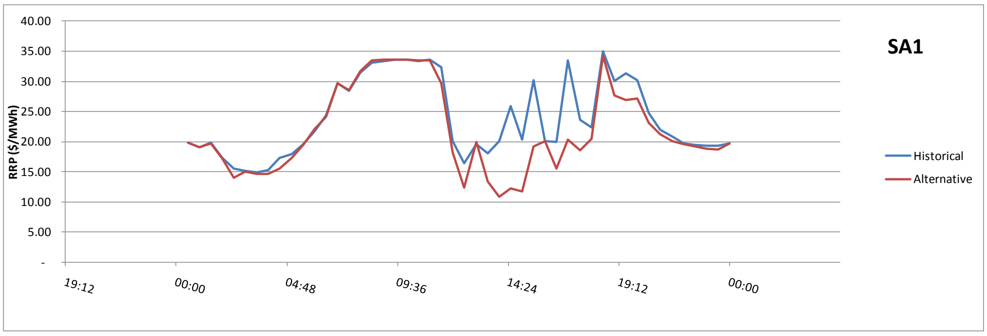


Figure 50 Tasmanian Spot Prices for Historical and Alternative Dispatch 7/12/2009

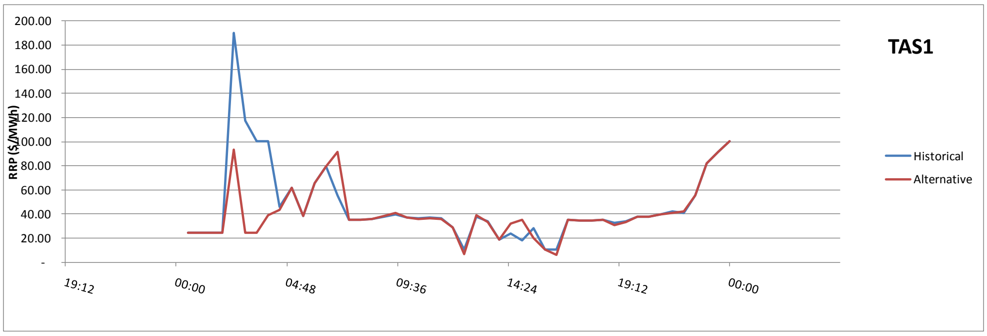
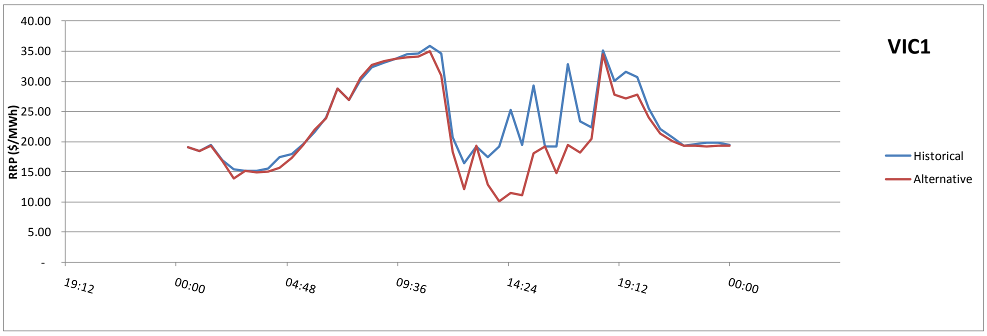


Figure 51 Victorian Spot Prices for Historical and Alternative Dispatch 7/12/2009



F.4 Dispatch Cost Impacts

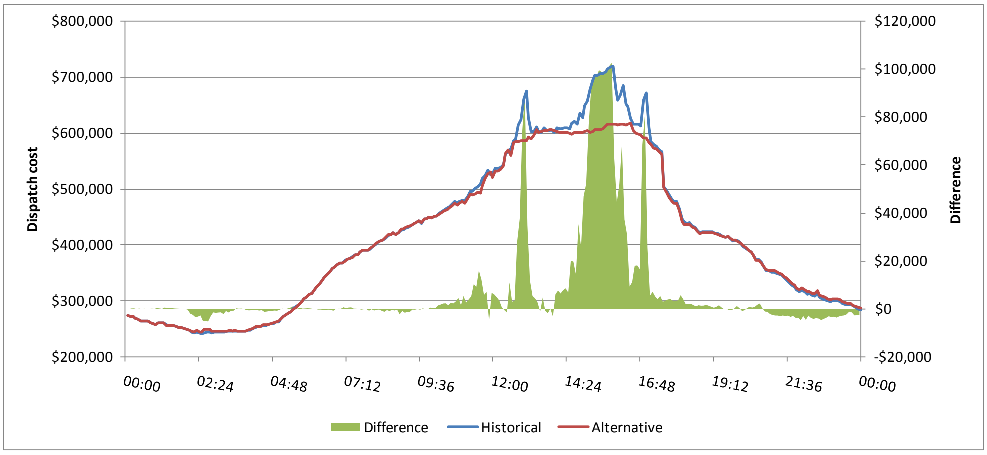
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 21 Historical and Alternative Dispatch Costs for 7/12/2009

	Historical	Alternative	Difference
Total generation cost ($)	119,509,936	117,420,641	2,089,295

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 52 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 7/12/2009



F.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 22 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 7/12/2009

Plant	Historical	Alternative	Difference
AGLHAL	0	0	0
AGLSOM	589,619	568,549	21,070
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	263,850	263,850	0
BARCALDN	129,998	128,568	1,430
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	225,097	224,764	333
BBTHREE1	446,628	446,628	0
BBTHREE2	534,911	534,911	0
BBTHREE3	530,441	532,304	-1,863
BDL01	0	0	0
BDL02	3,394	3,394	0
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	71,910	71,622	288
BRAEMAR1	772,597	774,906	-2,309
BRAEMAR2	1,642,284	1,639,259	3,025
BRAEMAR3	532,286	536,023	-3,737
BRAEMAR5	1,609,041	1,608,334	707
BRAEMAR6	917,121	916,869	252
BRAEMAR7	1,091,954	1,083,865	8,089
BW01	2,066,493	2,054,202	12,291
BW02	2,045,621	2,030,930	14,691
BW03	2,011,346	2,005,171	6,175
BW04	1,955,487	2,003,514	-48,026
CALL_B_1	1,165,528	1,249,562	-84,034
CALL_B_2	1,150,456	1,232,220	-81,764
CETHANA	193,206	189,081	4,124
CG1	0	0	0
CG2	781,801	713,909	67,892
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	-184,617	-184,619	2
COLNSV_1	106,990	109,839	-2,849
COLNSV_2	39,758	40,123	-365
COLNSV_3	98,571	98,571	0
COLNSV_4	89,632	89,514	118
COLNSV_5	124,581	123,108	1,473
CPP_3	1,355,606	1,349,264	6,342
CPP_4	1,442,490	1,441,067	1,422
CPSA	0	0	0

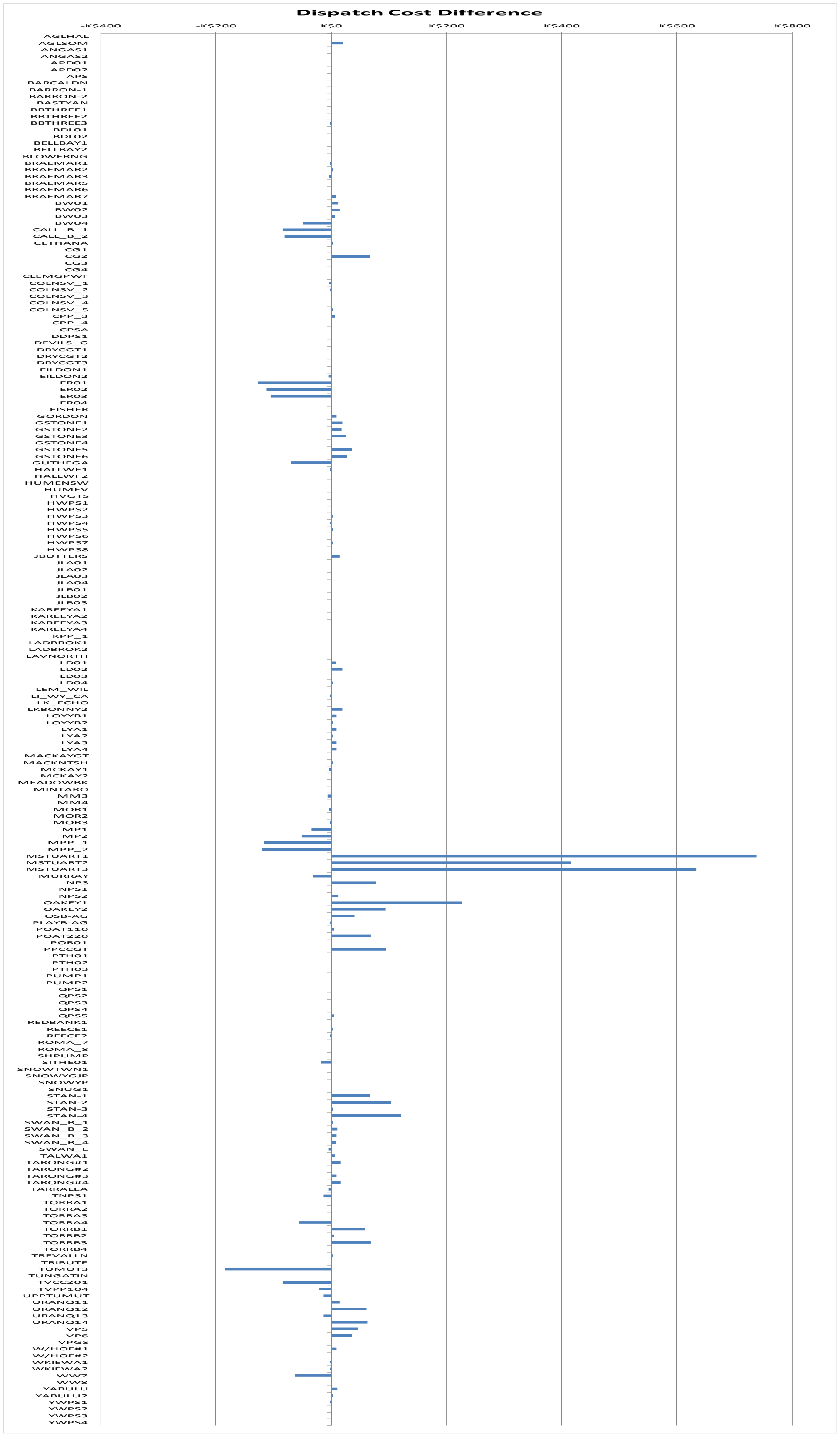
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	147,933	147,480	452
DRYCGT1	0	0	0
DRYCGT2	0	0	0
DRYCGT3	0	0	0
EILDON1	0	0	0
EILDON2	109,010	113,293	-4,283
ER01	2,711,784	2,839,952	-128,167
ER02	2,727,662	2,839,952	-112,290
ER03	2,734,950	2,839,952	-105,001
ER04	0	0	0
FISHER	295,983	295,596	387
GORDON	492,123	483,048	9,075
GSTONE1	845,747	827,211	18,536
GSTONE2	845,555	827,211	18,344
GSTONE3	811,277	785,159	26,118
GSTONE4	0	0	0
GSTONE5	825,321	789,691	35,630
GSTONE6	816,366	788,720	27,645
GUTHEGA	95,791	166,158	-70,367
HALLWF1	-118,116	-117,836	-281
HALLWF2	-77,365	-77,419	54
HUMENSW	198,720	197,340	1,380
HUMEV	0	0	0
HVGTS	0	0	0
HWPS1	95,840	95,840	0
HWPS2	0	0	0
HWPS3	145,319	143,072	2,247
HWPS4	68,298	68,493	-195
HWPS5	139,854	137,265	2,589
HWPS6	137,594	137,042	551
HWPS7	130,669	128,740	1,930
HWPS8	114,235	114,235	0
JBUTTERS	816,182	800,892	15,291
JLA01	0	0	0
JLA02	0	0	0
JLA03	0	0	0
JLA04	0	0	0
JLB01	0	0	0
JLB02	0	0	0
JLB03	0	0	0
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	1,119,099	1,119,099	0
LADBROK1	361,935	361,854	81
LADBROK2	361,924	361,854	70
LAVNORTH	1,058,669	1,057,406	1,263
LD01	1,126,016	1,118,669	7,347
LD02	1,649,946	1,630,717	19,228
LD03	0	0	0
LD04	1,877,451	1,874,913	2,538

Plant	Historical	Alternative	Difference
LEM_WIL	241,846	241,402	444
LI_WY_CA	697,962	698,290	-327
LK_ECHO	0	0	0
LKBONNY2	-167,422	-187,175	19,753
LOYYB1	861,118	851,236	9,883
LOYYB2	861,387	858,176	3,210
LYA1	324,867	314,998	9,869
LYA2	310,740	309,021	1,719
LYA3	336,089	327,187	8,902
LYA4	326,936	317,667	9,269
MACKAYGT	0	0	0
MACKNTSH	288,251	284,775	3,476
MCKAY1	80,974	85,120	-4,146
MCKAY2	0	0	0
MEADOWBK	142,226	141,603	624
MINTARO	0	0	0
MM3	1,079,932	1,086,134	-6,201
MM4	0	0	0
MOR1	126,222	129,712	-3,490
MOR2	66,822	65,461	1,361
MOR3	168,879	170,120	-1,241
MP1	3,150,958	3,185,707	-34,749
MP2	3,161,826	3,213,071	-51,245
MPP_1	994,737	1,111,751	-117,014
MPP_2	997,288	1,117,531	-120,242
MSTUART1	1,686,607	947,399	739,208
MSTUART2	1,411,636	995,726	415,910
MSTUART3	1,639,866	1,005,207	634,659
MURRAY	1,748,616	1,779,851	-31,235
NPS	1,099,101	1,020,398	78,702
NPS1	1,204,725	1,204,134	591
NPS2	1,252,489	1,239,971	12,519
OAKEY1	451,945	225,538	226,407
OAKEY2	180,465	86,493	93,972
OSB-AG	1,445,748	1,405,503	40,245
PLAYB-AG	806,067	808,090	-2,024
POAT110	157,749	152,947	4,802
POAT220	523,260	454,326	68,934
POR01	0	0	0
PPCCGT	3,555,974	3,460,994	94,980
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	0	0	0
QPS2	0	0	0
QPS3	0	0	0
QPS4	0	0	0
QPS5	811,935	806,936	4,998
REDBANK1	522,510	522,071	439
REECE1	655,310	652,403	2,907
REECE2	7,219	7,354	-134

