ROAM CONSULTING

ENERGY MODELLING EXPERTISE

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Report (TSY00001) to

Australian Government

The Treasury

Projections of Electricity Generation in Australia to 2050

August 2011

GLOSSARY

Term	Meaning
2-4-C	ROAM dispatch modelling software package
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
DKIS	Darwin Katherine Interconnected System
GEC	Gas Electricity Certificate
GJ	Gigajoule
GW	Gigawatt (1000 MW)
GWh	Gigawatt-hour (1000 MWh)
IGCC	Integrated Gasification Combined Cycle
LRET	Large-scale Renewable Energy Target
LTIRP	ROAM Consulting's Long Term Integrated Resource Planning model
MW	Megawatt
MWh	Megawatt-hour
MMRF	Monash Multi-Regional Forecasting Model, used by Treasury to determine electricity demand
NEM	National Electricity Market
GGAS	NSW Greenhouse Gas Abatement Scheme
NTNDP	National Transmission Network Development Plan
NWIS	North West Interconnected System
OCGT	Open Cycle Gas Turbine
PJ	Petajoule
RET	Renewable Energy Target
ROAM	ROAM Consulting
Solar PV	Solar Photovoltaic
SRES	Small-scale Renewable Energy Scheme
SWIS	South West Interconnected System
Treasury	Department of the Treasury
TWh	Terawatt-hour (1000 GWh)
WACC	Weighted Average Cost of Capital

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1) Introduction

The Department of the Treasury (Treasury) has commissioned ROAM to provide projections for the development in the electricity sector between 2010-11 and 2049-50.

The purpose of this report is to present the results for two alternative reference scenarios and two alternative policy scenarios, as described below:

1. **Medium Global Action:** World action to achieve a 550ppm emissions target, without any domestic carbon price
2. **Ambitious Global Action:** World action to achieve a 450ppm emissions target, without any domestic carbon price
3. **Core Policy:** World action to achieve a 550ppm emissions target, with a $20 starting carbon price.
4. **High Price:** World action to achieve a 450ppm emissions target, with a $30 starting carbon price.

The four scenarios incorporate different macroeconomic drivers, particularly driven by international action and the resulting demand for Australia's resources. This has an impact on such things as domestic electricity demand, and commodity prices for combustible fuels. For each scenario Treasury has advised on the change to each of these parameters.

The methodology used for conducting the investigations for this report is a two-step process:

- Development of a least cost plan for generation and major transmission over the whole of their operating lifetimes, including the retirement of existing generators when they are no longer the least cost means of providing energy supply, inclusive of the costs of carbon emissions, depending on the scenario
- Modelling the least cost planning outcome in a half hourly time sequential manner from 2010 to 2050, observing the market rules for the NEM.

This report includes information relating to:

- Generation development
- Transmission development
- Wholesale pool prices
- Retail pricing
- Emissions

A number of sensitivity cases have been considered around the four scenarios, to explore the change in development if the future evolves differently from the assumptions of the four scenarios. These are discussed, but in a lesser level of detail than for the four scenarios.

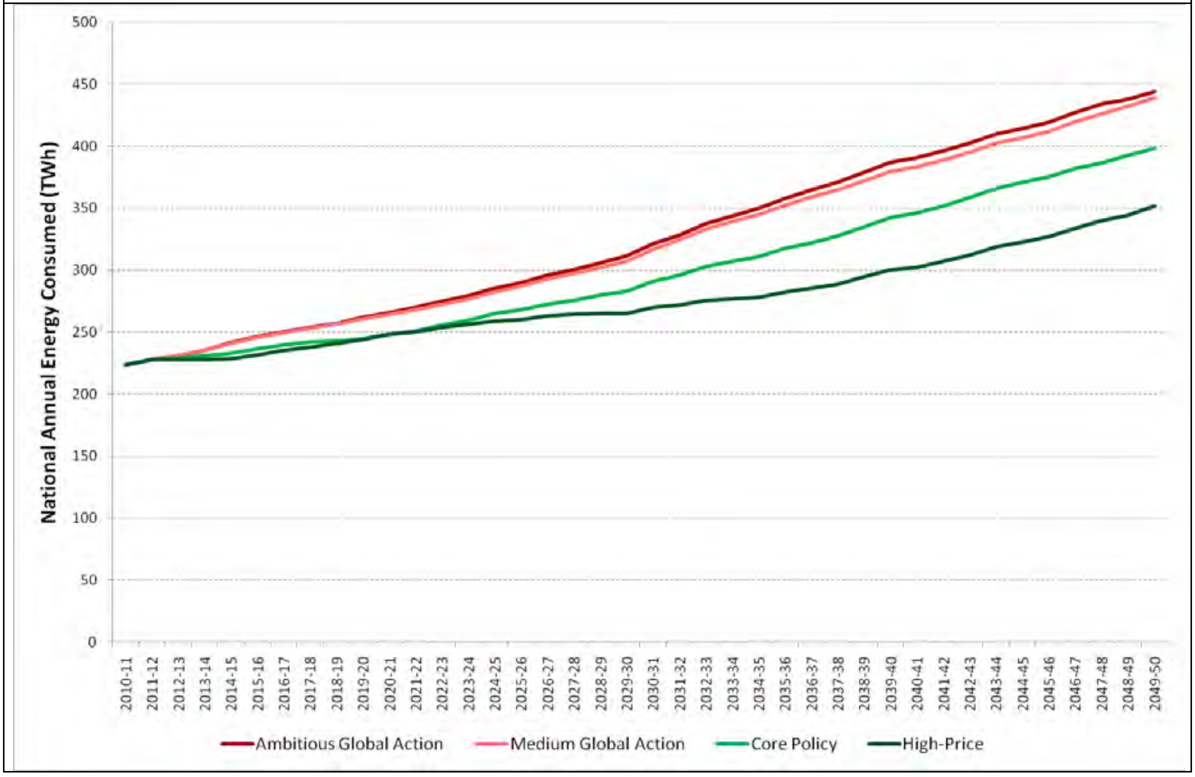
Key modelling data and detailed calculation methodology are included in the appendices to this report (Appendix A).

2) SIGNIFICANT INPUT PARAMETERS: ELECTRICITY DEMAND AND CARBON PRICE

2.1) *ELECTRICITY DEMAND*

The national annual electricity demand for each scenario is shown in the figure below.

Figure 2.1 – National Annual Electricity Demand



2.2) *CARBON PRICE TRAJECTORIES*

Carbon price assumptions were provided by the Treasury for the two carbon pricing scenarios and for the low price sensitivity case. The carbon price for the core policy scenario commences from July 2012 at $18.5 t/$CO_2$e, and then jumps in FY 2016 from $20/t CO_2e to $25/t CO_2e, and grows at 5% per annum thereafter. Under the high price scenario the initial carbon price is $27.5/t CO_2e, commencing in July 2012. As with the core policy scenario the price steps up in FY 2016, although to a much higher level (from $30.5/t CO_2e to $52/t CO_2e) and it continues to grow at 5% per annum thereafter. The carbon price for the low price sensitivity case also commences from July 2012 at $9/t CO_2e. However, the step jump in price is deferred to FY 2023 when it jumps from $14/t CO_2e to around $35.5/t CO_2e, where the latter price is identical to that of the core policy scenario in FY 2023. The carbon price trajectory for the low price sensitivity case then tracks that of the core policy scenario having a growth rate of 5% per annum thereafter.

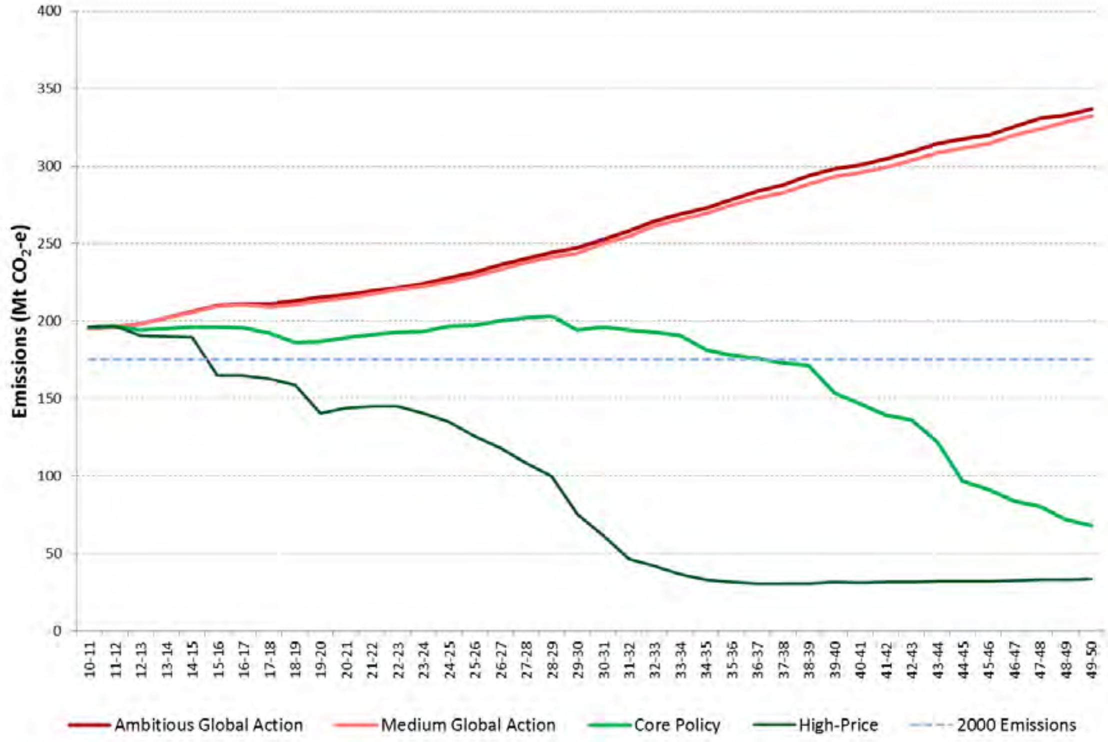
3) SIGNIFICANT OBSERVATIONS: EMISSIONS

3.1) *EMISSIONS TRAJECTORY*

Figure 3.1 shows the total annual carbon emissions resulting from electricity generation in all four scenarios. Both reference cases exhibit a steady upward trajectory over the entire period of this analysis. These outcomes are consistent with energy growth and increases in the level of coal generation and demonstrate that some form of emissions reduction policy is needed to deliver emissions reductions in the future, even with the RET scheme in place. Both policy scenarios show significant reductions in emissions by 2050 with the High Price scenario showing a rapid decrease in emissions compared to Core Policy scenario. This is consistent with the generation outcomes which show that a $30 starting carbon price results in earlier retirement of some of the brown coal generators in particular.

Figure 3.1 also shows the performance of the market in terms of its emissions reduction as compared to the level of electricity sector emissions in 2000.

Figure 3.1 – Emissions Trajectories



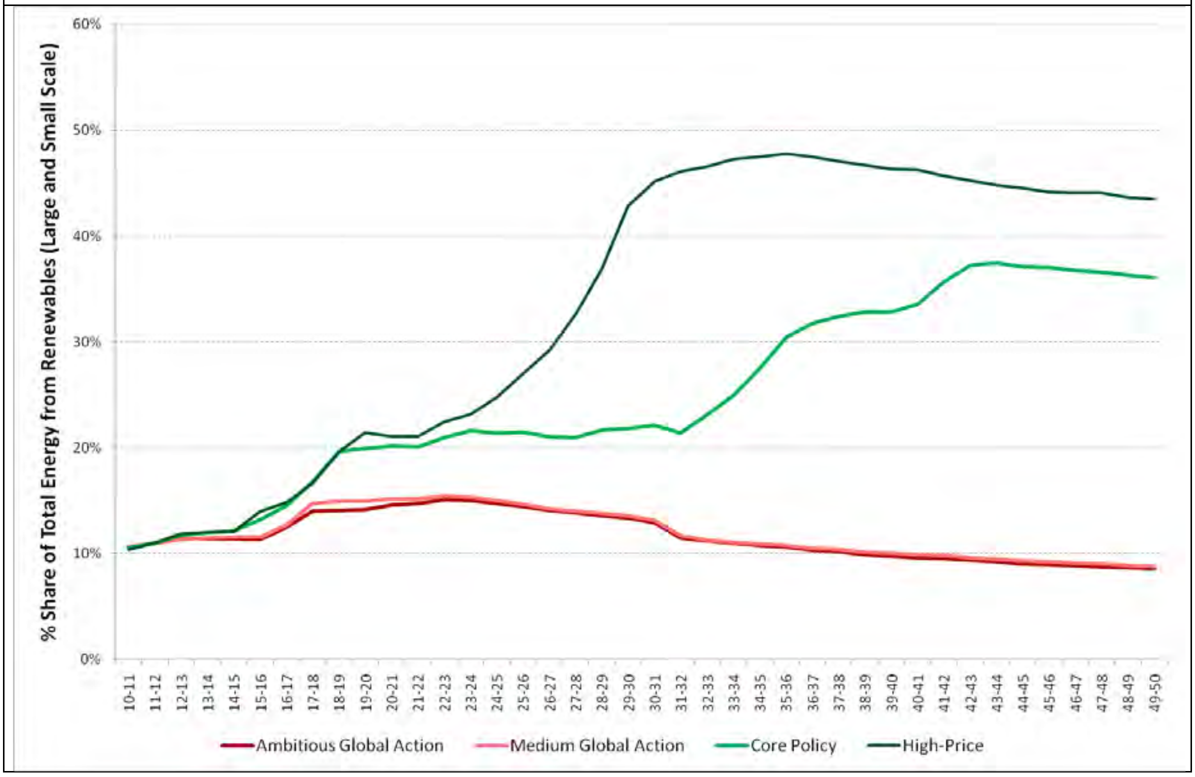
3.2) *GENERATION FROM RENEWABLES: MEETING THE LRET*

Key to management of electricity sector emissions is the increased development of low emissions and zero emissions technologies.

The following figure shows the share of total annual energy provided by renewable generators, inclusive of forecast small scale distributed SRES eligible generators such as rooftop PV and solar water heaters. As the figure shows, despite the LRET of 20% by 2020 incentivising renewables in the reference scenarios, there exists insufficient subsidy in the long term to justify sufficient installation of renewables to meet this target without a carbon policy or changes to the LRET scheme. Significant expansion of the renewable sector is seen until approximately 2020 in response to the increasing value of renewable energy certificates in the reference scenarios and the availability of high energy wind resources in southern Australia. However it is still least cost to pay the penalty price (which being in nominal terms reduces in value over time) than installing additional wind capacity (discussed in the following section).

Under the core policy and high price scenarios, the carbon price is sufficient to drive at least 20% renewables by 2020, and in the case of the high price scenario renewables achieve almost 50% of total annual energy in the 2030s until carbon capture and storage could emerge as a commercial large scale alternative.

Figure 3.2 – Renewable Share of Annual Energy



3.3) *RENEWABLE ENERGY CERTIFICATE MARKET*

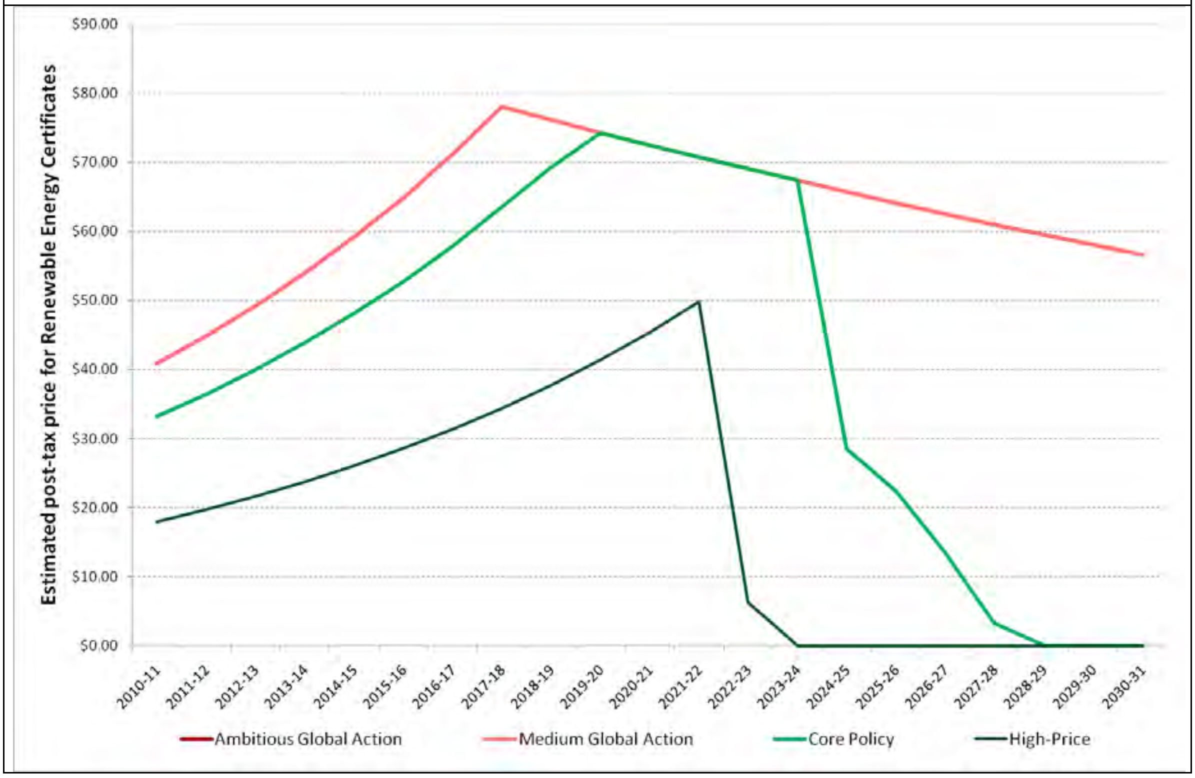
ROAM has forecast the estimated price of Renewable Energy Certificates under each of the four scenarios.

ROAM's modelling shows that the least cost expansion of supply includes development of renewables under all scenarios, incentivised by the Renewable Energy Target, as discussed previously. However, under the reference scenarios there is insufficient incentive to meet the target, and as such the price of RECs is forecast to reach the price cap when the existing surplus of certificates runs out.

Under the core policy scenario, supply of RECs is also forecast to fall short of the legislated annual LRET targets (41,000GWh in 2020), albeit temporarily. As such the price for RECs is expected to reach the price cap by approximately 2020. However the increasing carbon price and the availability of higher capacity factor technologies such as geothermal and solar thermal plant results in the market exceeding the target by 2030.

It should be noted that the forecast prices shown here are estimates only. The estimate is calculated from the subsidy, over each generators operating life, required to meet the annual targets – if that subsidy is higher than the price cap, the penalty price will be paid rather than installing additional new renewable. The estimate has been calculated from the expected NEM contribution to the federal target, and excludes the price impact of renewables installed in other regions of Australia. ROAM has assumed that 90% of the Australian target will be met through renewables installed in the NEM, leaving 10% to be installed in Western Australia or the Northern Territory. This is in line with recent State Government announcements which suggest Western Australia will look to contribute its proportionate share in renewable generation to meet the LRET. The surplus shown in Figure 3.4 below however is calculated on the whole of Australia REC supply, and therefore the timing of the REC shortfall is only indicative of the likely trajectory.

Figure 3.3 – Estimated Renewable Energy Certificate Price



Box 1 – REC price forecast methodology

ROAM's LTIRP model has been used to construct the REC price forecast. The price of RECs is calculated as the subsidy required to make eligible renewable generation least cost using the legislated annual REC targets. If the subsidy is greater than the calculated REC shortfall charge (taking into account the adjustment to convert the shortfall charge in nominal dollars to modelling in real dollars) then the REC target is not achieved in that year and the price is set as the post-tax shortfall charge.

Presently there is an abundance of banked RECs – eligible certificates which are yet to be surrendered and may be surrendered in future years to meet future annual liabilities. The value of these certificates is determined by the first year in which either the shortfall charge is paid, or the subsidy is calculated as less than the shortfall charge.

As an example, in the Core Policy case there exist sufficient banked certificates and newly generated certificates to achieve the annual targets until 2019-20. In this year there is insufficient generation from renewable generators to create sufficient certificates to meet the LRET liability, and therefore the REC price is set at the shortfall charge. Beyond 2025 the carbon price incentivises sufficient renewables to enter, lowering the subsidy below the shortfall charge.

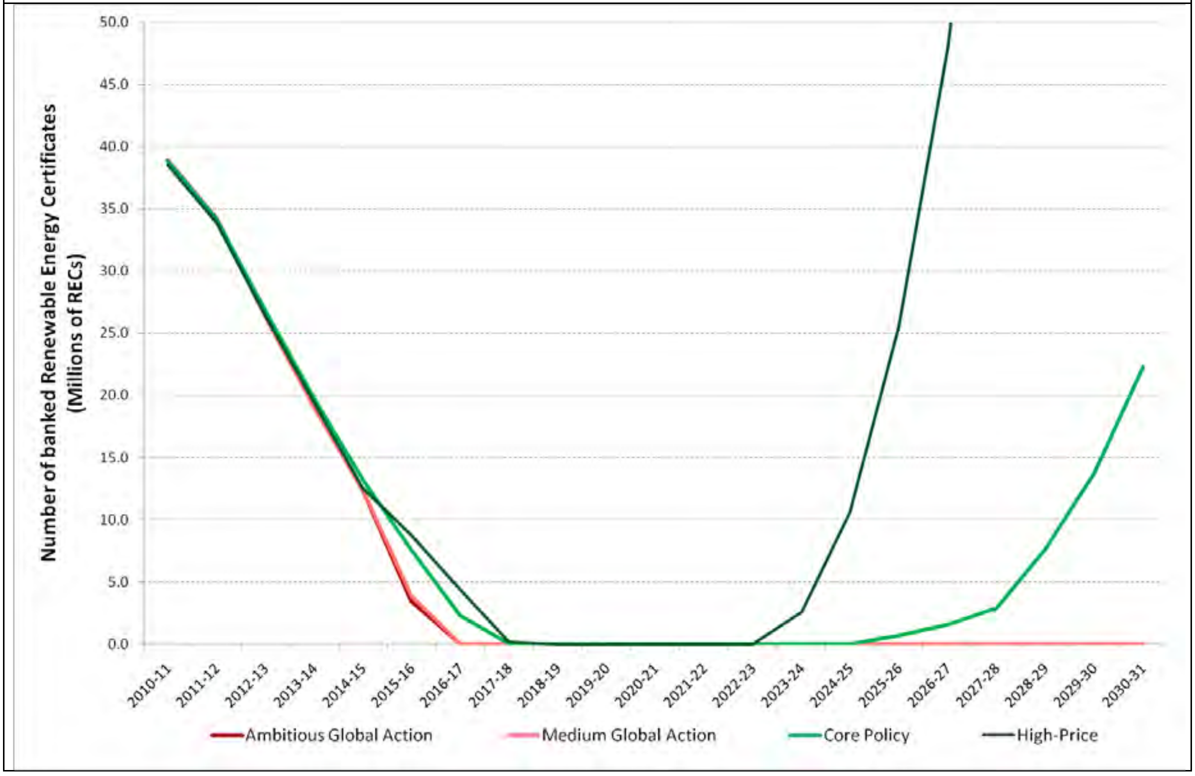
There are two points of interest here. Firstly, the price up to 2019-20 grows annually until the shortfall charge is reached. In 2010-11 there is an abundance of certificates, far in excess of the annual target in that year. A certificate could be either surrendered in that year, or banked until there is a shortage of certificates – 2019-20 in this case. The value of the certificate therefore in 2010-11 is therefore the discounted value of the 2019-20 price. The discount rate used is the WACC as defined previously. A renewable generator would consider it equivalent to either to sell a certificate to a retailer to surrender to meet its 2010-11 liability at the discounted price, or to bank the certificate until 2019-20 and receive the full shortfall charge.

The second point is the price which is determined in 2024-25 in the Core Policy (and similarly 2022-23 in the High Price scenario) – that is, a price which is between the shortfall charge and zero. In this year, there does not exist a surplus of certificates. However, in order to make renewable generation least cost the calculated subsidy is lower than the shortfall charge. The model therefore determines that it is least cost to generate sufficient RECs to *meet* the annual target, and the price of RECs is the calculated value of the subsidy.

Figure 3.3 above shows that the renewable energy certificate price is estimated to increase from the current low price levels of approximately $30 to $40 to the market price cap by as early as 2017-18 if no carbon price is introduced. Considerable numbers of banked certificates currently exist in the market, which has lowered the price to its present level. Limited investment in renewables over the period to 2020, particularly in the reference scenarios, results in insufficient supply of RECs, and therefore the value of RECs will increase. ROAM has determined that it is least cost to pay the penalty price in some years and generate from lower cost alternatives rather than installing sufficient renewables to meet the LRET target of 41,000GWh per annum between 2020 and 2030 (inclusive of small scale generators).

Figure 3.4 depicts the oversupply of banked certificates. Presently, approximately 40 million certificates exist but have yet to be surrendered, and may therefore be used in future years to meet RET liabilities. Limited investment in renewable generators results in a significant reduction in that oversupply. In all cases, the number of banked certificates reduces to zero. In the High Price policy scenario, the introduction of a high carbon price results in the least cost generation option being renewable generation, and therefore sufficient certificates are generated annually to meet the RET liabilities and the REC price does not reach the price cap. From 2023-24 the value of RECs reduces to zero in this scenario as the carbon price alone provides sufficient incentive for the creation of greater than the annual targets of RECs. In the Core Policy scenario this also occurs, although not until after 2025. In the Core Policy case, the price cap is reached, as in the years from 2019-20 to 2023-24 there are insufficient certificates until additional renewables are installed lowering the REC price to zero by 2030.

Figure 3.4 – Number of Banked or Surplus Renewable Energy Certificates



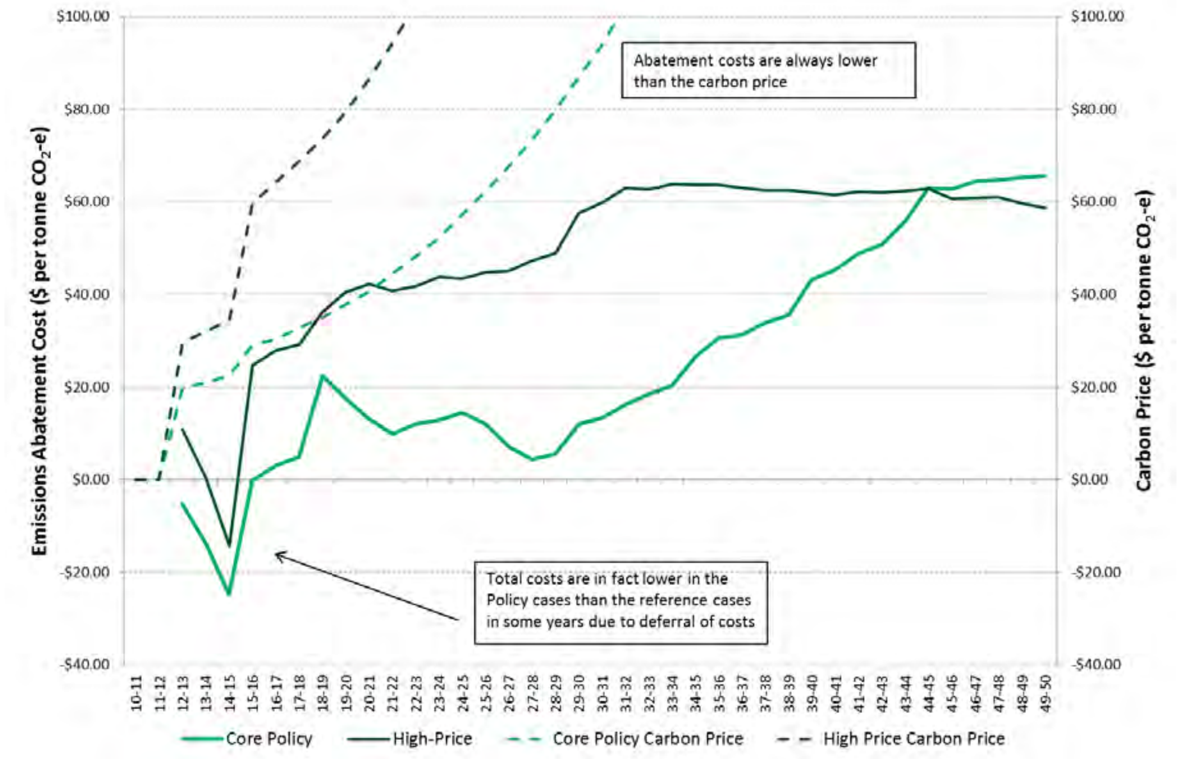
3.4) *ABATEMENT COSTS*

ROAM has assessed the costs associated with the abatement achieved in the policy scenarios, compared to their respective reference cases. Taking the difference in total cost and dividing it by the difference in emissions, ROAM has calculated an approximate annual cost of abatement per tonne of CO_2-e as delivered through the change in least cost generation (and transmission) development in response to carbon policy. These are plotted in Figure 3.5, along with the carbon price.

Abatement costs increase to approximately $60 per tonne CO_2-e in the High Price scenario, before stabilizing. In the Core Policy scenario, the change in least cost expansion plan is less than $20 per tonne CO_2-e until around 2035, although it does trend upwards from 2030 and reaches just over $60 per tonne CO_2-e by the end of the forecast horizon.

The abatement cost is the average cost of abatement. The carbon price will drive abatement up to the level where the marginal cost of emitting is equal to the marginal cost of abating. Hence the average cost of abatement is less than the marginal cost of abatement. The average cost of abating a high proportion of all emissions is estimated to be in the vicinity of $60/MWh in real terms over the lifetime of low emission generation options. However the marginal cost of abating all emissions exceeds that of the High Price scenario, at least to 2050.

