Market benefits of Heywood upgrade

A REPORT PREPARED FOR MACQUARIE GENERATION

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1 Introduction

Frontier Economics (Frontier) has been engaged by Macquarie Generation to independently assess the forecast gross market benefits of an upgrade to the Heywood Interconnector between Victoria and South Australia proposed by ElectraNet and AEMO. This report presents the findings of our analysis and highlights a number of areas where further information is required before it is possible to come to a robust conclusion on the merits of the proposed upgrade.

1.1 Background

In January 2013, ElectraNet and AEMO jointly published a Regulatory Investment Test for Transmission (RIT-T) Project Assessment Conclusions Report (PACR) that examined a number of options for augmenting the Heywood Interconnector.[1] The PACR found that the 'preferred option', which yielded the highest net market benefits under the RIT-T was Option 1b. This option involves three key elements:

- Installation of a third 500/275 kV transformer at Heywood in South Australia and a 500 kV bus tie in Victoria
- Reconfiguration of the 132 kV network in south-east South Australia
- Series compensation of the Tailem Bend to south east South Australia 275 kV double-circuit lines at Black Range.[2]

According to the PACR, development of this option would enable an increase in the nominal capacity of the Heywood interconnector of 190 MW in both directions, from 460 MW to 650 MW and relax existing constraints that often limit interconnector flows below the current nominal capacity.[3]

Frontier has reviewed the analysis Option 1b in the PACR and undertaken high-level modelling of the option using assumptions similar to those in ElectraNet and AEMO's "Revised Central" scenario. This scenario incorporates the most up-to-date and realistic assumptions for electricity demand and carbon pricing of all the scenarios considered in the PACR.

1 ElectraNet-AEMO, *South Australia – Victoria (Heywood) Interconnector Upgrade, RIT-T: Project Assessment Conclusions Report*, January 2013.

2 PACR, p.29.

3 PACR, p.24.

This report describes our preliminary findings from:

- Analysing the source and drivers of the purported gross market benefits of Option 1b as reported by ElectraNet and AEMO based on information released with the PACR
- Based on the same input assumptions used by ElectraNet and AEMO in the PACR, independently quantifying the gross market benefits of Option 1b using *WHIRLYGIG*, Frontier's least-cost investment and dispatch electricity market model.

1.2 Structure of report

The remainder of this report is structured as follows:

- Section 2 provides our analysis of ElectraNet and AEMO's PACR findings
- Section 3 outlines the assumptions we employed in our modelling
- Section 4 discusses our assessment of market benefits of the proposed upgrade
- Section 5 summarises our findings and suggests some questions to put to ElectraNet and AEMO.

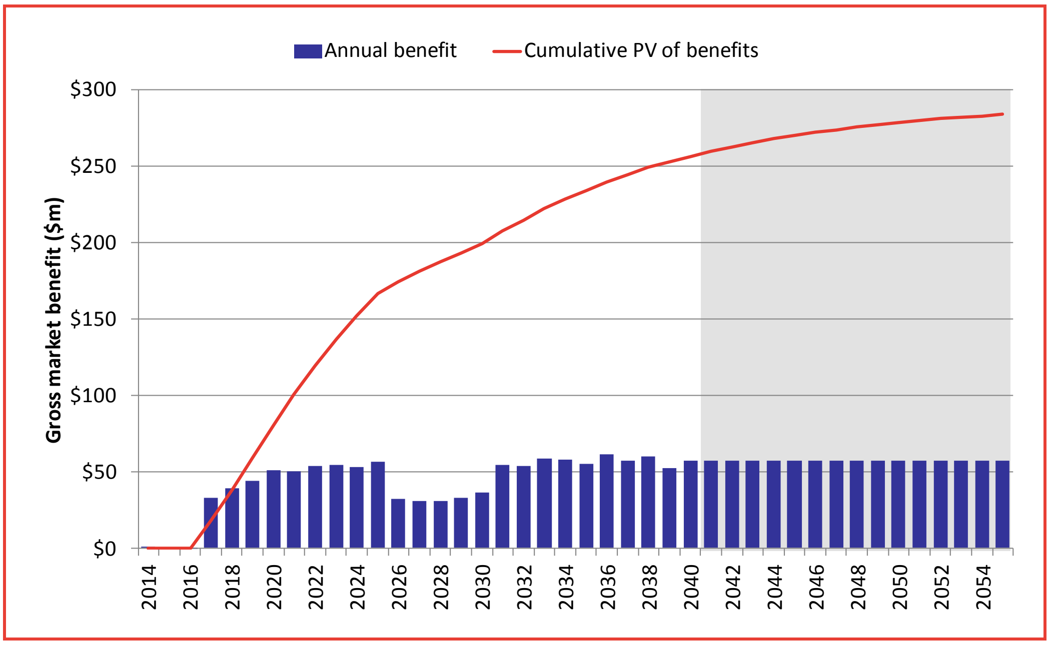
2 Analysis of ElectraNet and AEMO's findings

This section recounts and analyses AEMO's quantification of gross market benefits of Option 1b under the Revised Central scenario. The source of the data used in this analysis is that outlined in the data appendix[4] to the PACR.

2.1 Gross market benefits

Under the Revised Central scenario, ElectraNet and AEMO report the present-value of gross market benefits of Option 1b as $284m in $2011/12. Outlined in Figure 1 are the annual gross market benefits (blue bars) and the cumulative present value of annual benefits (red line). The period post 2039/40 – which was not modelled by AEMO explicitly – is highlighted grey.

Figure 1: Gross market benefits – Option 1b, Revised Central scenario



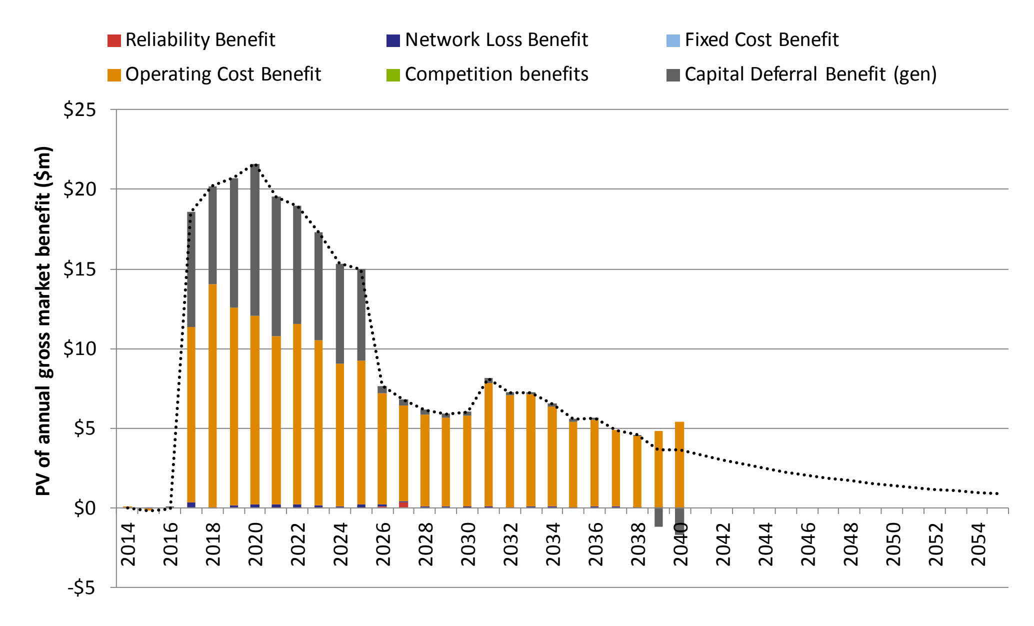
Source: Frontier analysis of AEMO PACR data Appendix

As noted in Section 5.1 of the PACR, ElectraNet and AEMO have modelled out to 2039/40. They inferred the annual gross market benefits for the remaining 15 years (2040/41 to 2054/55) by taking the average annual gross market benefits over the last 5 years of the modelling period (2035/36 to 2039/40) and assuming that these benefits remain constant in real terms. Due to the nature of compound

4 Available here.

discounting, roughly 90% of present value of gross market benefits accrue before 2040.