Plant	Historical	Alternative	Difference
ROMA_7	557,589	557,589	0
ROMA_8	598,550	598,550	0
SHPUMP	0	0	0
SITHE01	1,433,207	1,450,703	-17,496
SNOWTWN1	-313,080	-313,080	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	0	0	0
STAN-1	1,137,191	1,069,949	67,242
STAN-2	1,167,460	1,064,058	103,402
STAN-3	1,256,420	1,252,390	4,030
STAN-4	1,204,737	1,084,135	120,603
SWAN_B_1	380,121	375,844	4,277
SWAN_B_2	450,042	439,505	10,537
SWAN_B_3	479,382	470,686	8,696
SWAN_B_4	448,720	440,777	7,943
SWAN_E	2,335,540	2,339,974	-4,434
TALWA1	2,656,192	2,649,569	6,623
TARONG#1	822,490	806,176	16,314
TARONG#2	0	0	0
TARONG#3	795,133	785,293	9,840
TARONG#4	789,700	772,730	16,969
TARRALEA	629,982	634,790	-4,808
TNPS1	988,678	1,002,729	-14,051
TORRA1	0	0	0
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	261,509	317,751	-56,242
TORRB1	612,657	553,700	58,957
TORRB2	508,086	502,764	5,322
TORRB3	956,122	887,177	68,945
TORRB4	0	0	0
TREVALLN	227,642	224,847	2,795
TRIBUTE	144	0	144
TUMUT3	2,650,505	2,834,682	-184,176
TUNGATIN	261,872	261,457	415
TVCC201	215,222	298,734	-83,512
TVPP104	721,238	741,758	-20,521
UPPTUMUT	2,195,447	2,209,391	-13,944
URANQ11	943,952	929,325	14,627
URANQ12	919,389	857,240	62,149
URANQ13	395,089	408,334	-13,245
URANQ14	901,046	838,186	62,861
VP5	2,864,256	2,818,586	45,670
VP6	2,839,731	2,803,221	36,510
VPGS	0	0	0
W/HOE#1	288,389	279,451	8,938
W/HOE#2	0	0	0
WKIEWA1	86,918	88,336	-1,418
WKIEWA2	51,358	53,735	-2,378
WW7	1,527,002	1,590,299	-63,297
WW8	0	0	0
YABULU	1,006,927	996,664	10,263

Plant	Historical	Alternative	Difference
YABULU2	557,383	553,412	3,972
YWPS1	249,807	249,823	-16
YWPS2	249,702	249,678	24
YWPS3	255,967	255,919	48
YWPS4	261,808	261,773	35
Total	119,509,936	117,420,641	2,089,295

Figure 53 Dispatch Cost Changes



Appendix G Day 07: 11/01/10

G.1 Introduction

This appendix provides the detailed results for Monday, 11 January 2010, Day 07. The offers for this day were modified as follows.

Table 23 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[8]	To[1]	With[1]
Day 07	11/01/10	13:00	19:00	Torrens Island A	SA	13:00	19:00	13:00
				Torrens Island B	SA	13:00	19:00	13:00
				Loy Yang A	VIC	14:00	18:00	14:00

G.2 Overview and Discussion of Results

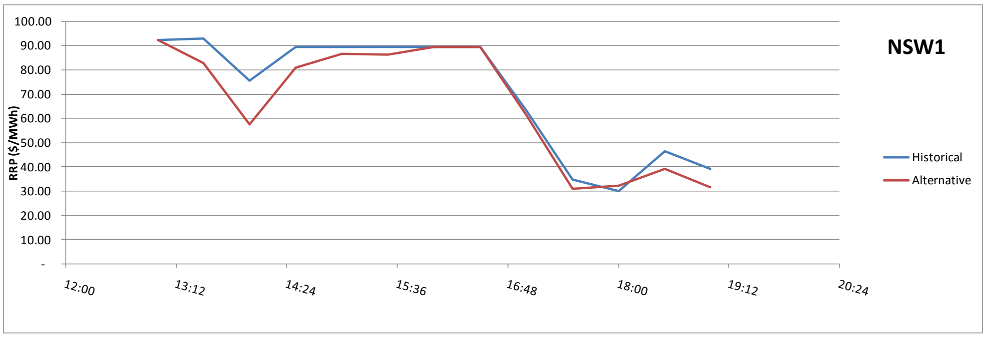
The alternative scenario resulted in decreased dispatch costs of $354,000. Snuggery and Lake Bonney generation were increased and Mackay and Tumut 3 generation were decreased significantly and many other generators had their outputs reduced a little.

An increase in Lake Bonney generation reduces dispatch costs because the dispatch of wind generation was assumed to have a negative cost of $40/MWh due to an assumed value of a REC of $40/MWh. The increase in Lake Bonney generation is probably related to the easing of a network constraint with the revised dispatch pattern.

G.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 54 New South Wales Spot Prices for Historical and Alternative Dispatch 11/1/2010



[8] Period ending trading interval

Figure 55 Queensland Spot Prices for Historical and Alternative Dispatch 11/1/2010

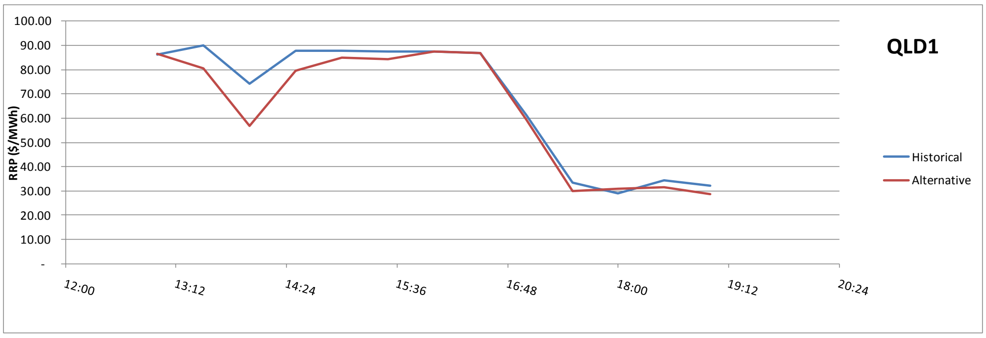


Figure 56 South Australian Spot Prices for Historical and Alternative Dispatch 11/1/2010

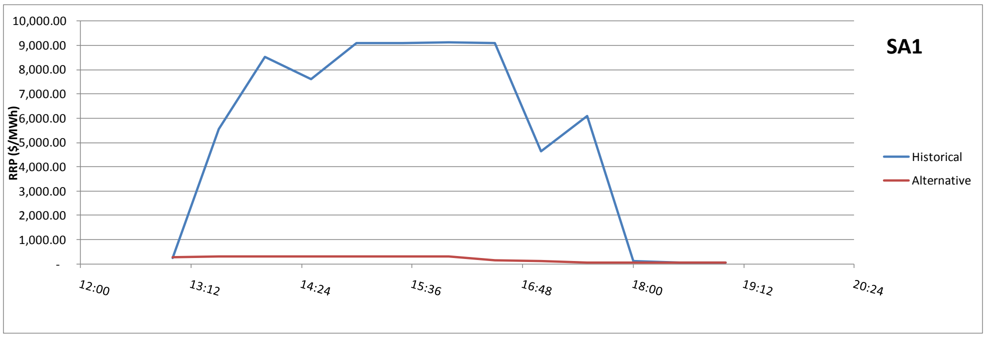


Figure 57 Tasmanian Spot Prices for Historical and Alternative Dispatch 11/1/2010

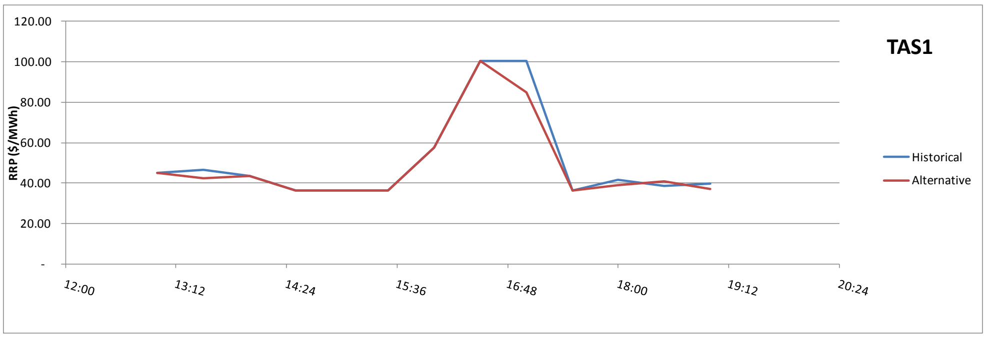
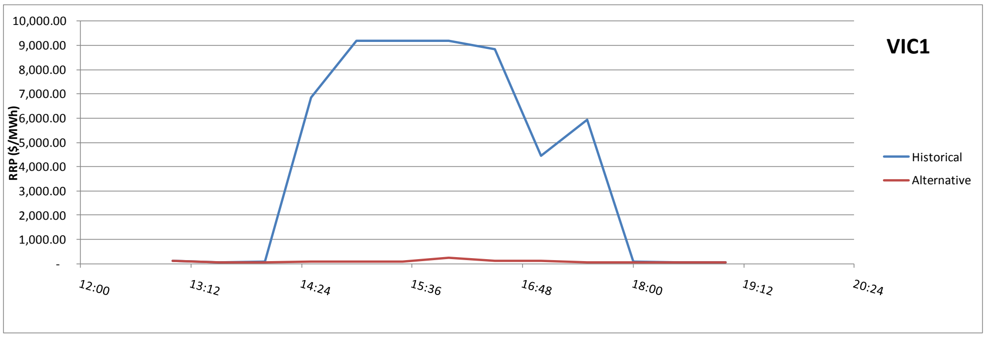


Figure 58 Victorian Spot Prices for Historical and Alternative Dispatch 11/1/2010



G.4 Dispatch Cost Impacts

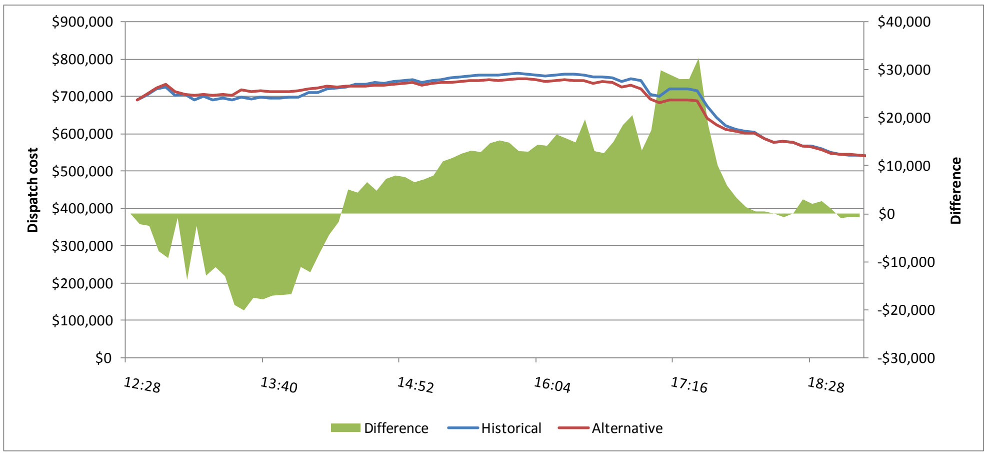
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 24 Historical and Alternative Dispatch Costs for 11/1/2010

	Historical	Alternative	Difference
Total generation cost ($)	54,205,049	53,851,404	353,644

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 59 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 11/1/2010



G.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 25 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 11/1/2010

Plant	Historical	Alternative	Difference
AGLHAL	1,393,762	1,393,762	0
AGLSOM	690,173	690,173	0
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	69,834	69,815	19
BARCALDN	0	0	0
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	215,007	215,007	0
BBTHREE2	232,440	232,440	0
BBTHREE3	0	0	0
BDL01	126,815	126,815	0
BDL02	23,501	23,501	0
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	27,300	27,300	0
BRAEMAR1	393,524	399,474	-5,950
BRAEMAR2	420,964	425,847	-4,883
BRAEMAR3	445,593	445,593	0
BRAEMAR5	486,080	485,298	782
BRAEMAR6	486,038	485,024	1,014
BRAEMAR7	482,885	481,863	1,022
BW01	682,078	682,078	0
BW02	578,733	578,733	0
BW03	682,078	682,078	0
BW04	682,078	682,078	0
CALL_B_1	228,031	228,222	-191
CALL_B_2	268,111	267,558	554
CETHANA	147,407	145,442	1,965
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	812,923	819,385	-6,462
CLEMGPWF	-135,712	-135,713	1
COLNSV_1	26,696	26,696	0
COLNSV_2	26,696	26,696	0
COLNSV_3	26,696	26,696	0
COLNSV_4	0	0	0
COLNSV_5	53,392	53,392	0
CPP_3	376,435	375,999	435
CPP_4	406,852	406,852	0
CPSA	18,480	18,480	0