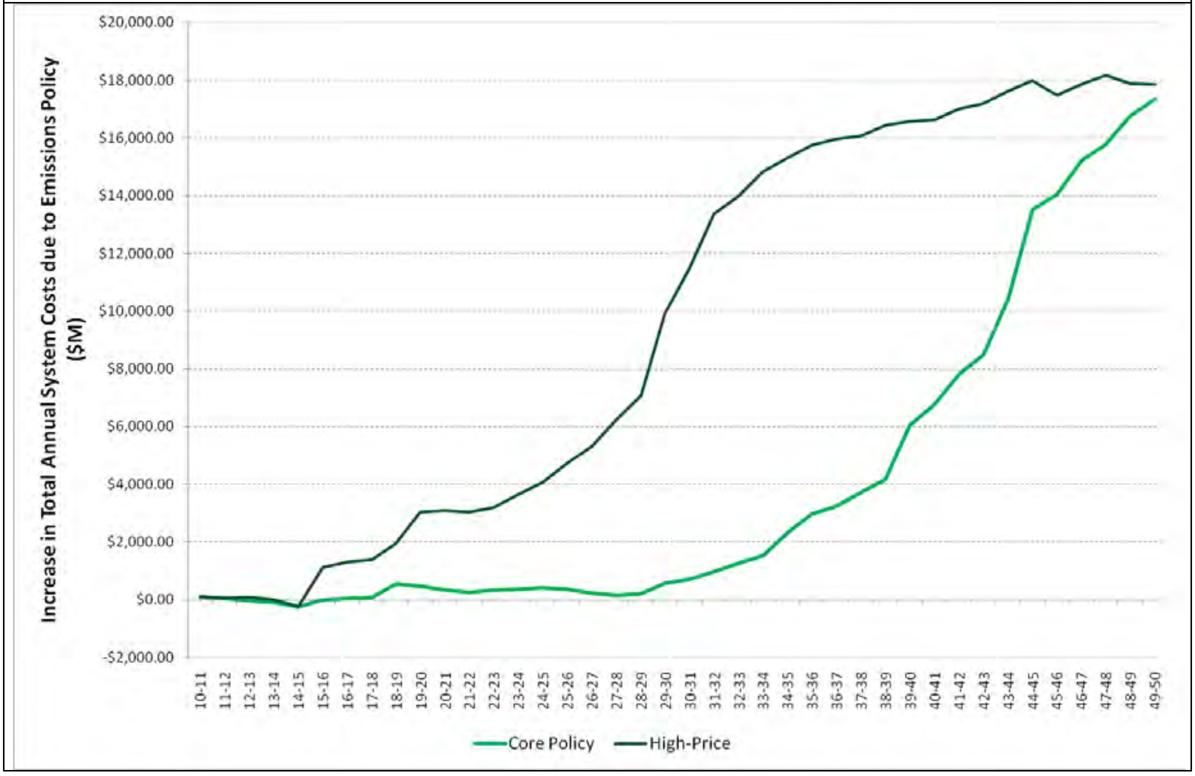
Figure 3.5 – Average Abatement Costs of Carbon Policy



Considering the change in total annual system cost as shown in Figure 3.6 (that is, the total annual cost of operating the generators, including fuel, operations and maintenance, as well as the annualised repayments of generator capital costs and interconnector transmission capital but excluding the carbon emissions costs) shows that the Core Policy scenario is only marginally more expensive than the reference scenario until approximately 2030. System costs are approximately $200 million greater per annum given the change in development in response to the carbon price, with some years showing temporary reductions in total costs paid. This can occur if there is a difference in electricity demand providing a temporary surplus of capacity and a reduction in energy production costs.

As expected, the High Price scenario shows significantly higher system costs (excluding carbon costs), and starting far earlier than the Core Policy. This is due to the earlier retirement and replacement schedule in the High Price policy. Given that existing generators' capital costs are considered sunk, the retirement and replacement of the black and brown coal fleet due to carbon policy is one of the single largest costs to the system

Figure 3.6 – Change in Total System Costs



For the period until 2030, the Core Policy scenario's total system costs are only marginally higher per annum than the reference scenario. In the Core Policy scenario the introduction of a carbon price promotes expansion of the renewable industry, particularly from 2015. This results in higher capital costs relative to the Medium Global Action scenario. Offsetting this, the Core Policy scenario has lower operating costs compared with the reference scenario, resulting in a minor total cost difference as energy usage is lower, as shown previously (Figure 2.1). However, beyond 2030 the retirement schedule of existing coal generators, particularly the brown coal generators in Victoria, ensure increased capital repayments, while operating cost savings reduce as higher cost gas plant captures energy no longer provided by the coal sector. This is also apparent in the High Price scenario; however the retirement schedule for coal generators commences far earlier, resulting in a rapid separation in the total system costs (excluding carbon costs) of the reference and policy cases.

3.5) *Reliability of Renewable Generators*

The inherent difficulty with expanding the renewable generator fleet is the intermittent nature of existing economic renewable technologies. Wind and solar generators in particular are exposed to rapid changes in generating levels depending upon the prevailing wind speeds or level of cloud coverage respectively.. However, the Reliability Standards[1] state that the market must continue to deliver no more than 0.002% unserved energy, and therefore the market must be expanded in

[1] This is the mandatory reliability of supply specified for 'Bulk Supply Points' for electricity in the NEM and SWIS

such a way that the installed capacity of *reliable* generation must be sufficient to cover the loss of generation and/or transmission elements and still meet electricity demand[2].

ROAM's LTIRP model incorporates the intermittency of wind. ROAM has implemented the following rules with regard to renewable generators and their availability at regional peak demand periods:

- Wind generators are *not* available during peak demand periods. That is, wind generators provide 0MW during peak demand periods
- Solar generators (without storage) are available but only to their average capacity factor. That is, if a solar generator was expected to generate at 35% capacity factor throughout the year, these generators will only contribute 35% of their installed MWs in the peak period
- Solar generators with storage are fully available
- Geothermal and hydro plant are fully available. Operators of hydro generators will conserve water leading up to peak periods (if necessary) so that they may be fully dispatched in the peak periods.

To model the intermittency of wind in the model, ROAM has varied the output from wind generators such that the total annual energy is equal to the target capacity factor; however in any given period (except the peak period) dispatch for a wind farm may vary anywhere from 0MW to its installed capacity. The dispatch is correlated to the prevailing electricity demand in that period, aligned to historic data.

These reliability assumptions are not overly conservative – the NEM assumes very low levels of reliability from existing wind generators. In the 2010 Electricity Statement of Opportunities[3], Tasmanian and Queensland wind farms are assumed in reliability forecasting to not generate during the maximum demand period, while New South Wales, Victoria and South Australia assume 5%, 8% and 3% contribution factors respectively. In the 2011 South Australian Supply Demand Outlook[4] the firm capacity of existing wind farms, defined to be the level of generation considered to be statistically reliable during 85% of peak demand periods, is only 8% of the installed capacity.

The cost of meeting the renewable energy targets with intermittent supply from wind generators therefore effectively includes an additional installation of peaking plant, unless sufficient existing or other new dispatchable plant is in place. The intermittency of wind contributes to the failure of the market to meet the RET in the reference scenarios, as the additional capital expenditure needed to install peaking capacity with wind generators means that wind generators are not least cost, even with the LRET scheme. The least cost model assumes that wind does not pick up its full share of peak prices, as it does not operate at peak times, which may limit the development of

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[2] The documentation surrounding the AEMO Minimum Reserve Levels (http://www.aemo.com.au/electricityops/mrl.html) provide additional material if further understanding of market reliability is necessary

[3] http://www.aemo.com.au/planning/esoo2010.html

[4] http://www.aemo.com.au/planning/SASDO2011/report.html

wind in all scenarios, and result in a somewhat pessimistic level of wind entering compared with actual wind development.

3.6) *PROFITABILITY OF WIND GENERATORS*

Wind generators tend to suppress prices. The 2011 South Australian Supply and Demand Outlook, as published by AEMO, demonstrates this, showing that while the volume weighted average South Australian pool price in 2010-11 was $45.17/MWh, the volume weighted average price at times when renewable generators were dispatched was only $22.82/MWh. Furthermore, thermal generators earned more than the average price, implying they generated more during calmer periods. This suggests that wind generators, being the primary renewable generation type currently installed in South Australia, tend to suppress prices when operating compared to other thermal technologies and/or operate often during periods of low price, such as off-peak and overnight periods.

Table 3.1 – Volume Weighted Wholesale Market Prices for South Australia since 2004[5]

	Renewables		Thermal		South Australian Market		
Financial Year	**Full Year ($/MWh)**	**Summer ($/MWh)**	**Full Year ($/MWh)**	**Summer ($/MWh)**	**Full Year ($/MWh)**	**Summer ($/MWh)**	**Full year time weighted ($/MWh)**
2003-04	33.09	40.56	39.96	50.43	43.85	61.09	38.33
2004-05	38.47	56.72	44.56	67.50	44.61	67.92	39.10
2005-06	32.57	39.59	43.91	67.50	43.26	65.78	37.76
2006-07	49.69	51.55	58.71	67.21	58.35	66.43	51.61
2007-08	63.31	63.94	102.01	149.92	98.46	142.32	73.50
2008-09	46.39	91.80	70.50	165.34	67.16	155.12	50.98
2009-10	47.39	77.43	86.69	140.98	80.17	131.01	55.31
2010-11[6]	22.82	29.75	50.78	91.74	45.17	78.60	33.99

The following figures show the forecast volume weighted average operating price received by each technology, compared with the time weighted average pool price. Some observations of the thermal plant include:

- Peaking plant in particular only generates when pool prices are high; ;
- Baseload generators, such as brown and black coal, tend to marginally exceed the pool price. The withdrawal of capacity to minimum load during lower price periods enables black coal generators in particular to increase its average price while operating to about 5% higher than the average annual pool price; and

[5] Australian Energy Market Operator, 2011 Draft South Australian Supply and Demand Outlook, http://www.aemo.com.au/planning/0400-0031.pdf

[6] The values for 2010-11 financial year are based on the period 1 July 2010 to 31 March 2011

- Combined cycle plant, which traditionally operate during the peak periods and either at minimum loads or cycle offline overnight, operate at 5% to 10% higher than the average annual pool price.

Figure 3.7 – Average Price when Operating – Thermal Plant (Average of all scenarios)

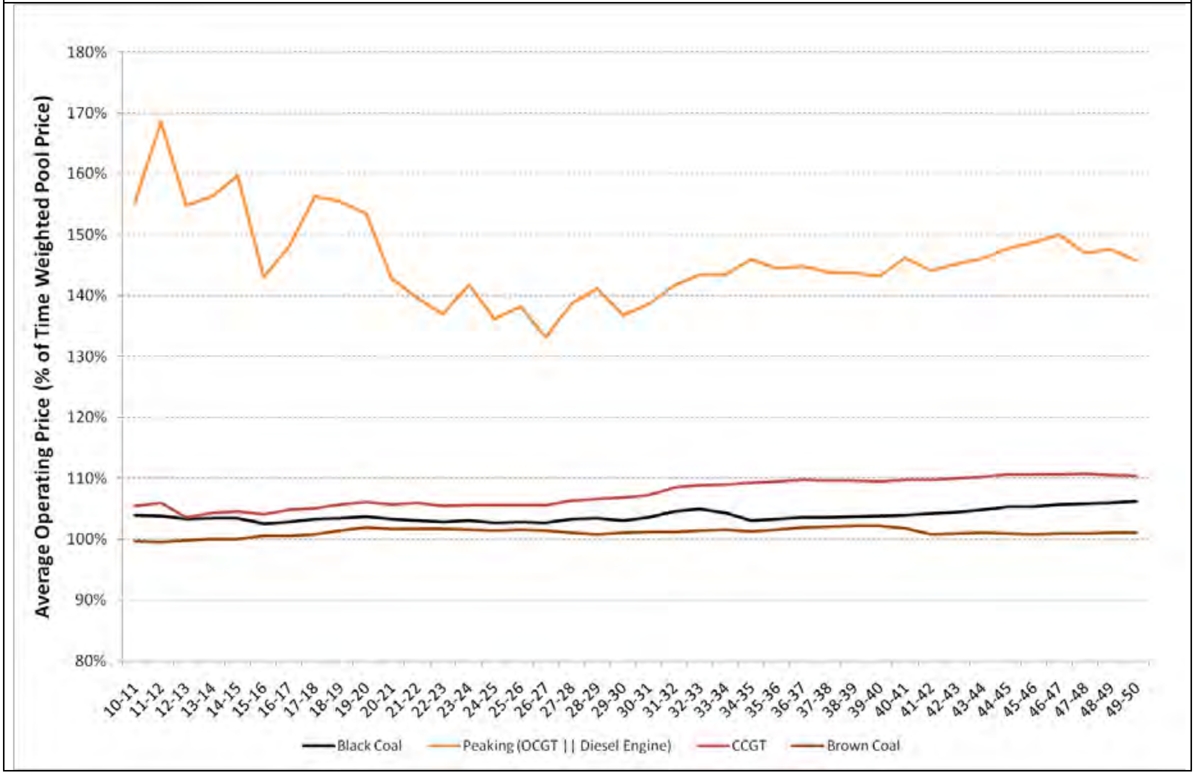
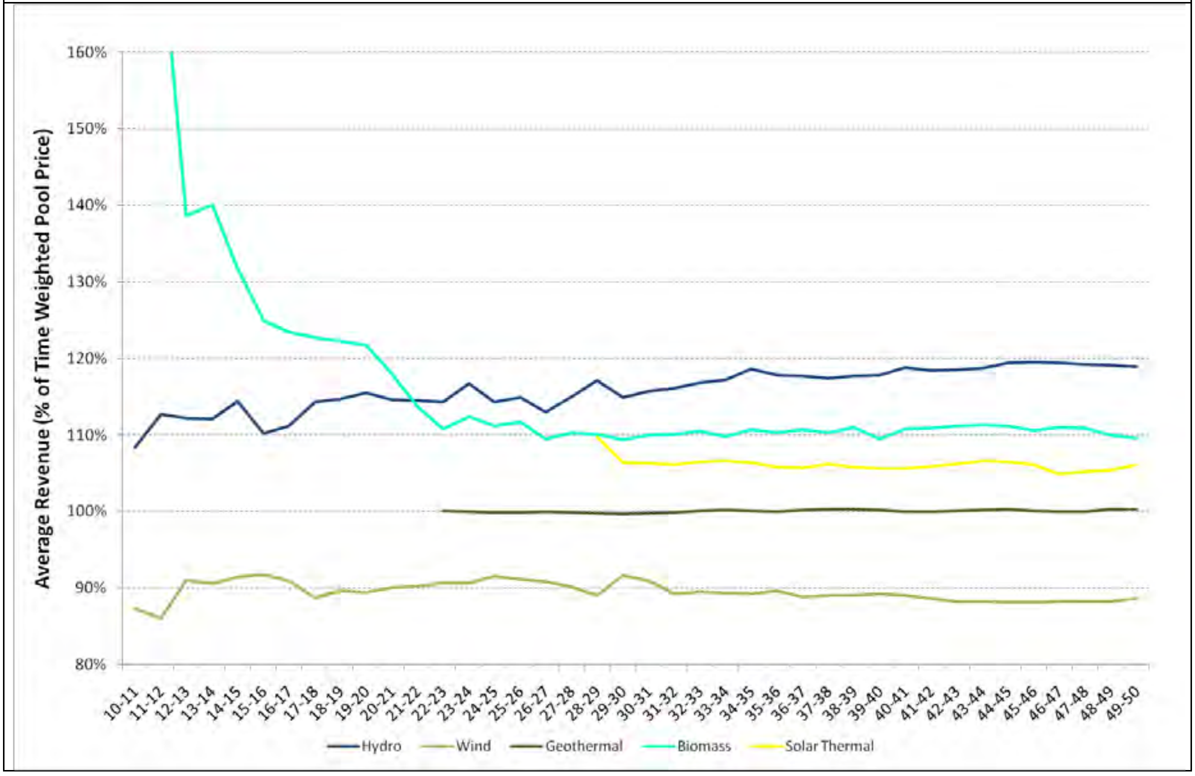


Figure 3.8 – Average Price when Operating – Renewable Plant (Average of all scenarios)



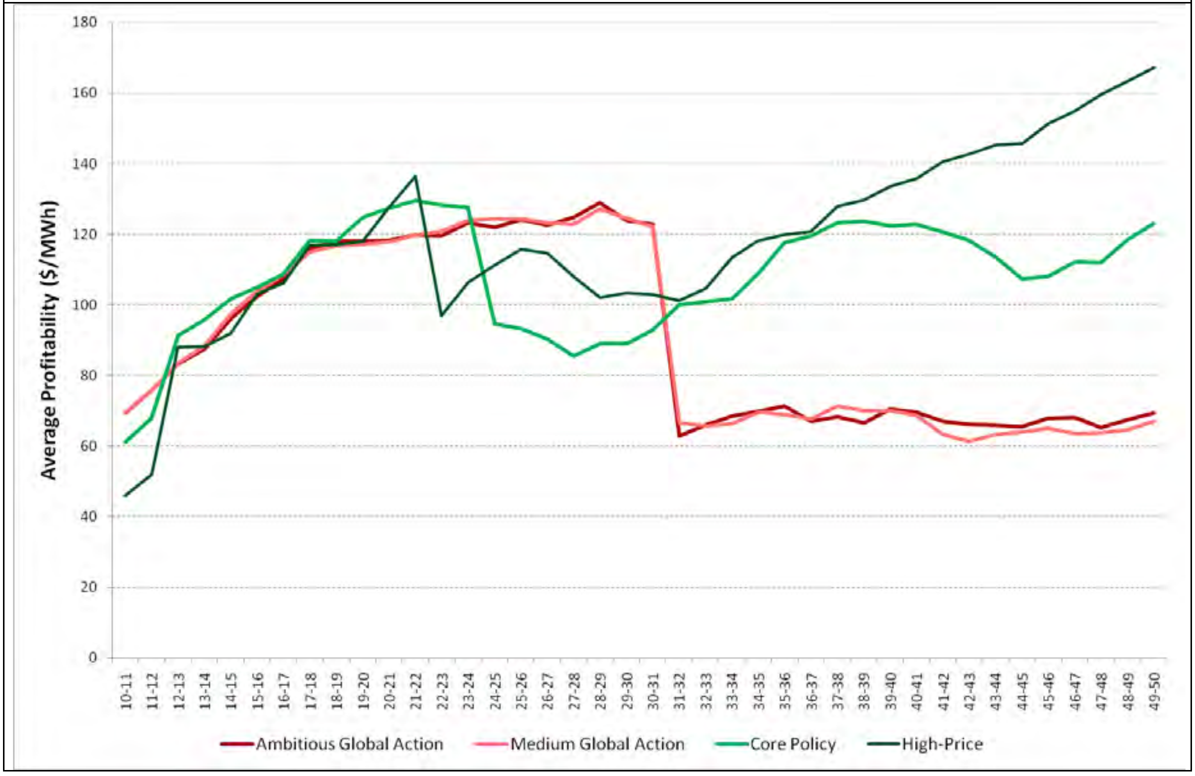
For renewable plant, the following is observed:

- Existing biomass plant tends to withdraw to higher price periods, resulting in a very high price premium – this is expected to reduce in future as biomass generation shifts towards base load operations;
- Hydro power stations operate to maximise revenues for the limited energy available by operating at higher priced periods. On average these generators tend to achieve an average price at least 10% higher than the average pool price;
- Geothermal plant are pure price takers, operating baseload (but for random forced outages), and therefore are the closest of all technologies to operational and pool price parity;
- Solar Thermal operates only during hours of sunshine, and therefore avoids the overnight pricing lows. As more solar is installed, a natural premium of approximately 5%-10% is achieved; and
- Wind farms operate at all times of the day, depending upon the prevailing winds. As such they are equally prone to operating at overnight periods where prices are low, and during the day. On average wind farms suppress pool prices, such that when they are not operating prices tend to increase. This is shown here as they achieve only 90%, on average, of the average annual pool price when operational. This may be optimistic given the historic analysis provided in Table 3.1 above. However, expanded interconnections in ROAM's modelling have assisted in raising pool prices for windy regions.

In terms of generator profitability, eligible renewable generators receive revenue from the sale of RECs. As the previous section covered, the introduction of a carbon price will reduce the value of the REC market, which in turn will reduce that component of the total revenue for renewable generators. The following figure shows the profitability for an average existing wind farm in South Australia for each of the cases. This includes both the increased revenue due to the carbon price increasing pool prices, and the decline in REC revenue due to the reduction in the value of the REC market.

This analysis assumes that the capital costs of existing wind farms are sunk.

Figure 3.9 – Average Profitability of Existing Wind Farms (South Australia)



As Figure 3.9 above shows, the highest carbon price (High Price scenario) has the lowest starting profitability for existing wind farms in South Australia, as the value of RECs is lowest. What is also perhaps unexpected is the proximity of the scenarios after the commencement of the carbon price. From 2012-13, initially it might be expected that the profitability in the carbon price scenarios would be significantly higher than the reference cases, as the higher pool prices would help renewables such as wind. However, the reference cases keep pace with the policy scenarios, and prove more profitable in the final 5-10 years of the REC scheme as the REC price stays at the price cap in the reference cases, whereas it falls to zero or near zero values in the policy scenarios[7]. This forecast difference in profitability can be attributed to the difference in REC prices in the two scenarios. Although pool prices increase by approximately $17.00/MWh on average across all regions upon the commencement of the carbon price, the value of RECs is

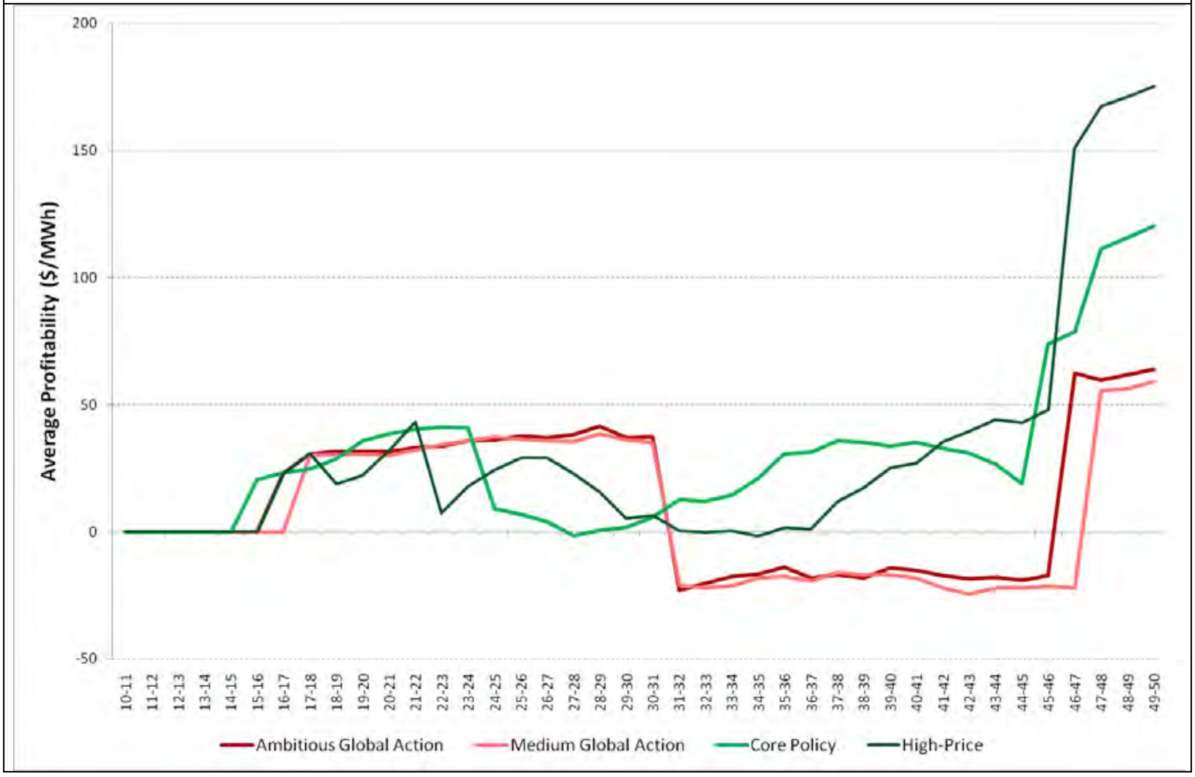
[7] The policy cases deliver higher levels of renewables which draw on the less favourable resources, in particular poorer quality wind sites, and therefore the average profitability of renewables is expected to weaken in these cases which contributes to the relative decline of profitability as compared to the reference scenarios.

approximately $10.00/MWh lower in the Core Policy scenario, which impacts wind generators average revenue. By 2020 the pool price of energy is approximately $10.00/MWh higher than the reference scenario, and with REC prices being near equivalent, the profitability of wind farms is approximately $10.00/MWh higher than the reference case. However, by 2030 the REC price in the Policy scenario reduces to zero, as the carbon price effectively removes the necessity to provide additional financial support to incentivise renewable energy, and as such the pool price difference of approximately $28.00/MWh does not balance with the reduced value of REC revenue of approximately $57.00/MWh, and average revenues of wind generators in these years are approximately $30.00/MWh below the reference scenario. Post 2030, when the REC scheme ends, the profitability of these generators falls significantly in the reference cases relative to the policy scenarios.

The volume of renewable capacity is significantly higher in the Policy scenario. It is considered that the wind resource is a marginally deteriorating commodity – that is, that the best wind sites are developed first and subsequent wind sites progressively have reduced energy to use due to their inferior wind resource. Therefore, in the Policy scenarios it is expected that the average profitability of all wind generators will reduce as more capacity is installed, due to the reduced capacity factors.

Figure 3.10 below shows the average profitability of a new entrant wind farm installed in South East South Australia (one of the highest energy producing wind regions in the NEM). As the figure shows, the profitability of wind generators deteriorates when the REC market ends. Towards the end of the study, the profitability increases markedly as the accounting life of the project ends and the annualised capital costs have been fully paid.

Figure 3.10 – Average Profitability of New Entrant Wind Farms (South East South Australia)



4) SIGNIFICANT OBSERVATIONS: MARKET PRICES

4.1) *WHOLESALE POOL PRICES*

The scenarios provide different outcomes in terms of the overall trends in wholesale pool prices. ROAM has used the 2-4-C market dispatch software to model the half hourly interaction of electricity supply and demand for the NEM given the new entrant development programs developed using the least cost LTIRP model. Half hourly dispatch is necessary to accurately model pool prices given the intermittent nature of various renewables technologies such as wind and solar as well as random forced full and partial outages. Furthermore, particularly in the presence of carbon prices, the marginal generator which sets market prices will change throughout the day and year. ROAM uses detailed half hourly generation traces developed from historic BOM data on wind speeds and solar insolation, correlated to historic electricity demand, to develop the intermittent generation profiles for wind and solar plant. Similarly, a Monte Carlo dispatch technique is used to randomise generator outages – ROAM has conducted 25 iterations of each simulation year to develop 25 alternate outage profiles for each case for each forecast year, which are then aggregated to provide a smoothed estimate of price.

Wholesale pool prices rise in all scenarios. In the reference scenarios, the increasing cost of fuel towards international parity, particularly for gas fired generators, will increase the wholesale price. Furthermore, the introduction of a carbon price in the policy scenarios places another cost on generators which will be passed through to customers.

The following figures show the pool price for each region of Australia under each scenario[8].

[8] It should be noted that detailed half hourly modelling has not been performed for Western Australia, and as such the prices are reasonable estimates directly from the least cost dispatch modelling using the LTIRP of the SWIS. The SWIS prices are less volatile as the market rules require generators to bid their short run marginal costs, so a half hourly dispatch outcome is less critical. The Northern Territory is not included as no wholesale market exists.