Figure 2: Breakdown of gross market benefits – Option 1b, Revised Central scenario



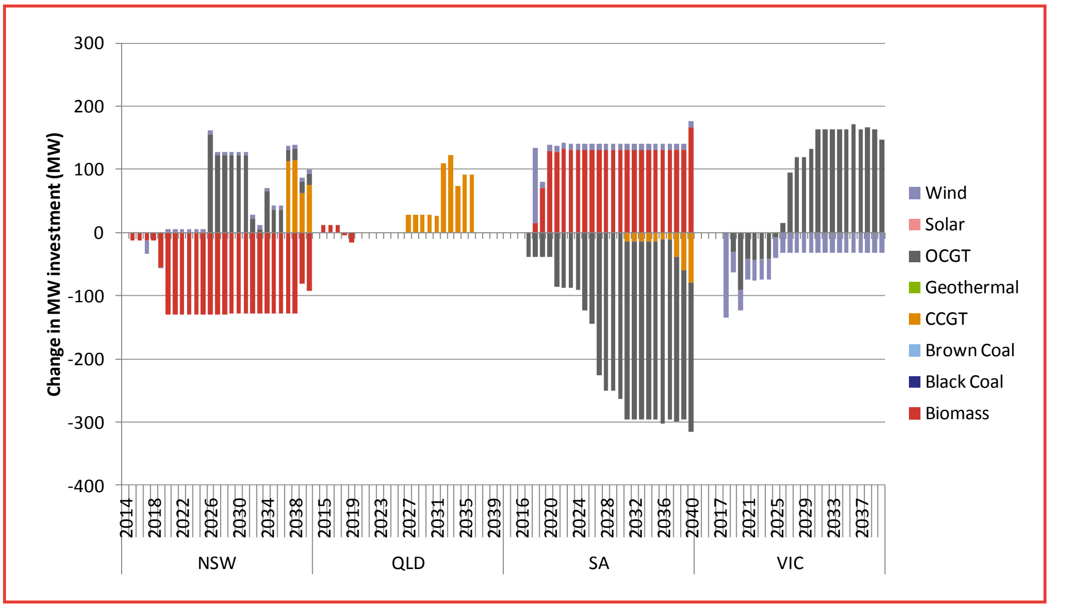
Source: Frontier analysis of AEMO PACR data Appendix

Outlined in Figure 2 is a breakdown by source of the present value of annual gross market benefits for Option 1b under the Revised Central scenario. Figure 2 indicates that the majority of the purported gross market benefits of Option 1b accrue due to 'operating cost' benefits (primarily fuel cost savings). The present value of these annual benefits declines over time due to discounting, but they nevertheless contribute strongly from the first year following the augmentation (2016/17) onwards. Over the period 2016/17 to 2024/25, generation capital cost deferral benefits make up the balance of annual gross market benefits.

2.2 Impact on plant investment and retirement

The impact of Option 1b on plant investment and retirement calculated by ElectraNet and AEMO under the Revised Central scenario is outlined in Figure 3. The chart shows the change in MW investment / retirement between the Base case and Upgrade case, with a positive bar indicating more investment in the Upgrade case and a negative bar indicating less investment.

Figure 3: Change in annual investment (MW) – Option 1b, Revised Central scenario



Source: Frontier analysis of AEMO PACR data Appendix

The 190 MW upgrade of Heywood under Option 1b leads to a shifting of roughly 200-300 MW of investment between regions and technologies. Based on Frontier's analysis of the 2010 NTNDP generator capital cost input assumptions used by AEMO, it is worth noting that:

- Cost differences between regions for biomass are negligible – as such the large MW-for-MW shift in biomass investment from NSW to SA is unlikely to be contributing much to generation capital cost savings.
- Likewise the cost differences for wind plant as between VIC, NSW and SA are also small. While Option 1b does result in a net reduction in wind investment (the reduction in wind investment in VIC is greater than the sum of increases in SA and NSW), the magnitude of the net decrease in wind investment (~16 MW) and the negligible cost differential for wind plant between regions means that changes in wind investment is not a key driver of gross market benefits.

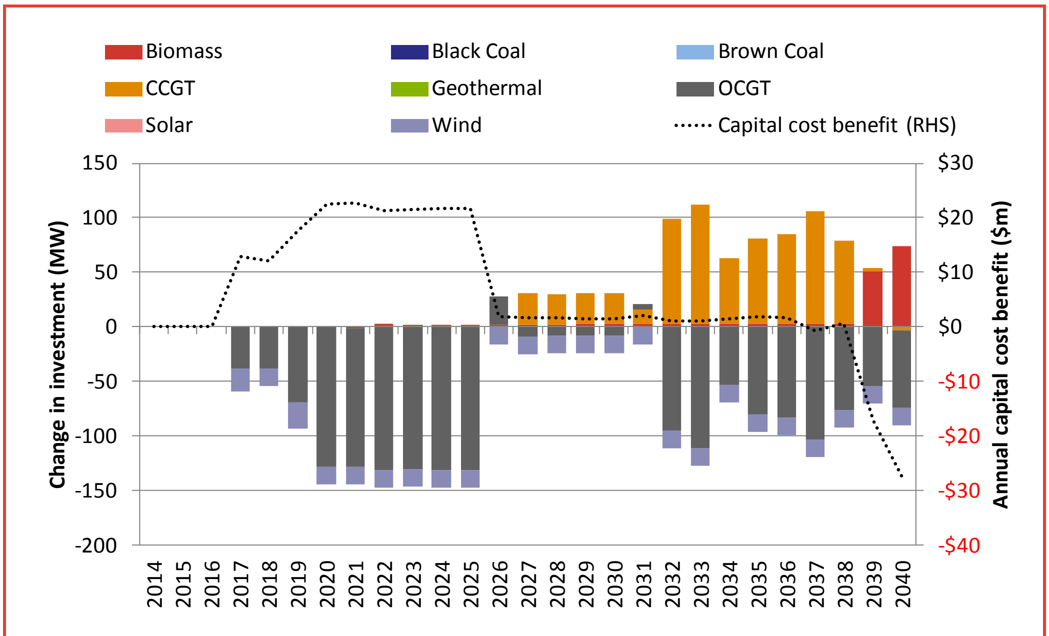
The majority of Option 1b's gross market benefits that accrue due to savings in generator capital costs arise from:

- **Deferral** of OCGT investment in SA and VIC over the period 2016/17 to 2024/25.
- **Substitution** of OCGT investment in SA with OCGT investment in VIC and CCGT investment in QLD and NSW over the period 2025/26 to 2039/40. Due to the small relative cost differential between OCGT plant in

different regions and the bigger, but still relatively modest, capital cost differential between OCGT and CCGT[5], the benefits from capital substitutions over this period are markedly less than the benefits of outright capital deferral that accrue over the period 2016/17 to 2024/25.

The pattern of changes to investment compared with changes in generator capital costs is outlined in Figure 4. The chart confirms that the majority of generator capital cost benefits arise due to deferral (as opposed to later substitution) of OCGT investment in SA.

Figure 4: Change in investment (MW) and capital cost savings ($m)



Source: Frontier analysis of AEMO PACR data Appendix

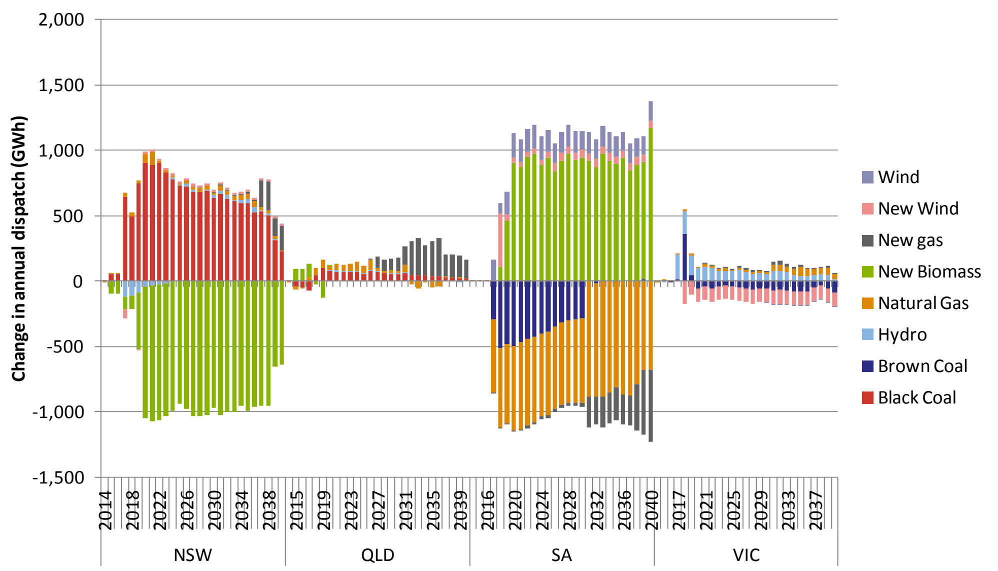
In the final two years of the modelling period there is a net positive increase in biomass investment in SA (in years prior to these the increase in biomass investment in SA is perfectly offset by decreases in NSW – see Figure 3). Due to the relatively high capital cost of biomass plant (~$5,300/kW, as compared to OCGT at ~ $1,000/kW) this results in an increase in net generation capital costs as a result of the augmentation (negative capital cost benefit). However, given the timing of this shift (towards the end of the modelling period) the present value impact on annual gross market benefits is relatively modest (see Figure 2).

5 The 2010 NTNDP assumed that the capital cost of CCGT plant was roughly 40% greater than the capital cost of OCGT plant.

2.3 Impact on plant dispatch

The impact of Option 1b on plant dispatch (of both existing generators and new entrants) calculated by ElectraNet and AEMO under the Revised Central scenario is shown in Figure 5. The chart shows the change in annual dispatch between the Base case and Upgrade case, with a positive bar indicating more dispatch in the Upgrade case and a negative bar indicating less dispatch.