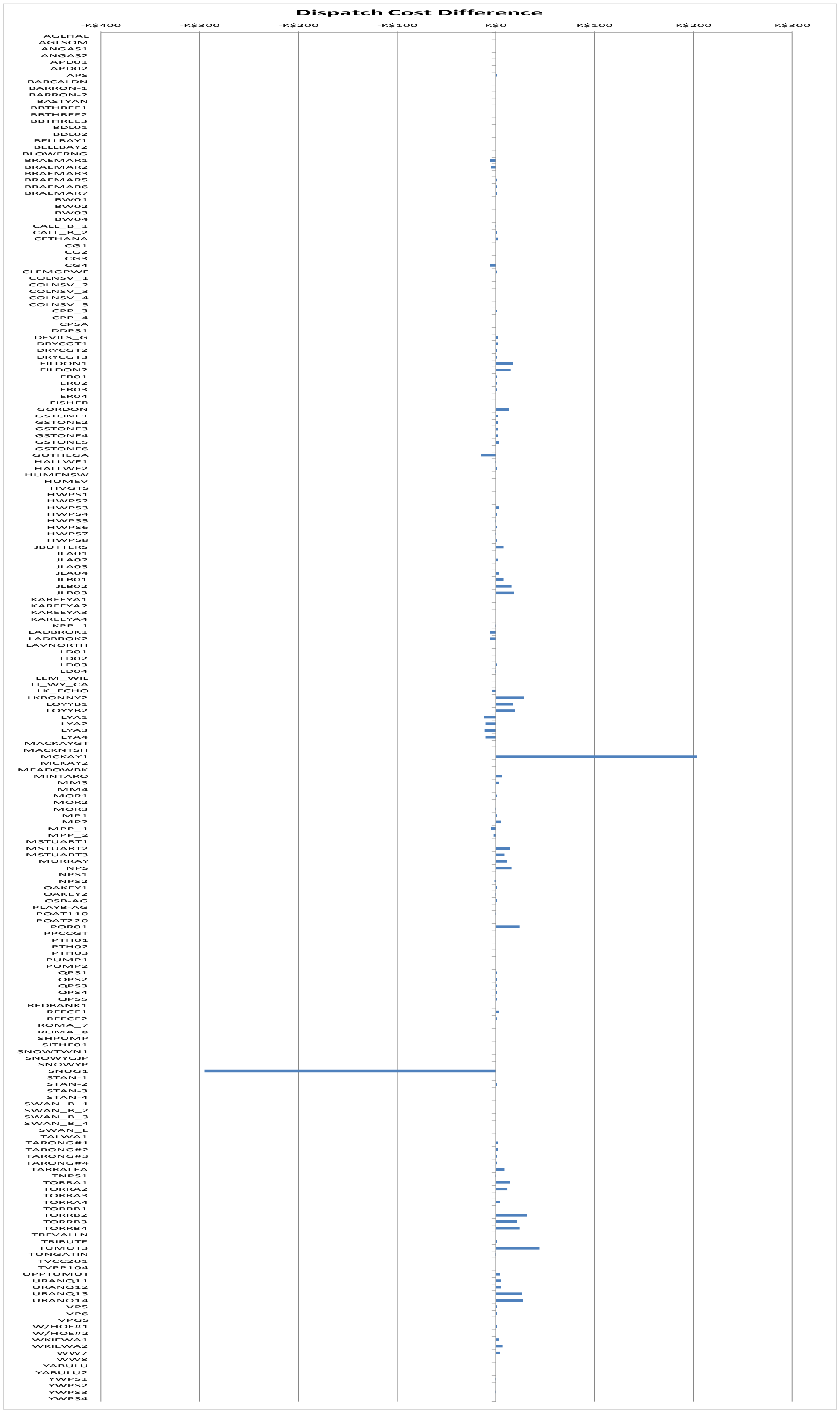
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	98,860	97,204	1,656
DRYCGT1	200,999	199,175	1,824
DRYCGT2	200,155	199,175	980
DRYCGT3	188,615	187,161	1,454
EILDON1	146,598	128,850	17,748
EILDON2	125,312	110,141	15,171
ER01	818,264	817,254	1,010
ER02	818,810	817,254	1,556
ER03	818,633	817,254	1,379
ER04	0	0	0
FISHER	71,744	71,744	0
GORDON	615,538	602,110	13,428
GSTONE1	278,832	276,868	1,965
GSTONE2	279,222	276,866	2,356
GSTONE3	284,148	282,503	1,645
GSTONE4	281,483	279,890	1,594
GSTONE5	277,673	275,071	2,602
GSTONE6	0	0	0
GUTHEGA	40,792	55,408	-14,617
HALLWF1	-227,230	-226,338	-892
HALLWF2	-176,360	-176,550	190
HUMENSW	0	0	0
HUMEV	57,330	57,330	0
HVGTS	0	0	0
HWPS1	26,817	26,817	0
HWPS2	35,802	35,802	0
HWPS3	36,324	33,771	2,553
HWPS4	38,469	37,455	1,014
HWPS5	32,280	32,406	-126
HWPS6	33,879	32,807	1,072
HWPS7	30,797	30,834	-37
HWPS8	33,252	32,830	422
JBUTTERS	177,976	170,519	7,457
JLA01	0	0	0
JLA02	85,902	83,958	1,945
JLA03	0	0	0
JLA04	71,642	68,925	2,716
JLB01	163,714	156,181	7,533
JLB02	168,164	152,143	16,021
JLB03	156,378	137,807	18,571
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	436,087	436,099	-12
LADBROK1	155,460	162,137	-6,678
LADBROK2	158,944	165,622	-6,678
LAVNORTH	1,290,640	1,290,640	0
LD01	320,116	320,116	0
LD02	507,771	507,771	0
LD03	317,191	315,808	1,384
LD04	531,334	531,334	0

Plant	Historical	Alternative	Difference
LEM_WIL	117,809	117,809	0
LI_WY_CA	229,458	229,458	0
LK_ECHO	35,340	39,397	-4,057
LKBONNY2	-193,938	-222,330	28,392
LOYYB1	226,401	208,514	17,887
LOYYB2	227,673	208,571	19,102
LYA1	76,556	88,603	-12,047
LYA2	73,314	83,726	-10,412
LYA3	76,462	87,321	-10,859
LYA4	74,437	84,747	-10,311
MACKAYGT	0	0	0
MACKNTSH	0	0	0
MCKAY1	629,742	425,927	203,815
MCKAY2	0	0	0
MEADOWBK	50,519	50,519	0
MINTARO	374,688	368,507	6,181
MM3	409,586	406,467	3,119
MM4	0	0	0
MOR1	50,376	50,276	100
MOR2	0	0	0
MOR3	45,277	45,833	-556
MP1	960,481	960,208	272
MP2	962,980	957,819	5,162
MPP_1	231,327	235,905	-4,578
MPP_2	232,835	235,193	-2,358
MSTUART1	0	0	0
MSTUART2	963,033	948,783	14,250
MSTUART3	191,154	182,570	8,584
MURRAY	2,259,762	2,249,054	10,709
NPS	1,449,325	1,433,114	16,212
NPS1	331,981	331,981	0
NPS2	339,562	340,751	-1,189
OAKEY1	465,570	465,310	261
OAKEY2	142,056	142,330	-274
OSB-AG	452,788	452,568	220
PLAYB-AG	311,935	311,935	0
POAT110	195,554	195,713	-159
POAT220	295,837	295,837	0
POR01	962,737	938,397	24,340
PPCCGT	1,048,740	1,048,740	0
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	108,140	108,120	20
QPS2	113,831	113,810	21
QPS3	113,831	113,810	21
QPS4	113,831	113,810	21
QPS5	654,534	654,410	125
REDBANK1	68,324	68,324	0
REECE1	159,919	156,603	3,316
REECE2	49,079	47,904	1,176

Plant	Historical	Alternative	Difference
ROMA_7	119,044	119,044	0
ROMA_8	164,742	164,742	0
SHPUMP	0	0	0
SITHE01	476,075	476,075	0
SNOWTWN1	-267,960	-267,960	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	1,093,082	1,387,666	-294,584
STAN-1	293,974	293,974	0
STAN-2	337,534	337,526	8
STAN-3	304,862	304,862	0
STAN-4	337,526	337,526	0
SWAN_B_1	116,712	116,712	0
SWAN_B_2	116,712	116,712	0
SWAN_B_3	136,164	136,164	0
SWAN_B_4	116,712	116,712	0
SWAN_E	757,436	757,436	0
TALWA1	906,690	906,690	0
TARONG#1	187,315	185,195	2,121
TARONG#2	186,492	184,859	1,633
TARONG#3	174,720	173,584	1,137
TARONG#4	174,143	173,584	560
TARRALEA	109,449	100,507	8,942
TNPS1	307,568	307,595	-26
TORRA1	329,689	315,081	14,608
TORRA2	326,190	314,466	11,725
TORRA3	0	0	0
TORRA4	318,229	314,049	4,180
TORRB1	0	0	0
TORRB2	439,433	407,515	31,918
TORRB3	431,808	409,696	22,112
TORRB4	430,907	406,976	23,931
TREVALLN	126,775	126,775	0
TRIBUTE	121,658	120,134	1,524
TUMUT3	765,716	721,408	44,309
TUNGATIN	123,145	123,315	-170
TVCC201	0	0	0
TVPP104	0	0	0
UPPTUMUT	1,083,781	1,079,734	4,047
URANQ11	781,913	776,443	5,470
URANQ12	781,889	776,443	5,445
URANQ13	706,450	680,086	26,365
URANQ14	733,748	706,564	27,184
VP5	634,790	633,243	1,547
VP6	609,763	608,278	1,485
VPGS	1,397,695	1,397,695	0
W/HOE#1	315,728	315,115	613
W/HOE#2	0	0	0
WKIEWA1	97,875	94,099	3,776
WKIEWA2	95,160	88,437	6,724
WW7	415,651	411,603	4,048
WW8	0	0	0
YABULU	436,935	436,935	0

Plant	Historical	Alternative	Difference
YABULU2	228,208	228,208	0
YWPS1	65,274	65,275	-1
YWPS2	57,564	57,564	0
YWPS3	65,381	65,382	-1
YWPS4	68,600	68,600	0
Total	54,205,049	53,851,404	353,644

Figure 60 Dispatch Cost Changes



Appendix H Day 08: 18/01/10

H.1 Introduction

This appendix provides the detailed results for Monday, 18 January 2010, Day 08. The offers for this day were modified as follows.

Table 26 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[9]	To[1]	With[1]
Day 08	18/01/10	6:30	23:30	Swanbank B	QLD	6:30	23:00	23:00
				Swanbank E	QLD	12:00	17:00	12:00
				Callide B	QLD	11:30	17:00	11:30
				Callide C	QLD	6:30	23:30	6:30
				Tarong	QLD	12:00	22:00	12:00
				Tarong North	QLD	12:00	17:00	12:00

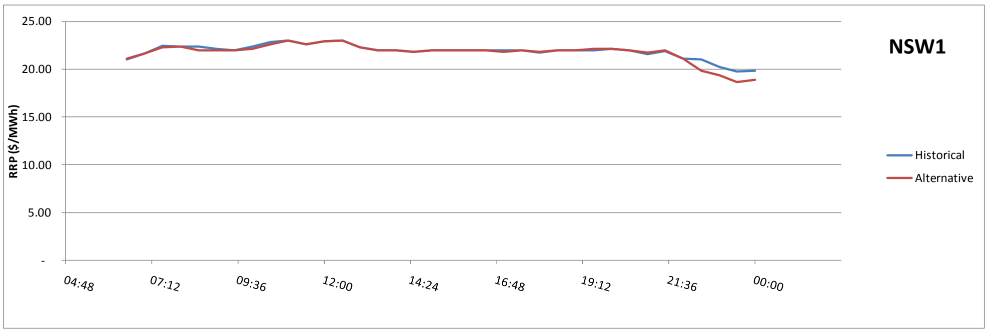
H.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $4,830,000 or 5.7% reduction. Reduced Mt Stuart costs were the most substantial changes.

H.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 61 New South Wales Spot Prices for Historical and Alternative Dispatch 18/1/2010



[9] Period ending trading interval

Figure 62 Queensland Spot Prices for Historical and Alternative Dispatch 18/1/2010

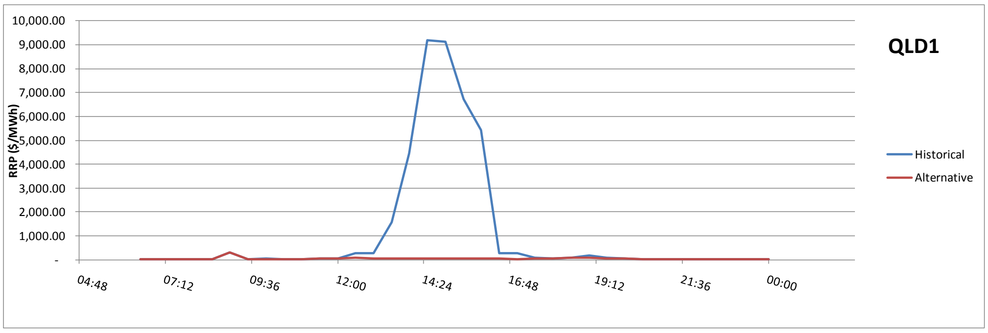


Figure 63 South Australian Spot Prices for Historical and Alternative Dispatch 18/1/2010

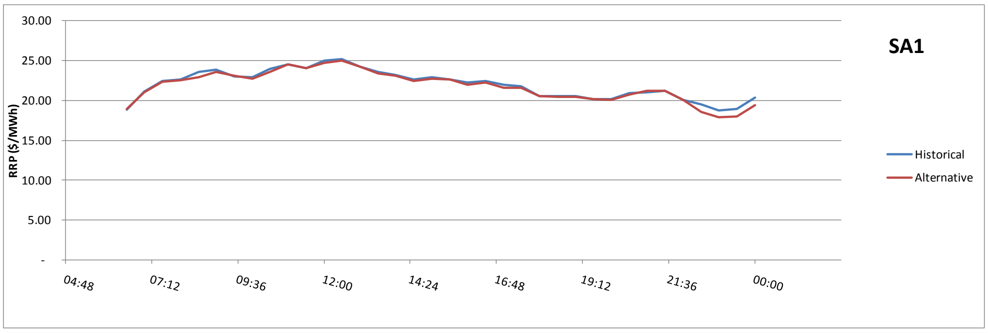


Figure 64 Tasmanian Spot Prices for Historical and Alternative Dispatch 18/1/2010

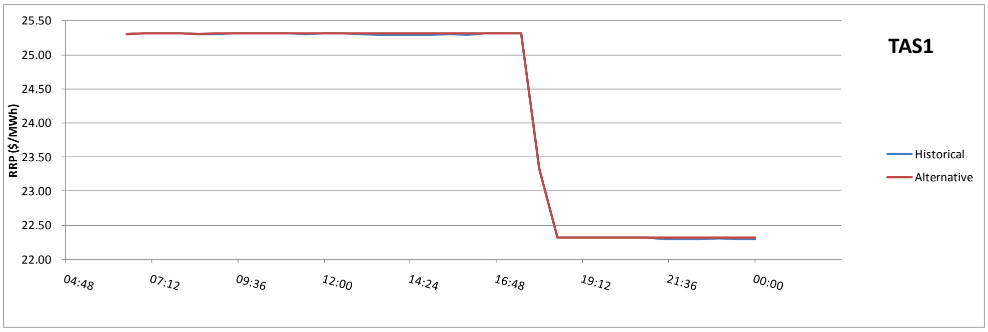
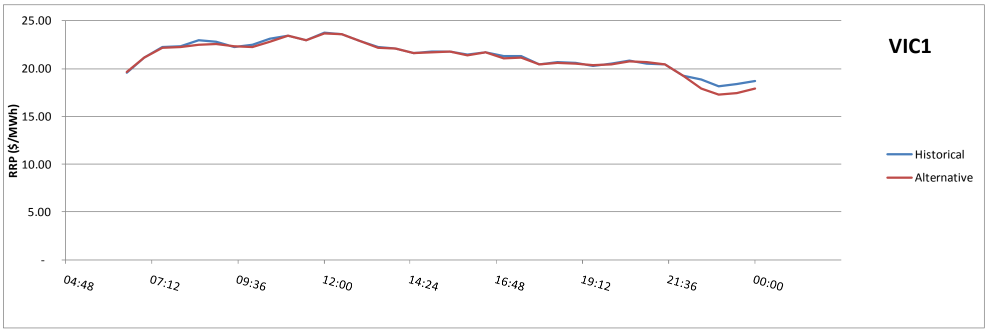