Figure 4.1 – Wholesale Pool Prices

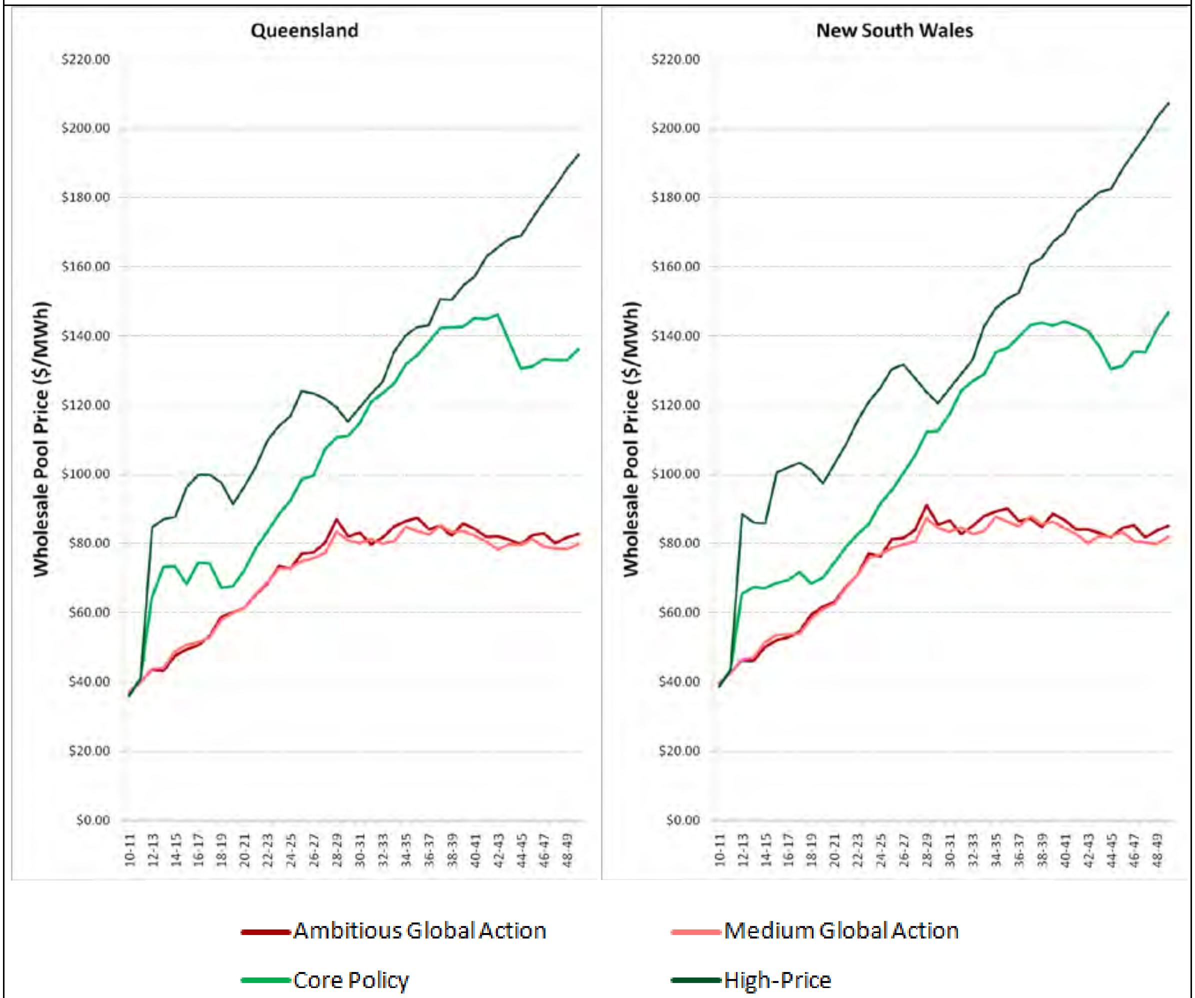


Figure 4.1 – Wholesale Pool Prices

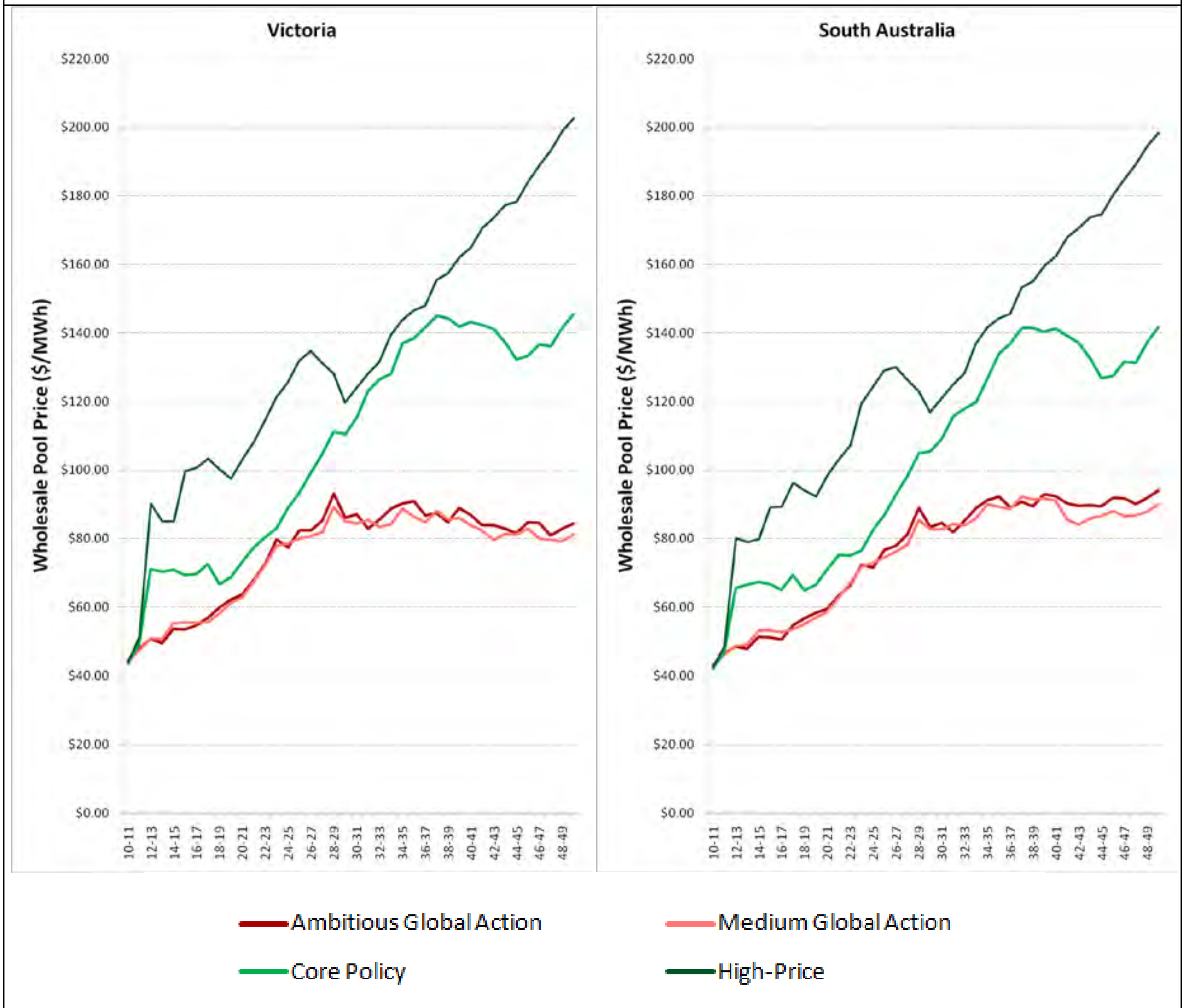
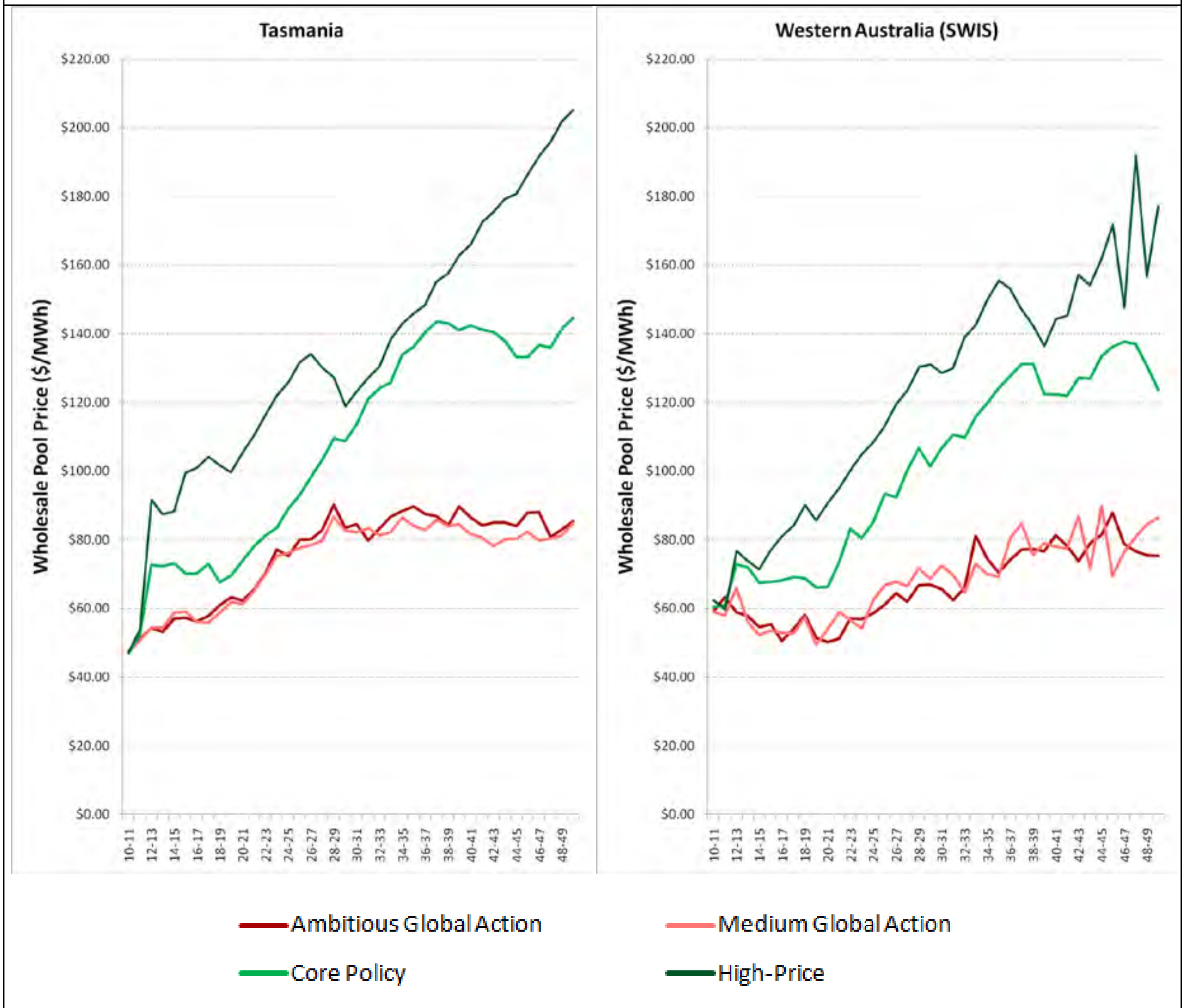


Figure 4.1 – Wholesale Pool Prices



See the appendices (Appendix I) for a case by case view of the results.

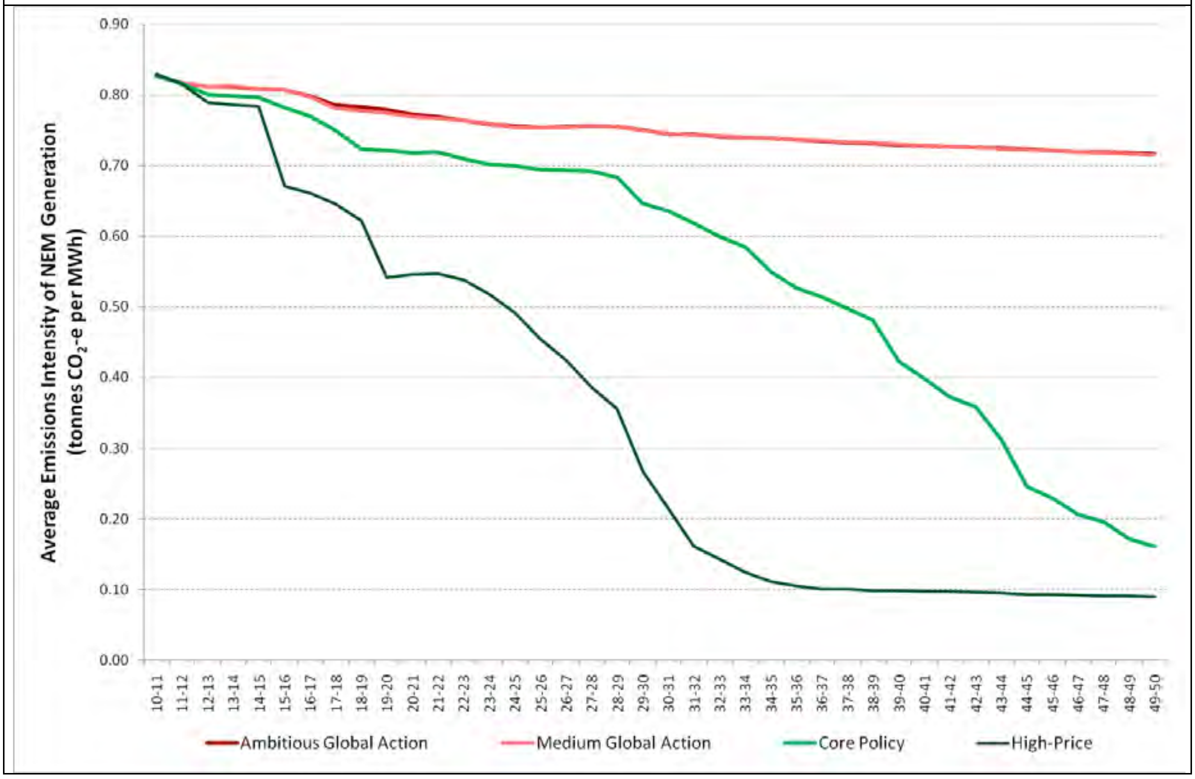
The charts show the increase in price in all regions and in all scenarios driven primarily by the increasing cost of fuel. The High Price scenario shows a significant dip in pool prices surrounding 2030-31 as the majority of the existing coal fleet is becomes uneconomic in response to the carbon price and is replaced with low emissions technologies – significantly lowering the average emissions intensity of the market and reducing the impact of the carbon price on the wholesale price. However, it still remains higher in price than the Core Policy scenario.

The effect that the carbon price is having on wholesale pool prices is determined by the emissions intensity of the *marginal* generator in each half hour. It is the marginal generator which sets the price of electricity in any given half hour, and therefore sets the pass through of carbon price. In this way it is expected that a higher pass through of carbon price would occur in off-peak periods than in peak periods, as coal plant is more likely to be the marginal generator at low load periods while in peak periods the marginal generator is likely to be gas fired plant, which has a lower emissions intensity than coal.

ROAM has assumed that generators pass through the additional costs associated with the carbon policy into their individual generator bids, in an attempt to recover costs. ROAM has modelled the attempted recovery of emissions costs by generator such that the market would adjust to deliver a breakeven position as a whole. The carbon pass through is applied individually to each generator, and therefore maintains the differentiation between different technologies and fuels, as more efficient generators are uplifted by proportionally less than less efficient generators.

The following figure shows the *average* emissions intensity of all generation in the NEM over the forecast period.

Figure 4.2 – Annual Average Emissions Intensity of NEM Generation

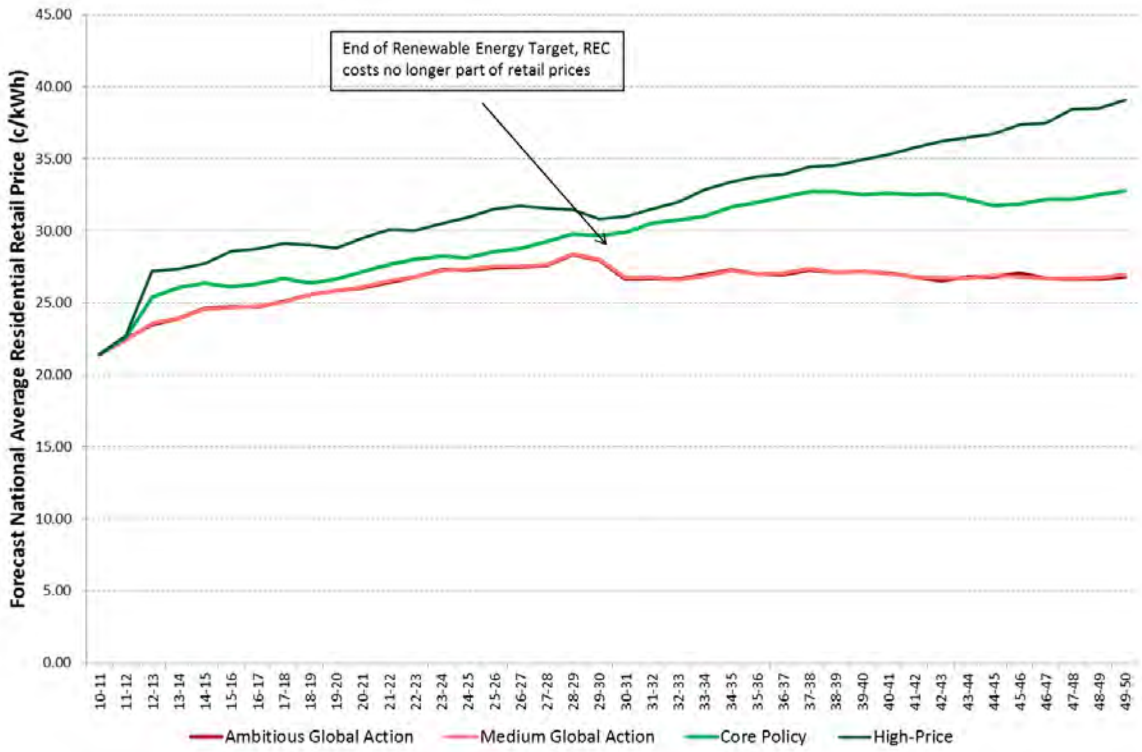


As shown above, the retirement and replacement of existing coal plant with low emissions CCS and renewable technologies under high carbon prices delivers substantial reductions to the average emissions intensity of the electricity sector.

4.2) *Retail Prices*

Retail prices include not only the wholesale cost of electricity, but also costs relating to transmission, distribution and other market policies and initiatives. This section reviews the forecast retail prices for each State of Australia.

Figure 4.3 – Annual Average Australian Retail Prices



The figure above shows that the impact of a carbon policy is to raise prices by up to 5c/kWh until 2030-31. After the RET ends in 2030, retail prices will reduce, as the green component is no longer priced. By 2050 retail prices are forecast to be approximately 25% higher than 2010-11 in the reference scenarios. However in the policy scenarios, the retail price (averaged across all States) is expected to be 50% to 80% higher than 2010-11.

ROAM's analysis excludes any pass through of increased transmission and distribution costs. Approximately 50% of retail prices are transmission and distribution costs. In this assessment ROAM has used the gazetted transmission price increases from 2010-11 to 2014-15, with network costs remaining constant in real terms beyond this point. The expectation of constant transmission and distribution costs per kWh in real terms from 2014-15 is reasonable, since the transmission and distribution infrastructure will have reached a highly developed stage and the market is growing in volume sufficiently to support investment while maintaining prices in real terms. ROAM's detailed analysis of transmission network development has been restricted to inter-regional transmission expansion, while the majority of transmission costs are due to intra-regional transmission infrastructure. However, as discussed this intra-regional infrastructure is paid for through regulated network charges. For a review of the least cost transmission development in each scenario, see Section 5.4).

5) SIGNIFICANT OBSERVATIONS: EVOLUTION OF THE SUPPLY SIDE

5.1) *TECHNOLOGY SHARES OF ENERGY*

Figure 5.1 below shows the suppliers of energy for each scenario by technology. The policy scenarios reduce the energy produced by coal plant while the overall energy demand is also significantly lower in the policy scenarios.

Figure 5.1 – Total Annual Generation by Technology

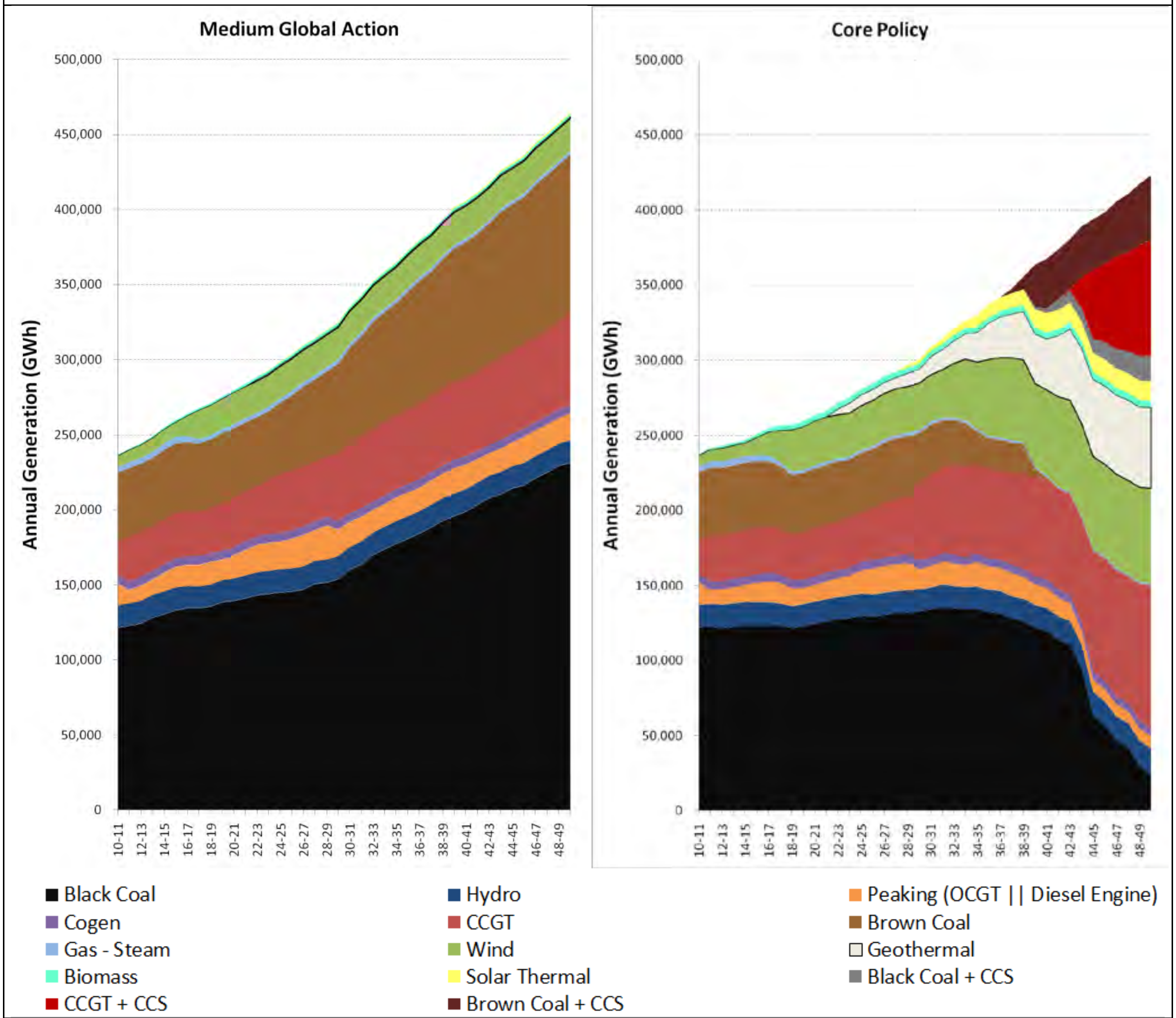


Figure 5.1 – Total Annual Generation by Technology

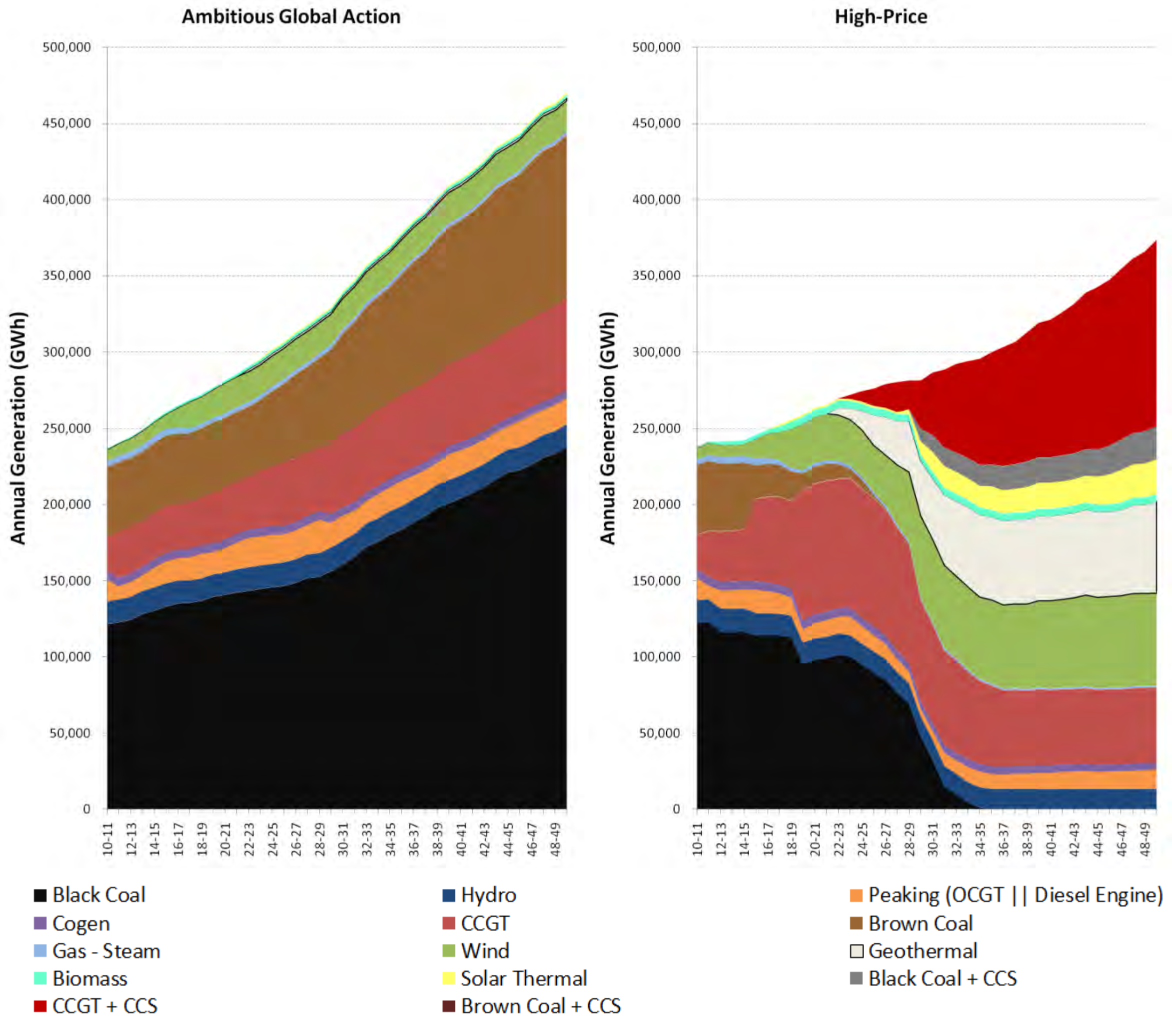
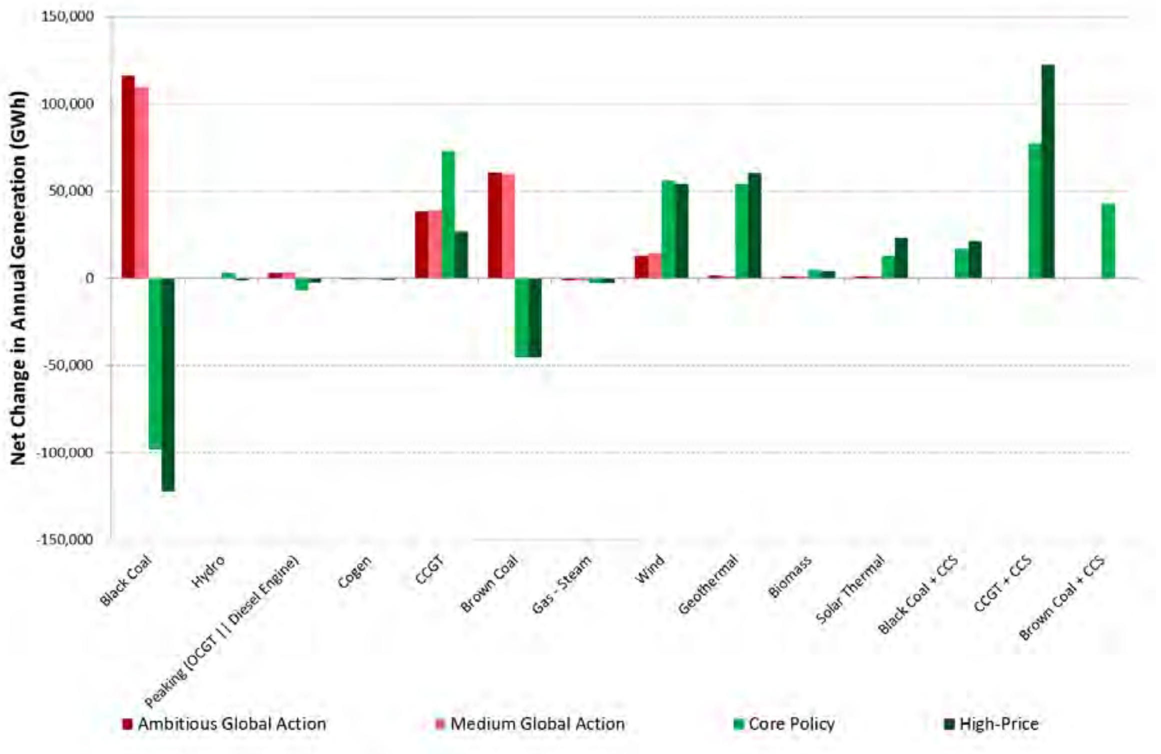


Figure 5.2 – Net Change in Annual Generation



It is evident from these results that without the introduction of a carbon price, there is strong growth in both the amount of installed capacity and the total annual generation for both black and brown coal plant. It can also be seen that there is a significant increase in the capacity and output of wind generation which is primarily a result of the incentives provided by policies such as the Renewable Energy Target. The intermittent nature of this wind generation is a contributing factor for the substantial increase in the amount of peaking capacity that is installed in these scenarios, which is reflected more in the installed capacity than in the energy produced by peaking OCGTs, as shown in the following section.