Figure 5: Change in annual dispatch (GWh) – Option 1b, Revised Central scenario



Source: Frontier analysis of AEMO PACR data Appendix

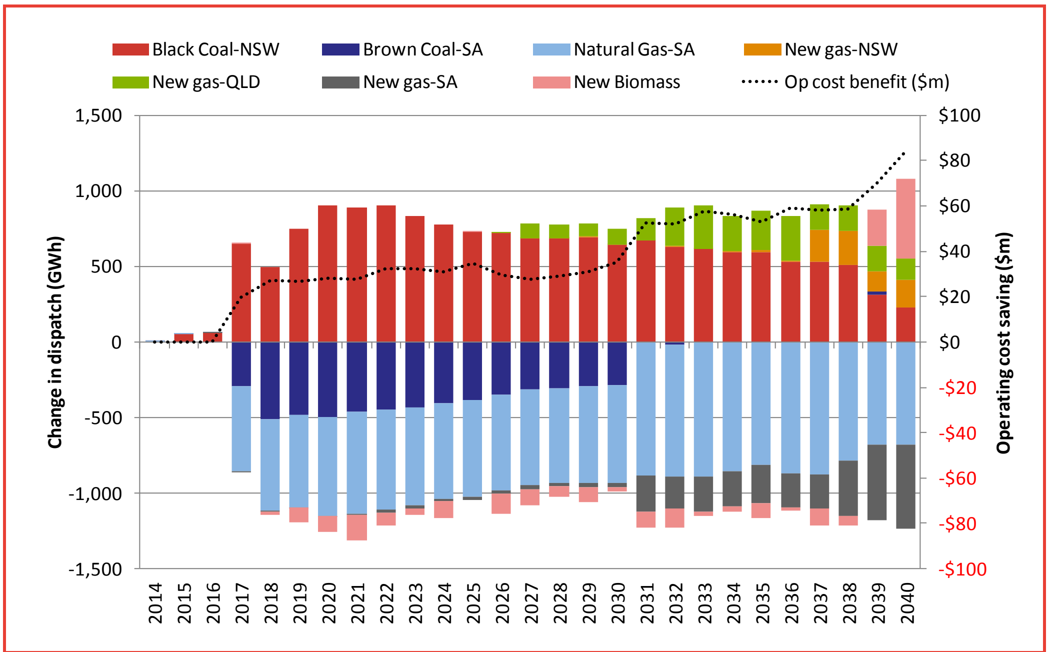
According to ElectraNet and AEMO, Option 1b leads to roughly 1,000 GWh per annum of altered dispatch:

- Between 500 and 1,000 GWh per annum additional black coal generation is dispatched in NSW over the period 2016/17 to 2039/40 and roughly 180 GWh per annum additional wind is dispatched in SA. There is also between 100 and 300 GWh per annum of additional gas plant dispatched in QLD over the period 2027/28 to 2039/40 and roughly 180 GWh per annum of additional gas plant dispatched in NSW post 2035/36.
- Between 250 and 500 GWh per annum less brown coal plant is dispatched in SA over the period 2016/17 to 2029/30 and between 600 and 800 GWh per annum less gas plant is dispatched in SA over the period 2016/17 to 2039/40.

The large shift in biomass dispatch from NSW to SA mirrors the shift in investment discussed above. Based on the 2010 NTNDP fuel cost assumptions, there is no regional fuel cost differential for biomass. As such, the shift in biomass investment (and resulting dispatch) from NSW to SA does not appear to be a driver of gross market benefits for the proposed upgrade.

The key changes in plant dispatch that are likely to be generating the majority of the purported operating cost benefits of Option 1b are outlined in Figure 6. These changes generate ElectraNet and AEMO's reported annual operating cost benefits (dotted black line – RHS scale).

Figure 6: Change in dispatch (GWh) and operating cost savings ($m) for key plant



Source: Frontier analysis of AEMO PACR data Appendix

Figure 6 indicates that ElectraNet and AEMO expect the following benefits from Option 1b:

- A saving of roughly $30m per annum due to the increased scope for NSW black coal to displace SA brown coal and gas over the period 2016/17 to 2030/31.
- A saving of between $50 and $60m per annum due to the increased scope for existing NSW black coal and entrant QLD and NSW gas plant to displace a larger quantity of SA gas in the period post 2030/31. A larger quantity of SA gas is displaced post 2030/31 due to the assumed retirement of 544 MW of brown coal generation in SA (ie Northern Power Station) in 2030/31 in both the Base case and Upgrade case. In the Base case, Northern's retirement results in additional dispatch from existing gas plant in SA and additional dispatch from new entrant gas plant in SA. This additional SA gas dispatch is largely displaced in the Upgrade case by new entrant gas plant in QLD and NSW.

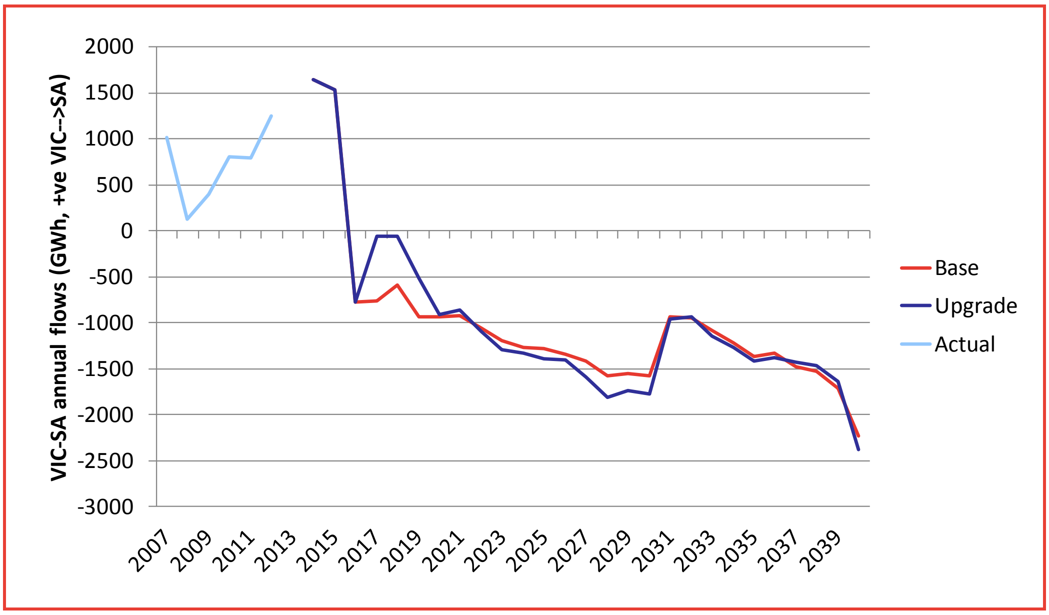
- A saving of roughly $80m in the final year of the modelling due to the increase in investment (and hence dispatch) of new biomass in SA. While biomass has a high capital cost (which results in a negative capital cost benefit in the final year – see Figure 4) it has very low operating costs, which result in large operating cost savings relative to dispatching SA gas.

2.4 Impact on VIC-SA flows

As noted in Section 2.3, a key driver of ElectraNet and AEMO's purported gross market benefits of Option 1b is the increased scope of NSW black coal to initially displace SA brown coal and gas. In the longer term, once Northern is assumed to retire, SA gas (existing and new entrant) continues to be displaced by NSW black coal and entrant QLD and NSW gas plant.

The modelled changes to plant dispatch reported by ElectraNet and AEMO can be combined with the assumed annual levels of energy demand in South Australia to infer annual net interconnector flows between VIC and SA in both AEMO's Base and Upgrade cases. Inferring flows is necessary since ElectraNet and AEMO did not release import or export flow data between NEM regions as part of its PACR results.

Figure 7: Implied VIC-SA flows (GWh) – Option 1b, Revised Central scenario



Source: Frontier analysis of AEMO PACR data Appendix; AEMO historical flow data

Figure 7 illustrates that ElectraNet and AEMO are forecasting SA to become a **net exporter** of energy by 2015/16. This is in response to ~1,500 MW of wind that is assumed to enter (in a single annual lump) in the same year. Over the period 2015/16 to 2019/20, SA is forecast to export less energy on a net basis in the Upgrade case as compared to the Base case. Over the period 2020/21 to 2029/30, this is expected to shift such that SA is forecast to export more energy on a net basis due to the Heywood upgrade. Beyond this point, net flows between the Base case and Upgrade case are broadly similar.

In order for net flows to SA to remain broadly balanced while approximately 1,000 GWh of black coal generation in NSW displaces brown coal and gas generation in SA, a similar quantity of South Australian generation must displace generation elsewhere in the NEM. Figure 5 shows that the upgrade leads to a shift in biomass output from NSW to SA. Based on the 2010 NTNDP's assumed maximum biomass capacity factor of 90%, the shift of 130 MW of biomass capacity from NSW to SA allows SA to import ~1,000 GWh per annum of additional conventional energy without significantly altering its net export position.

Given the very low operating cost and high operating capacity factor of biomass assumed in ElectraNet and AEMO's modelling, the pattern of investment, dispatch and net flows suggests that SA:

- Is a net importer of energy in peak demand times – the Heywood upgrade facilitates increased imports of NSW black coal energy at these times, causing a reduction in SA brown coal and gas.
- Is a net exporter of energy during off-peak demand times – this energy being produced by the increased biomass plant in SA.

In sum, Option 1b facilitates increased imports at peak demand times as well as increased exports at off-peak demand times. The overall effect on SA net exports is relatively small. Both with and without the upgrade, SA increasingly becomes a net exporter across the year, as wind investment continues to expand.

3 Assumptions key to Frontier's analysis

In modelling the gross market benefits of Option 1b, Frontier has sought to use input assumptions that are as close as possible to those used by ElectraNet and AEMO for the modelling performed for the PACR. Specifically, Frontier has focused on those updated input assumptions used in the Revised Central scenario.