Figure 65 Victorian Spot Prices for Historical and Alternative Dispatch 18/1/2010



H.4 Dispatch Cost Impacts

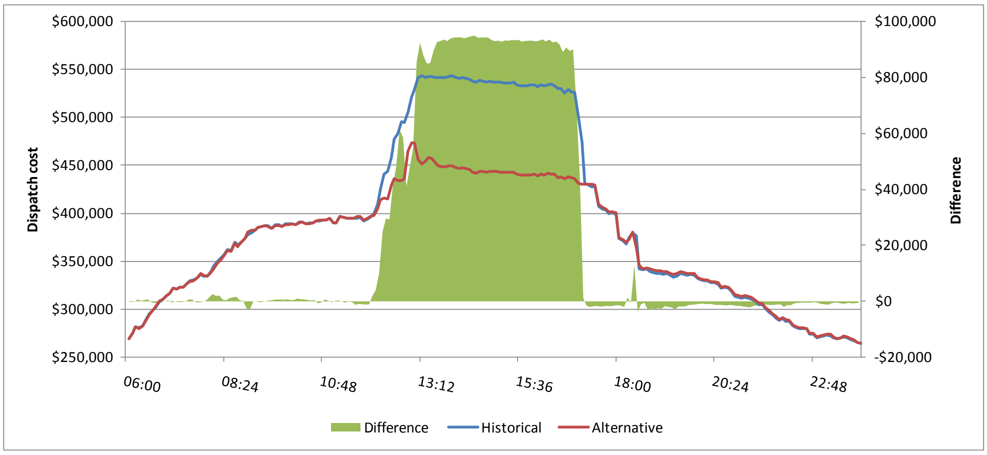
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 27 Historical and Alternative Dispatch Costs for 18/1/2010

	Historical	Alternative	Difference
Total generation cost ($)	84,629,726	79,799,933	4,829,793

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 66 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 18/1/2010



H.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 28 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 18/1/2010

Plant	Historical	Alternative	Difference
AGLHAL	0	0	0
AGLSOM	0	0	0
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	197,408	197,406	2
BARCALDN	81,870	84,864	-2,994
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	0	0	0
BDL02	0	0	0
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	40,200	40,200	0
BRAEMAR1	865,213	875,483	-10,270
BRAEMAR2	1,262,213	1,262,213	0
BRAEMAR3	637,394	647,726	-10,332
BRAEMAR5	849,450	843,965	5,486
BRAEMAR6	844,310	843,940	370
BRAEMAR7	859,710	854,603	5,107
BW01	1,402,696	1,386,151	16,544
BW02	1,400,751	1,386,030	14,721
BW03	1,409,380	1,393,507	15,873
BW04	1,367,490	1,347,319	20,171
CALL_B_1	648,913	695,108	-46,194
CALL_B_2	754,265	814,763	-60,498
CETHANA	0	0	0
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	-157,030	-157,029	0
COLNSV_1	74,248	74,498	-250
COLNSV_2	74,222	74,498	-276
COLNSV_3	0	0	0
COLNSV_4	74,245	74,502	-257
COLNSV_5	148,449	149,002	-553
CPP_3	998,394	1,133,603	-135,210
CPP_4	1,102,438	1,126,146	-23,708
CPSA	93,486	94,105	-619

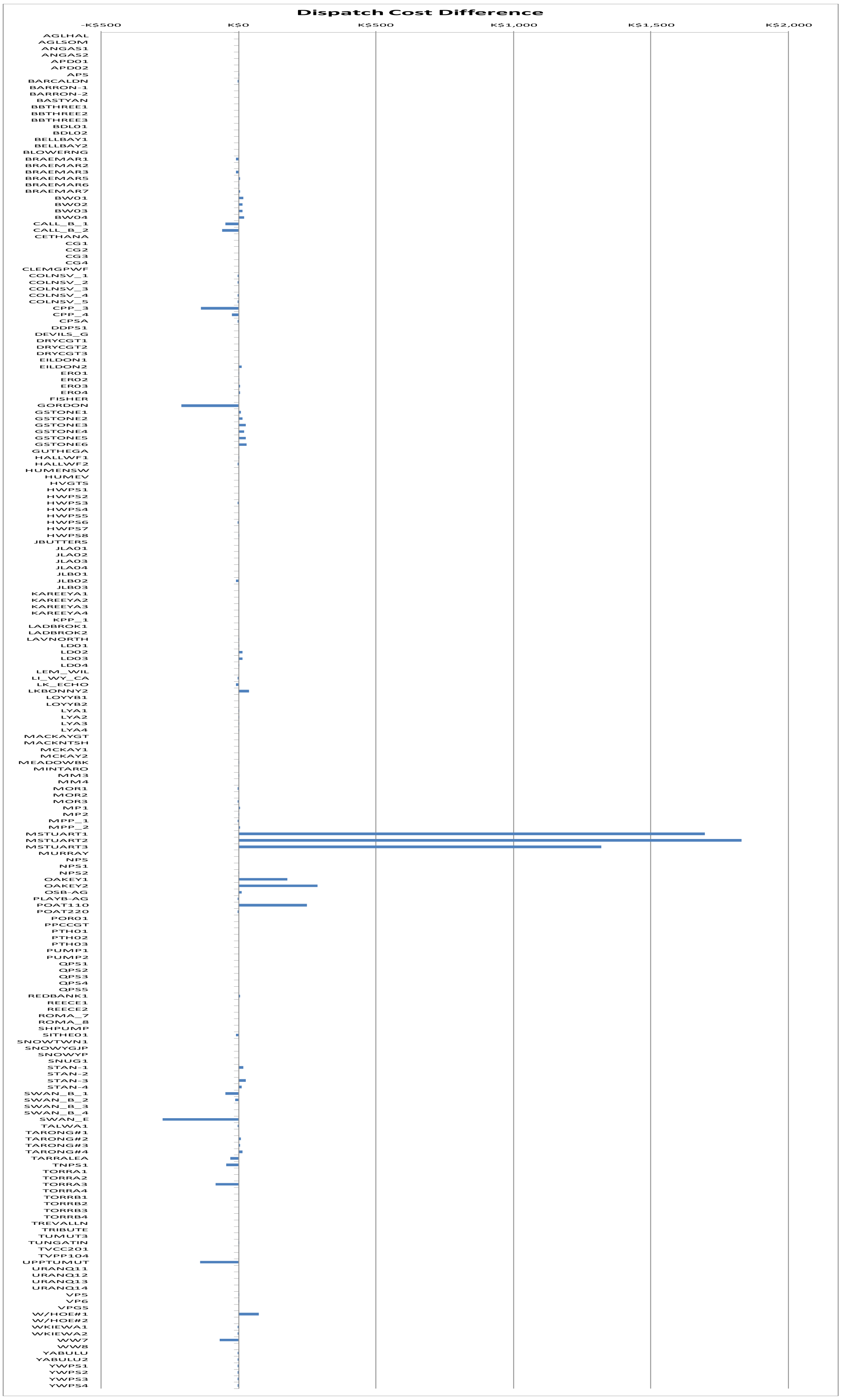
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	0	0	0
DRYCGT1	0	0	0
DRYCGT2	0	0	0
DRYCGT3	0	0	0
EILDON1	0	0	0
EILDON2	125,312	113,479	11,833
ER01	2,030,502	2,026,466	4,036
ER02	2,030,789	2,026,466	4,322
ER03	2,031,618	2,026,466	5,151
ER04	2,031,203	2,026,466	4,737
FISHER	0	0	0
GORDON	104,355	312,500	-208,145
GSTONE1	728,098	720,080	8,017
GSTONE2	724,513	709,758	14,755
GSTONE3	744,954	718,622	26,331
GSTONE4	739,266	718,853	20,413
GSTONE5	727,471	699,436	28,035
GSTONE6	756,158	726,640	29,518
GUTHEGA	0	0	0
HALLWF1	-298,891	-298,952	62
HALLWF2	-235,842	-235,647	-195
HUMENSW	108,180	108,180	0
HUMEV	0	0	0
HVGTS	0	0	0
HWPS1	73,200	73,200	0
HWPS2	103,506	103,506	0
HWPS3	107,666	107,669	-2
HWPS4	95,002	95,002	0
HWPS5	94,658	94,658	0
HWPS6	85,423	85,444	-21
HWPS7	90,952	90,952	0
HWPS8	91,716	91,709	7
JBUTTERS	0	0	0
JLA01	0	0	0
JLA02	0	0	0
JLA03	0	0	0
JLA04	0	0	0
JLB01	0	0	0
JLB02	24,446	33,274	-8,828
JLB03	0	0	0
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	1,229,906	1,229,906	0
LADBROK1	0	0	0
LADBROK2	0	0	0
LAVNORTH	1,001,671	1,001,625	46
LD01	836,261	834,424	1,837
LD02	1,140,070	1,124,822	15,248
LD03	1,136,609	1,122,969	13,640
LD04	1,223,390	1,222,511	879

Plant	Historical	Alternative	Difference
LEM_WIL	74,130	74,130	0
LI_WY_CA	406,643	408,246	-1,603
LK_ECHO	115,833	123,441	-7,608
LKBONNY2	-468,784	-507,352	38,567
LOYYB1	646,758	646,758	0
LOYYB2	646,758	646,758	0
LYA1	254,226	254,128	98
LYA2	233,411	233,308	103
LYA3	251,374	251,336	38
LYA4	249,753	249,731	22
MACKAYGT	0	0	0
MACKNTSH	0	0	0
MCKAY1	0	0	0
MCKAY2	0	0	0
MEADOWBK	67,016	66,718	297
MINTARO	0	0	0
MM3	652,943	651,569	1,375
MM4	0	0	0
MOR1	150,753	150,962	-209
MOR2	0	0	0
MOR3	123,054	124,257	-1,203
MP1	2,552,028	2,546,211	5,817
MP2	2,525,569	2,524,525	1,044
MPP_1	666,482	668,704	-2,223
MPP_2	702,304	695,166	7,138
MSTUART1	2,822,244	1,124,703	1,697,541
MSTUART2	2,905,564	1,076,272	1,829,292
MSTUART3	2,425,828	1,105,789	1,320,040
MURRAY	0	0	0
NPS	0	0	0
NPS1	919,243	919,243	0
NPS2	883,275	880,166	3,108
OAKEY1	548,940	370,606	178,335
OAKEY2	676,873	390,313	286,560
OSB-AG	1,147,490	1,135,831	11,659
PLAYB-AG	338,998	342,494	-3,496
POAT110	471,904	222,828	249,076
POAT220	587,434	587,881	-446
POR01	0	0	0
PPCCGT	2,254,435	2,254,435	0
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	0	0	0
QPS2	0	0	0
QPS3	347,064	347,064	0
QPS4	0	0	0
QPS5	0	0	0
REDBANK1	380,099	374,993	5,106
REECE1	0	0	0
REECE2	0	0	0

Plant	Historical	Alternative	Difference
ROMA_7	265,047	265,047	0
ROMA_8	460,433	460,433	0
SHPUMP	0	0	0
SITHE01	1,223,802	1,231,970	-8,168
SNOWTWN1	-288,360	-288,360	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	0	0	0
STAN-1	920,630	902,280	18,350
STAN-2	0	0	0
STAN-3	999,228	972,444	26,784
STAN-4	973,940	961,587	12,353
SWAN_B_1	282,921	330,030	-47,109
SWAN_B_2	326,186	337,541	-11,355
SWAN_B_3	0	0	0
SWAN_B_4	0	0	0
SWAN_E	1,796,076	2,071,586	-275,510
TALWA1	2,214,828	2,215,872	-1,044
TARONG#1	204,575	204,575	0
TARONG#2	642,553	634,025	8,528
TARONG#3	635,260	628,372	6,888
TARONG#4	635,010	621,060	13,949
TARRALEA	308,401	338,448	-30,047
TNPS1	925,822	969,721	-43,899
TORRA1	564,097	564,097	0
TORRA2	0	0	0
TORRA3	173,618	256,944	-83,326
TORRA4	0	0	0
TORRB1	0	0	0
TORRB2	624,992	624,992	0
TORRB3	0	0	0
TORRB4	0	0	0
TREVALLN	211,084	211,084	0
TRIBUTE	0	0	0
TUMUT3	0	0	0
TUNGATIN	197,272	197,261	11
TVCC201	1,111,147	1,111,147	0
TVPP104	0	0	0
UPPTUMUT	258,548	397,288	-138,740
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	0	0	0
URANQ14	0	0	0
VP5	1,938,267	1,936,813	1,454
VP6	1,841,341	1,837,076	4,265
VPGS	0	0	0
W/HOE#1	360,285	284,918	75,368
W/HOE#2	0	0	0
WKIEWA1	59,286	63,080	-3,794
WKIEWA2	46,142	49,937	-3,796
WW7	927,245	995,191	-67,946
WW8	0	0	0
YABULU	1,138,341	1,138,552	-211

Plant	Historical	Alternative	Difference
YABULU2	616,656	616,807	-151
YWPS1	187,055	187,078	-22
YWPS2	184,842	184,970	-128
YWPS3	193,868	193,993	-125
YWPS4	197,772	197,776	-4
Total	84,629,726	79,799,933	4,829,793

Figure 67 Dispatch Cost Changes



Appendix I Day 09: 22/01/10

I.1 Introduction

This appendix provides the detailed results for Friday, 22 January 2010, Day 09. The offers for this day were modified as follows.