There is minimal investment in CCGTs and in other renewable technologies in the reference scenarios, as the high international gas price for natural gas penetrates the domestic market as the market for local LNG exports expands. This indicates that a carbon price is required for these technologies to be commercially competitive. Present developments of CCGTs in Queensland are in response to carbon price uncertainty and the temporary abundance of gas as the LNG sector in Queensland rapidly develops – in this modelling it is not expected that such low gas prices will continue. With a carbon price, gas plant is preferred to coal given its reduced carbon footprint. This extends to CCS technology with nominally 90% capture, as it is typically installed with combined cycle plant rather than black or brown coal. This is also influenced by the cost of emissions capture – the proximity to relatively low cost storage locations (such as the Latrobe or Surat basins) is paramount to the development of this new CCS technology.

Detailed results are contained within the appendices for the projected generation development plans (Appendix F) and generation outcomes (Appendix G).

5.2) GENERATION DEVELOPMENT

Figure 5.3 shows the level of installed capacity in Australia in each of the four scenarios categorized by the type of generation. ROAM has not considered the possible introduction of wave energy technologies in this modelling as the scale of such developments is unlikely to be of a level that will materially influence development of other generation.

ROAM's modelling did not restrict generation types according to their individual emissions levels. However, the modelling did not install any generation that exceeded the 0.86 tonnes CO_2-e/MWh 'Cleaner Future for Power Stations' limit.

Figure 5.3 – Total Installed Capacity by Technology

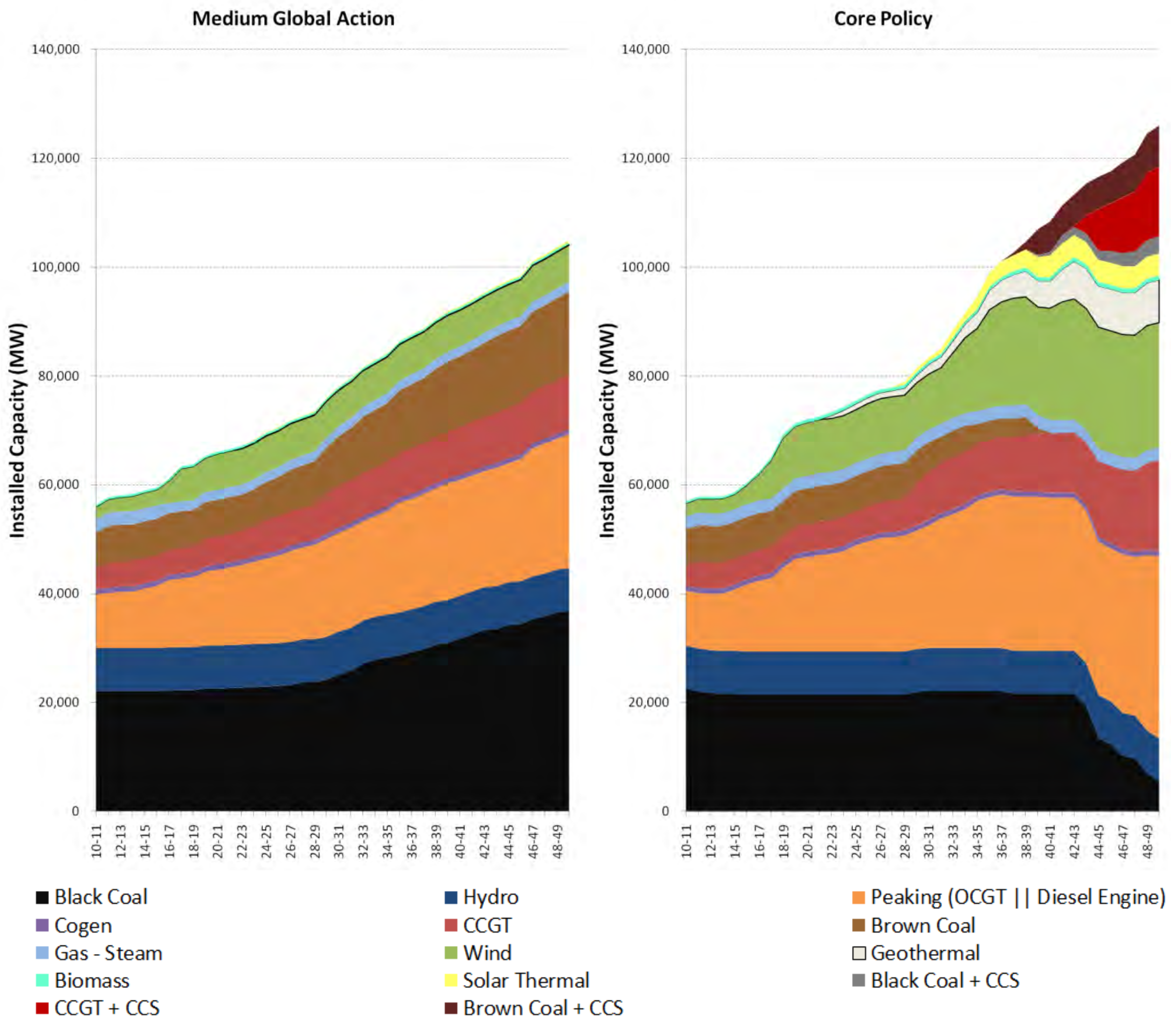
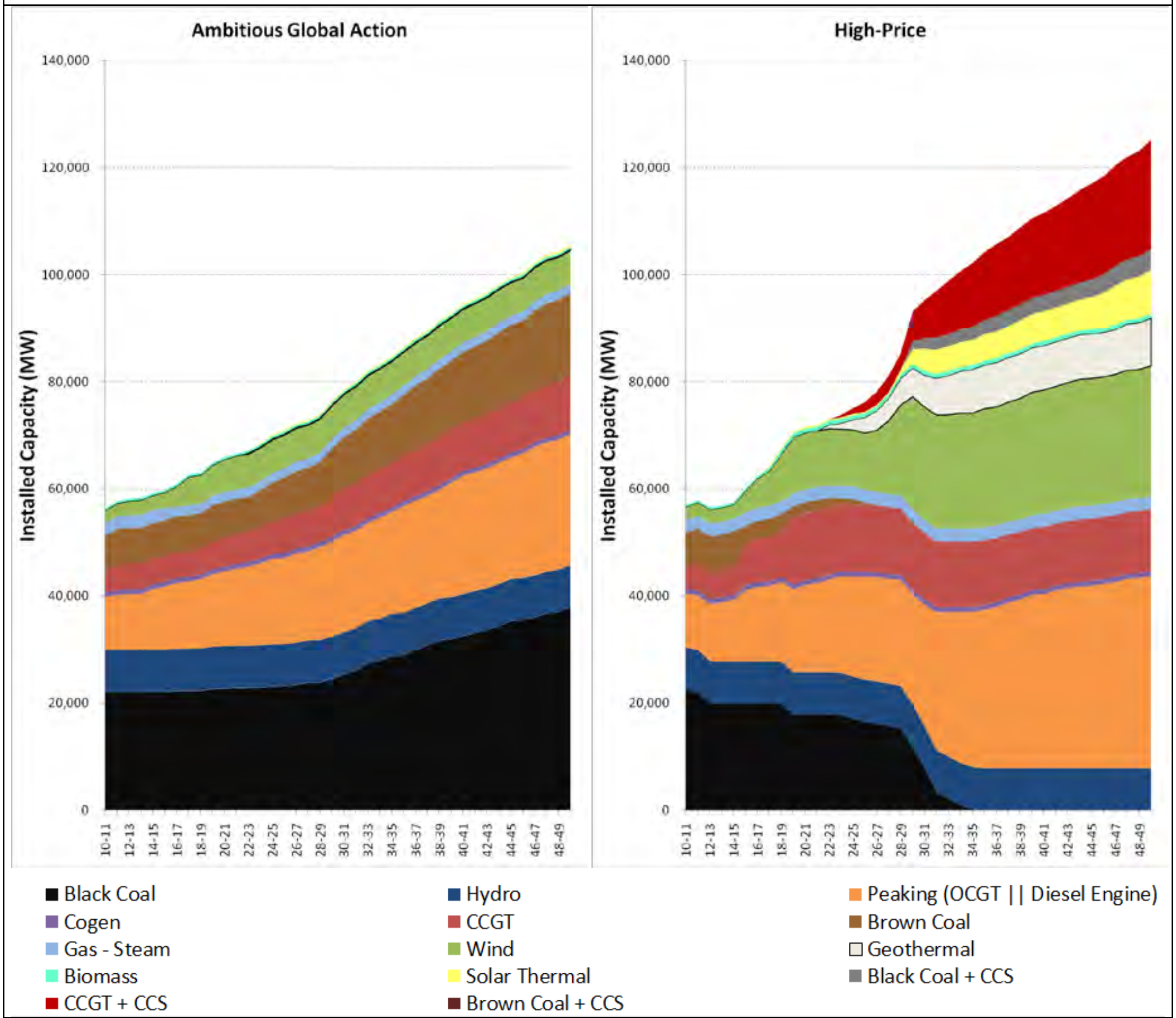


Figure 5.3 – Total Installed Capacity by Technology



The table below shows the total cumulative investment in capital by 2019-20 and 2049-50 for each of the technologies.

Table 5.1 –Capital Expenditure by Generation Technology including Interconnections ($M)				
Cumulative Expenditure to 2019-20				
	Global Action	**Core Policy**	**Ambitious Global Action**	**High Price**
Black Coal	$ 1,083	$ 0	$ 1,275	$ 0
Hydro	$ 0	$ 0	$ 0	$ 0
Peaking (OCGT || Diesel Engine)	$ 3,925	$ 6,854	$ 3,904	$ 5,490
Cogen	$ 0	$ 0	$ 0	$ 0
CCGT	$ 2,230	$ 1,916	$ 2,333	$ 10,903
Brown Coal	$ 0	$ 0	$ 0	$ 0
Gas - Steam	$ 0	$ 0	$ 0	$ 0
Wind	$ 9,963	$ 17,805	$ 8,512	$ 20,328
Geothermal	$ 0	$ 0	$ 0	$ 0
Biomass	$ 0	$ 894	$ 0	$ 1,789
Solar Thermal	$ 0	$ 0	$ 0	$ 1,479
Black Coal + CCS	$ 0	$ 0	$ 0	$ 0
CCGT + CCS	$ 0	$ 0	$ 0	$ 0
Brown Coal + CCS	$ 0	$ 0	$ 0	$ 0
Interconnectors	$ 849	$ 421	$ 884	$ 710
Total	**$ 18,050**	**$ 27,890**	**$ 16,907**	**$ 40,699**

Table 5.1 –Capital Expenditure by Generation Technology including Interconnections ($M)				
Cumulative Expenditure to 2049-50				
	Global Action	**Core Policy**	**Ambitious Global Action**	**High Price**
Black Coal	$ 31,740	$ 1,389	$ 34,208	$ 0
Hydro	$ 0	$ 0	$ 0	$ 0
Peaking (OCGT || Diesel Engine)	$ 13,476	$ 20,771	$ 13,380	$ 22,503
Cogen	$ 0	$ 0	$ 0	$ 0
CCGT	$ 8,471	$ 15,643	$ 8,432	$ 10,903
Brown Coal	$ 24,391	$ 0	$ 24,784	$ 0
Gas - Steam	$ 0	$ 0	$ 0	$ 0
Wind	$ 10,790	$ 45,595	$ 9,758	$ 49,229
Geothermal	$ 1,085	$ 42,699	$ 1,364	$ 50,052
Biomass	$ 0	$ 1,789	$ 0	$ 1,789
Solar Thermal	$ 1,282	$ 12,991	$ 1,400	$ 24,965
Black Coal + CCS	$ 0	$ 10,297	$ 0	$ 12,935
CCGT + CCS	$ 0	$ 21,835	$ 0	$ 36,537
Brown Coal + CCS	$ 0	$ 32,742	$ 0	$ 0
Interconnectors	$ 3,613	$ 6,482	$ 3,985	$ 8,825
Total	**$ 94,847**	**$ 212,232**	**$ 97,311**	**$ 217,738**

As discussed previously, the intermittent nature of renewables requires additional capacity to be installed to cover for peak periods where wind and solar generators are not fully available. This results in increased levels of installed capacity in the policy scenarios as compared to the reference scenarios. Furthermore, although the impact of a carbon price is to reduce annual energy demand, the peak demands are the same in both the core policy and medium global action scenarios. Similarly, the peak demands are the same in the high price scenario and the ambitious global action scenario (as discussed in Section B.1). That is, although users are expected to increase energy efficiency throughout the year, the peak demand period (where extreme temperatures result in very high loads, with air conditioners and other high powered devices being significant domestic load contributors) are assumed to be the same irrespective of the carbon price. If peak demands are curtailed by a carbon price, then the installed peaking capacity could be reduced somewhat from the levels shown, without degrading consumer's reliability of supply.

The net change in capacity for each category of generation over the 40 year period is summarized in Figure 5.4.

Figure 5.4 – Net Change in Installed Capacity

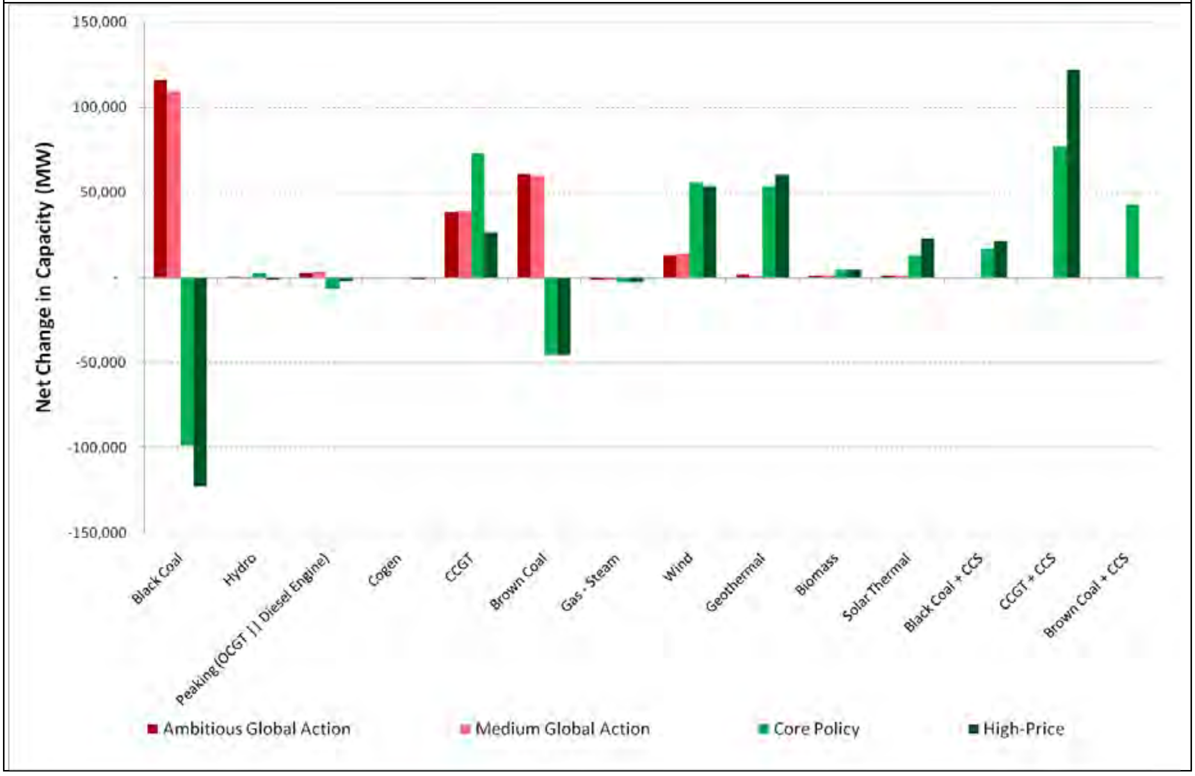


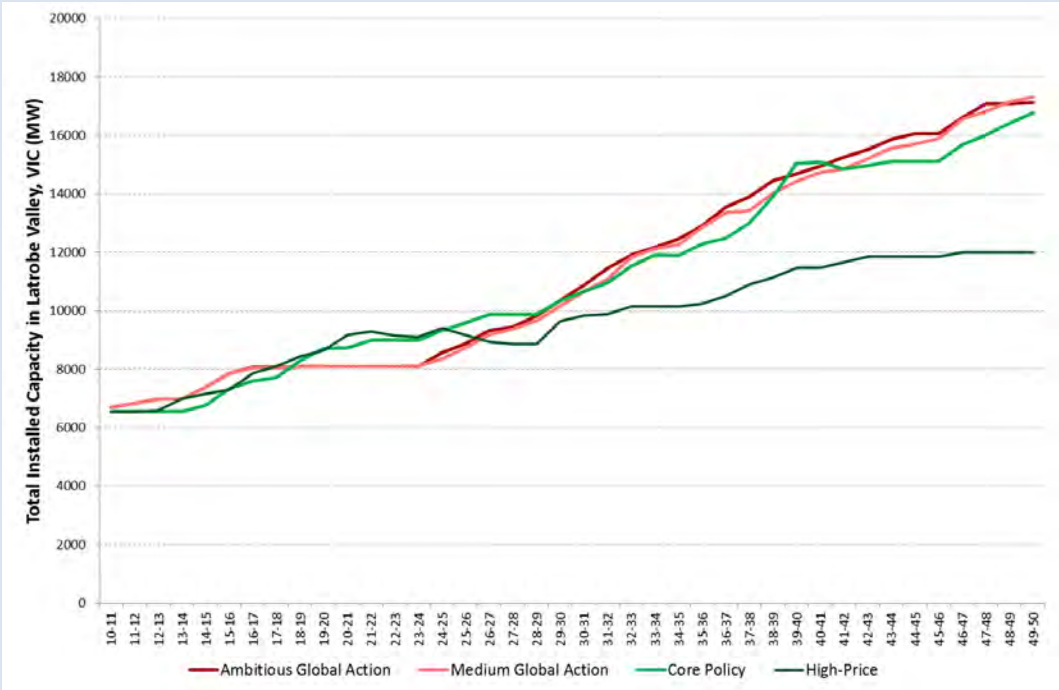
Figure 5.4 shows that without the presence of a carbon price, there is no significant installation of renewable generation other than wind incentivised by the RET. It can be seen in Figure 5.3 that the development of wind starts to stagnate after 2020 as the availability of high quality wind locations decreases and the real value of RECs declines. A carbon price will incentivise increased investment in wind generation and also results in significant development in other renewables, particularly Geothermal and Solar Thermal, as well as CCS technologies.

Box 2 – Evolution of Latrobe Valley generation

The Latrobe Valley is of particular interest considering the relatively high emissions of brown coal plant, and the timing of retirements of particular generators in that location.

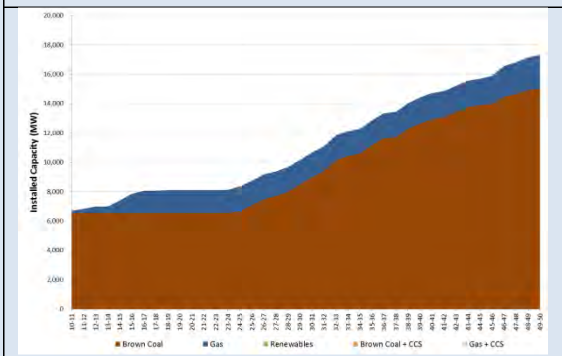
The replacement of brown coal typically results in substitution of other generation locally as other resources, particularly gas, are available to fill the gap at least cost to the electricity system.

The figure below shows the generation capacity (existing and new entrant generators) over the forecast period for each of the four scenarios. As the figure shows, in each of the scenarios the capacity installed in the Latrobe Valley is expected to increase. Despite the presence of a carbon price, there is forecast to be an equivalent capacity installed in the Latrobe Valley in the Core Policy scenario as the reference scenarios. The High Price scenario shows reduced growth in Latrobe Valley capacity, however by 2050 the capacity installed is still approximately double the existing installed capacity.

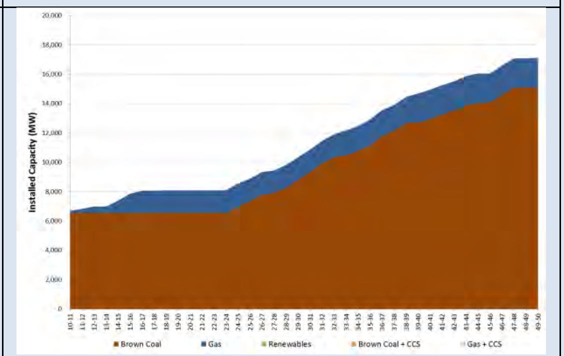


The following four figures show the evolution of Latrobe Valley generation by technology for each of the four scenarios.

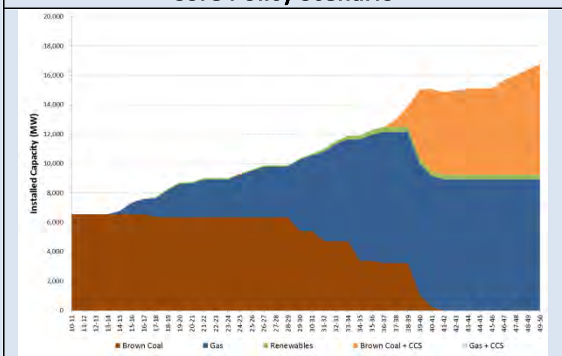
Medium Global Action



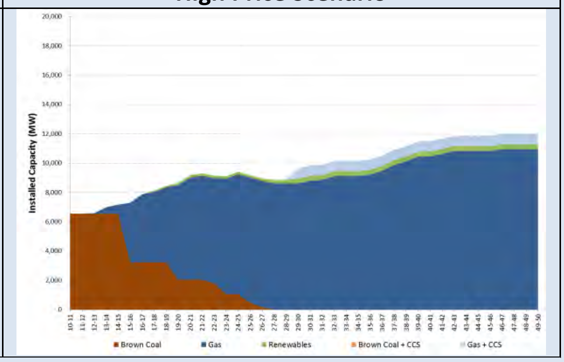
Ambitious Global Action



Core Policy Scenario



High Price Scenario



These charts demonstrate that the Latrobe Valley remains a generation hub for all scenarios – although under a carbon price there is incentive for increased diversification into gas, renewable and CCS technologies.

5.3) *Technology Cost Comparison*

Figure 5.4 below shows that for each of the different scenarios modelled, the underlying cost structure of the technologies differs sufficiently to drive alternate least cost development plans for each scenario. In particular, the carbon price is a significant component to each technology's long run marginal cost.

The following charts show the LRMC at time of install for each year of the forecast period under each of the four carbon price trajectories for new traditional gas and coal thermal plant (with and without CCS technology) for a site in the Latrobe Valley, Victoria (CCGT and Brown Coal) and South West Queensland (Black Coal).

Figure 5.5 – Long Run Marginal Costs by Technology

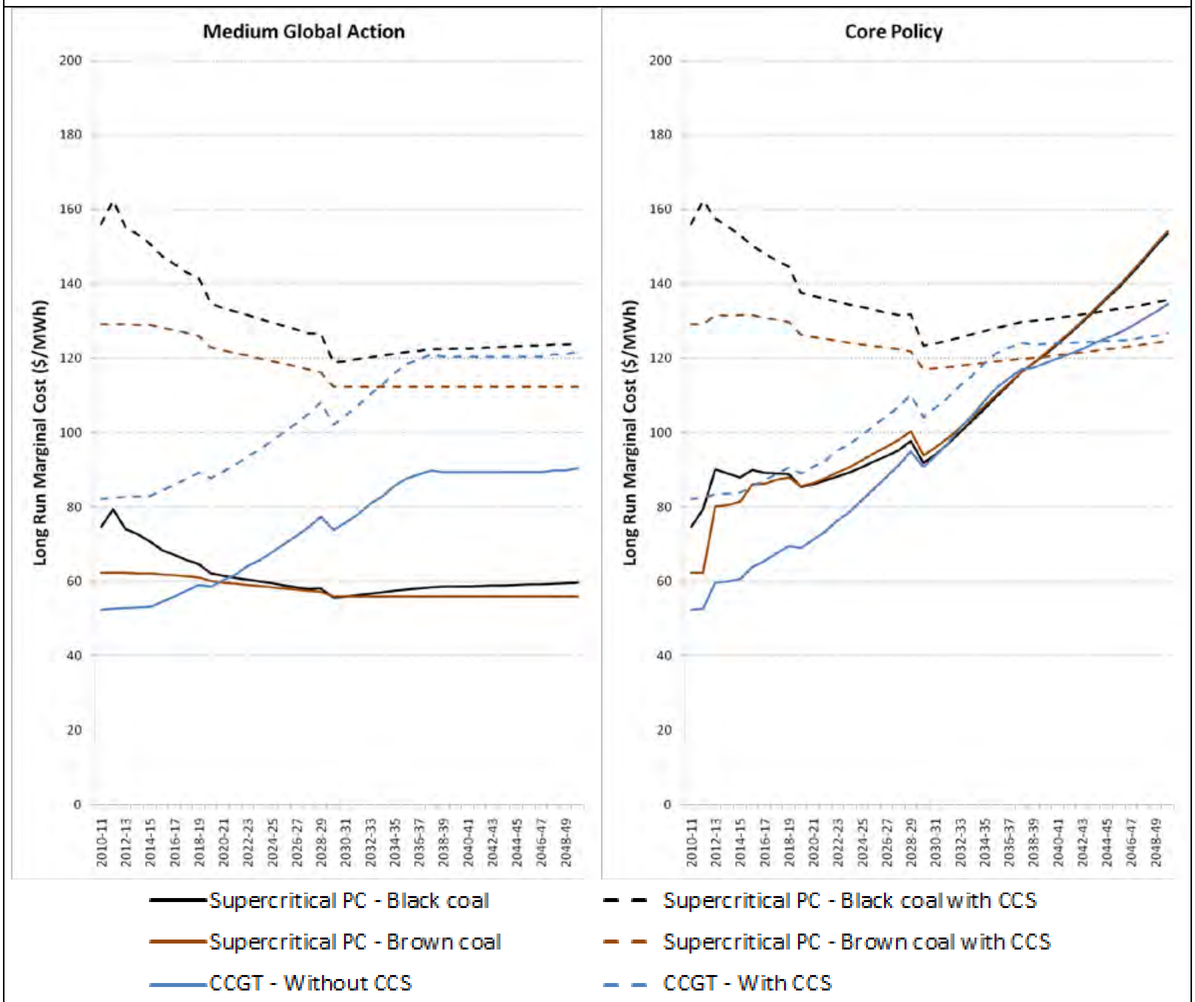
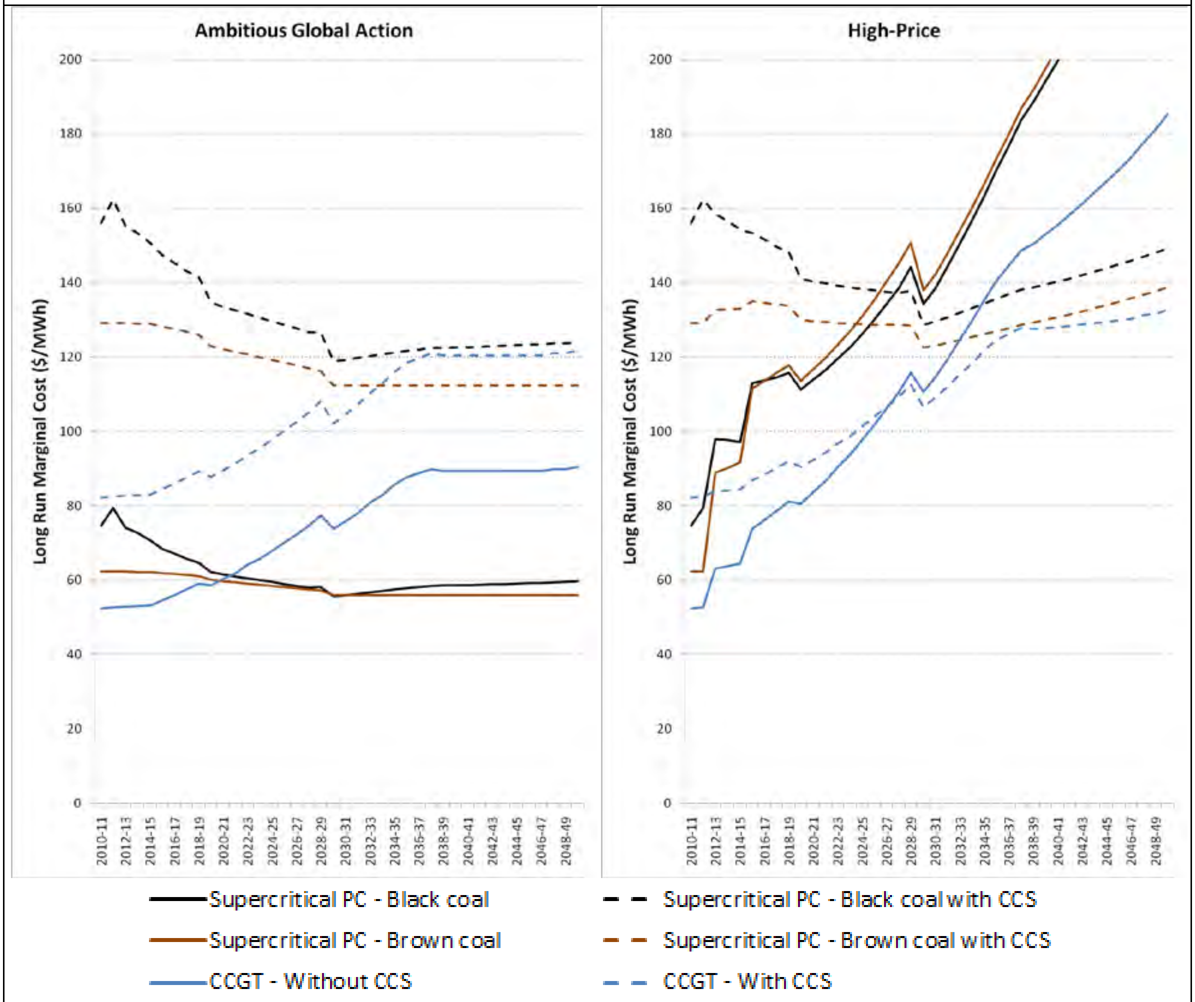