The purpose of using a consistent set of input assumptions is twofold:

- To confirm that the methodology and approach used by ElectraNet and AEMO, given the input assumptions used, results in a gross market benefit comparable to that reported in the PACR.
- To enable sensitivity analysis to be performed to explore the importance of various input assumptions to the final gross market benefit results.

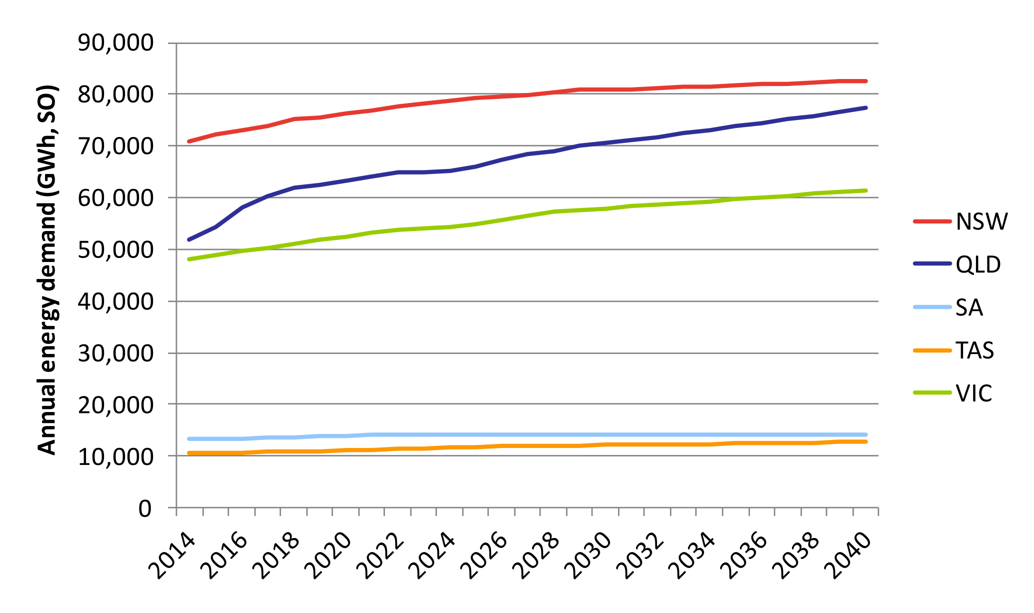
The remainder of this section outlines the key input assumptions utilised by Frontier in modelling the gross market benefits of Option 1b. Attention is paid to those input assumptions that are either partially or completely omitted from the PACR. While the large majority of key input assumptions are adequately documented and sourced, in cases where specific information has not been provided, Frontier has utilised assumptions that are as consistent as possible with previous work publically released by AEMO.

3.1 Demand growth

Consistent with the Revised Central scenario, energy and peak demand growth are taken from Scenario 3 of AEMO's 2012 National Electricity Forecasting Report (**2012 NEFR**). Scenario 3 is AEMO's 'planning case' and reflects its best estimate of the likely future direction of peak demand and consumption growth over the next 10 years. Frontier has extrapolated the final 5 years of demand growth from AEMO's forecasts out to the end of 2039/2040 (the end of the modelling period).

ElectraNet and AEMO do not explain how demand growth is extrapolated past the final year presented in the 2012 NEFR (2021/22). However, for the majority of NEM regions (the exception being Queensland), demand growth in the final 5 years of the 2012 NEFR forecasts are relatively modest under Scenario 3. When these terminal growth rates are extrapolated forward out to 2039/40, the resulting demand growth projections are relatively modest. The assumed level of annual energy demand (presented on a sent-out basis) modelled in each NEM region out to 2039/40 is outlined in Figure 8.

Figure 8: Assumed energy demand growth (GWh)



Source: AEMO 2012 NEFR, Frontier analysis

3.2 Carbon price and LRET target

3.2.1 Carbon price

Consistent with the Revised Central scenario, Frontier has incorporated a carbon price in our modelling that reflects:

- The announced fixed carbon prices for 2013/14 and 2014/15 ($23 and $23.58 in $2011/12, respectively)
- The announced floor prices for 2015/16 to 2017/18 ($13.59, $14.14 and $14.70 in $2011/12, respectively)
- The final year floor price rolled forward at 4% per annum in real terms.

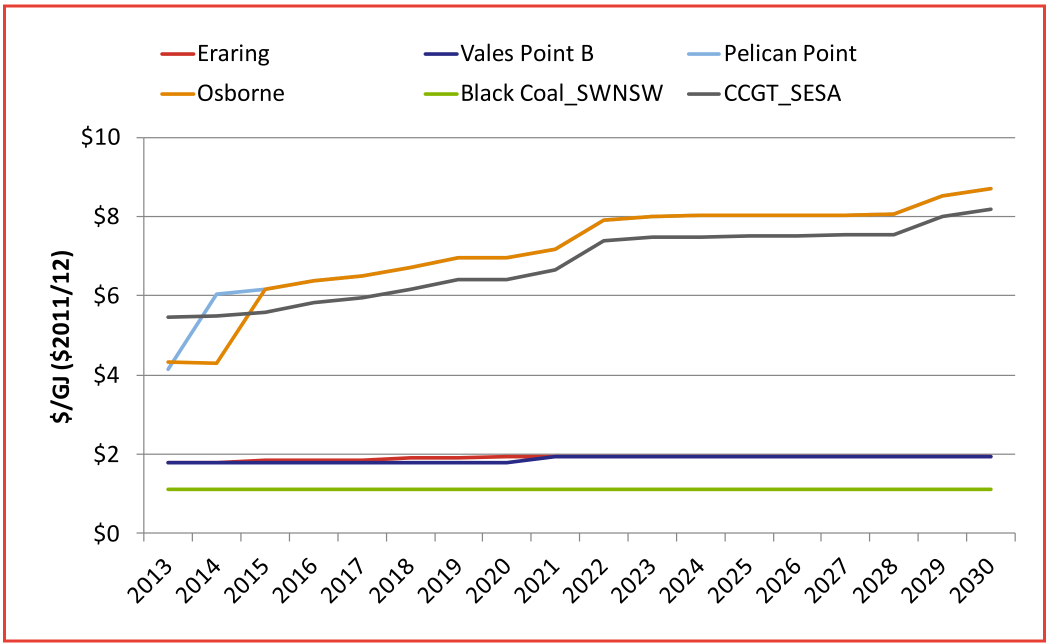
3.2.2 LRET target

Frontier has modelled the LRET target for the Revised Central scenario as set out in Figure C-3 of the PACR. Recently committed wind farms (Snowtown Stage 2 North and South in South Australia, Musselroe Wind Farm in Tasmania) are not assumed to be committed plant for the purposes of meeting the LRET target. This is based on public data released by AEMO in the second half of 2012 which had yet to label these wind plant as being committed. Further, neither plant was considered a committed project in AEMO's 2012 Electricity Statement of Opportunities.

3.3 Fuel prices

Based on Section C.4 of the PACR, Frontier has modelled existing and new entrant gas and coal prices from the "Decentralised World" scenario of the 2010 NTNDP. The 2010 NTNDP fuel price assumptions were developed sometime in late 2009 and finalised in early 2010 – as such, they are at this point roughly 3 years out of date. The 2010 NTNDP provides fuel price forecasts out to 2029/30. Past this point Frontier has assumed that fuel prices for all plant remain constant at their 2029/30 level in real terms for the remainder of the modelling period.

Figure 9: Assumed fuel prices of key plant



Source: AEMO 2010 NTNDP, "Decentralised World"

As is discussed further in subsequent sections, a key source of the gross market benefits reported for Option 1b under the Revised Central scenario is operating (ie fuel) cost savings that arise from the displacement of SA gas plant with generation from NSW black coal plant.

Outlined in Figure 9 are the assumed fuel prices in $/GJ of four key plant – Eraring and Vales Point (NSW black coal) and Pelican Point and Osborne (SA mid-merit gas plant). Also included for reference is the cheapest delivered fuel price for an entrant black coal plant in NSW (located in the south-west of the state) and an entrant CCGT gas plant in SA (located in the south-east of the state).

Notwithstanding the fact that the gas price forecasts from the 2010 NTNDP are close to 3 years old, the assumed prices are broadly reasonable in our view and fairly consistent with our expectation of delivered gas prices in the NEM over the next two decades. Based on a more contemporaneous estimate of costs and likely LNG demand, gas prices could be expected to be slightly higher in the 2014-2018 period when the majority of committed LNG plant in Gladstone are expected to be commissioned. In the longer term, depending on future LNG demand, gas prices could be expected to rise closer to $10/GJ by the mid-2020s.

Regarding coal price forecasts, in Frontier's view the assumed prices for both existing and entrant plant are too low. This is particularly the case for entrant plant in SWNSW, which are assumed to be able to secure long-term coal supplies for as little as $1.11/GJ. In our view, NSW black coal prices in the $2-3/GJ range over the next two decades would be more reasonable. As noted in subsequent sections, due primarily to lower demand growth but also to a moderate carbon price, no new coal-fired generation is forecast to enter the market in either ElectraNet and AEMO's or Frontier's analysis. As such, the unreasonably low entrant black coal price is of no consequence.

3.4 Transmission network capability

Frontier has modelled regional interconnection in the NEM only – our analysis does not consider intra-regional constraints. This is a significant departure from ElectraNet and AEMO's modelling framework, which does model intra-regional constraints. The consequence of this difference in approach is further discussed in subsequent sections.