Table 29 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[10]	To[1]	With[1]
Day 09	22/01/10	0:30	0:00	Eraring	NSW	0:30	0:00	7:00
				Mt Piper	NSW	7:30	19:00	7:30
				Vales Pt	NSW	9:30	23:30	19:00
				Wallerawang	NSW	4:00	0:00	4:00
				Swanbank B	QLD	6:00	22:30	6:00

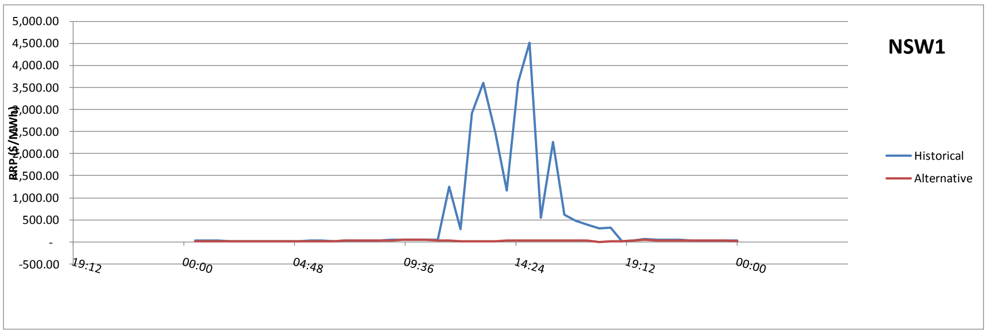
I.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $1,086,000 or 0.9% reduction. Increased Eraring costs and reduced Bayswater, Liddell, Mt Piper, Murray and NPS costs were the most substantial changes.

I.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 68 New South Wales Spot Prices for Historical and Alternative Dispatch 22/1/2010



[10] Period ending trading interval

Figure 69 Queensland Spot Prices for Historical and Alternative Dispatch 22/1/2010

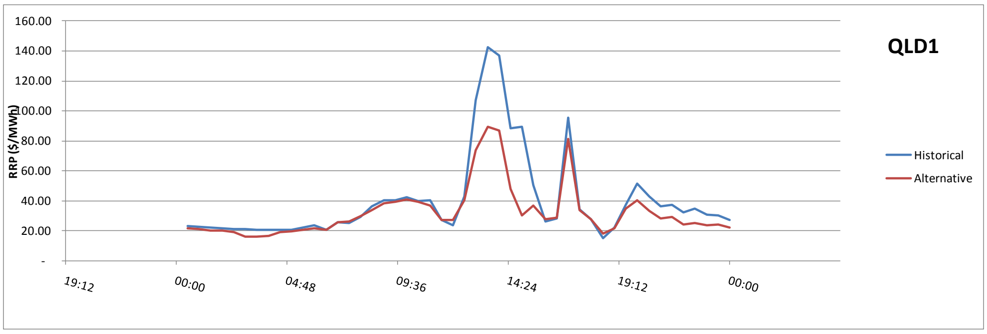


Figure 70 South Australian Spot Prices for Historical and Alternative Dispatch 22/1/2010

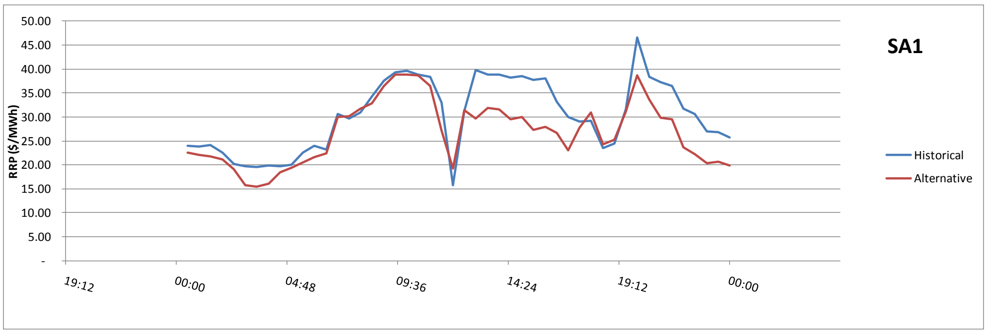


Figure 71 Tasmanian Spot Prices for Historical and Alternative Dispatch 22/1/2010

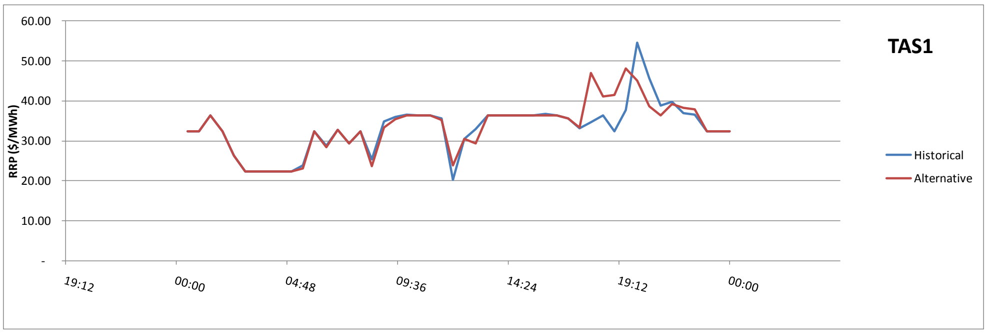
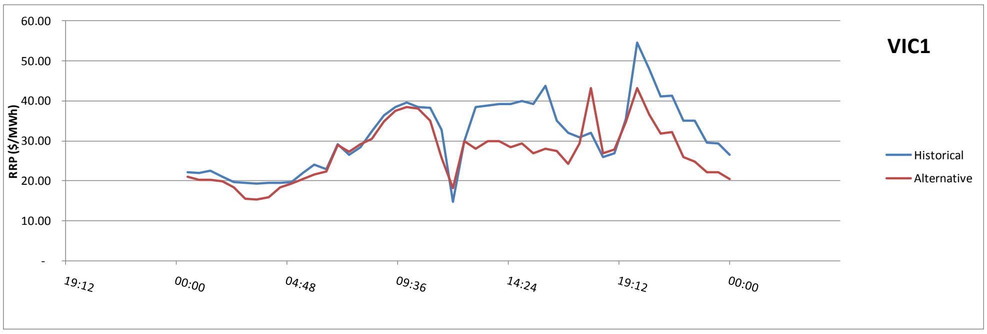


Figure 72 Victorian Spot Prices for Historical and Alternative Dispatch 22/1/2010



I.4 Dispatch Cost Impacts

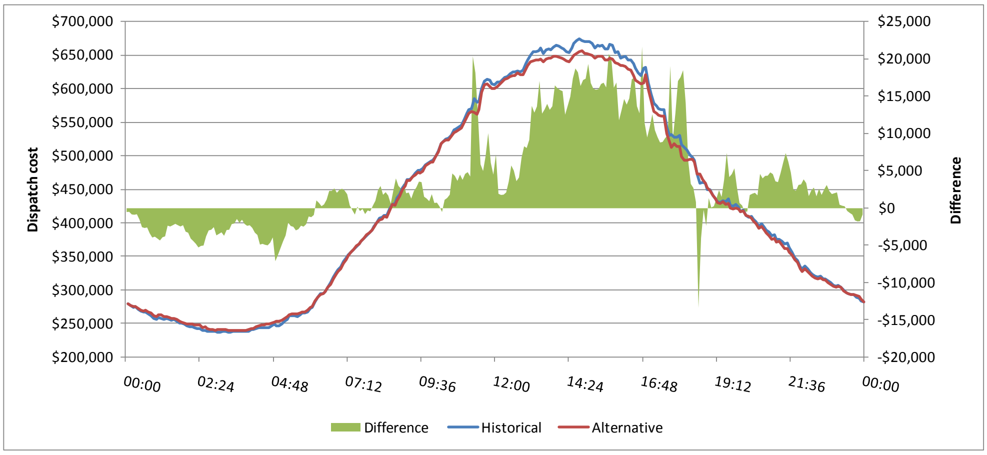
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 30 Historical and Alternative Dispatch Costs for 22/1/2010

	Historical	Alternative	Difference
Total generation cost ($)	123,254,011	122,168,217	1,085,794

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 73 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 22/1/2010



I.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 31 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 22/1/2010

Plant	Historical	Alternative	Difference
AGLHAL	424	424	0
AGLSOM	1,467,281	1,468,356	-1,076
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	259,569	259,527	42
BARCALDN	82,561	77,843	4,718
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	405,281	405,281	0
BDL01	138,930	138,866	64
BDL02	29,464	29,449	15
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	47,690	47,590	100
BRAEMAR1	685,700	710,285	-24,586
BRAEMAR2	982,390	991,028	-8,638
BRAEMAR3	572,788	591,849	-19,061
BRAEMAR5	840,243	838,126	2,117
BRAEMAR6	611,072	609,724	1,348
BRAEMAR7	763,972	763,114	859
BW01	2,152,018	2,042,742	109,276
BW02	2,141,080	2,036,944	104,136
BW03	2,120,490	2,023,869	96,621
BW04	2,075,083	1,986,517	88,567
CALL_B_1	865,033	851,206	13,827
CALL_B_2	1,009,298	993,087	16,211
CETHANA	212,695	217,782	-5,087
CG1	0	0	0
CG2	1,288,933	1,197,128	91,805
CG3	1,369,200	1,377,941	-8,742
CG4	848,679	846,934	1,745
CLEMGPWF	-500,178	-500,053	-125
COLNSV_1	98,571	98,571	0
COLNSV_2	98,571	98,571	0
COLNSV_3	97,101	94,121	2,980
COLNSV_4	98,571	98,571	0
COLNSV_5	1,580	4,107	-2,527
CPP_3	1,361,741	1,357,883	3,858
CPP_4	1,454,707	1,450,861	3,846
CPSA	165,330	165,364	-35

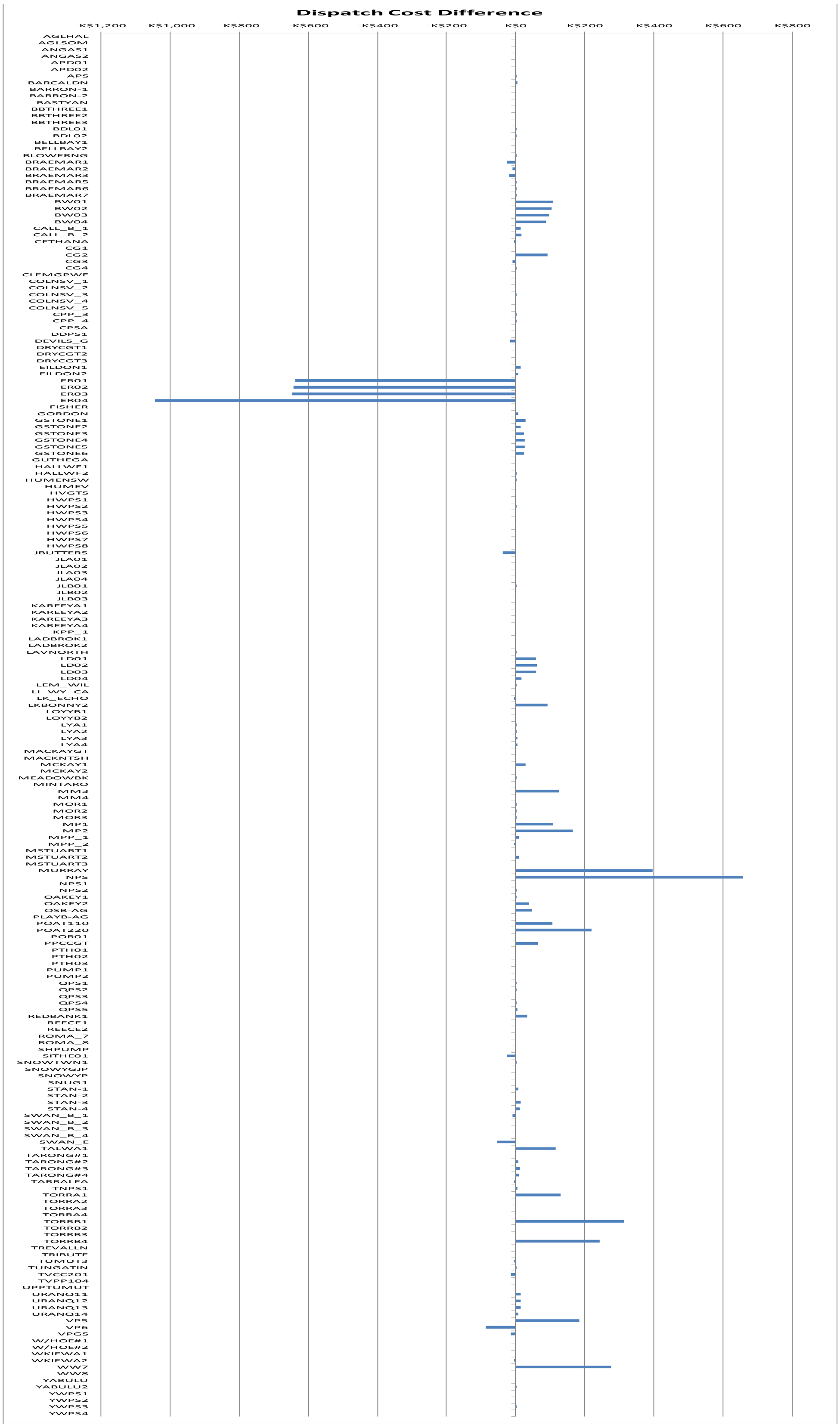
Plant	Historical	Alternative	Difference
DDPS1	0	0	0
DEVILS_G	128,385	145,159	-16,775
DRYCGT1	0	0	0
DRYCGT2	0	0	0
DRYCGT3	0	0	0
EILDON1	195,628	182,272	13,356
EILDON2	125,705	118,941	6,764
ER01	2,087,501	2,725,106	-637,605
ER02	2,083,990	2,727,007	-643,018
ER03	2,082,629	2,729,710	-647,082
ER04	2,279,100	3,322,672	-1,043,573
FISHER	59,130	59,130	0
GORDON	690,524	682,867	7,657
GSTONE1	985,758	958,208	27,549
GSTONE2	874,784	860,887	13,898
GSTONE3	896,973	872,053	24,920
GSTONE4	895,230	868,033	27,197
GSTONE5	908,316	882,927	25,389
GSTONE6	907,946	882,901	25,045
GUTHEGA	58,311	58,757	-446
HALLWF1	-949,743	-949,512	-231
HALLWF2	-723,189	-723,286	97
HUMENSW	128,580	128,100	480
HUMEV	0	0	0
HVGTS	0	0	0
HWPS1	99,145	99,145	0
HWPS2	85,105	84,988	117
HWPS3	145,218	145,322	-104
HWPS4	137,279	137,341	-62
HWPS5	129,090	129,290	-200
HWPS6	134,431	134,431	0
HWPS7	131,291	131,516	-225
HWPS8	0	0	0
JBUTTERS	258,355	294,587	-36,232
JLA01	0	0	0
JLA02	0	0	0
JLA03	0	0	0
JLA04	0	0	0
JLB01	97,137	97,107	31
JLB02	0	0	0
JLB03	97,107	97,107	0
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	1,577,266	1,578,543	-1,276
LADBROK1	250,560	250,560	0
LADBROK2	250,560	250,560	0
LAVNORTH	2,453,309	2,452,988	322
LD01	1,755,701	1,695,673	60,028
LD02	1,689,233	1,628,299	60,934
LD03	1,781,483	1,723,108	58,374
LD04	1,510,810	1,494,118	16,692