Figure 5.5 – Long Run Marginal Costs by Technology

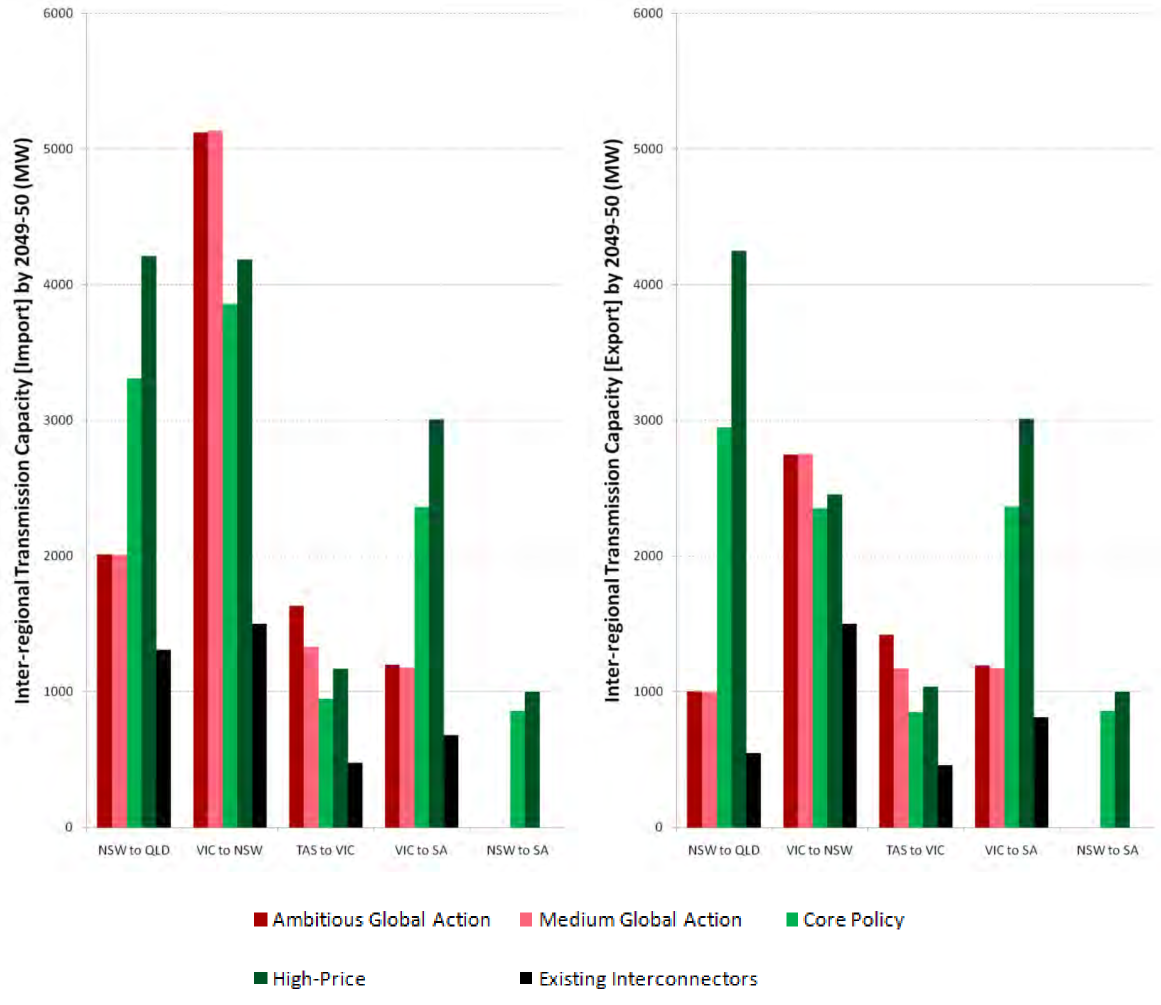


As the charts above show, for new thermal plant it is least cost in all scenarios which price carbon to develop gas, despite a gas price which transitions towards international LNG price parity. Carbon capture and storage technology will be preferred at higher carbon prices, although this may still be for gas plant rather than coal (depending on the location of the plant).

5.4) *TRANSMISSION DEVELOPMENT*

The six different scenarios produce different outcomes in terms of the development of inter-regional transmission infrastructure. The transmission network in the model is limited to the inter-regional network, i.e. the interconnectors between regions. As Figure 5.6 below shows, all scenarios include some investment in transmission upgrades between regions in the least cost solution. In the Reference scenarios, this is to support the export of black coal in the Northern States and wind generation (built in response to the RET) in the Southern States. In the Policy scenarios the driver is the diversity of renewables development, with geothermal plant in Queensland and South Australia giving cause to strengthen the transmission backbone of the NEM, as well as wind. In the Policy scenarios there is justification to add an additional flow path between New South Wales and South Australia.

Figure 5.6 – New Interconnector Capacity



ROAM's modelling did not take into account interconnectors wholly within regions, on the basis that any network developments within a region will be covered by routine regulated upgrades by transmission companies and included in the network charges. Depending on whether significant retirements and replacements within a region are widely separated, some such augmentations may be needed over time.

No transmission connections between existing unconnected regions such as the SWIS, NWIS and DKIS were considered. These may occur within the time frame, but were omitted owing to the distances involved and the added complexities of evaluating their benefits and cost in the presence of considerable uncertainty. For more detailed analysis of the development of interconnectors, see the appendices (Appendix H).

6) SENSITIVITY ANALYSIS

In addition to the four scenarios detailed above, ten additional sensitivities have been modelled which relate to either the Medium Global Action or the Core Policy scenario. The following sensitivities have been modelled:

- Gas Price Sensitivities: Two additional sensitivities relating to both the Medium Global Action and the Core Policy scenario. These sensitivities applied an alternative domestic gas price which grows in a straight line to $6.50/GJ (real $2009-10) in 2030 and remains constant for the duration of the study.
- Coal Price Sensitivities: Two additional sensitivities relating to both the Medium Global Action and the Core Policy scenario. In these sensitivities, the decline in coal price is half that of the rate used in the core scenarios.
- Renewable Energy Cost Sensitivities: Two additional sensitivities relating to both the Medium Global Action and the Core Policy scenario. These sensitivities adopted the solar and wind technology costs comparable to those provided by CSIRO through the Treasury Stakeholder Reference Group consultation[9]:
    - Wind - $1,898/kW installed in 2015 and $1,497/kW in 2030
    - Photovoltaic (fixed flat plate) - $3,399/kW in 2015 and $2,154/kW in 2030
    - Solar thermal w/o storage - $2,932/kW in 2015 and $2,037/kW in 2030
- Learning Rate Sensitivities: Two additional sensitivities relating to both the Medium Global Action and the Core Policy scenario. These sensitivities involved reducing the learning rate, that is the reduction in capital cost over time due to the increased uptake of a technology, for all technologies by 50%.
- CCS Availability Sensitivity: One additional sensitivity applied to the Core Policy scenario in which no CCS technologies are available.
- Low Price Sensitivity: One additional sensitivity where the initial carbon price is lower than that used in the Core Policy scenario. The two trajectories converge by 2022-23. Treasury has also determined, through the use of the MMRF model, that the economy will more slowly adapt to carbon pricing under this sensitivity, and therefore the annual energy consumed will be higher beyond the period where the carbon prices differ.

6.1) *GAS PRICE SENSITIVITY*

6.1.1) Medium Global Action

As a result of lowering the domestic gas price for the Medium Global Action scenario, there is a significant increase in the level of gas-fired generation at the expense of coal-fired generation. This is clearly evident in Figure 6.1 which shows that the increase in gas-fired generation in the sensitivity case is highly correlated with the reduction in coal-fired generation. This increased investment in gas-fired plant leads to a reduction in emissions as seen in Figure 6.2.

[9] Internal Treasury communications

Figure 6.1 – Generation Outcomes – Medium Global Action, Gas Price Sensitivity

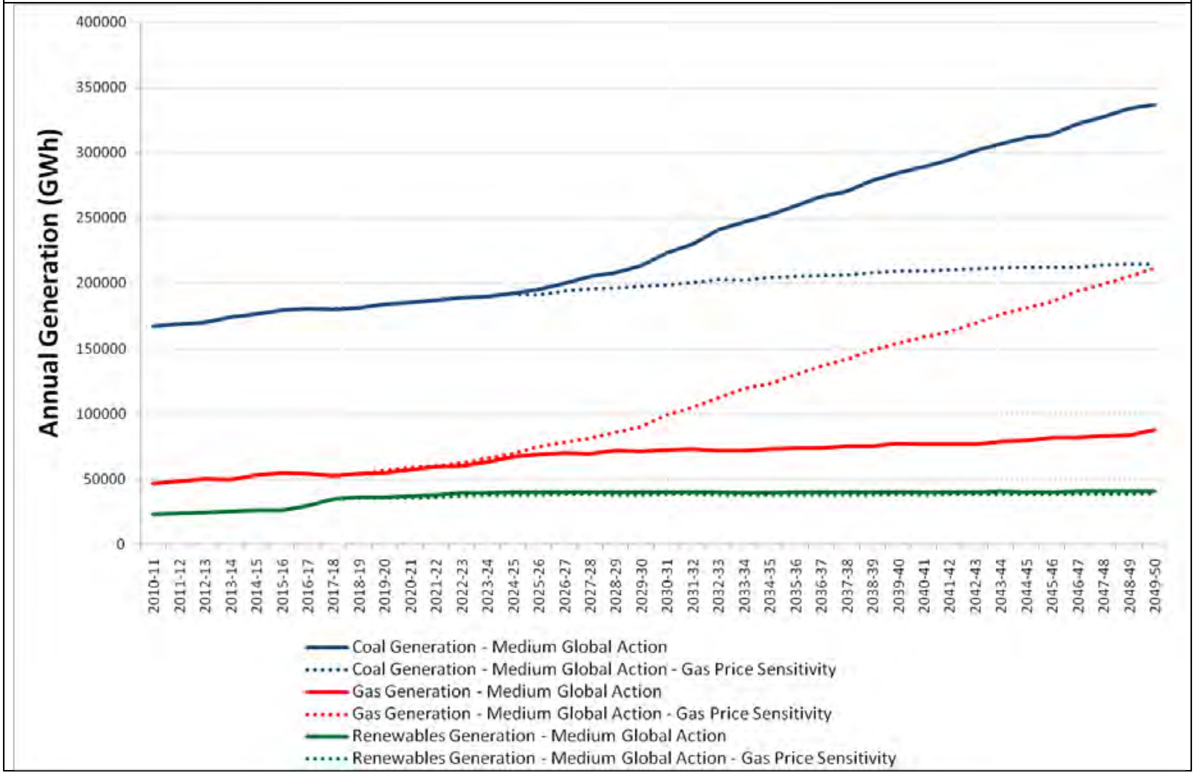
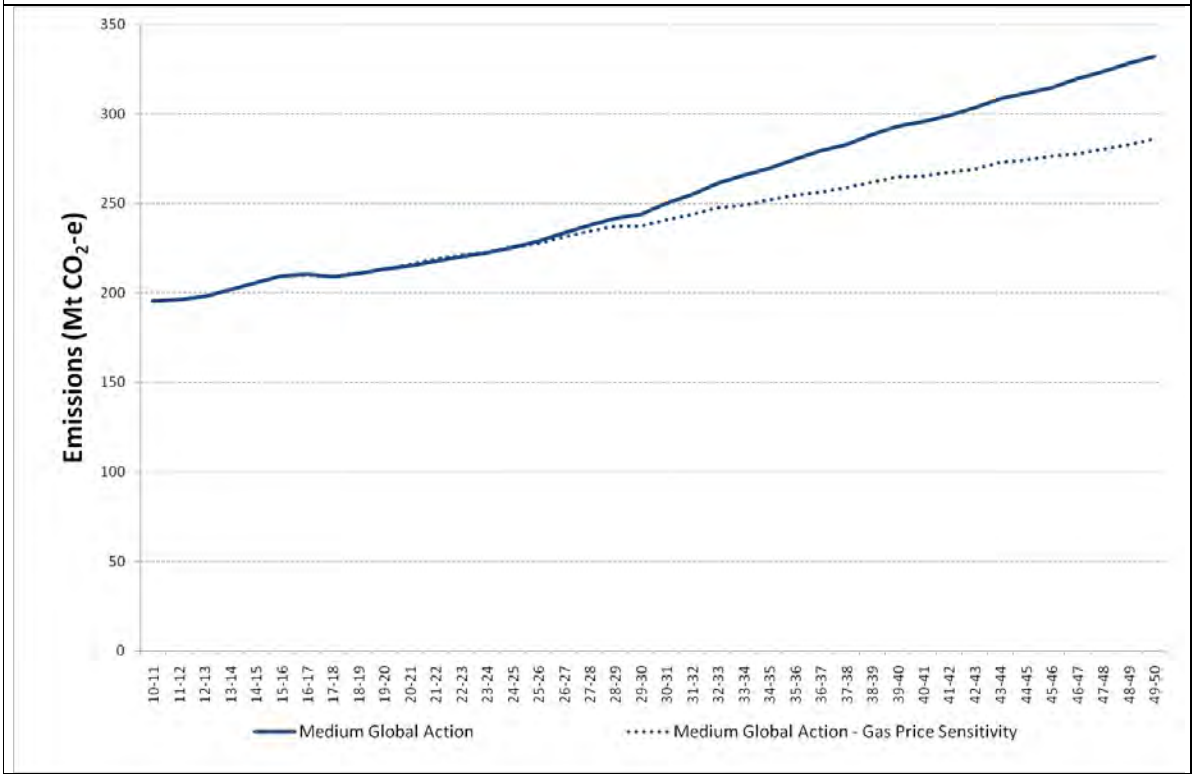


Figure 6.2 – Emissions – Medium Global Action, Gas Price Sensitivity



6.1.2) Core Policy

The major effect of a lower gas price in the Core Policy scenario is that the retirement of coal-fired generation in favour of gas-fired is accelerated. The retirement of coal generation which occurs rapidly between 2027-28 and 2032-33 is evident in Figure 6.3. The significant increase in the level of gas-fired generation comes also at the expense of renewable generation which had previously been installed under the original gas price scenario. Specifically, wind, solar thermal and biomass and geothermal all are installed to a lesser extent when the gas price is capped at $6.50/GJ making CCGT and CCGT+CCS the preferred supplier of energy. Therefore, although the initial replacement of coal-fired generation with gas-fired generation leads to a significant decrease in the level of emissions in the middle of the study, the decreased investment in renewable generation results in higher emissions by the end of the study. This is illustrated in Figure 6.4.

Figure 6.3 – Generation Outcomes – Core Policy, Gas Price Sensitivity

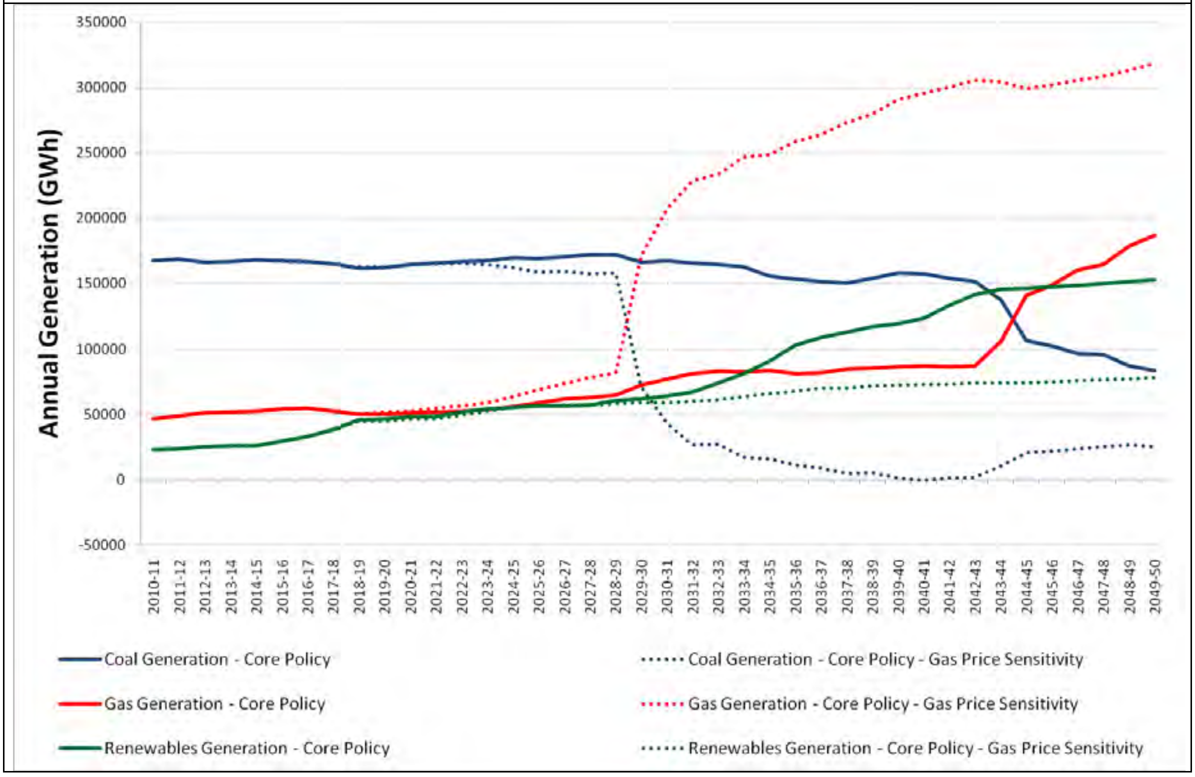
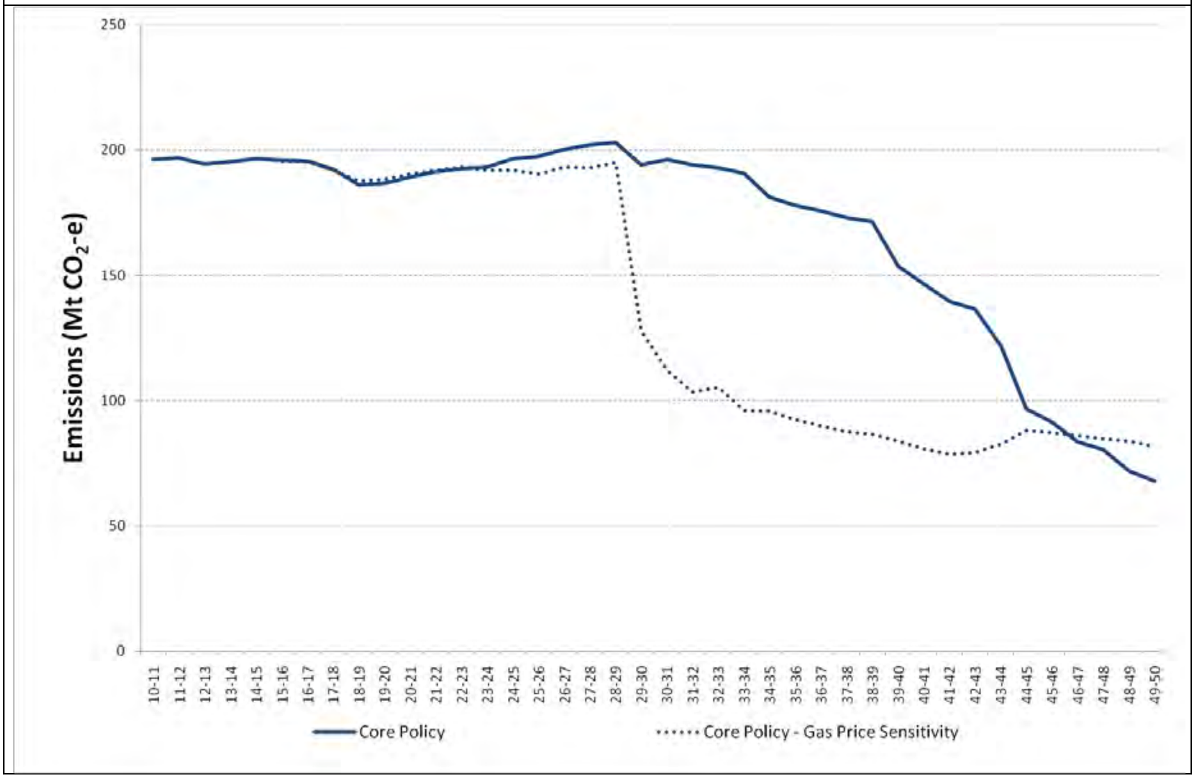


Figure 6.4 – Emissions – Core Policy, Gas Price Sensitivity



6.2) *Coal Price Sensitivity*

6.2.1) Medium Global Action

The increase in the price of coal in the Medium Global Action scenario has a very minimal effect on the generation outcomes (see Figure 6.5) and therefore also has a minimal effect on emissions (see Figure 6.6).

Figure 6.5 – Generation Outcomes – Medium Global Action, Coal Price Sensitivity

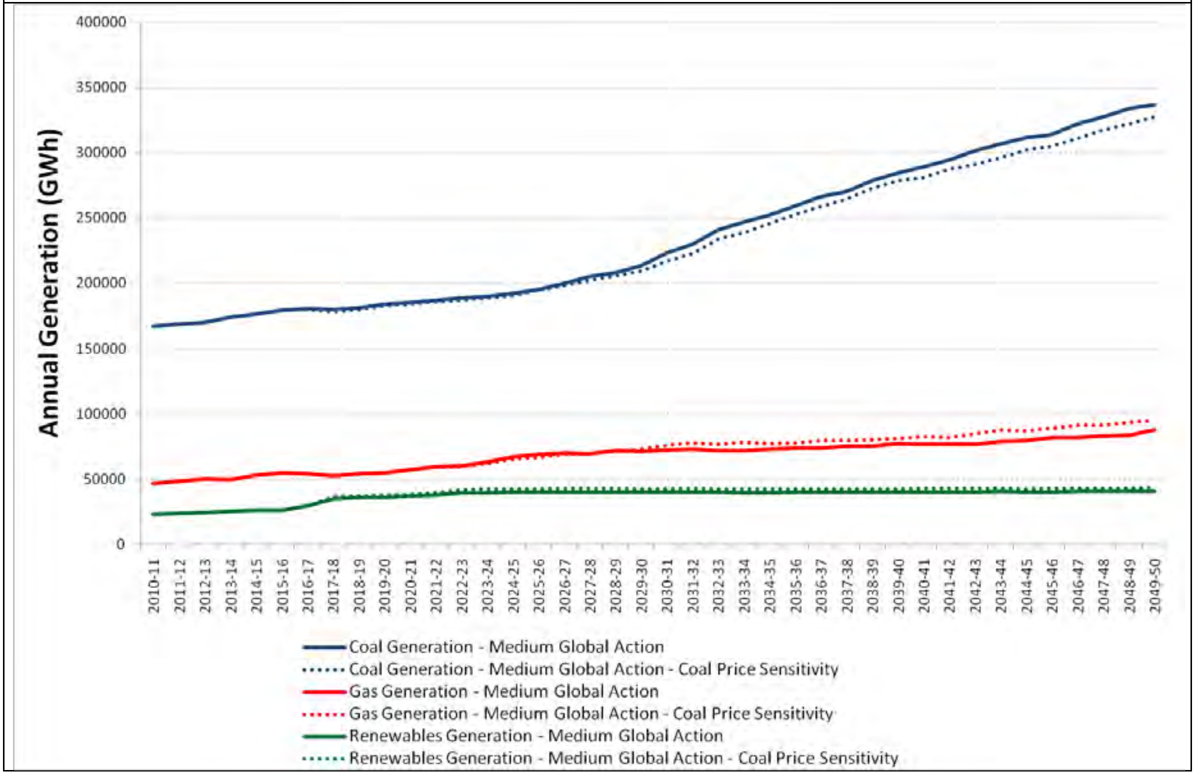
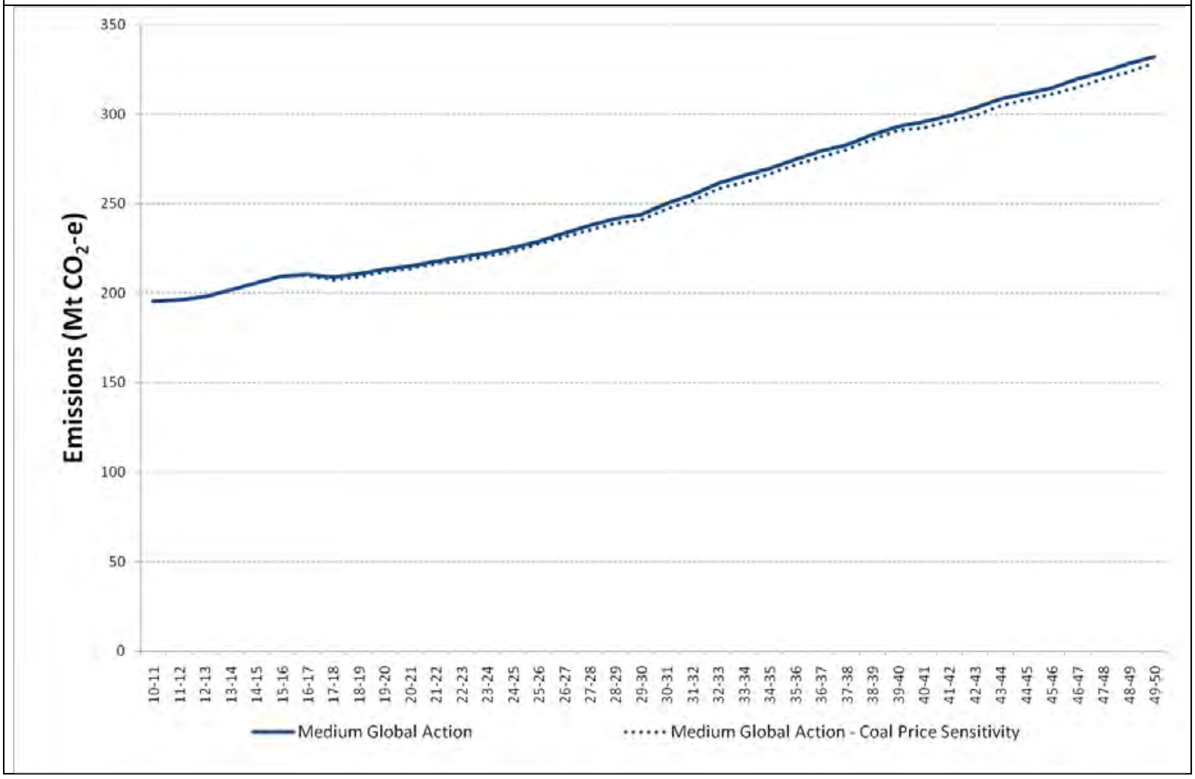


Figure 6.6 – Emissions – Medium Global Action, Coal Price Sensitivity



6.2.2) Core Policy

Figure 6.7 and Figure 6.8 illustrate that the coal price sensitivity also has a minimal effect when applied to the Core Policy scenario. As the carbon policy already reduces the competitiveness of coal plant, the impact of the coal sensitivity is even less in the Core Policy than the Global Action scenario.