When modelling regional interconnection, Frontier has calibrated dynamic loss equations to the parameters outlined in AEMO's 2011/12 Regional Boundaries and Marginal Loss Factors report. As per that report, in the Base case, the Heywood interconnector is assumed to have a notional bi-directional transfer limit of 460 MW. When exploring the impact of Option 1b, this limit is increased by 190 MW to 650 MW, holding all other input assumptions constant.

3.5 Existing and committed plant capacity and operating parameters

Frontier has taken existing and committed plant capacities from the 2011 ESOO. ElectraNet and AEMO did not publish the plant capacities used in their Revised Central case modelling for the PACR. However, given that the 2011 ESOO would have been the most likely contemporaneous view of plant capacities available to AEMO around the time that the modelling was being conducted, we have adopted the assumptions from that document.

Existing and committed plant operating parameters were taken from the 2010 NTNDP. This is based on Appendix D of the PACR, which notes that the 2010 NTNDP was the primary source of input assumptions for the RIT-T analysis.

3.6 Entrant plant capital costs and operating parameters

As was the case with existing and committed plant operating parameters, new entrant plant operating parameters and capital costs have been taken from the 2010 NTNDP. The 2010 NTNDP provides entrant plant capital costs on a $/kW basis. Frontier has amortised these capital costs assuming a 10% WACC, consistent with the discount rate assumed by ElectraNet and AEMO in their modelling.

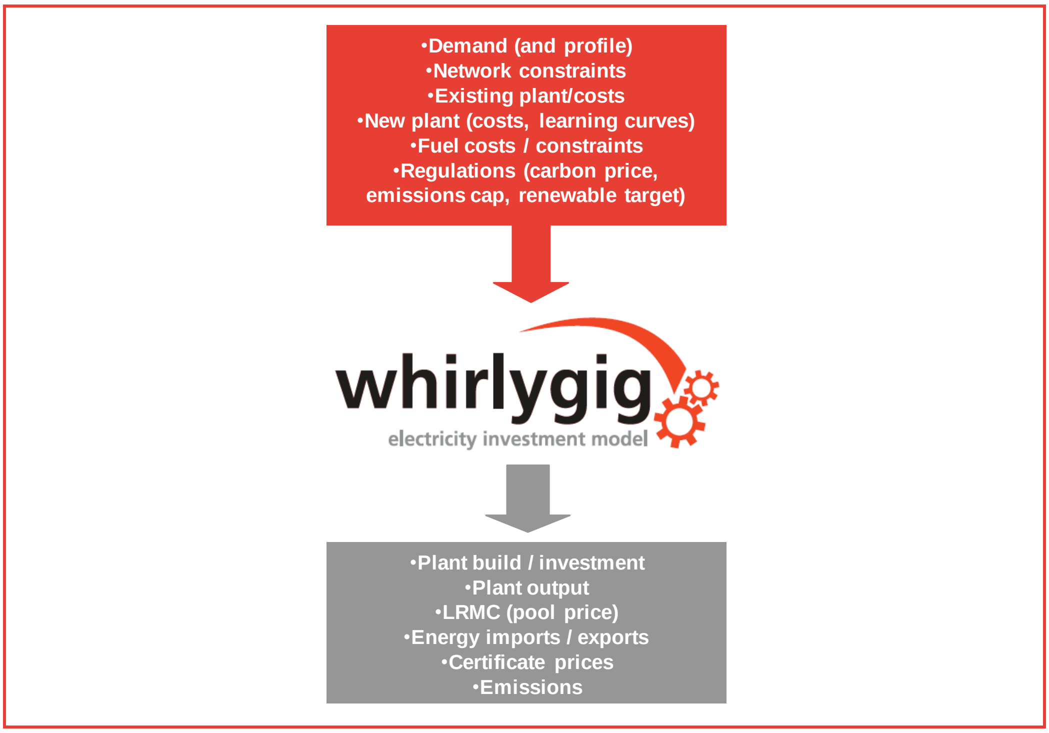
4 Frontier's assessment of market benefits

This section outlines the results of Frontier's assessment of the gross market benefits of Option 1b under the Revised Central scenario. As discussed in Section 3, Frontier has used an input assumptions set that is as consistent as possible with those assumptions used (or expected to have been used) by ElectraNet and AEMO in their analysis.

4.1 Overview of *WHIRLYGIG*

To assess the gross market benefits of Option 1b, Frontier has utilised our least-cost electricity market development and dispatch model, *WHIRLYGIG*. *WHIRLYGIG* computes the least-cost mix of generation and investment to meet demand, subject to meeting system reliability targets, renewable targets (for instance, the Large Scale Renewable Energy Target (LRET), and a CO_2 emissions trading scheme or carbon price. This approach involves forecasting the least-cost mix of generation investment and dispatch, and hence the long run marginal cost (LRMC) of the generation system. A diagram of high level inputs/outputs for *WHIRLYGIG* is provided in Figure 10.

Figure 10: Model inputs and outputs



Source: Frontier Economics

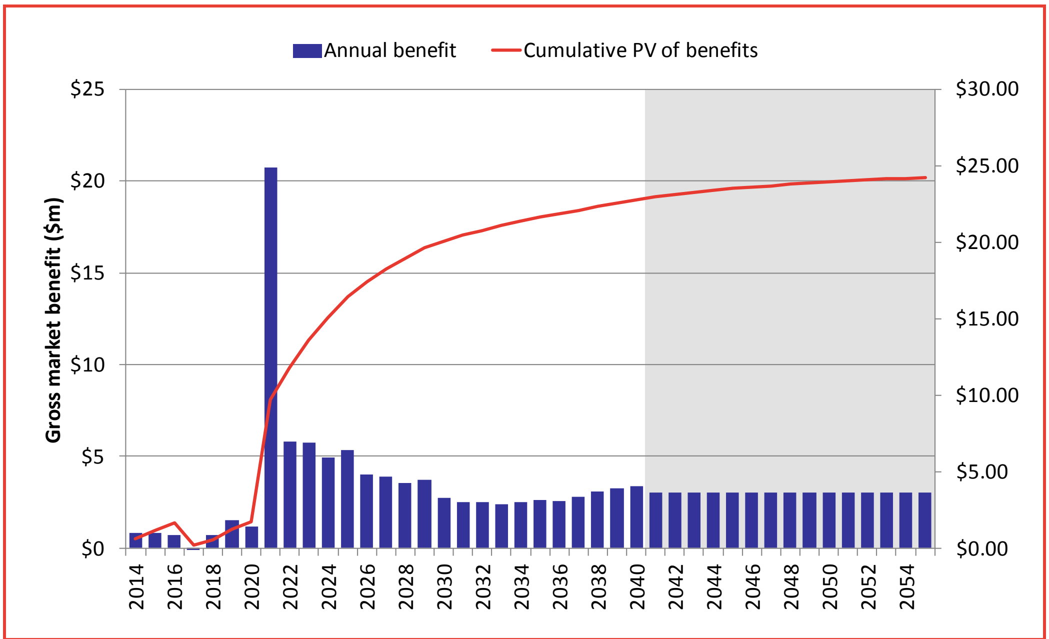
As a cost-minimisation model, *WHIRLYGIG* dispatches generation according to estimated SRMCs in order to minimise the total cost of serving load. This implies that all generation plant bid their capacity into the market on a highly competitive basis, which is consistent with the framework adopted by ElectraNet and AEMO (Section 5.3.2 of the PACR).

4.2 Frontier's estimate of gross market benefits of Option 1b

Frontier has calculated the gross market benefits of Option 1b under the Revised Central scenario to be **$24.23m** ($2011/12, present value as at 2011/12). This compares to AEMO's estimate on a comparable basis of **$284m**.

Figure 11 shows the annual gross market benefits (blue bars) and the cumulative present value of annual benefits (red line) forecast by Frontier. Annual benefits in the period post 2039/40 – highlighted grey – have not been modelled, consistent with AEMO's approach. Benefits in this period are estimated based on the average annual benefits derived over the period 2035/36 to 2039/40.

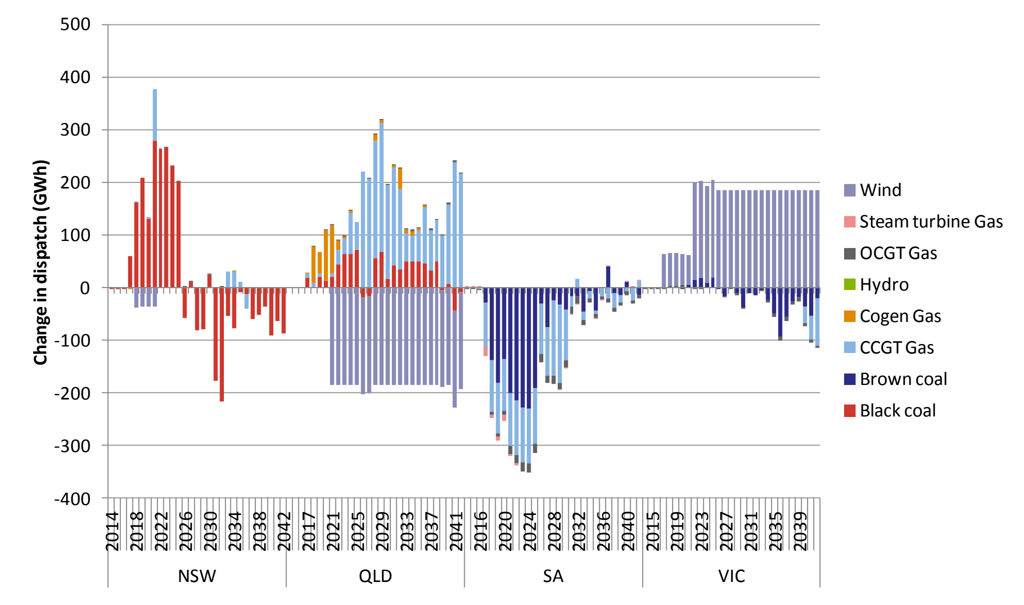
Figure 11: Frontier's gross market benefits – Option 1b, Revised Central scenario



Source: Frontier modelling and analysis

Outlined in Figure 12 is the change in annual dispatch as a result of the proposed Heywood upgrade. The upgrade facilitates a modest increase in NSW and QLD black coal dispatch, and leads to a similar-sized reduction in SA brown coal and gas dispatch. Post 2024/25, the magnitude of SA brown coal that is displaced drops off, but remains positive. Over this period, QLD gas displaces SA gas and a small amount of VIC brown coal.