Plant	Historical	Alternative	Difference
LEM_WIL	118,960	118,852	109
LI_WY_CA	553,239	553,239	0
LK_ECHO	152,663	156,322	-3,658
LKBONNY2	-614,318	-707,039	92,721
LOYYB1	859,587	861,029	-1,442
LOYYB2	859,626	860,890	-1,263
LYA1	329,052	326,263	2,790
LYA2	304,407	303,652	756
LYA3	336,158	331,131	5,027
LYA4	331,537	326,565	4,972
MACKAYGT	0	0	0
MACKNTSH	0	0	0
MCKAY1	36,870	8,092	28,778
MCKAY2	0	0	0
MEADOWBK	92,298	91,703	595
MINTARO	0	0	0
MM3	1,277,741	1,153,218	124,523
MM4	0	0	0
MOR1	122,737	122,159	577
MOR2	70,738	68,423	2,315
MOR3	157,359	156,790	568
MP1	3,293,772	3,184,712	109,060
MP2	3,313,409	3,148,528	164,881
MPP_1	996,487	987,875	8,611
MPP_2	986,833	991,732	-4,900
MSTUART1	0	0	0
MSTUART2	630,148	619,241	10,907
MSTUART3	0	0	0
MURRAY	2,104,226	1,708,729	395,497
NPS	2,684,225	2,027,058	657,167
NPS1	1,150,805	1,151,620	-815
NPS2	1,174,327	1,170,961	3,366
OAKEY1	576,004	575,889	115
OAKEY2	182,221	143,594	38,628
OSB-AG	1,316,288	1,269,411	46,877
PLAYB-AG	893,616	895,125	-1,510
POAT110	627,433	520,345	107,088
POAT220	1,027,895	807,782	220,113
POR01	0	0	0
PPCCGT	3,501,574	3,437,717	63,857
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	169,486	169,406	80
QPS2	175,066	174,664	402
QPS3	432,735	432,735	0
QPS4	187,065	186,934	131
QPS5	639,257	635,157	4,100
REDBANK1	490,180	457,245	32,936
REECE1	94,406	95,174	-768
REECE2	112,387	112,799	-412

Plant	Historical	Alternative	Difference
ROMA_7	589,910	589,910	0
ROMA_8	612,503	612,503	0
SHPUMP	0	0	0
SITHE01	1,414,727	1,441,250	-26,524
SNOWTWN1	-881,680	-881,800	120
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	0	0	0
STAN-1	1,218,382	1,211,214	7,168
STAN-2	0	0	0
STAN-3	1,277,747	1,264,398	13,350
STAN-4	1,218,746	1,206,822	11,924
SWAN_B_1	373,659	382,970	-9,311
SWAN_B_2	0	0	0
SWAN_B_3	0	0	0
SWAN_B_4	0	0	0
SWAN_E	2,270,183	2,324,017	-53,834
TALWA1	2,734,590	2,619,142	115,448
TARONG#1	485,934	486,760	-826
TARONG#2	925,092	916,682	8,410
TARONG#3	855,716	844,330	11,387
TARONG#4	860,124	849,908	10,216
TARRALEA	461,989	466,109	-4,120
TNPS1	1,061,466	1,055,615	5,851
TORRA1	884,302	755,118	129,184
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	0	0	0
TORRB1	1,168,054	853,333	314,720
TORRB2	0	0	0
TORRB3	0	0	0
TORRB4	992,681	750,327	242,355
TREVALLN	238,642	238,642	0
TRIBUTE	155,369	157,174	-1,805
TUMUT3	3,331,736	3,335,168	-3,432
TUNGATIN	235,537	234,468	1,069
TVCC201	600,605	615,040	-14,435
TVPP104	803,933	804,304	-371
UPPTUMUT	2,064,760	2,067,436	-2,676
URANQ11	1,064,187	1,048,742	15,445
URANQ12	1,032,385	1,016,908	15,477
URANQ13	950,312	936,934	13,378
URANQ14	989,047	981,967	7,080
VP5	2,839,035	2,654,885	184,150
VP6	1,739,140	1,826,107	-86,968
VPGS	1,875,831	1,888,694	-12,862
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	99,939	101,796	-1,857
WKIEWA2	45,911	49,937	-4,026
WW7	1,656,246	1,380,960	275,285
WW8	0	0	0
YABULU	1,351,802	1,352,022	-219

Plant	Historical	Alternative	Difference
YABULU2	761,004	760,943	60
YWPS1	243,418	243,444	-26
YWPS2	247,429	247,485	-56
YWPS3	250,279	250,244	35
YWPS4	260,333	260,364	-31
Total	123,254,011	122,168,217	1,085,794

Figure 74 Dispatch Cost Changes



Appendix J Day 10: 9/02/10

J.1 Introduction

This appendix provides the detailed results for Tuesday, 9 February 2010, Day 10. The offers for this day were modified as follows.

Table 32 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[11]	To[1]	With[1]
Day 10	9/02/10	10:00	18:30	Torrens Island A	SA	12:00	18:30	12:00
				Torrens Island B	SA	12:00	18:30	12:00
				Loy Yang A	VIC	10:00	17:00	17:00
				Loy Yang B	VIC	13:30	17:30	13:30

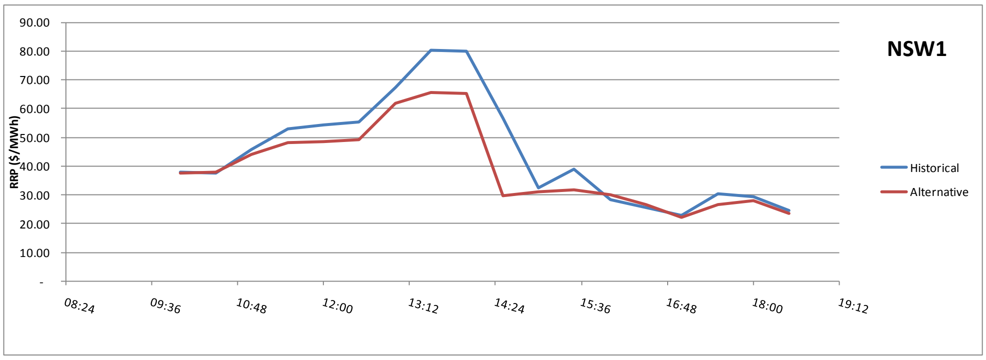
J.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $1,377,000 which equates to approximately a 2% reduction in dispatch costs. Increased Torrens Island and reduced Port Lincoln (POR01) costs were the most substantial changes.

J.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 75 New South Wales Spot Prices for Historical and Alternative Dispatch 9/2/2010



[11] Period ending trading interval

Figure 76 Queensland Spot Prices for Historical and Alternative Dispatch 9/2/2010

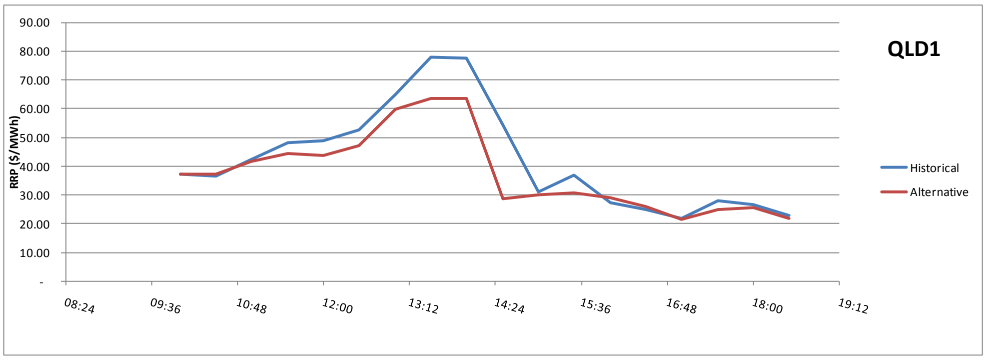


Figure 77 South Australian Spot Prices for Historical and Alternative Dispatch 9/2/2010

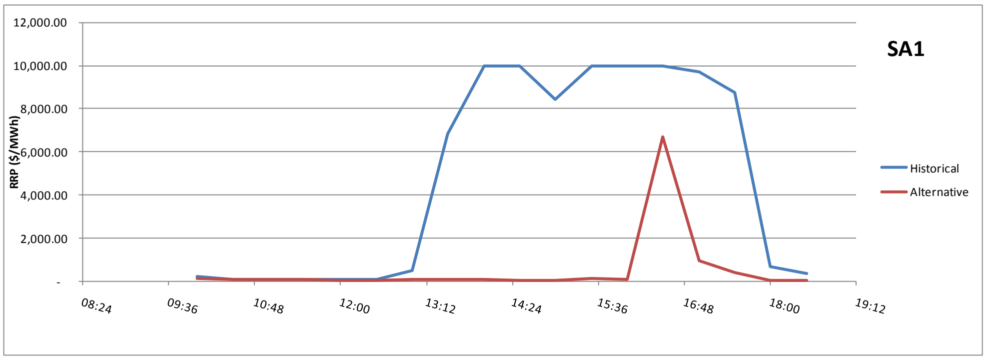


Figure 78 Tasmanian Spot Prices for Historical and Alternative Dispatch 9/2/2010

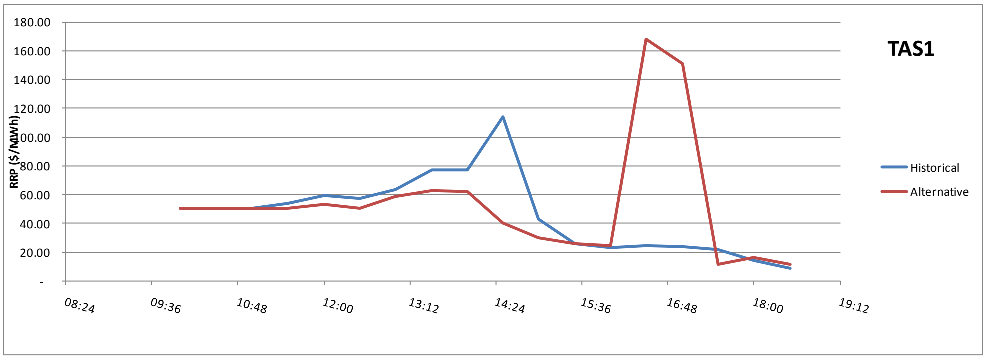
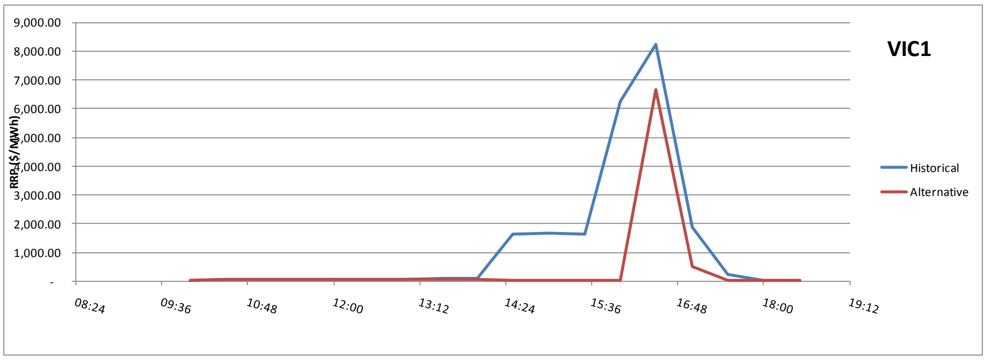


Figure 79 Victorian Spot Prices for Historical and Alternative Dispatch 9/2/2010



J.4 Dispatch Cost Impacts

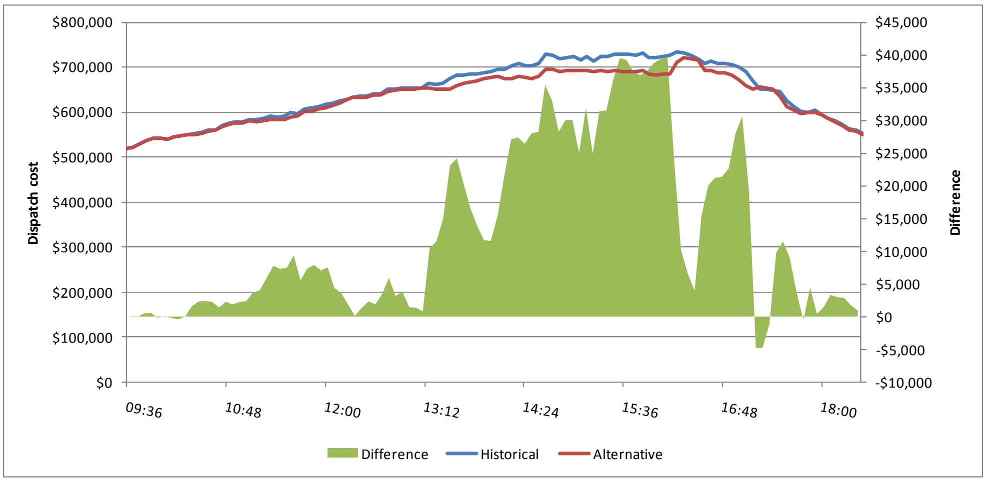
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 33 Historical and Alternative Dispatch Costs for 9/2/2010

	Historical	Alternative	Difference
Total generation cost ($)	69,624,376	68,247,405	1,376,971

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 80 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 9/2/2010



J.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 34 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 9/2/2010

Plant	Historical	Alternative	Difference
AGLHAL	1,793,762	1,793,480	282
AGLSOM	897,927	897,990	-63
ANGAS1	134,257	49,725	84,532
ANGAS2	89,501	33,150	56,351
APD01	0	0	0
APD02	0	0	0
APS	94,890	94,868	23
BARCALDN	0	0	0
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	176,985	176,958	27
BDL02	34,079	34,060	19
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	5,400	5,400	0
BRAEMAR1	624,890	624,890	0
BRAEMAR2	539,246	544,332	-5,085
BRAEMAR3	595,672	595,735	-62
BRAEMAR5	665,370	665,370	0
BRAEMAR6	665,370	665,370	0
BRAEMAR7	0	0	0
BW01	939,284	936,911	2,373
BW02	939,205	936,911	2,294
BW03	939,265	936,911	2,354
BW04	939,101	936,677	2,425
CALL_B_1	321,463	319,209	2,253
CALL_B_2	382,294	379,475	2,819
CETHANA	152,557	152,015	542
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	-15,194	-15,193	0
COLNSV_1	0	0	0
COLNSV_2	0	0	0
COLNSV_3	41,896	41,756	140
COLNSV_4	41,151	41,387	-236
COLNSV_5	76,342	76,823	-481
CPP_3	562,199	562,199	0
CPP_4	554,619	555,510	-891
CPSA	0	0	0