Figure 6.7 – Generation Outcomes – Core Policy, Coal Price Sensitivity

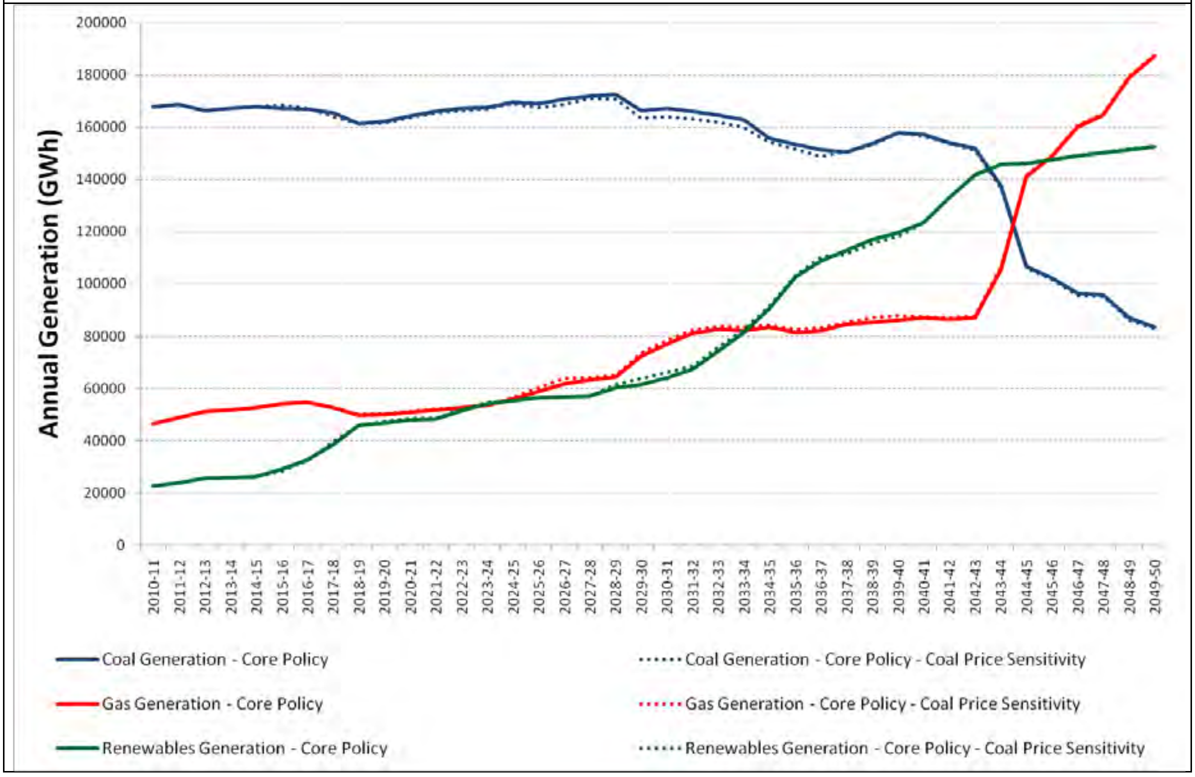
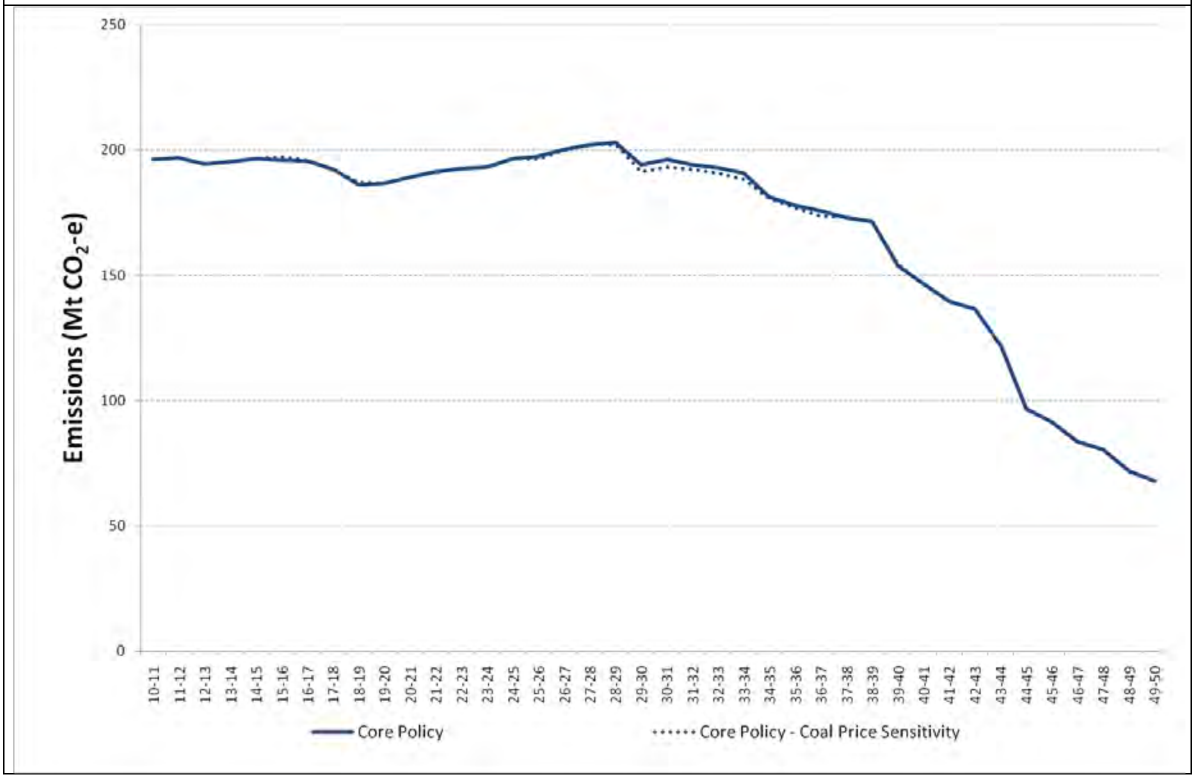


Figure 6.8 – Emissions – Core Policy, Coal Price Sensitivity



6.3) *Renewable Energy Cost Sensitivity*

6.3.1) Medium Global Action

Figure 6.9 shows that a decrease in the cost of the core renewable technologies of wind, solar PV and solar thermal in the Medium Global Action scenario leads to an increase in the investment in renewable technology at the expense of coal generation. This increase occurs between 2016-17 and 2021-22 with the increase in renewable generation being sustained beyond this point. This can also be seen in Figure 6.10 which shows a drop in the level of emissions which is sustained for the duration of the study. The sensitivity increases wind installed capacity by approximately 5000MW by the end of the study. As discussed previously, due to the unreliable nature of wind generation, this also requires an additional 2500MW of peaking plant to replace the 2700MW of coal and combined cycle plant which the wind replaces.

Unlike the Medium Global Action core scenario, with the lower renewable costs the RET target of 45,000GWh is achieved. REC prices are estimated to reach the price cap at about 2020, however the increased supply of certificates due to the increased utilisation of wind generation results in the certificate price falling to zero by 2028.

Figure 6.9 – Generation Outcomes – Medium Global Action, Renewable Energy Cost Sensitivity

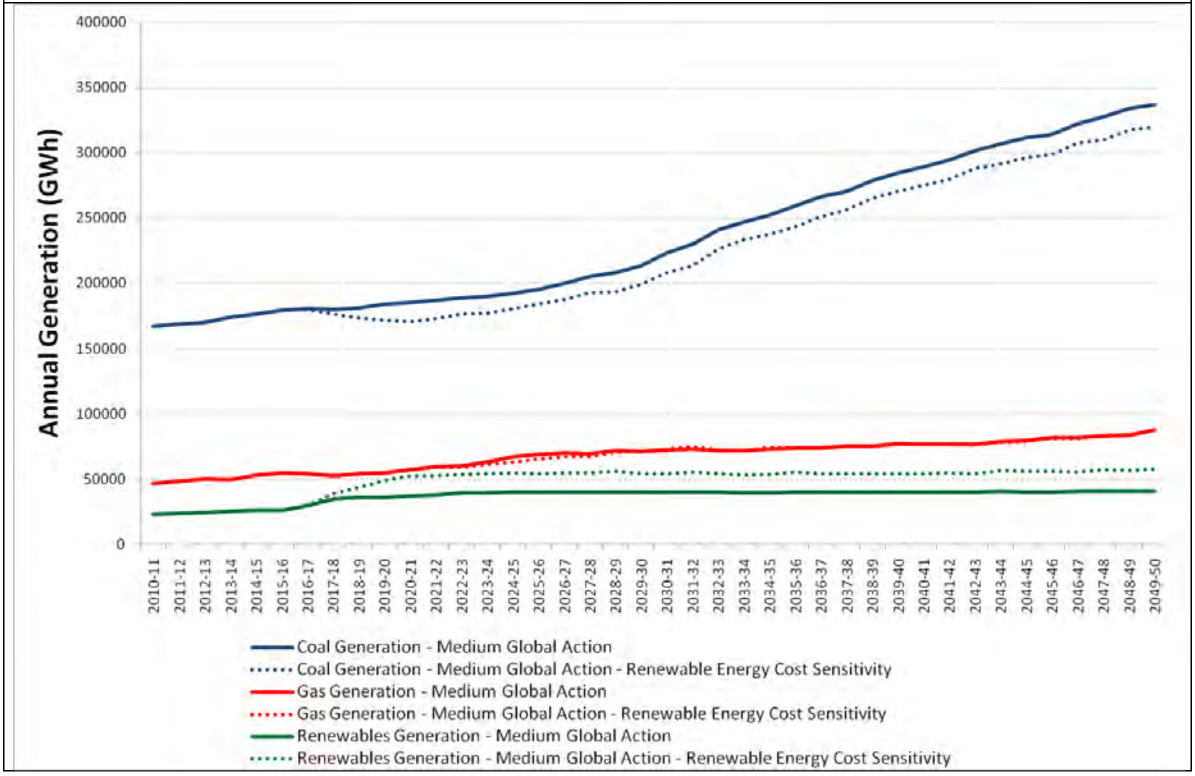


Figure 6.10 – Emissions – Medium Global Action, Renewable Energy Cost Sensitivity

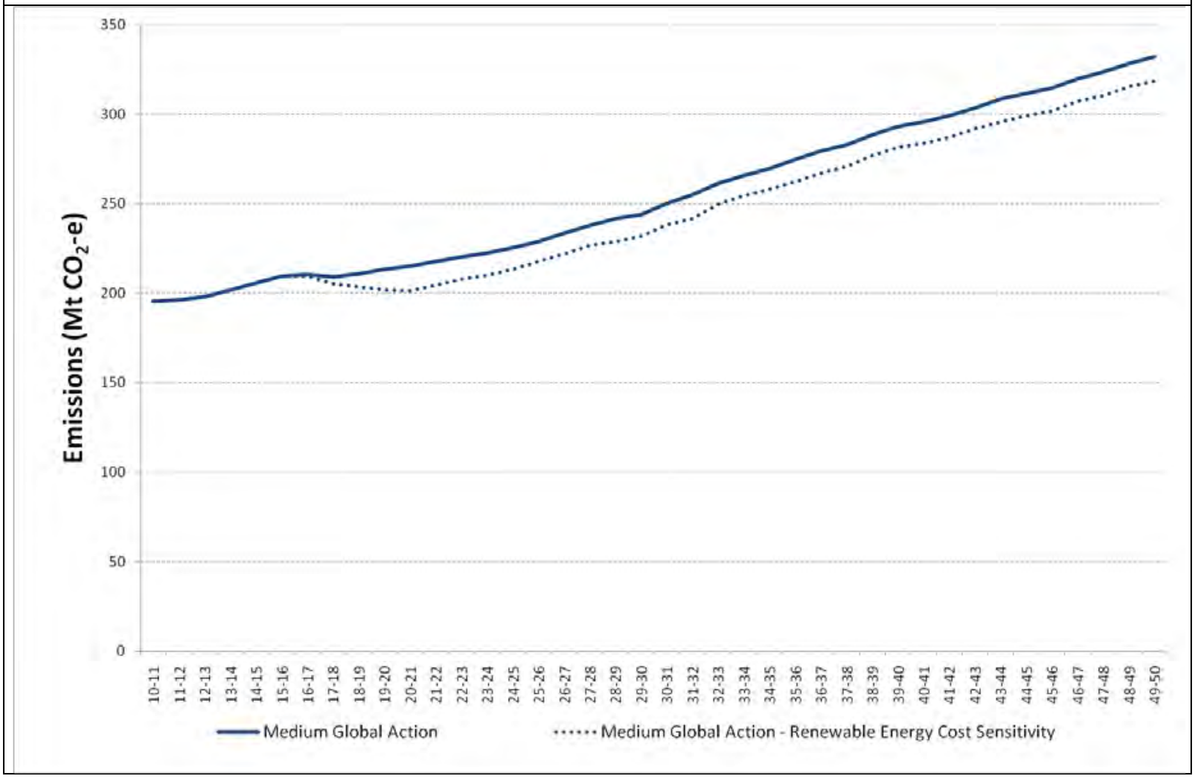
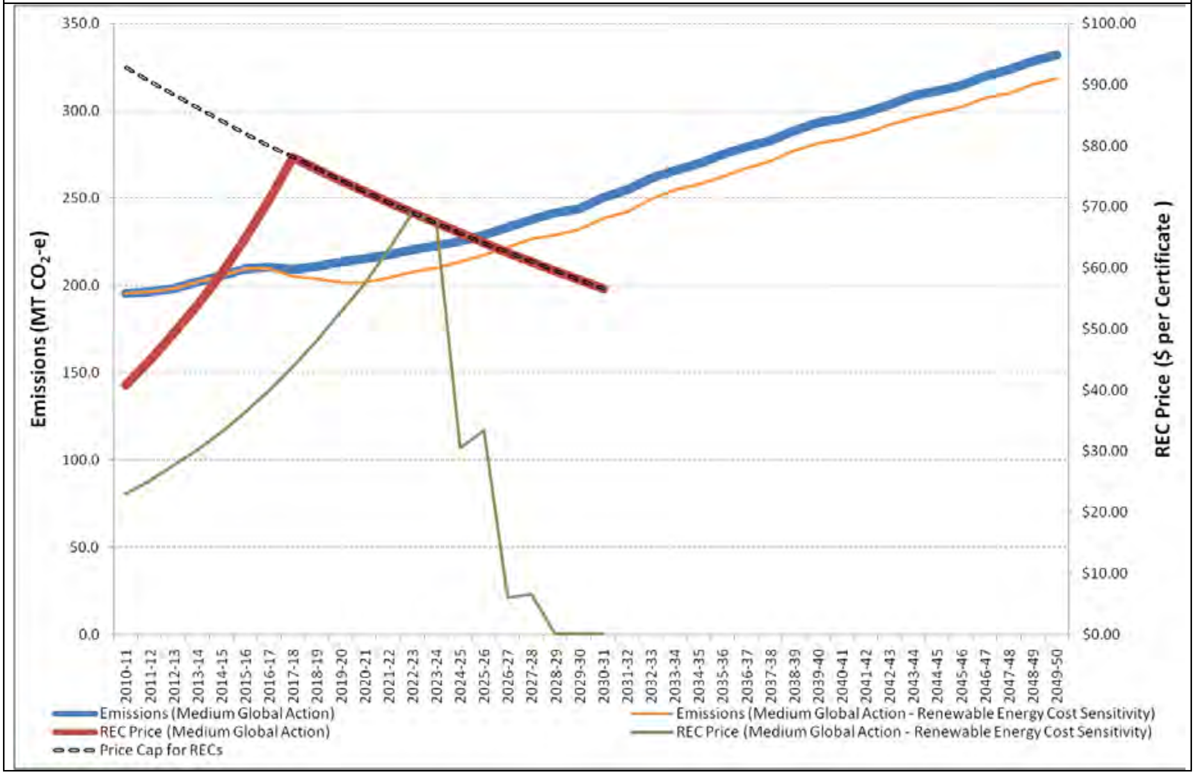


Figure 6.11 – REC pricing – Medium Global Action, Renewable Energy Cost Sensitivity



6.3.2) Core Policy

When applied to the Core Policy Scenario, the decrease in the cost of renewable technologies leads to an increase in the level of renewable generation at the expense of both coal and gas-fired generation. It can be seen in Figure 6.12 that the increase in renewable generation as a result of the decrease in costs varies significantly over the duration of the study. Figure 6.13 shows that the greatest reductions in emissions are evident between 2028-29 and 2038-39. After this point, the emissions trajectories begin to converge as a result of a decrease in the amount of additional renewables with only a minimal difference in the level of coal-fired generation.

The change in renewable costs results in a significantly increased installation of wind farms before 2020, with approximately 2800MW of additional capacity installed providing approximately 7700GWh of additional renewable energy. Later in the forecast period, solar thermal receives a boost – by 2050 an additional 2000MW of solar thermal, or an increase of approximately 4500GWh of energy. The increased wind and solar installations increases the rate of retirement of the existing coal fleet, reduces the build programme for CCS plant, replaces some 2000MW of combined cycle plant, requires up to 4000MW of peaking plant in some years for peak period operation and takes some market share away from other renewables such as geothermal. The faster build rate of wind generators results in a reduction in REC prices, as sufficient energy is available in all years to meet the annual targets, as seen in Figure 6.14

Figure 6.12 – Generation Outcomes – Core Policy, Renewable Energy Cost Sensitivity

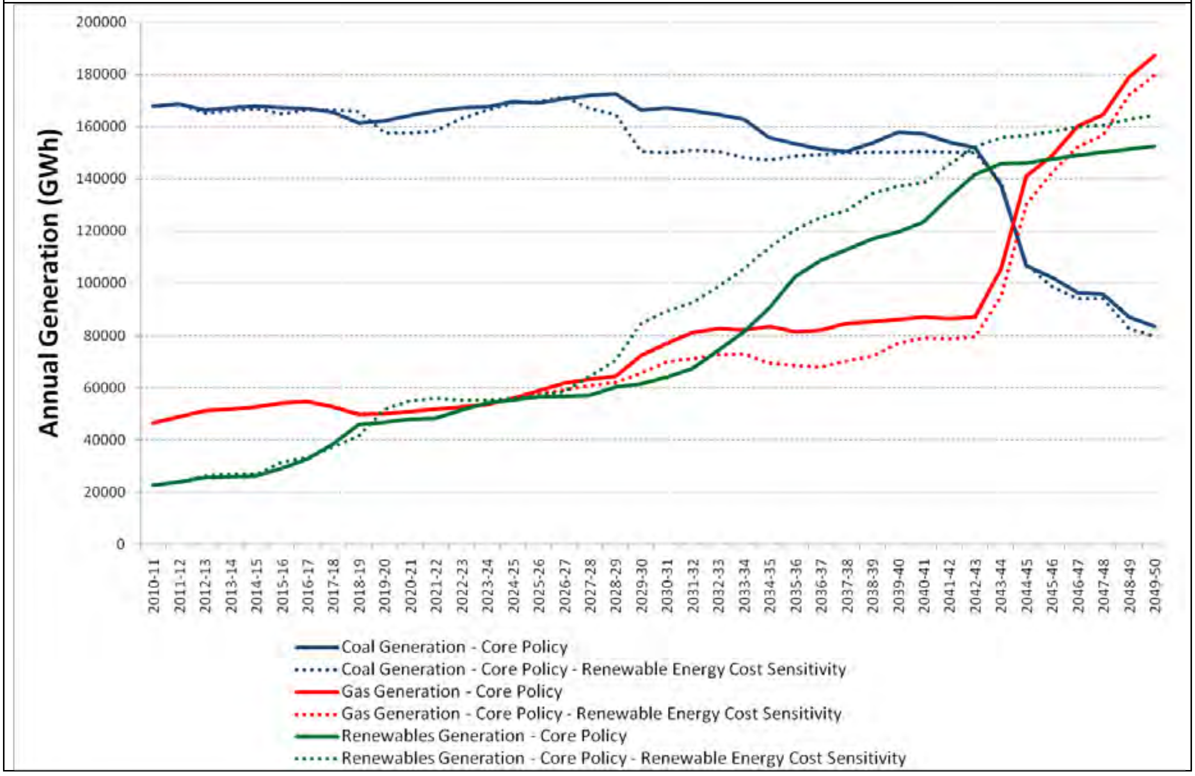


Figure 6.13 – Emissions – Core Policy, Renewable Energy Cost Sensitivity

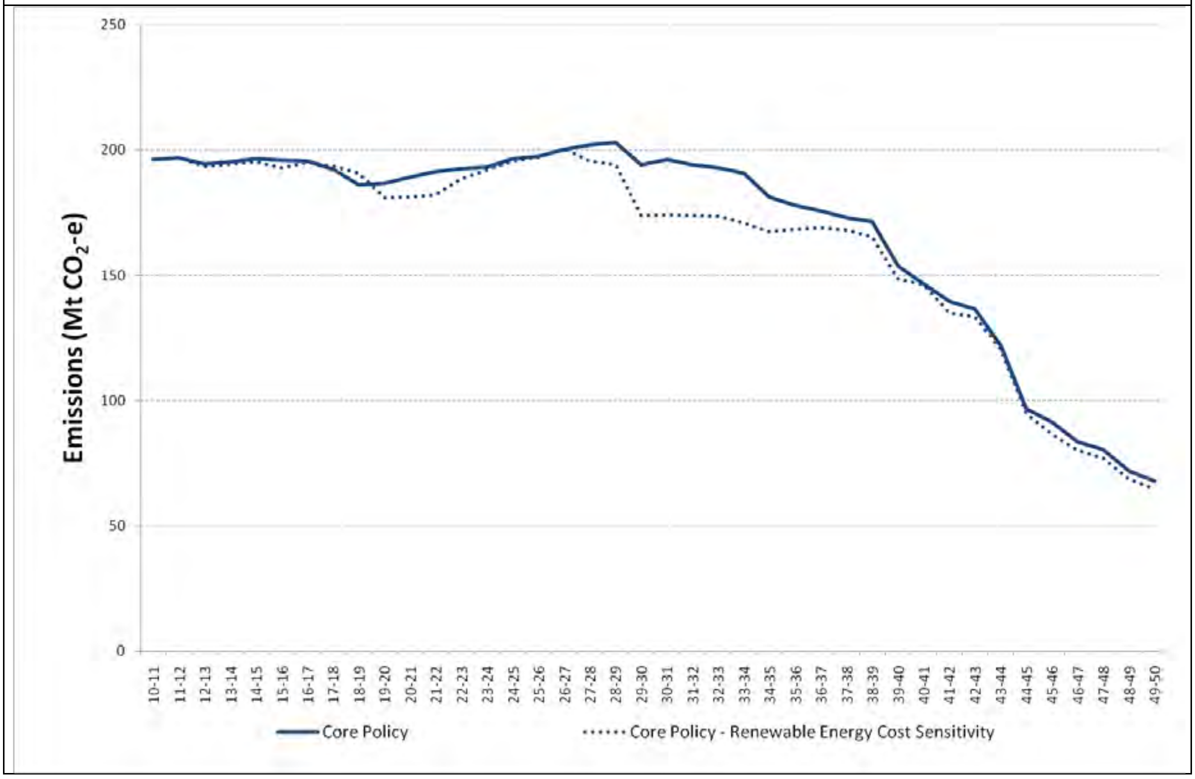
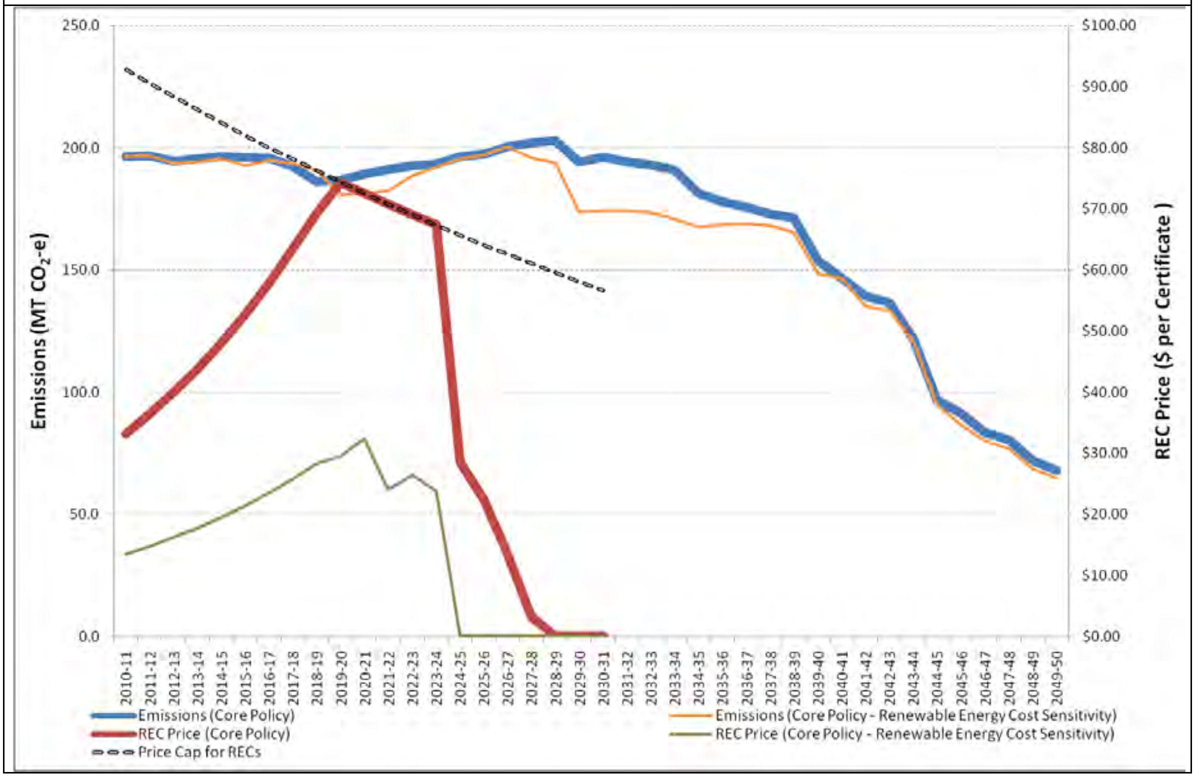


Figure 6.14 – REC Pricing – Core Policy, Renewable Energy Cost Sensitivity



6.4) *LEARNING RATE SENSITIVITY*

6.4.1) Medium Global Action

The outcomes of the Medium Global Action scenario are very robust to a change in the learning rate for all technologies. Figure 6.15 and Figure 6.16 exhibit almost no difference in either generation or emissions outcomes between the base scenario and the sensitivity.

Figure 6.15 – Generation Outcomes – Medium Global Action, Learning Rate Sensitivity

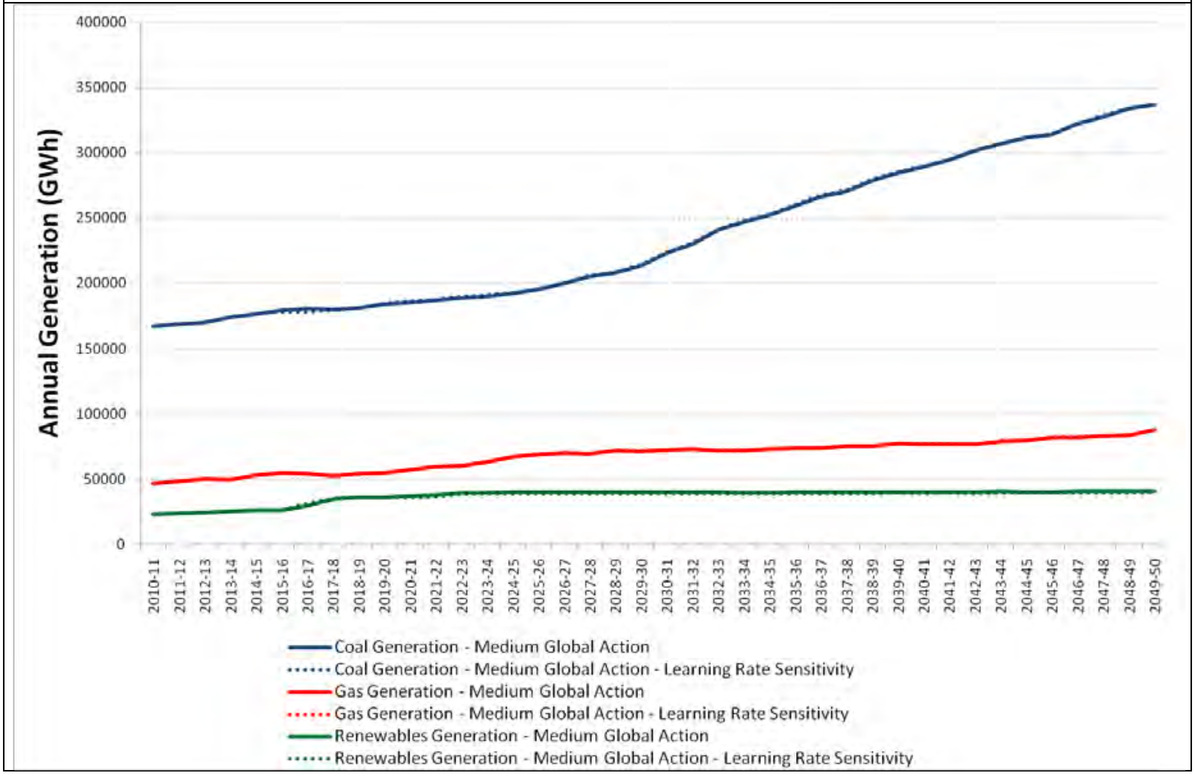
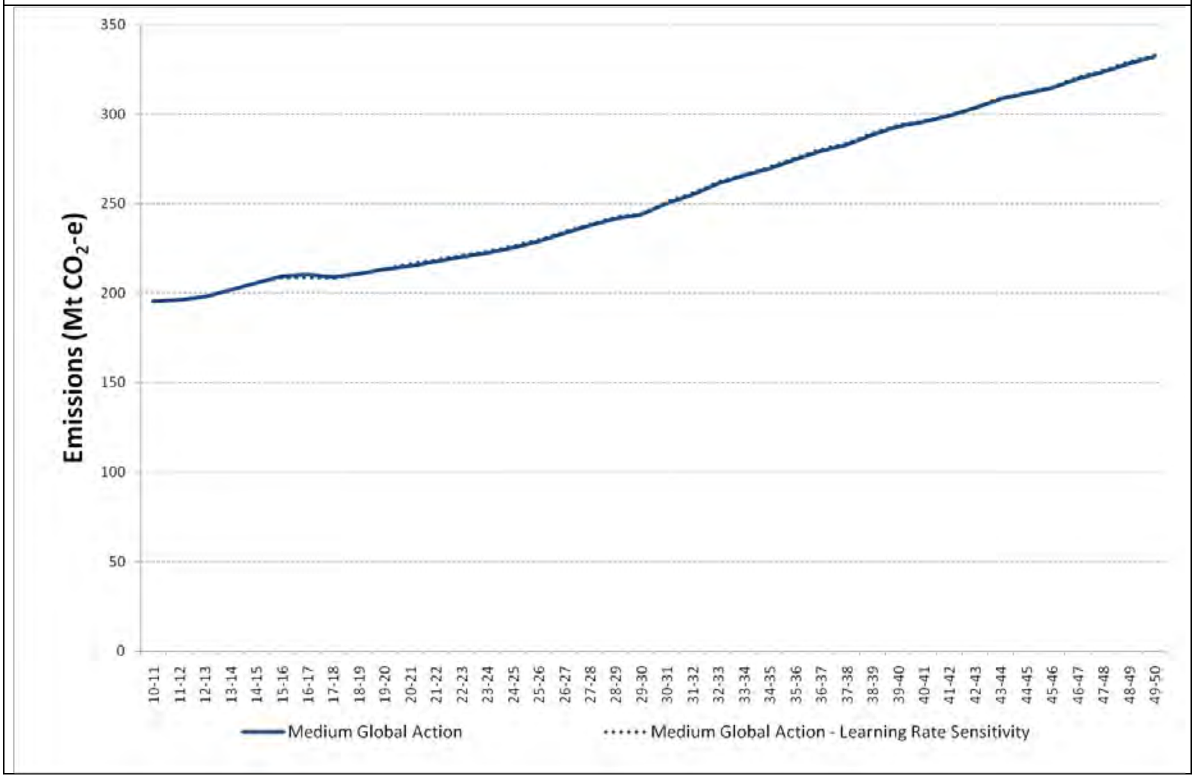


Figure 6.16 – Emissions – Medium Global Action, Learning Rate Sensitivity



6.4.2) Core Policy

The effect of a reduction in the learning rate for all technologies is more pronounced in the Core Policy scenario. Figure 6.17 shows that the decrease in learning rate results in a reduction in investment in renewable generation with a commensurate increase in the level of gas-fired generation. The reduction in learning rate also has a marginal impact on the retirement years of several coal generators, and slows the uptake of CCS technology. The overall impact is to increase emissions by approximately 5 per cent per annum, and up to 30 per cent per annum by the end of the study period.