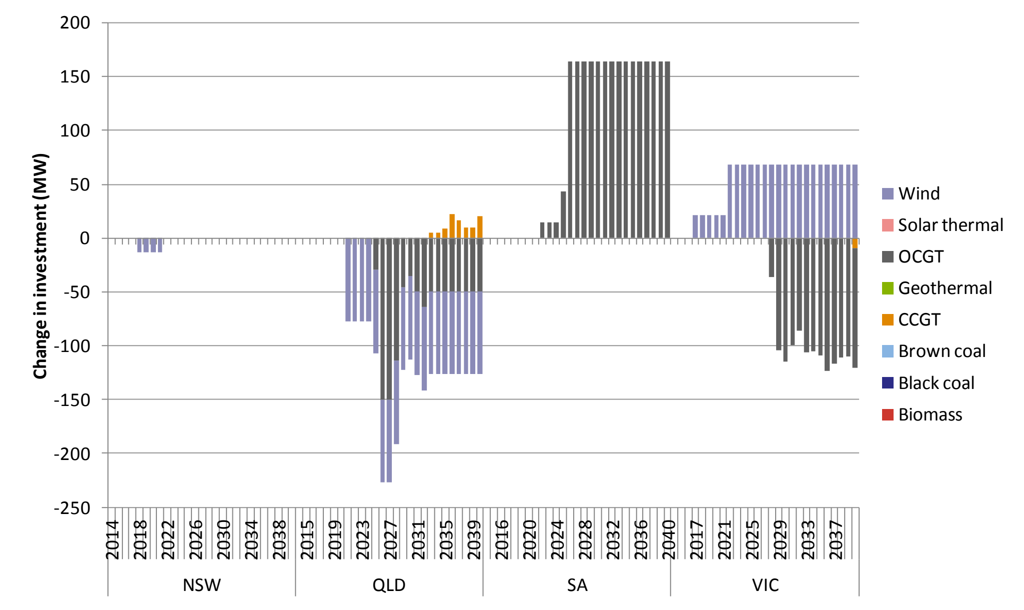
Figure 12: Change in dispatch (GWh)



Source: Frontier modelling and analysis

Figure 13 shows the change in annual investment from Option 1b.

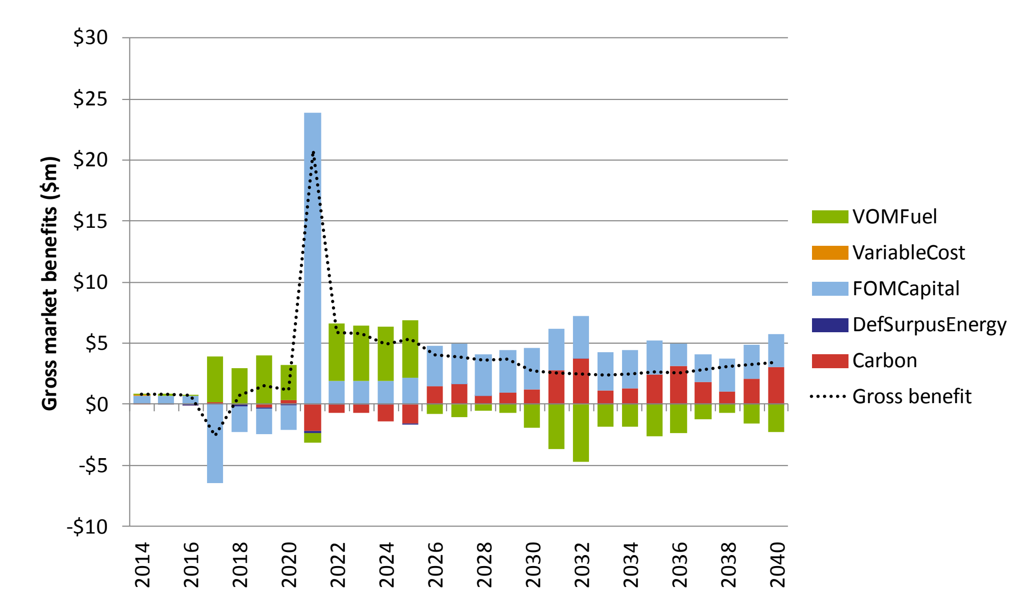
Figure 13: Change in investment (GWh)



Source: Frontier modelling and analysis

The upgrade results in a reduction in wind investment in QLD and an increase in VIC. Due to higher wind capacity factors in VIC, the overall amount of wind investment falls, leading to a minor capital cost saving. The upgrade also shifts OCGT investment from QLD and VIC into SA. Due to marginally lower connection costs in SA, this also results in a small capital cost saving.

Figure 14: Frontier's gross market benefits - breakdown



Source: Frontier modelling and analysis

Outlined in Figure 14 is a breakdown of forecast gross market benefits by source. The pattern of gross market benefits we forecast reflects the changes to investment and dispatch above:

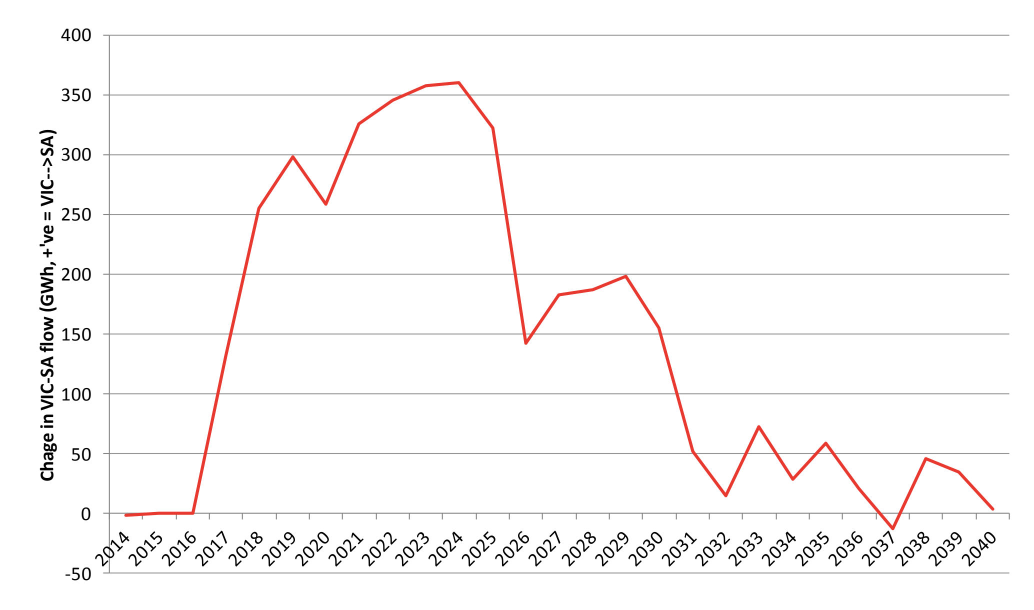
- In the period up to 2025/26, roughly 200 MW of NSW black coal (Eraring, Vales Point, and Wallerawang) and 100 MW of QLD black coal (Gladstone) displaces a similar quantity of SA brown coal and gas-fired generation. This displacement leads to a lower fuel and variable operating and maintenance (VOM) costs and slightly higher carbon costs, with the net result being a decrease in total operating costs. In the period 2025/26 onwards, a smaller amount of brown coal and gas-fired plant in SA continues to be displaced. However, over this period, the majority of displacement comes from CCGT gas plant in Queensland, with the increase in fuel costs being marginally outweighed by savings in carbon costs in most years.
- Over the period 2020/21 onwards, capital cost savings accrue due to an overall lower level of aggregate wind investment (wind shifts to VIC, which has better wind capacity factors) and a very small fixed cost saving due to the

shift in OCGT investment (assumed connection costs are marginally lower in SA as compared to QLD and VIC).

As is evidenced by Figure 14 and the lower present value of gross benefits ($24.23m), the modelling and analysis performed using *WHIRLYGIG* suggests there are only moderate gross market benefits from Option 1b under the Revised Central scenario.

Outlined in Figure 15 is the change in annual net flows between VIC and SA as a result of the Option 1b upgrade. From the first year of the upgrade, net exports from VIC to SA increase by around 300 GWh/annum. The change in net exports gradually fall over time, reflecting the fact that the additional transfer capability becomes less utilised as brown coal and gas generation in SA becomes less displaced over time (Figure 12).