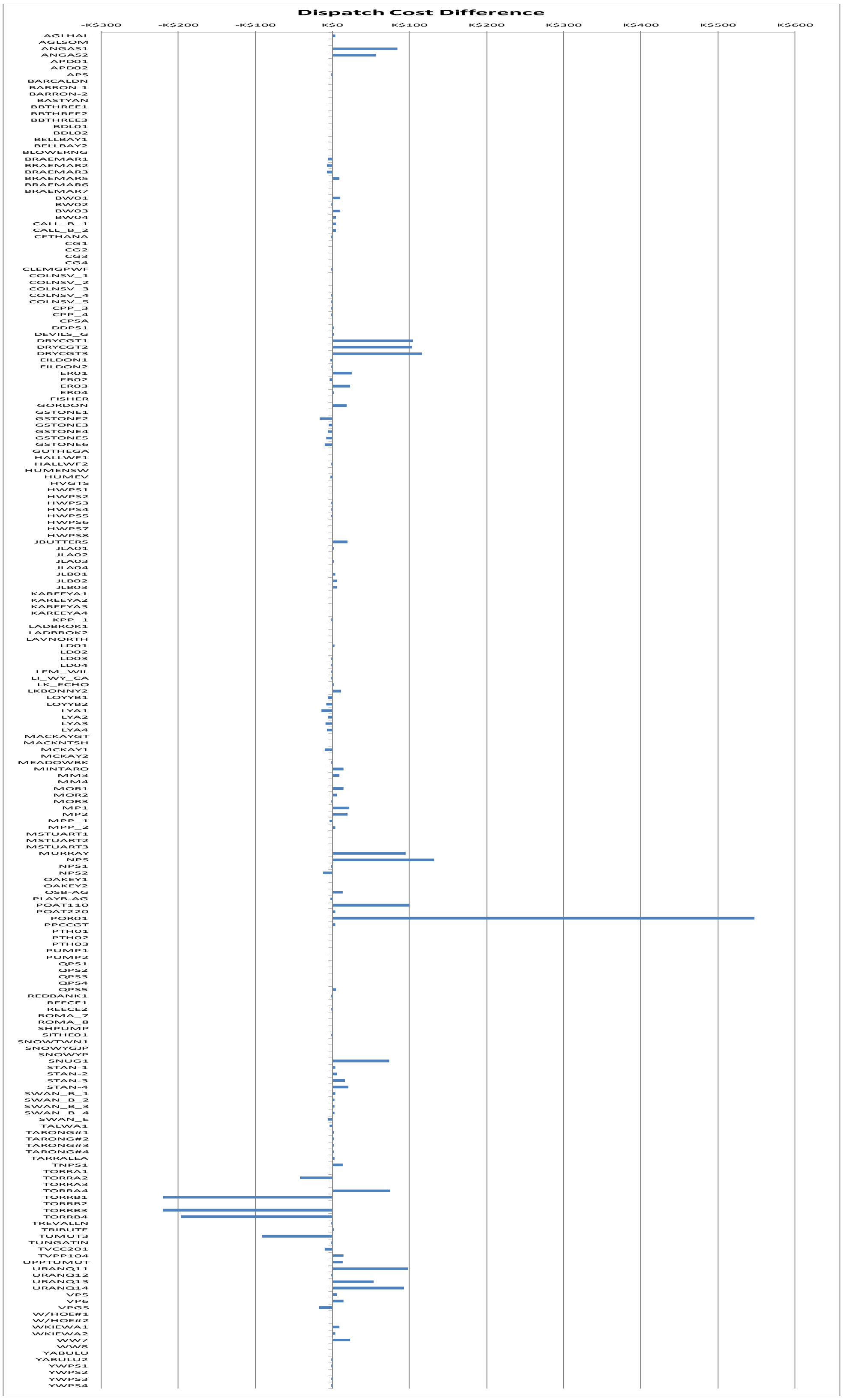
Plant	Historical	Alternative	Difference
DDPS1	438,944	436,807	2,137
DEVILS_G	135,815	133,383	2,433
DRYCGT1	242,564	134,499	108,064
DRYCGT2	232,654	126,859	105,795
DRYCGT3	270,812	147,495	123,317
EILDON1	127,904	128,732	-828
EILDON2	109,332	110,040	-708
ER01	1,125,060	1,093,782	31,279
ER02	1,132,093	1,130,649	1,444
ER03	1,124,922	1,095,856	29,066
ER04	1,208,264	1,204,603	3,661
FISHER	67,540	67,540	-1
GORDON	843,059	825,932	17,127
GSTONE1	0	0	0
GSTONE2	389,067	388,582	485
GSTONE3	397,949	395,972	1,977
GSTONE4	380,406	379,295	1,111
GSTONE5	381,647	379,899	1,747
GSTONE6	381,577	379,899	1,678
GUTHEGA	0	0	0
HALLWF1	-35,180	-35,340	160
HALLWF2	-33,346	-33,102	-244
HUMENSW	0	0	0
HUMEV	40,158	42,770	-2,612
HVGTS	0	0	0
HWPS1	38,419	38,419	0
HWPS2	54,495	54,495	0
HWPS3	51,296	51,319	-23
HWPS4	18,144	19,060	-916
HWPS5	44,227	44,503	-275
HWPS6	48,804	48,801	3
HWPS7	43,644	43,732	-88
HWPS8	44,737	44,661	76
JBUTTERS	255,412	236,273	19,140
JLA01	52,085	50,726	1,358
JLA02	40,812	40,812	0
JLA03	52,628	51,270	1,358
JLA04	101,792	101,792	0
JLB01	291,968	285,682	6,286
JLB02	93,383	97,424	-4,041
JLB03	300,817	299,826	990
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	598,392	598,392	0
LADBROK1	235,927	235,927	0
LADBROK2	235,927	235,927	0
LAVNORTH	1,831,660	1,831,660	0
LD01	442,580	440,974	1,606
LD02	397,386	397,135	251
LD03	437,724	440,974	-3,250
LD04	440,977	440,478	499

Plant	Historical	Alternative	Difference
LEM_WIL	129,495	129,624	-130
LI_WY_CA	288,475	288,791	-316
LK_ECHO	53,710	47,193	6,518
LKBONNY2	-40,142	-45,598	5,457
LOYYB1	316,076	321,867	-5,791
LOYYB2	313,568	321,081	-7,512
LYA1	106,350	121,889	-15,539
LYA2	108,324	114,187	-5,864
LYA3	115,145	123,829	-8,684
LYA4	114,595	121,562	-6,967
MACKAYGT	0	0	0
MACKNTSH	0	0	0
MCKAY1	427,761	437,629	-9,868
MCKAY2	0	0	0
MEADOWBK	67,061	67,244	-183
MINTARO	571,071	557,146	13,925
MM3	552,896	547,546	5,350
MM4	0	0	0
MOR1	50,115	49,489	626
MOR2	27,389	27,121	267
MOR3	61,699	61,351	348
MP1	1,332,819	1,328,370	4,450
MP2	1,334,211	1,329,380	4,831
MPP_1	357,356	359,698	-2,342
MPP_2	364,749	361,002	3,747
MSTUART1	0	0	0
MSTUART2	0	0	0
MSTUART3	0	0	0
MURRAY	2,689,551	2,611,011	78,540
NPS	1,994,755	1,857,422	137,334
NPS1	465,189	465,288	-99
NPS2	469,913	468,339	1,574
OAKEY1	0	0	0
OAKEY2	250,893	250,720	174
OSB-AG	728,108	724,301	3,807
PLAYB-AG	429,588	429,588	0
POAT110	270,741	190,181	80,560
POAT220	408,421	401,369	7,052
POR01	1,118,409	548,683	569,726
PPCCGT	1,466,675	1,464,364	2,312
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	157,574	157,574	0
QPS2	157,756	157,756	0
QPS3	157,756	157,756	0
QPS4	157,574	157,574	0
QPS5	884,699	885,084	-385
REDBANK1	195,499	195,962	-463
REECE1	206,299	203,259	3,040
REECE2	99,193	101,000	-1,807

Plant	Historical	Alternative	Difference
ROMA_7	43,662	43,662	0
ROMA_8	37,595	37,595	0
SHPUMP	0	0	0
SITHE01	659,181	659,181	0
SNOWTWN1	-52,840	-52,840	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	1,352,024	1,279,620	72,403
STAN-1	357,988	356,949	1,039
STAN-2	388,004	384,695	3,309
STAN-3	495,305	482,280	13,025
STAN-4	496,163	481,689	14,475
SWAN_B_1	202,036	198,102	3,934
SWAN_B_2	195,187	192,332	2,856
SWAN_B_3	170,832	168,500	2,332
SWAN_B_4	199,912	196,487	3,425
SWAN_E	836,803	836,941	-138
TALWA1	1,269,586	1,269,173	414
TARONG#1	272,127	271,966	161
TARONG#2	271,858	271,662	196
TARONG#3	267,984	268,248	-264
TARONG#4	267,458	267,143	315
TARRALEA	170,952	170,965	-13
TNPS1	463,871	463,871	0
TORRA1	0	0	0
TORRA2	321,653	230,783	90,871
TORRA3	0	0	0
TORRA4	416,056	425,563	-9,507
TORRB1	813,483	992,750	-179,267
TORRB2	0	0	0
TORRB3	815,299	996,321	-181,022
TORRB4	811,560	995,976	-184,416
TREVALLN	151,513	152,807	-1,294
TRIBUTE	150,892	143,527	7,364
TUMUT3	585,785	634,901	-49,116
TUNGATIN	154,713	155,264	-551
TVCC201	785,363	797,871	-12,508
TVPP104	23,431	8,587	14,844
UPPTUMUT	1,298,006	1,290,052	7,954
URANQ11	585,492	487,140	98,352
URANQ12	778,697	779,083	-386
URANQ13	657,908	604,849	53,059
URANQ14	278,132	185,182	92,950
VP5	1,128,595	1,124,379	4,216
VP6	1,128,321	1,124,762	3,559
VPGS	1,991,837	1,991,837	0
W/HOE#1	0	0	0
W/HOE#2	0	0	0
WKIEWA1	82,938	71,683	11,255
WKIEWA2	75,891	70,693	5,198
WW7	674,147	649,534	24,614
WW8	0	0	0
YABULU	597,280	597,280	0

Plant	Historical	Alternative	Difference
YABULU2	315,980	315,980	0
YWPS1	93,675	93,683	-9
YWPS2	93,683	93,647	36
YWPS3	88,274	88,238	36
YWPS4	92,757	92,852	-94
Total	69,624,376	68,247,405	1,376,971

Figure 81 Dispatch Cost Changes



Appendix K Day 11: 15/02/10

K.1 Introduction

This appendix provides the detailed results for Monday, 15 February 2010, Day 11. The offers for this day were modified as follows.

Table 35 Modified Offers

Scenario	Day	Start	End	Modified Offers				
				Station	Region	From[12]	To[1]	With[1]
Day 11	15/02/10	4:30	0:00	Swanbank B	QLD	6:00	22:30	6:00
				Swanbank E	QLD	12:00	0:00	12:00
				Tarong	QLD	4:30	19:00	19:00
				Tarong North	QLD	9:30	0:00	9:30
				Callide C	QLD	10:30	18:30	10:30
				Millmerran	QLD	10:00	21:00	10:00
				Gladstone	QLD	9:00	19:30	9:00

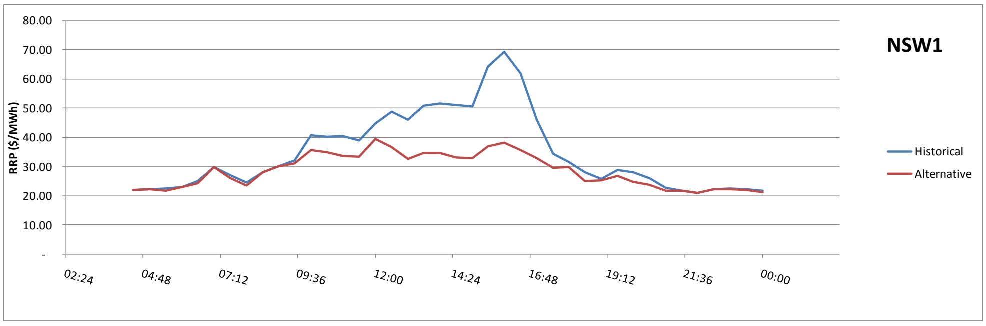
K.2 Overview and Discussion of Results

The alternative scenario resulted in significantly decreased dispatch costs of $1,858,000 or 1.8% reduction. Increased Swanbank and reduced Mt Stuart costs were the most substantial changes.

K.3 Spot Price Impacts

The revised offers for the selected generators resulted in very substantial reductions in spot prices for some regions. The historical and alternative spot prices are presented in the following figures for all of the NEM regions.