Figure 6.17 – Generation Outcomes – Core Policy, Learning Rate Sensitivity

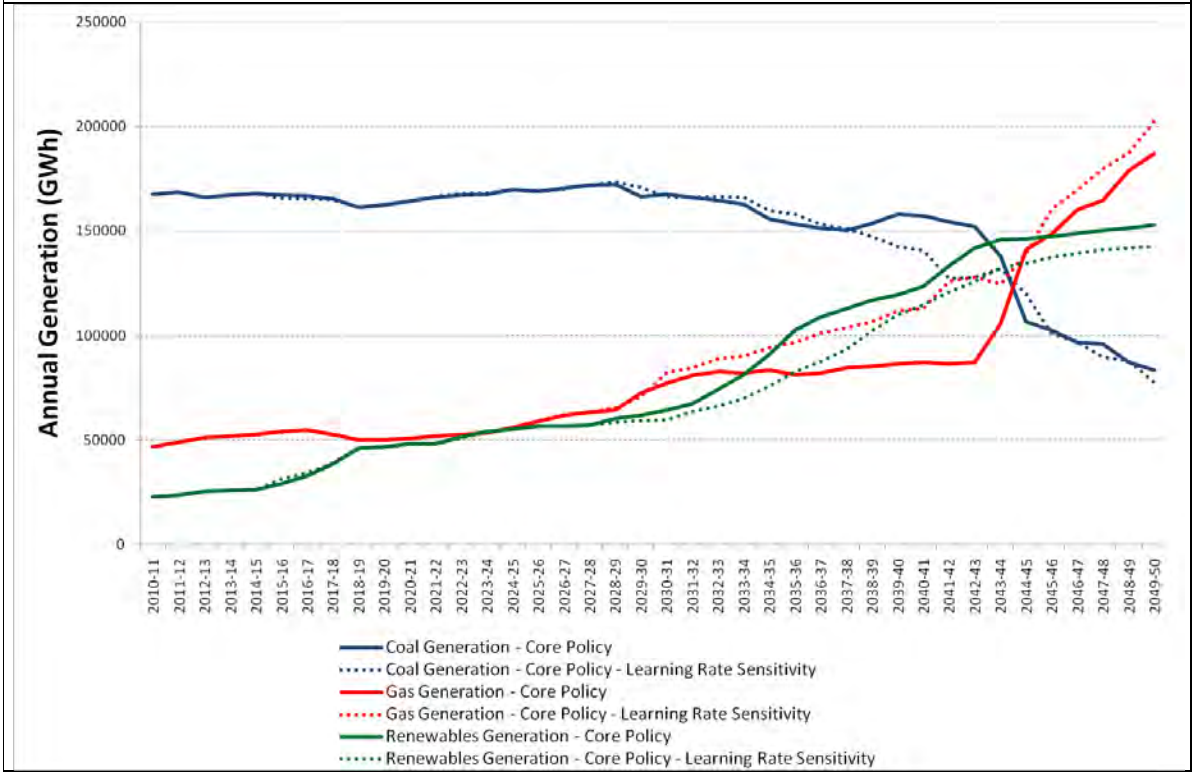
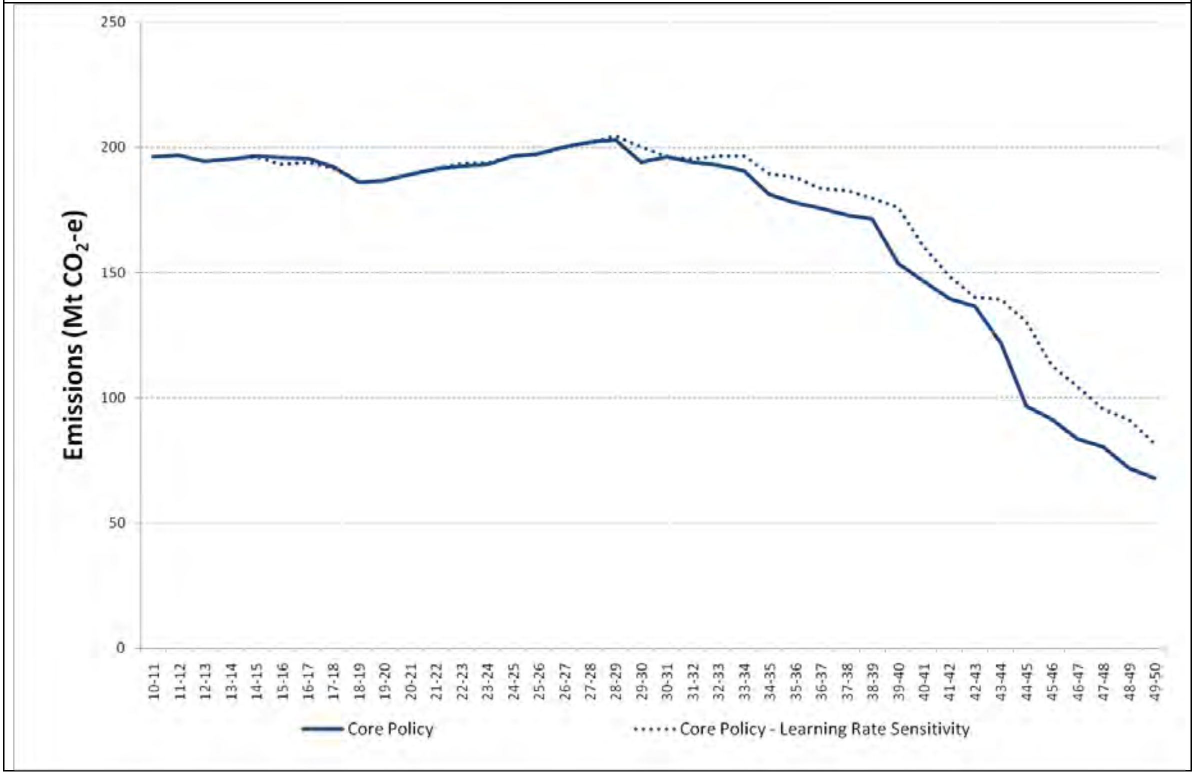


Figure 6.18 – Emissions – Core Policy, Learning Rate Sensitivity



6.5) *CCS Availability Sensitivity*

6.5.1) Core Policy

The unavailability of CCS in the Core Policy scenario results in the replacement of both coal and gas-fired CCS plant with combined cycle gas plant. The restriction on CCS availability only affects the later years of the study where the carbon price is such that gas-fired plant is preferred over coal-fired plant. These generation outcomes can be seen in Figure 6.19. The unavailability of CCS technologies also leads to a marginal increase in the level of renewable generation. However, Figure 6.20 illustrates that this increase in renewable generation is not of a significant magnitude to fully offset the increased emissions which result from the removal of carbon capture and sequestration as a development option.

Figure 6.19 – Generation Outcomes – Core Policy, CCS Availability Sensitivity

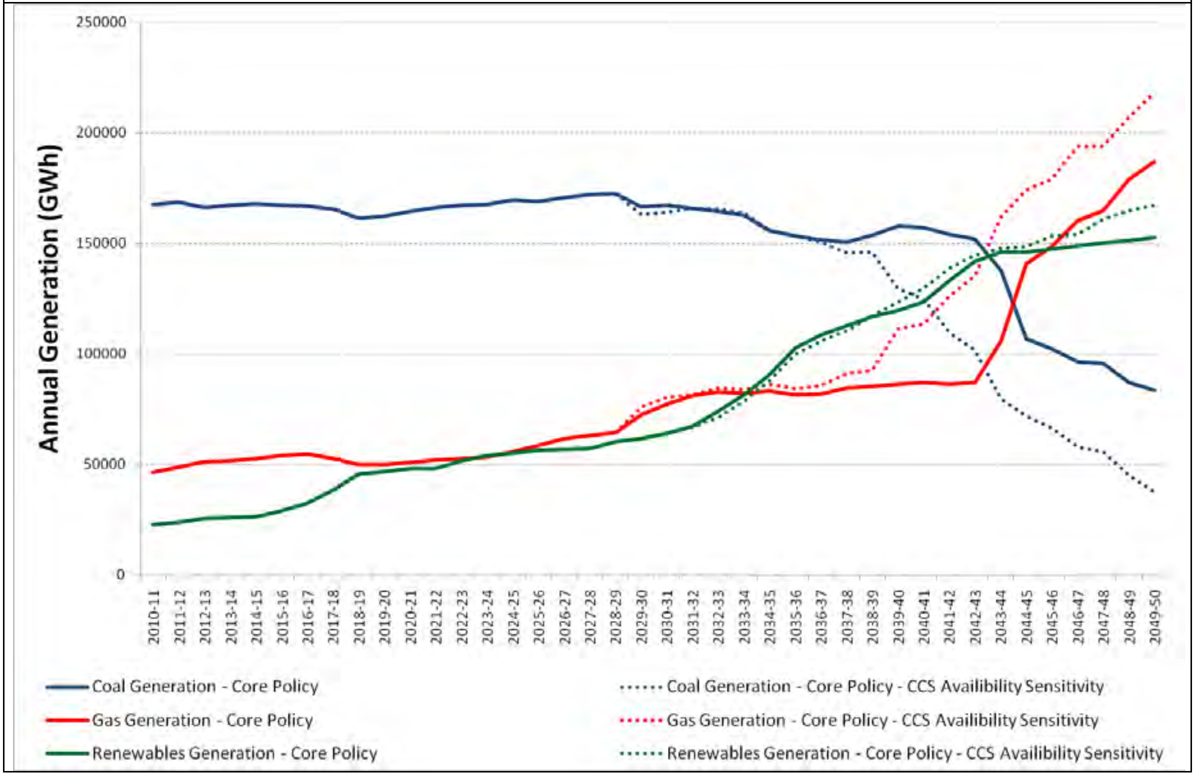
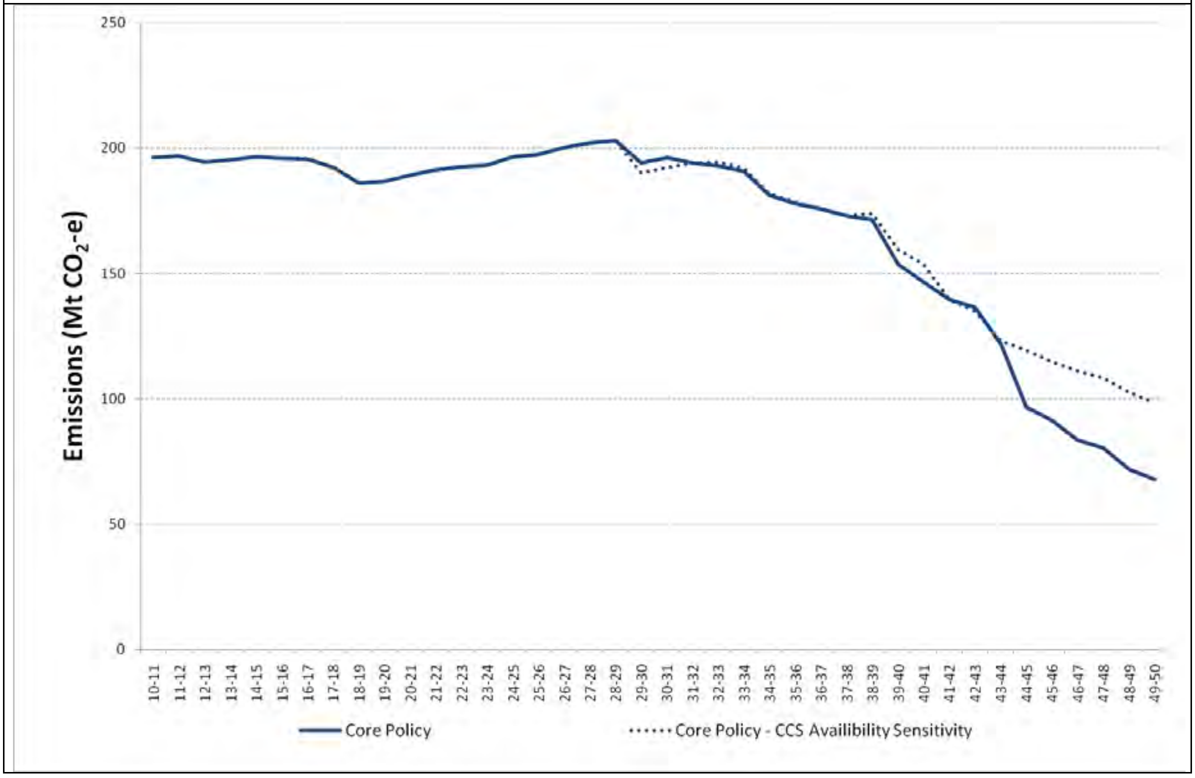


Figure 6.20 – Emissions – Core Policy, CCS Availability Sensitivity



6.6) *Low Price Sensitivity*

6.6.1) Core Policy

The effect of a lower starting value for the carbon price on generation outcomes can be seen in Figure 6.21. Although the carbon price in the Low Price sensitivity converges to the carbon price in the Core Policy by 2022-23, differences in generation outcomes, and therefore emissions, are maintained for the duration of the study. Although minor, Treasury's MMRF model has determined that the annual energies will differ between the two possible futures as the domestic economy adapts slower over time given a softer start to carbon pricing, and as such these persisting differences after carbon price convergence are reasonable. The lower starting carbon price results in a reduction in the retirement of coal. This difference in coal generation is generally sustained for the duration of the study with mixed impacts on both gas and renewable generation. From Figure 6.22 it can be seen that the lower starting price for emissions and the resulting higher electricity demands results in higher emissions for the duration of the study.

Figure 6.21 – Generation Outcomes – Core Policy, Low Price Sensitivity

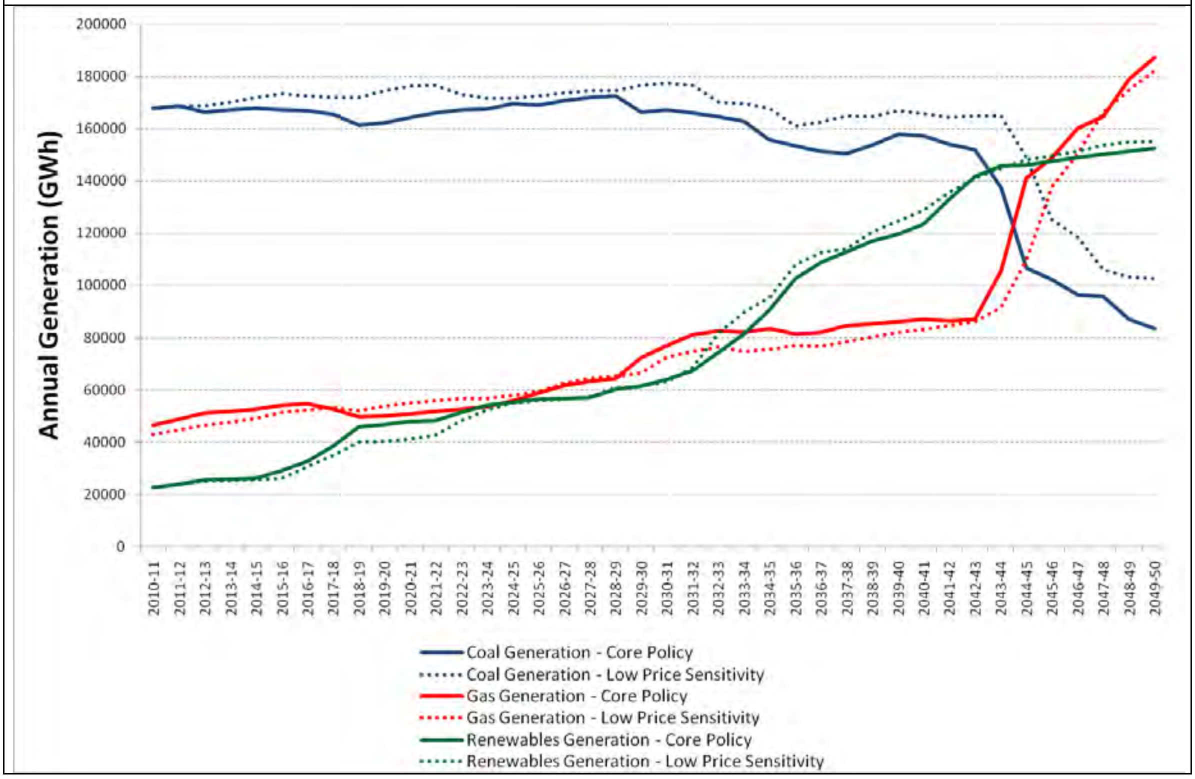
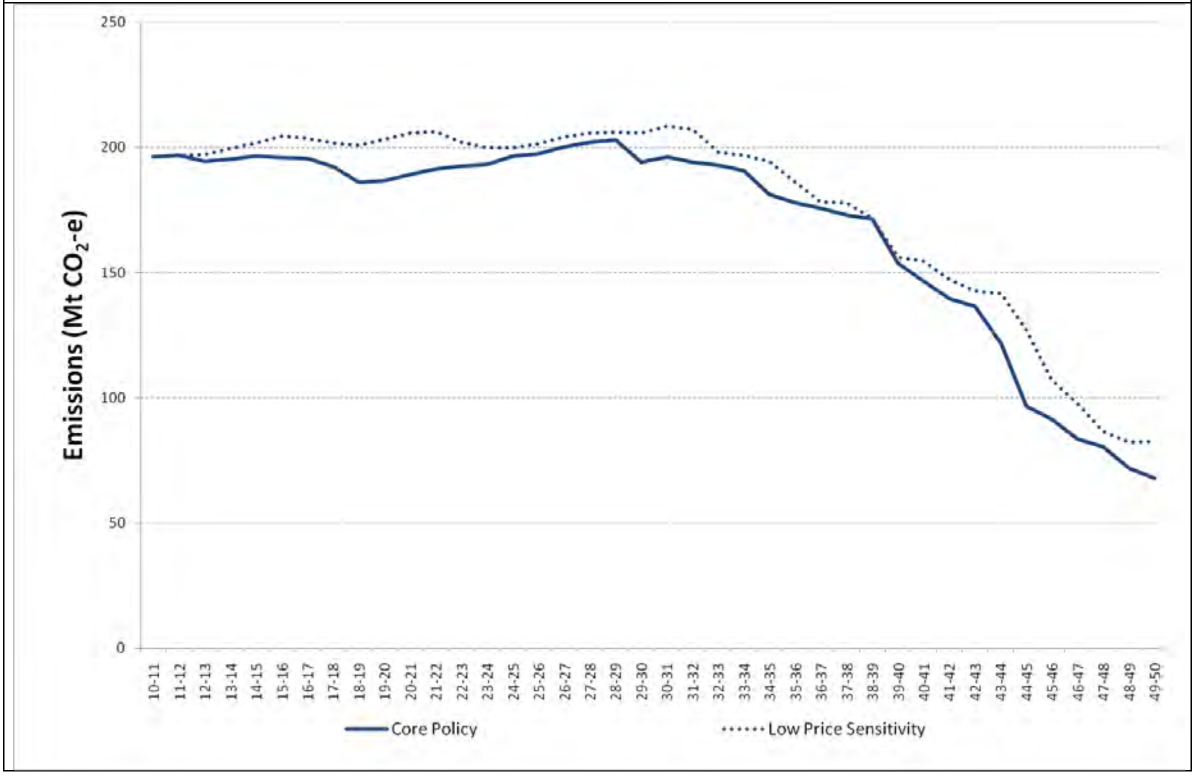


Figure 6.22 – Emissions – Core Policy, Low Price Sensitivity



Appendix A) Modelling Assumptions

In a modelling exercise as complex as this undertaking, a significant amount of input data is required to define the modelling parameters. ROAM has worked with Treasury to define these input assumptions. ROAM has used the 2010 National Transmission Network Development Plan (NTNDP) input data[10], prepared by ACIL Tasman on engagement by the Australian Energy Market Operator (AEMO) as the primary source for technical and financial assumptions used in the model. This includes generator capital costs, fuel prices, generator efficiencies and emissions intensities, capital cost de-escalation rates and other data.

ROAM has endeavoured to use the generator technical and financial assumptions as published within the 2010 NTNDP consultation documentation. The NTNDP included five scenarios, each including minor differences in the global themes which resulted in differences to the technical and financial assumptions. Scenario 2 ("An uncertain world") was chosen as the most representative scenario of the domestic state of affairs in the reference case. With only minor exceptions, such as minor adjustments to the timings of and the locational capacity limits of some new entrant technologies, ROAM has faithfully modelled the NTNDP Scenario 2 data set[11].

A.1) *Global Assumptions*

Table A.1 – Summary of Global Assumptions	
Timeframe	2010-11 to 2049-50
Systems	ROAM has modelled the following systems: • NEM • SWIS • NWIS • DKIS Interconnection between these systems has not been enabled.
Discount Rate	ROAM has used a real pre-tax Weighted Average Cost of Capital (WACC) of 9.70% as the discount rate
Currency Value	All values are reported in real 2009-10 Australian Dollars.

A.2) *Market Assumptions*

ROAM has modelled the electricity sector with two independent modelling runs:

- **National Electricity Market (NEM):**
  - comprising the interconnected regions of

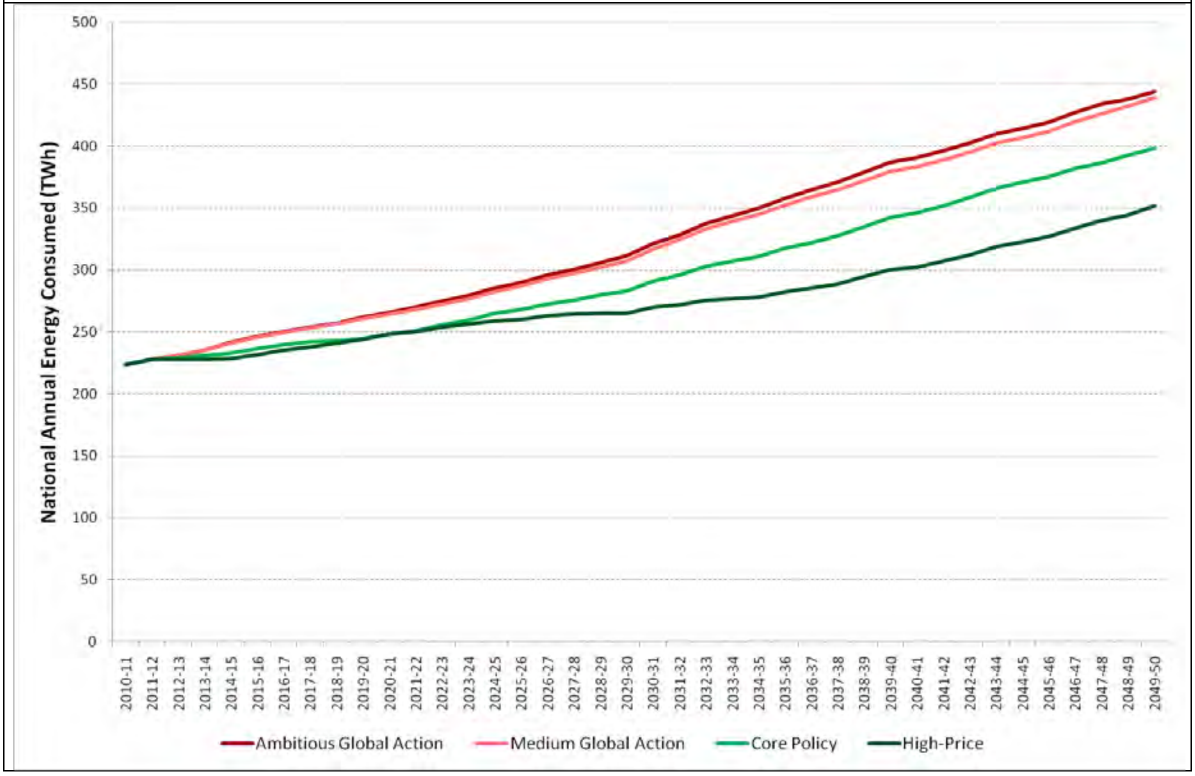
[10] For a full description on the 2010 NTNDP, see http://www.aemo.com.au/planning/ntndp.html. For the consultation documentation, including the background documentation defining the themes for each scenario, as prepared by MMA and ACIL Tasman, see http://www.aemo.com.au/planning/scenarios.html.

[11] National Transmission Network Development Plan Consultation, Supply Input Spreadsheets, Scenario 2: http://www.aemo.com.au/planning/0410-0029.zip

        - QLD
        - NSW
        - VIC
        - SA
        - TAS
    - Interconnectors modelled include
        - Queensland – New South Wales Interconnector (QNI) (NSW -> QLD)
        - Terranora (NSW -> QLD)
        - VIC_NSW (VIC -> NSW)
        - Heywood (VIC -> SA)
        - Murraylink (VIC -> SA)
        - Basslink (TAS -> VIC)
- **Remainder of Australia:**
    - Comprising the independent systems of
        - South West Interconnected System, WA (SWIS)
        - North West Interconnected System, WA (NWIS)
        - Darwin Katherine Interconnected System, NT (DKIS)
    - Each system is independent of the other, and no transmission between systems is included in the modelling

Treasury has provided electricity demand forecasts for each State of Australia through the use of the MMRF model. The calculation of each year's electricity demand is an iterative process, with initial outputs from ROAM regarding the impact of carbon policy on electricity demand being recalculated through MMRF before demands are finalised. ROAM has converted electricity demand into half hourly traces, using the 2009-10 historic electricity demand levels to create a half hourly trace of regional demands for each year of the forecast period. The growth in electricity demand is as follows for each of the scenarios:

Figure A.1 – National Annual Electricity Demand



Other major market assumptions include:

Table A.2 – Summary of Market Assumptions

Electricity Demands	♦ Energy demand is supplied by Treasury using the MMRF model. ♦ Adjustments for off-grid / remote loads (excluded from the modelling): • QLD: Mt Isa (Approximately 3400GWh of CCGT and OCGT gas fired generation at Mica Creek) • WA: East and West Kimberley, Esperance (Approximately 1000GWh of Hydro (Ord River 40MW), Natural Gas (pipeline) and Trucked LNG and diesel generation) • NT: Various off grid loads outside the DKIS, including Macarthur River, Borroloola, Tennant Creek and Alice Springs (Allowing approximately 2000GWh in 2011) ♦ Adjusted from 'As Consumed' to 'Sent Out' using regional average distribution and transmission losses.
Commodity Prices	As provided by Treasury, discussed in more detail in the following section
Transmission	NTNDP transmission upgrade options[12], including:

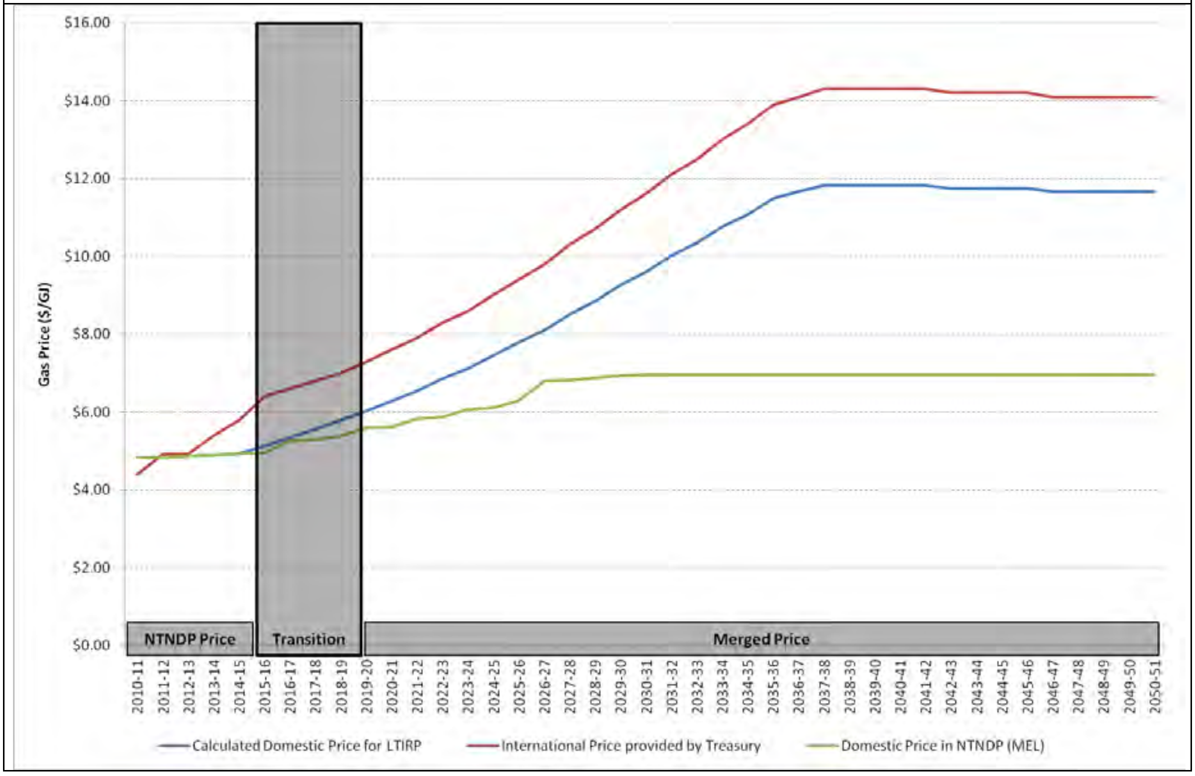
[12] 2010 AEMO National Transmission Network Development Plan, http://www.aemo.com.au/planning/0410-0066.pdf, pp175-177

Developments (NEM)	• 1400MW (North) / 2100MW (South) NSW to QLD Upgrade ($950m) • 500MW (North) / 1100MW (South) VIC to NSW Upgrade ($1079m) • 500MW (North) / 600MW (South) TAS to VIC Upgrade ($720m) • 800MW (West) / 800MW (East) VIC to SA Upgrade ($700m) • 100MW (West) / 1000MW (East) NSW to SA Upgrade ($2424m)
Exchange Rates	Exchange Rates and Commodity prices have been provided by Treasury. ROAM does not include exchange rates and metals prices in the model; however an adjustment to the capital cost of new entrants is included to account for fluctuations in exchange rates and commodity prices over the forecast period. The capital costs used are sourced from the 2010 AEMO NTNDP (Scenario 2). This body of work assumed a constant exchange rate of AU$1.00 : US$0.81. Given the improved exchange rate assumed for this modelling relative to the NTNDP, ROAM has passed this onto the capital costs of all plant types by lowering capital costs by approximately 19% for the forecast period, being the difference between the original NTNDP exchange rates and those provided by Treasury.
Renewable Energy Policies	**Renewable Energy Target (RET)** ROAM has included the RET in the modelling. This includes the adjusted targets to account for the separation of large scale renewable projects from small scale renewables upon creation of the SRES. The model therefore requires 41,000GWh of renewable energy certificates (RECs) to be sourced or the penalty price paid of $65.00 (nominal, pre-tax). **Small Scale Renewable Energy Scheme (SRES)** ROAM has separately forecast the deployment of small scale generation to meet the SRES target of 4,000GWh. This generation is included in the assessment of the total renewable generation as a share of total system energy. **New South Wales Greenhouse Gas Abatement Scheme (GGAS)** ROAM has not explicitly included the GGAS scheme as part of the modelling. However, the past actions of the NSW electricity sector in relation to the GGAS scheme have been encapsulated through bidding behaviour, demand profiles, generator efficiencies and other relevant information. **Queensland Gas Scheme** The Queensland Gas Scheme is included in the modelling. Current legislation requires that 15% of QLD consumed energy be sourced from natural gas fired generation. The penalty price is $12.75 (real $2009-10) (pre-tax).