Figure 15: Change in VIC-SA flows (GWh)



Source: Frontier modelling and analysis

4.3 Source of differences between AEMO and Frontier's results

On a present value basis, Frontier's analysis has found the gross market benefits of Option 1b to be roughly one tenth of the size of ElectraNet and AEMO's reported benefits. The source of the difference between Frontier's and ElectraNet/AEMO's estimates is:

- ElectraNet and AEMO find much larger and more enduring operating cost savings in response to the upgrade. This is driven by persistent displacement of SA brown coal and gas-fired generation by NSW black coal generation over the period of the modelling. Frontier finds a similar pattern of displacement. However, the result is on a far lower scale and does not persist to any significant degree past 2025/26.

- ElectraNet and AEMO find larger generation capital cost savings over the period 2016/17 to 2024/25 due to OCGT investment deferral in SA. Frontier's analysis does not find the same pattern of investment deferral, but does find capital cost savings due to shifting investment between QLD, VIC and SA. The level of capital cost savings found by *WHIRLYGIG* in response to the upgrade is also far lower than those reported by ElectraNet and AEMO.

4.3.1 Reasons for different level of displacement of SA generation

Based on size of the benefits reported by ElectraNet and AEMO, it is the first discrepancy – the pattern of SA brown coal and gas displacement by NSW black coal – that appears to be driving the majority of the differences between our and their results.

There are several possible reasons as to why the two modelling approaches are finding different results regarding the ability of NSW black coal to displace expensive SA generation. The most likely is due to the treatment of inter-regional flows. *WHIRLYGIG* has not been configured with a full set of intra-regional constraint equations. Power flows between regions are modelled using discrete inter-regional flow equations, which capture dynamic losses but effectively limit flows to notional import and export limits.

In the case of the Heywood interconnector, *WHIRLYGIG* has assumed that the interconnector is available bi-directionally at all times up to its full notional transfer limit of 460 MW. In the Upgrade case, this limit is increased by 190 MW to 650 MW. This approach to modelling inter-regional flows is different to that adopted by ElectraNet and AEMO, who modelled a subset of the 2010 NTNDP intra-regional constraints set. Rather than modelling inter-regional flows as being limited by notional import or export limits, the intra-regional constraints (depending on how they have been oriented) can result in inter-regional transfer limits at levels below the notional transfer capability of each interconnector, particular at times of peak demand. In the Upgrade case, ElectraNet and AEMO modified the subset of intra-regional constraints considered in their analysis. These modifications reflect the increased notional transfer capability from 460 MW to 650 MW, but also appear to reflect the relief of other constraints that often limit flows below the current notional interconnector limits.[6]

[6] PACR, p.21.

One consequence of modelling intra-regional constraints is that depending on the level of congestion that these constraints induce in the Base case, and how this level of congestion is alleviated once the constraints are re-oriented to reflect the Option 1b upgrade, the implied benefit of the upgrade can be very high. This is likely when inter-regional flows in the Base case are constraining frequently, leading to higher cost generation running in place of lower cost generation on the far side of the constraints. In the context of ElectraNet and AEMO's PACR modelling, Frontier's modelling and analysis suggests that in the Base case, the Heywood inter-connector is likely to be frequently import-binding during peak demand periods due to intra-regional constraints. This prevents lower cost NSW black coal generation from displacing higher cost SA brown coal and gas generation to the extent suggested by the nominal interconnector limit. In the Upgrade case – depending on how the intra-regional constraints are modified to reflect the augmentation – the incidence of peak period import constraints may reduce considerably. This will result in a large decrease in the operating costs in the Upgrade case relative to the Base case and thus yield a large gross market benefit.

When modelling inter-regional flows using notional import and export limits as opposed to intra-regional constraints, this outcome is less likely. This is because in both the Base and Upgrade cases, the level of inter-regional congestion is low. If the Heywood interconnector is already (close to) optimally utilised in the Base case, then the additional benefits of augmenting peak transfer capability only reduces operating costs at the absolute peak demand period, which is generally a small proportion of the year.

ElectraNet and AEMO did not release sufficient data with either the PADR or PACR to enable the above conjecture to be verified. In order to identify whether and to what degree the relief of existing intra-regional constraints contribute to the purported gross market benefits of Option 1b reported by ElectraNet AEMO, it would be necessary to scrutinise the pattern of inter-regional flows and congestion between VIC and SA prevailing in their modelling. The only comment that ElectraNet and AEMO make in regard to congestion in the Upgrade case relative to the Base case is in Section 4.16 of the PACR, where they note:

> ElectraNet and AEMO's modelling indicates that current constraints will be significantly reduced as a result of the augmentation.[7]

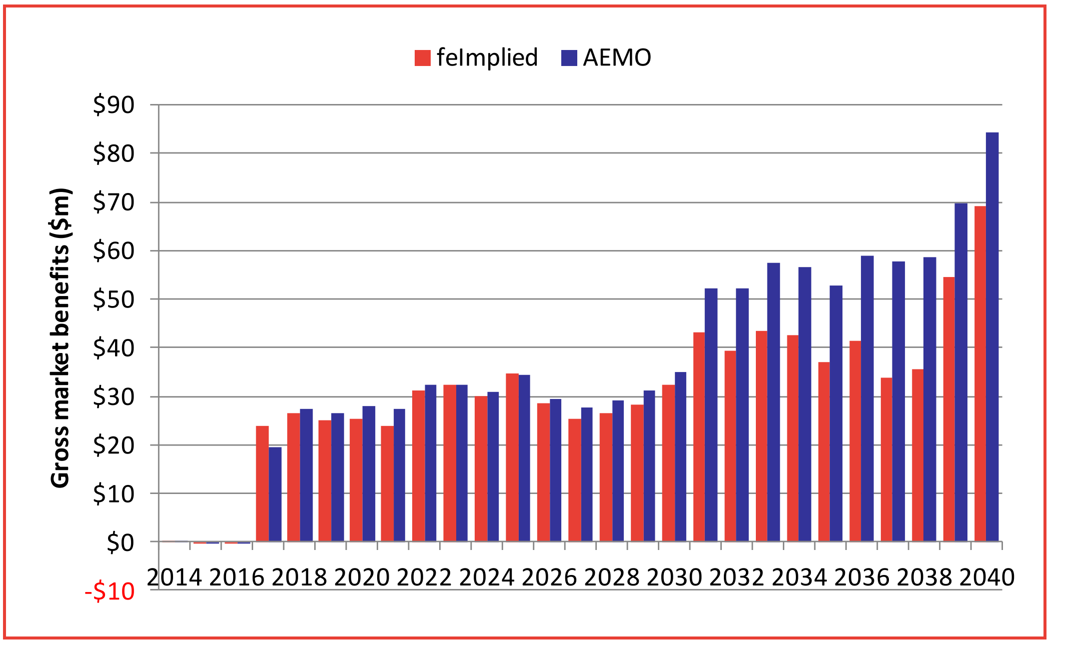
4.3.2 Ruling out differences in SRMC estimates

In order to narrow down the likely reasons for the large discrepancy between Frontier's and ElectraNet/AEMO's calculated gross market benefit of Option

7 PACR, p.68.

1b, we have attempted to quantify annual gross market benefits arising from operating cost savings using an amalgam of ElectraNet/AEMO's dispatch results and our input cost assumptions. Specifically, we have taken the change in plant dispatch as reported by ElectraNet and AEMO in each forecast year from the PACR and applied an average SRMC estimate to these changes based on our modelling and analysis. The purpose of this hybrid analysis is to confirm whether, using the input assumptions ElectraNet and AEMO state they have relied on and the patterns of dispatch they have published, it is possible to generate annual gross market benefits arising from operating cost savings that are comparable to the numbers published in the PACR.

Figure 16: Inferred operating cost benefits using ElectraNet/AEMO pattern of dispatch



Source: Frontier modelling and analysis

The results of this analysis are outlined in Figure 16. The chart compares the annual gross benefits arising from operating cost savings as reported by ElectraNet and AEMO to the inferred operating cost benefits that Frontier calculates using (i) ElectraNet and AEMO's altered dispatch pattern ex post the upgrade and (ii) Frontier's modelling inputs, which are based on the same input assumptions that ElectraNet and AEMO have used.

Figure 16 indicates that:

- Notwithstanding the differences highlighted below, the level of operating cost savings that can be verified using ElectraNet and AEMO's dispatch results indicate that the use of intra-regional constraints in ElectraNet and AEMO's modelling is having a very large impact on the expected total gross market benefits of Option 1b. Since the pattern of operating cost savings over the period 2013/14 to 2029/30 is very consistent, it would seem highly improbable that the various input assumptions which form each generator's SRMC (fuel prices, VOM estimates, carbon price, technical plant parameters, etc) used in ElectraNet and AEMO's modelling are somehow at odds with the original source of these assumptions which we have independently relied upon. It would appear that broadly the same SRMC assumptions for each generator in the NEM are being used by both ElectraNet/AEMO and Frontier. As such, it seems likely that the significantly different patterns of dispatch forecast by ourselves and ElectraNet/AEMO is being driven to a large degree by the treatment of intra-regional constraints.