Figure 82 New South Wales Spot Prices for Historical and Alternative Dispatch 15/2/2010



[12] Period ending trading interval

Figure 83 Queensland Spot Prices for Historical and Alternative Dispatch 15/2/2010

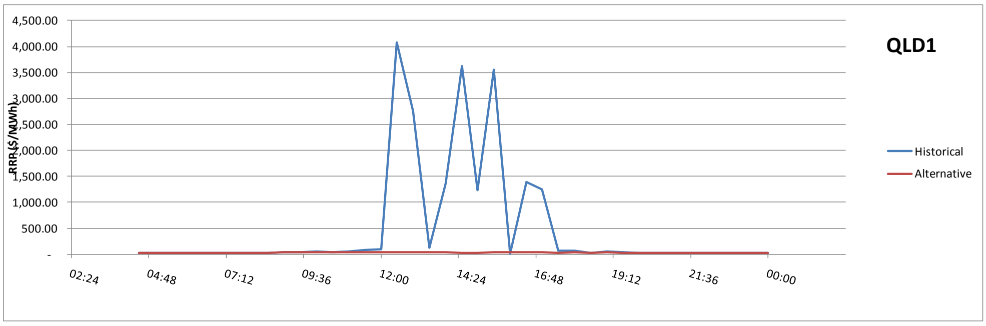


Figure 84 South Australian Spot Prices for Historical and Alternative Dispatch 15/2/2010

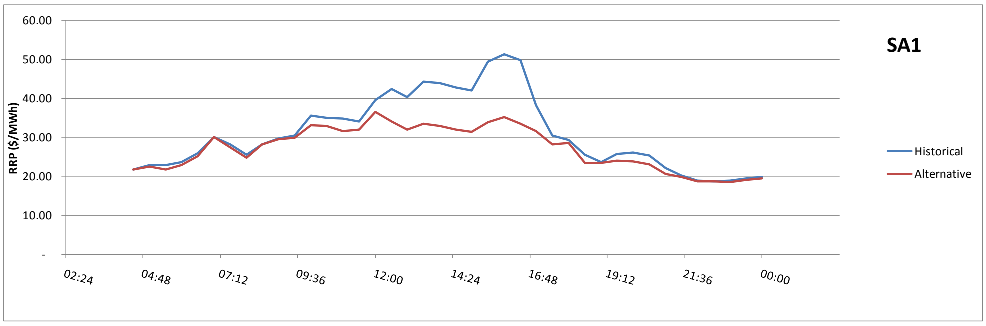


Figure 85 Tasmanian Spot Prices for Historical and Alternative Dispatch 15/2/2010

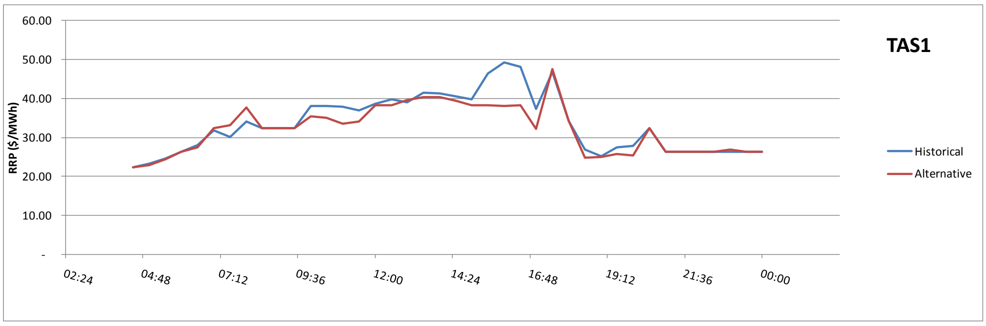
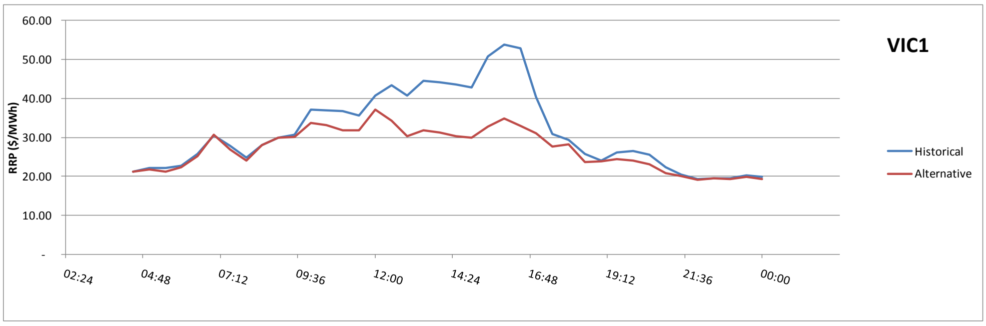


Figure 86 Victorian Spot Prices for Historical and Alternative Dispatch 15/2/2010



K.4 Dispatch Cost Impacts

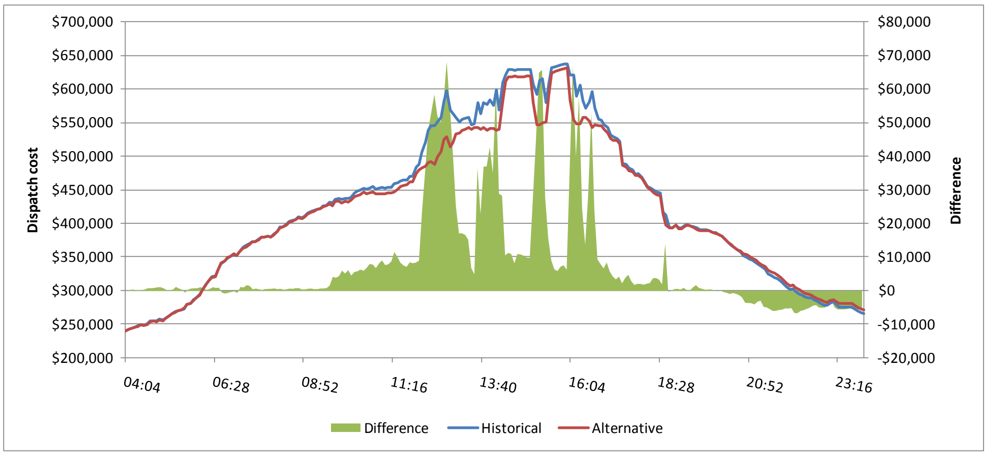
The historical and alternative total dispatch costs for the modelled period are presented in the table below.

Table 36 Historical and Alternative Dispatch Costs for 15/2/2010

	Historical	Alternative	Difference
Total generation cost ($)	101,586,590	99,728,247	1,858,343

The historical and alternative five minute dispatch costs are presented in the figure below. The differences in these dispatch costs are presented in the figure as the green shaded areas.

Figure 87 Dispatch Costs for Historic and Alternative Dispatch Scenarios for 15/2/2010



K.5 Dispatch Changes

The changes in dispatch costs for each power station in the NEM are presented in the table and corresponding figure below.

Table 37 Dispatch Costs Changes for Generators for Historic and Alternative Scenarios for 15/2/2010

Plant	Historical	Alternative	Difference
AGLHAL	0	0	0
AGLSOM	0	0	0
ANGAS1	0	0	0
ANGAS2	0	0	0
APD01	0	0	0
APD02	0	0	0
APS	220,119	220,119	0
BARCALDN	125,433	129,333	-3,899
BARRON-1	0	0	0
BARRON-2	0	0	0
BASTYAN	0	0	0
BBTHREE1	0	0	0
BBTHREE2	0	0	0
BBTHREE3	0	0	0
BDL01	12,246	13,797	-1,551
BDL02	0	0	0
BELLBAY1	0	0	0
BELLBAY2	0	0	0
BLOWERNG	0	0	0
BRAEMAR1	832,724	841,166	-8,442
BRAEMAR2	1,186,041	1,194,186	-8,146
BRAEMAR3	1,172,378	1,172,019	359
BRAEMAR5	931,222	926,690	4,532
BRAEMAR6	1,018,401	1,012,701	5,700
BRAEMAR7	983,530	978,064	5,466
BW01	1,864,257	1,828,672	35,584
BW02	1,859,229	1,830,981	28,248
BW03	1,863,484	1,828,855	34,629
BW04	1,767,646	1,729,822	37,824
CALL_B_1	743,003	731,237	11,766
CALL_B_2	875,099	861,407	13,693
CETHANA	104,100	107,094	-2,994
CG1	0	0	0
CG2	0	0	0
CG3	0	0	0
CG4	0	0	0
CLEMGPWF	-196,112	-196,114	2
COLNSV_1	0	0	0
COLNSV_2	0	0	0
COLNSV_3	82,082	82,142	-61
COLNSV_4	73,660	74,007	-347
COLNSV_5	171,189	171,310	-121
CPP_3	1,209,531	1,277,622	-68,091
CPP_4	1,265,788	1,265,926	-138
CPSA	0	0	0

Plant	Historical	Alternative	Difference
DDPS1	677,499	675,155	2,344
DEVILS_G	84,929	85,946	-1,017
DRYCGT1	0	0	0
DRYCGT2	0	0	0
DRYCGT3	0	0	0
EILDON1	80,990	86,255	-5,265
EILDON2	69,483	75,248	-5,765
ER01	2,092,222	2,064,184	28,038
ER02	1,973,234	1,962,659	10,574
ER03	1,973,479	1,960,929	12,550
ER04	2,099,680	2,056,168	43,512
FISHER	93,863	93,863	0
GORDON	752,926	675,550	77,376
GSTONE1	714,373	687,126	27,247
GSTONE2	810,596	771,465	39,131
GSTONE3	813,405	782,454	30,951
GSTONE4	930,282	901,749	28,533
GSTONE5	503,362	661,248	-157,886
GSTONE6	822,945	790,551	32,394
GUTHEGA	150,053	150,053	0
HALLWF1	-97,452	-97,422	-29
HALLWF2	-107,852	-107,789	-63
HUMENSW	0	0	0
HUMEV	92,400	92,400	0
HVGTS	0	0	0
HWPS1	82,357	82,357	0
HWPS2	121,177	121,177	0
HWPS3	111,343	111,373	-30
HWPS4	121,177	121,177	0
HWPS5	111,270	111,400	-131
HWPS6	114,345	114,372	-28
HWPS7	104,584	104,584	0
HWPS8	105,091	105,089	2
JBUTTERS	213,892	189,573	24,319
JLA01	0	0	0
JLA02	0	0	0
JLA03	0	0	0
JLA04	0	0	0
JLB01	510,952	512,018	-1,065
JLB02	0	0	0
JLB03	0	0	0
KAREEYA1	0	0	0
KAREEYA2	0	0	0
KAREEYA3	0	0	0
KAREEYA4	0	0	0
KPP_1	1,341,474	1,341,474	0
LADBROK1	287,019	287,019	0
LADBROK2	287,019	287,019	0
LAVNORTH	0	0	0
LD01	1,528,665	1,495,901	32,763
LD02	882,175	881,542	633
LD03	1,529,957	1,496,049	33,908
LD04	1,290,304	1,289,903	401

Plant	Historical	Alternative	Difference
LEM_WIL	192,936	192,917	19
LI_WY_CA	491,808	491,808	0
LK_ECHO	119,169	120,809	-1,640
LKBONNY2	-574,534	-580,240	5,706
LOYYB1	699,233	700,643	-1,410
LOYYB2	696,567	696,947	-380
LYA1	278,027	277,538	489
LYA2	251,290	251,411	-120
LYA3	267,237	266,855	382
LYA4	276,099	274,309	1,790
MACKAYGT	124,833	49,780	75,053
MACKNTSH	0	0	0
MCKAY1	0	0	0
MCKAY2	0	0	0
MEADOWBK	71,386	71,386	0
MINTARO	0	0	0
MM3	1,050,965	1,011,482	39,483
MM4	0	0	0
MOR1	112,592	112,979	-387
MOR2	64,695	64,959	-264
MOR3	139,138	137,406	1,733
MP1	2,927,032	2,917,009	10,023
MP2	2,927,276	2,918,670	8,606
MPP_1	788,841	929,388	-140,547
MPP_2	799,671	905,054	-105,383
MSTUART1	1,592,967	1,458,063	134,904
MSTUART2	2,545,204	1,654,409	890,795
MSTUART3	2,716,569	2,563,131	153,437
MURRAY	2,732,709	2,600,682	132,028
NPS	0	0	0
NPS1	847,609	821,904	25,706
NPS2	847,215	815,264	31,951
OAKEY1	680,204	616,453	63,751
OAKEY2	548,021	423,377	124,644
OSB-AG	1,263,406	1,258,526	4,879
PLAYB-AG	901,068	901,757	-690
POAT110	366,049	310,687	55,362
POAT220	577,422	439,470	137,952
POR01	0	0	0
PPCCGT	3,061,170	3,073,711	-12,540
PTH01	0	0	0
PTH02	0	0	0
PTH03	0	0	0
PUMP1	0	0	0
PUMP2	0	0	0
QPS1	0	0	0
QPS2	0	0	0
QPS3	379,784	379,784	0
QPS4	0	0	0
QPS5	0	0	0
REDBANK1	429,340	429,590	-250
REECE1	0	950	-950
REECE2	5,052	5,157	-105

Plant	Historical	Alternative	Difference
ROMA_7	198,420	198,420	0
ROMA_8	210,785	210,785	0
SHPUMP	0	0	0
SITHE01	1,277,784	1,292,161	-14,376
SNOWTWN1	-578,956	-578,956	0
SNOWYGJP	0	0	0
SNOWYP	0	0	0
SNUG1	0	0	0
STAN-1	1,006,756	1,005,085	1,671
STAN-2	1,068,477	1,044,483	23,994
STAN-3	0	0	0
STAN-4	1,117,409	1,100,579	16,830
SWAN_B_1	296,402	324,997	-28,596
SWAN_B_2	296,414	324,997	-28,583
SWAN_B_3	296,522	324,997	-28,475
SWAN_B_4	297,150	325,446	-28,296
SWAN_E	1,414,296	2,083,630	-669,334
TALWA1	2,293,886	2,294,852	-965
TARONG#1	747,246	710,111	37,135
TARONG#2	542,062	551,161	-9,099
TARONG#3	577,654	552,319	25,335
TARONG#4	597,096	616,510	-19,413
TARRALEA	388,205	388,424	-219
TNPS1	972,558	1,025,776	-53,218
TORRA1	0	0	0
TORRA2	0	0	0
TORRA3	0	0	0
TORRA4	669,291	549,491	119,800
TORRB1	1,306,288	1,033,516	272,772
TORRB2	0	0	0
TORRB3	0	0	0
TORRB4	1,324,852	1,008,671	316,181
TREVALLN	218,936	218,822	114
TRIBUTE	348	1,681	-1,332
TUMUT3	241,155	404,255	-163,100
TUNGATIN	254,932	254,932	0
TVCC201	1,859,483	1,846,795	12,688
TVPP104	0	0	0
UPPTUMUT	1,919,936	1,890,711	29,225
URANQ11	0	0	0
URANQ12	0	0	0
URANQ13	0	0	0
URANQ14	0	0	0
VP5	1,879,550	1,849,850	29,700
VP6	1,883,199	1,848,050	35,149
VPGS	0	0	0
W/HOE#1	134,016	125,591	8,425
W/HOE#2	0	0	0
WKIEWA1	84,701	87,443	-2,743
WKIEWA2	84,738	87,481	-2,744
WW7	1,600,071	1,579,511	20,560
WW8	0	0	0
YABULU	1,202,214	1,214,252	-12,039

Plant	Historical	Alternative	Difference
YABULU2	629,896	629,859	37
YWPS1	0	0	0
YWPS2	208,156	208,186	-30
YWPS3	210,792	210,835	-43
YWPS4	217,553	217,655	-102
Total	101,586,590	99,728,247	1,858,343

Figure 88 Dispatch Cost Changes