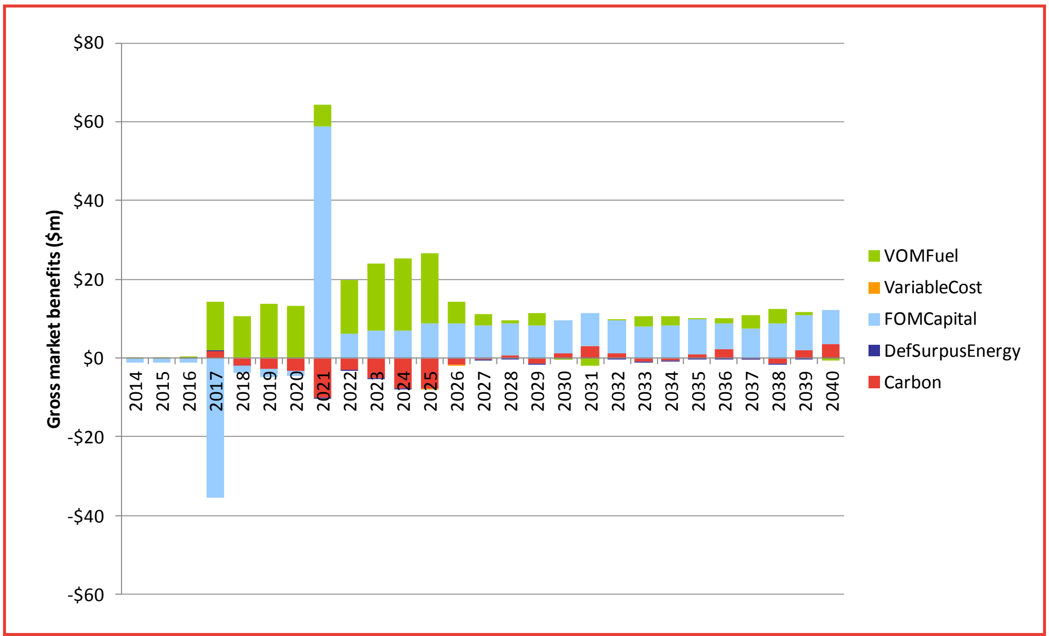
- Post 2029/30, the pattern of operating cost savings begins to systematically diverge – ElectraNet and AEMO's estimates begin to gradually increase while Frontier's inferred benefits stay broadly stable. It is not clear why this occurs. However, as noted in earlier sections, the 2010 NTNDP provides fuel price forecasts out to 2029/30. In Frontier's analysis we have assumed that fuel prices for the period post 2029/30 remain constant in real terms at this final year's level. Depending on how these future fuel price assumptions have been extrapolated forward, it is possible that ElectraNet and AEMO are assuming some growth in the price of gas past this point, particularly in SA. Since the magnitude of the operating cost benefit of Option 1b is a function of the SRMC differential between NSW black coal and SA gas, a rising gas price over this period would lead to a pattern of increasing annual operating cost benefits.

4.3.3 Simple investigation of impact of intra-regional constraints

In order to get a broad 'order-of-magnitude' feel for how much of an impact intra-regional constraints might be influencing the estimated gross market benefit of Option 1b, Frontier has modelled a second case. In this second case, we have implemented a crude approximation of the potential extent of export limits from VIC to SA at different levels of demand by constraining flows between these regions to the actual export limits experienced in 2009/10. The year 2009/10 was chosen to be consistent with ElectraNet and AEMO's modelled base year for demand and wind traces (see Section D.1 of the PACR). This approach is a very crude approximation of the impact that intra-regional constraints can have on flows between regions. Since the constraint is 'static' (it is based on actual outcomes from 2009/10), the interpretation of these results should be taken as only indicative of the sensitivity of the calculated market benefit of Option 1b to different assumptions about inter-regional congestion occurring at levels below Heywood's notional import/export limit of 460 MW (650 MW after the upgrade).

Based on the above approach, the present value of gross market benefits of Option 1b increase from **$24.23m** to **$66.13m** ($2011/12, present value 2011/12). The pattern of forecast gross market benefits is outlined in Figure 17.

Figure 17: "Order-of-magnitude" impact of congestion below notional limits



Source: Frontier modelling and analysis

The pattern of benefits is broadly consistent with our standard approach (Figure 14), however the magnitude of benefits is significantly higher. Over the period 2016/17 to 2024/25 the magnitude of annual gross benefits ($15-$20m) is reasonably consistent with ElectraNet and AEMO's reported annual gross benefits (~$20m). From 2030/31 onwards the magnitude of benefits is significantly lower than ElectraNet and AEMO's estimates. As noted in Section 4.3.2 the increase in operating cost savings reported by ElectraNet and AEMO from 2030/31 onwards might be due to the fuel prices assumed in their modelling over this period.

4.3.4 Comparison to Option 4

To the extent that ElectraNet and AEMO's high modelled benefits of Option 1b may be influenced by their treatment of intra-regional constraints that limit current interconnector flows below the notional limit of 460 MW, it is worth comparing their results for Option 4 against their results for Option 1b. Option 4 consists of:

- Installation of a 500 kV bus tie in Victoria
- Reconfiguration of the 132 kV network in south-east South Australia and

- Installation of a 100 MVAr capacitor in South Australia.[8]

The objective of Option 4 is to 'firm up' the existing 460 MW notional transfer capacity on the Heywood Interconnector.[9]

If Option 4 helps firm the 460 MW notional capacity of Heywood, then the incremental gross market benefits of Option 1b over Option 4 from the ElectraNet and AEMO modelling should yield a similar figure to the gross market benefits we found for Option 1b. However, ElectraNet and AEMO found the present value of gross market benefits from Option 4 to be approximately $191 million ($2011/12). This is about $93 million less than the present value of gross market benefits for Option 1b, far in excess of our estimate of $24.23 million.

8 PACR, pp.33-34.

9 PACR, pp.33-34.

5 Conclusions and next steps

Outlined below is a brief summary of our findings and a list of questions relating to ElectraNet and AEMO's work. We consider that further detail and information from ElectraNet and AEMO regarding some of these issues would add transparency and rigour to the modelling and analysis they have performed to date in estimating the gross market benefits of Option 1b.

5.1 Summary of Frontier's findings

Frontier has sought to independently assess the gross market benefits of Option 1b under the Revised Central scenario modelled by ElectraNet and AEMO. We have attempted to use as consistent a modelling framework and input assumptions to that used by ElectraNet and AEMO as has been feasible within the scope of our engagement. In brief:

- We have quantified the gross market benefits using *WHIRLYGIG*, which dispatches generation plant on a least-cost basis in a manner consistent with a perfectly competitive electricity market or 'SRMC' bidding. This is consistent with the approach used by ElectraNet and AEMO.
- We have relied where possible on the same primary source for input assumptions as ElectraNet and AEMO has used. These assumptions include fuel prices, plant technical and operating parameters, plant capacities, demand growth, carbon prices and the LRET target.
- One major point of departure between our analysis and ElectraNet and AEMO's is the consideration of intra-regional transmission constraints. Frontier's approach models inter-regional flow using discrete constraints that limit power transfers between regions to notional import and export regions. ElectraNet and AEMO's approach considers the impact that intra-regional constraints can have on constraining flow between regions to levels below notional transfer limits.

Based on the above approach, we have quantified the gross market benefit of Option 1b as **$24.23m** ($2011/12, present value as at 2011/12). This compares to ElectraNet and AEMO's estimate (on a comparable basis) of **$284m**. We have attempted to ascertain what is driving the large discrepancy between our and ElectraNet/AEMO's estimate of gross market benefits. Based on the information available, it would appear that the treatment of intra-regional constraints under ElectraNet/AEMO's approach is a large driver of this overall difference. This is because a large degree of congestion in the Base case – which prevents low-cost NSW black coal from displacing high-cost SA brown coal and gas – that is subsequently alleviated as a result of the Option 1b upgrade leads to large operating cost savings being attributed to the augmentation.

5.2 Questions in relation to AEMO's work

Below is a list of questions that have arisen over the course of our analysis regarding the modelling and analysis performed by ElectraNet and AEMO in estimating the gross market benefits of Option 1b:

(1) The impact of intra-regional constraints

- How sensitive are AEMO's gross market benefit estimates to the assumed configuration of intra-regional constraints – and resulting patterns of congestion that limit flows from VIC to SA at peak demand times – in the Base case?
- How sensitive are AEMO's gross market benefit estimates to the assumed configuration of intra-regional constraints – and resulting patterns of congestion that limit flows from VIC to SA at peak demand times – in the Upgrade case?
- Public release of the following data would assist stakeholders in understanding and interpreting the impact that assumed intra-regional constraints is having on the estimated gross market benefits:
  - Half-hourly inter-regional flow data between VIC and SA across both Heywood and Murraylink, for both the Base and Upgrade cases.
  - Half-hourly import and export limits on the flows between VIC and SA across both Heywood and Murraylink and which are a consequence of the intra-regional constraints modelled by AEMO, for both the Base and Upgrade case.

(2) Confirmation of assumed fuel prices post FY2030

- Our analysis of AEMO's derived gross market benefits indicate that from 2030/31 onwards the magnitude of operating cost benefits attributable to Option 1b appear to rise over time.
- The 2010 NTNDP supply input spreadsheets available on AEMO's website only provide fuel price forecasts out to 2029/30.
- It would be helpful if ElectraNet and AEMO could confirm what fuel price assumptions have been used for all generation plant in the NEM over the period 2030/31 to the end of the modelling horizon.

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