A.3) *FUEL PRICE ASSUMPTIONS*

ROAM has used the commodity and fuel price data provided by Treasury as an input in the cost of generation. In modelling gas prices, ROAM has implemented a method whereby the gas price transitions from the domestic price of gas given in the NTNDP dataset to a domestic equivalent of the international gas price trajectory provided by Treasury. An example of this can be seen in Figure A.2

Figure A.2 – East Coast Gas Price: Merge of Domestic and International Gas Price

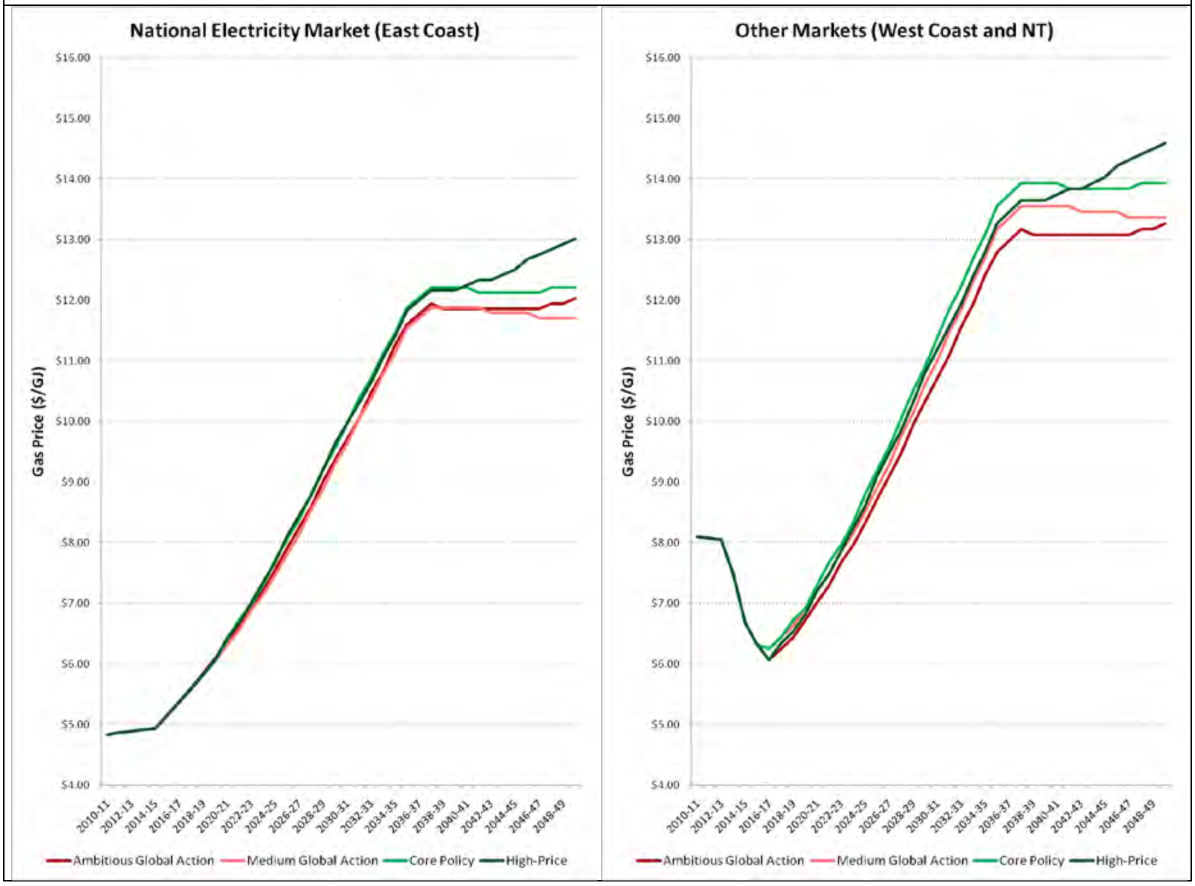


As is shown in the chart above, the gas price in the NEM does not converge to the international gas price. Local gas supplies provide sufficient competition to allow a margin between domestic east coast gas prices and the international price as delivered to foreign markets. Furthermore, an additional delivery cost is added to differentiate prices between NEM regions. By using the NTNDP gas price projections, ROAM has adjusted the east coast merged gas price to account for costs associated with delivery of gas along the pipeline network, such that the relative gas price for each NEM region is equivalent to the existing gas price differentials between NTNDP zones. For example, South West Queensland generators pay marginally less than North Queensland generators, due to the proximity to existing gas supplies. Similarly, Latrobe Valley gas generators have a marginally lower gas price than gas plant in Adelaide. These relationships continue throughout the modelled period.

The west coast already is a mature export-oriented gas market. Existing major LNG terminals exist at Karratha and Darwin, and major developments are already underway to expand this capacity (for example the Gorgon project at Barrow Island). As such, the gas prices in Western Australia and the Northern Territory is more likely to reflect international prices.

The collection of gas prices used in the modelling is shown in the figures below.

Figure A.3 – Gas Price Trajectory

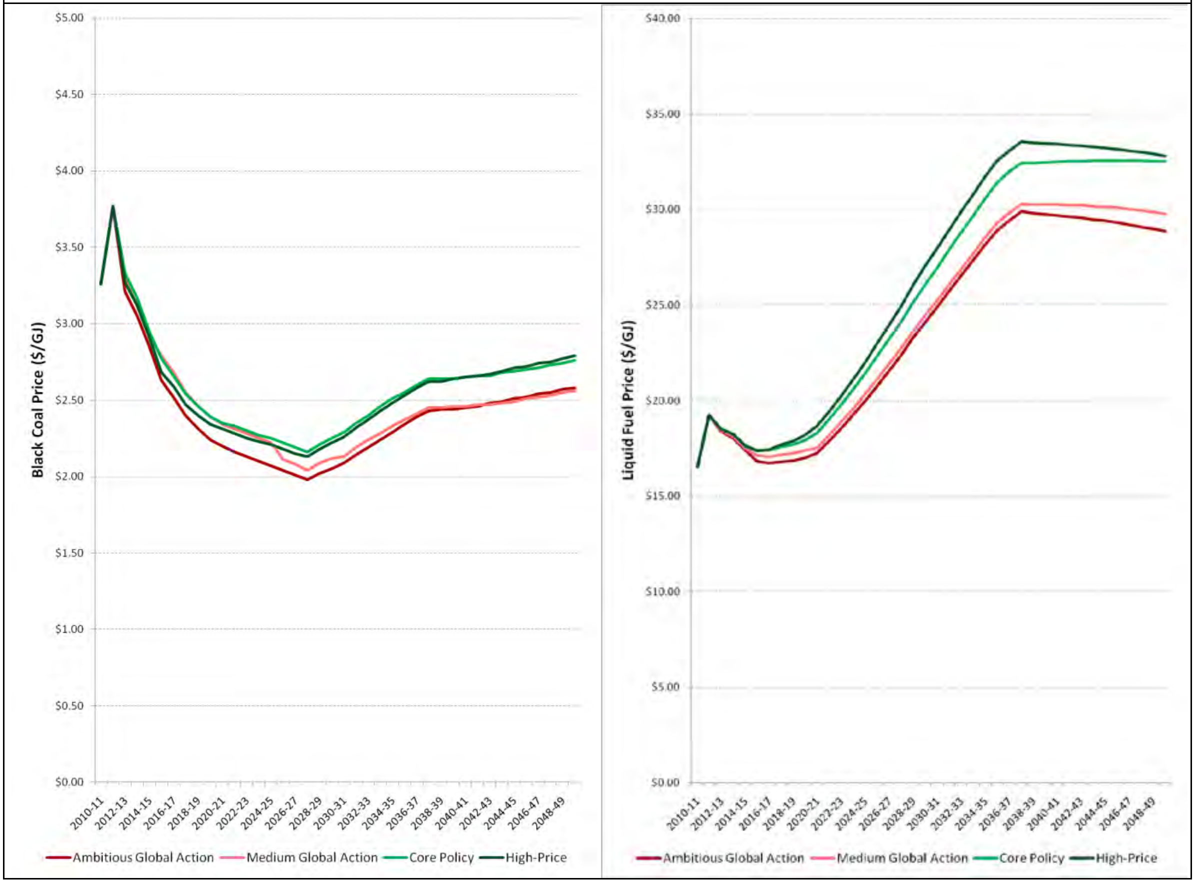


Existing gas plant which have gas contracts in place (as stated in the NTNDP data set) continue to pay their contracted gas price until the contract expires. After this point, the price paid for fuel will be the calculated domestic gas price shown above. New entrant gas plant will pay this price from their installation date.

The methodology for fuel costs for coal and liquid fuelled generators is the same as for gas plant. Existing coal plant will pay their existing contracted coal price. For new entrant coal fired generators, ROAM has implemented Treasury's international coal price projection, as shown below. Given the uncertainty surrounding the life of the Leigh Creek coal mine beyond 2017-18, ROAM has adopted the calculated domestic coal price as the cost of coal for the South Australian coal generators of Northern and Thomas Playford from this point.

As brown coal is not considered an exportable commodity, the price for brown coal does not follow the international coal price provided by Treasury. Instead the NTNDP brown coal prices have been modelled.

Figure A.4 – Black Coal and Liquid Fuel Price Trajectory



A.4) *Transmission Assumptions*

As mentioned, the transmission network in the NEM has been modelled with all of the existing six interconnectors installed and operating. ROAM has allowed for the development of several interconnectors in the modelling, as shown in the table below. Each of these options has been sourced by the 2010 NTNDP.

Table A.3 – Network Development Options

ID	Corridor	Description	Import Upgrade (MW)	Export Upgrade (MW)	Cost ($M)
QN1	NSW-QLD	Armidale second 330kV SVC	0	100	50
QN2	NSW-QLD	Bulli Creek to Dumaresq + Dumaresq to Armidale	-600	300	125

QN3	NSW-QLD	HVDC back to back	-400	700	490
QN4	NSW-QLD	Bulli Creek to Bayswater double circuit 330kV	-900	1300	950
QN6	NSW-QLD	Western Downs - Bayswater 500kV double circuit	-1400	2100	950
VN1	VIC-NSW	Loy Yang braking resistor	0	170	73
VN2	VIC-NSW	VN1 + SVC	0	50	73
VN3	VIC-NSW	4th Dederang transformer and other works	-150	0	116
VN4	VIC-NSW	VN3 + South Morang transformer	-350	0	105
VN5	VIC-NSW	VN4 + 330kV Dederang to South Morang line	-1100	500	1079
VT	TAS-VIC	HVDC undersea cable	-600	500	720
VS1	VIC-SA	Heywood transformer	-250	120	61
VS2	VIC-SA	VS1 plus series compensation Tailem Bend to South East	0	120	28
VS3	VIC-SA	500kV double circuit Heywood to Krongart	-800	800	700
SN	NSW-SA	500kV AC double circuit	-1000	1000	2424

Transmission upgrades are allowed to be developed in stages in the modelling. That is, the model ROAM employs is not restricted to whole upgrades. In this way, partial upgrades are allowed to be installed at a proportion of the total cost. The modelling allowed for replication of larger upgrades, where these proved economic. ROAM's internal testing has shown that the difference between partial upgrades or whole upgrades is immaterial in modelling over a forty year period.

Interconnector upgrades, modeled in the LTIRP, are allocated 5% average losses in deciding whether they are selected for development. Interconnector upgrades, modeled in the market models, are allocated the same quadratic loss factors as the major lines they operate in parallel with.

A.5) *Existing Generators Fuel Assumptions*

The following figure shows the assumed fuel costs for existing generators

Figure A.5 – Contracted Fuel Prices for existing coal plant in the NEM

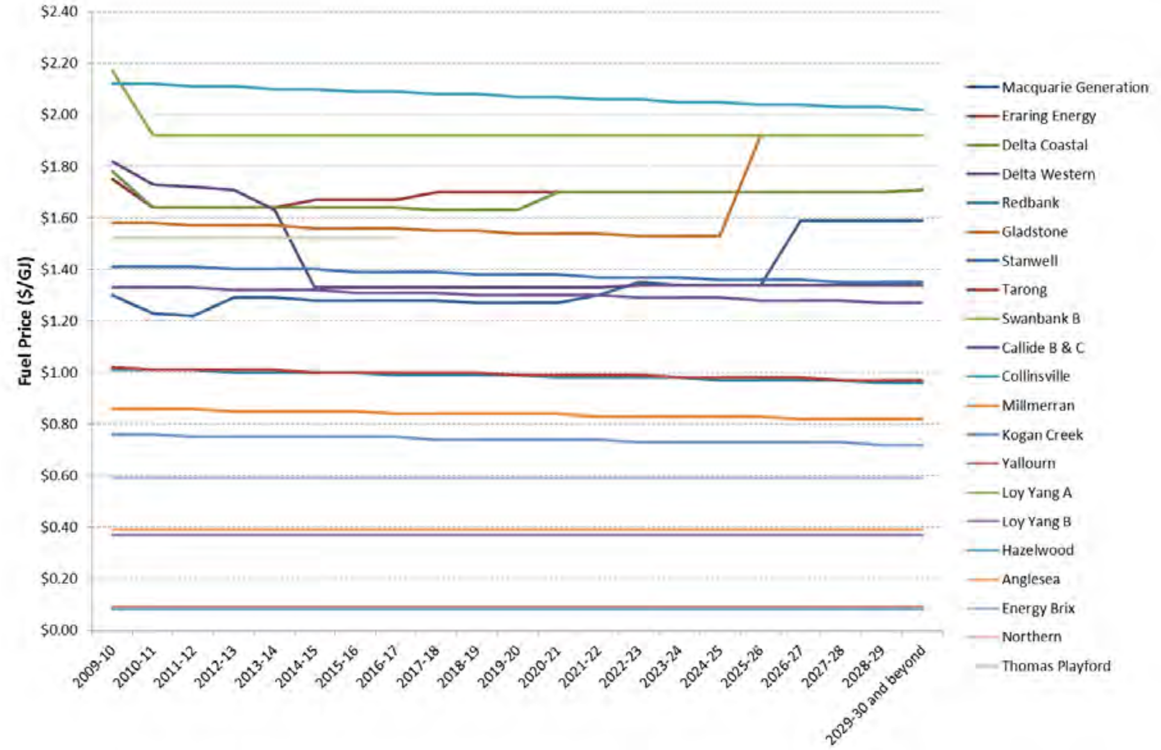
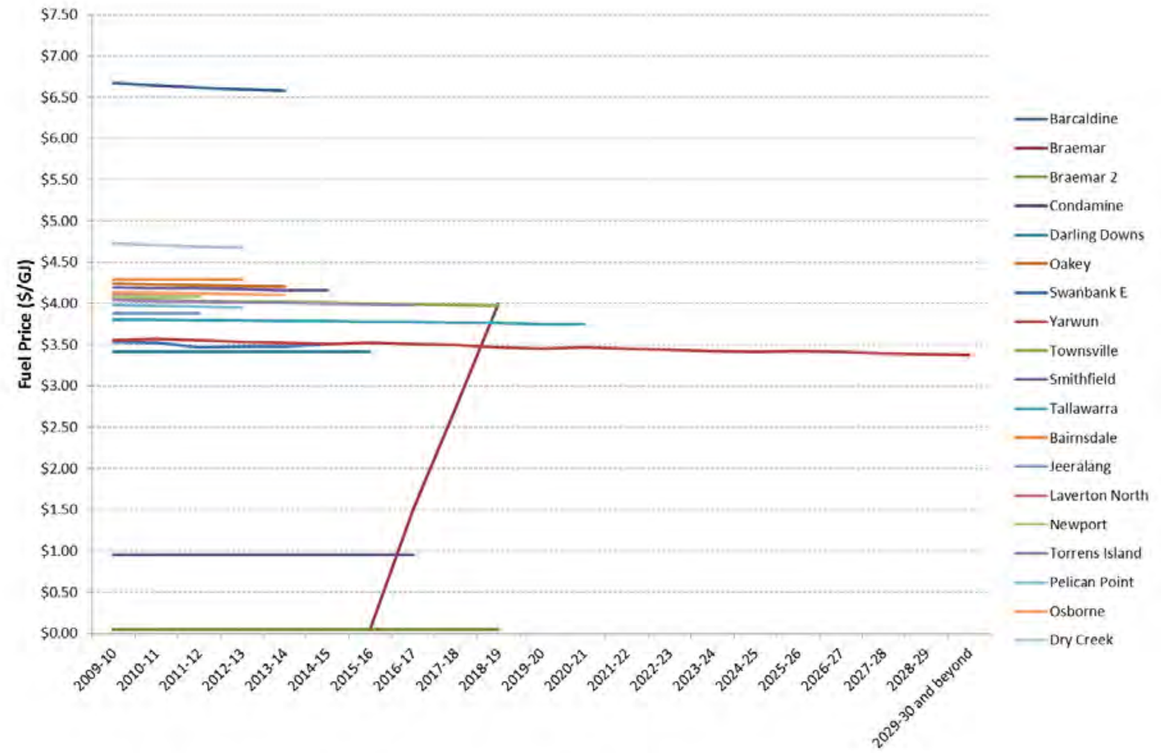


Figure A.6 – Contracted Fuel Prices for existing gas plant in the NEM



Those generators which do not have a fuel contract until 2029-30 and beyond revert to the new entrant or generic fuel price for their fuel supply. All gas plant (with the exception of Yarwun) and Northern and Thomas Playford coal power stations revert to the new entrant price for gas and coal respectively at some point throughout the period.

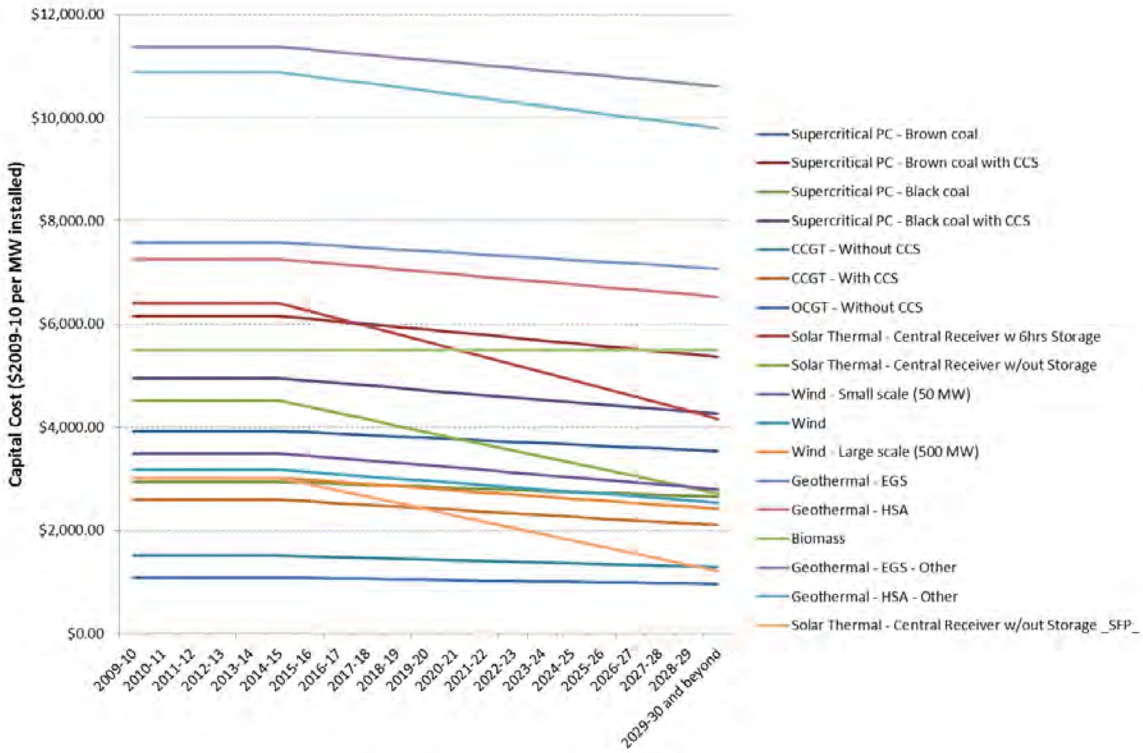
A.6) *New Entrant Technical and Financial Assumptions*

The following table shows the assumed technical and financial assumptions used in ROAM's modelling, as sourced from the NTNDP.

Table A.4 – New Entrant Technical and Financial Assumptions									
Technology	**Financial Life**	**Auxiliary Load**	**Capital Cost 2010 $/kW installed**	**Capital Cost Deescalator 2015-2030**	**Heat Rate 2010 (HHV as generated)**	**Heat Rate 2020 (HHV as Generated)**	**Heat Rate 2030 (HHV as Generated)**	**Variable O&M Costs ($/MWh)**	**Fixed O&M Costs ($/MW p.a.)**
Supercritical Black Coal	30yrs	9.8%	$ 2,393	0.7% p.a.	42.1%	45.8%	53.3%	$ 4.60	$ 33,000
Supercritical Black Coal with CCS	30yrs	23.3%	$ 4,017	0.9% p.a.	37.0%	41.4%	50.1%	$ 15.70	$ 55,000
Supercritical Brown Coal	30yrs	10.3%	$ 3,193	0.7% p.a.	38.8%	43.4%	52.5%	$ 5.10	$ 41,000
Supercritical Brown Coal with CCS	30yrs	23.9%	$ 5,008	0.9% p.a.	33.5%	38.9%	49.6%	$ 16.40	$ 67,000
Combined Cycle Gas Turbine	30yrs	2.9%	$ 1,224	1.0% p.a.	51.0%	53.8%	59.3%	$ 2.00	$ 14,000
Combined Cycle Gas Turbine with CCS	30yrs	15.4%	$ 2,110	1.3% p.a.	48.7%	51.9%	58.2%	$ 4.24	$ 25,000
Open Cycle Gas Turbine	30yrs	1.0%	$ 881	0.8% p.a.	48.7%	35.8%	40.4%	$ 2.50	$ 9,000
Solar Thermal – Central Receiver	30yrs	10.0%	$ 5,211	2.3% p.a.	100.0%	100.0%	100.0%	$ 0.00	$ 73,000
Solar Thermal – Central Receiver with 6hrs storage	30yrs	10.0%	$ 3,669	2.7% p.a.	100.0%	100.0%	100.0%	$ 0.00	$ 55,000
Wind Turbines	30yrs	0.0%	$ 2,581	1.3% p.a.	100.0%	100.0%	100.0%	$ 0.00	$ 39,000
Geothermal – Enhanced Geothermal System	30yrs	15.0%	$ 6,167	0.4% p.a.	100.0%	100.0%	100.0%	$ 0.00	$ 187,500
Geothermal – Hot Sedimentary Aquifiers	30yrs	15.0%	$ 5,902	0.7% p.a.	100.0%	100.0%	100.0%	$ 0.00	$ 125,000
Biomass	30yrs	0.0%	$ 4,472	0.0% p.a.	30.1%	30.1%	30.1%	$ 2.25	$ 40,000

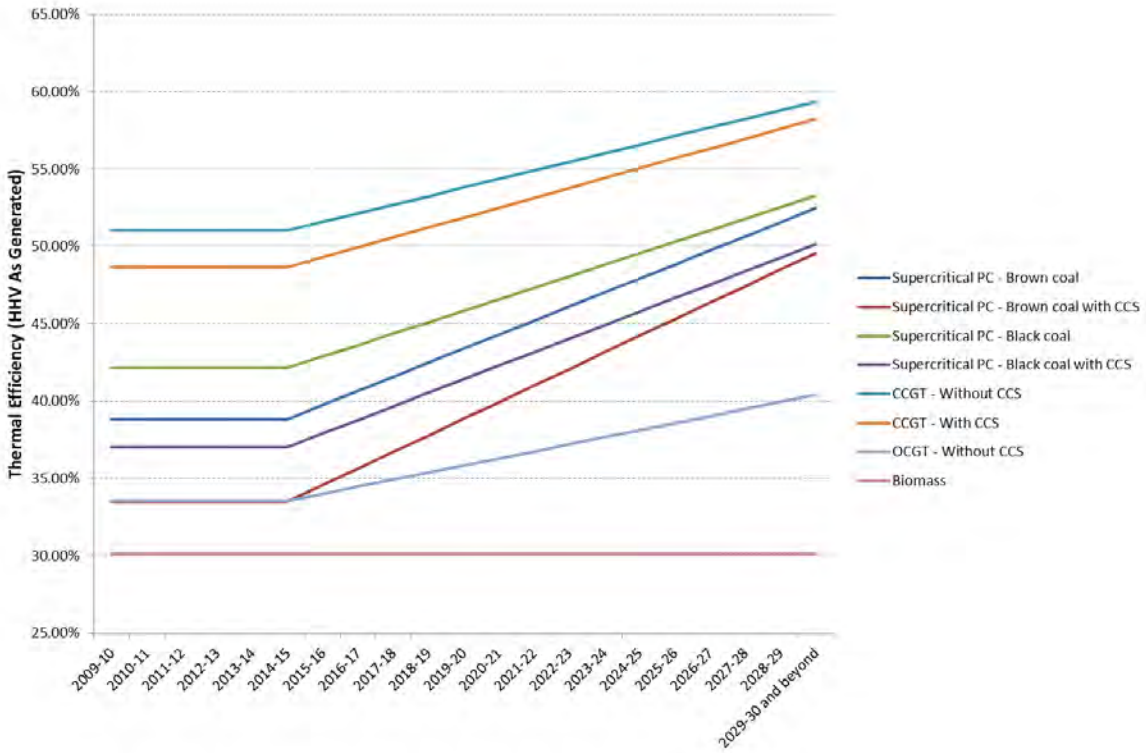
The following figure shows the change in capital cost assumed over the forecast period:

Figure A.7 – Capital Costs for new entrant technologies ($/MW)



The following chart shows the thermal efficiency of thermal generators over the forecast period. Note that ROAM models efficiency improvements in 'steps'. To maintain a reasonable problem size for the linear program, these steps occur once per decade. That is, the efficiency of all generators installed up until 2019-20 will be equal to the 2010-11 efficiency. In 2020-21 the efficiency of new entrants increases to the 2020-21 level, which it then stays at for all new entrants until 2030-31 after which the final efficiency step is selected.

Figure A.8 – Thermal Efficiency for new entrant thermal plant over the forecast period



A.7) *CARBON CAPTURE AND STORAGE*

Although capturing carbon emissions and storing them reduces the emissions intensity of the plant and therefore reduces the cost associated with a carbon price for that plant, there is an operations cost associated with this process (and capital cost associated with constructing the associated infrastructure). The following table shows the cost of capture and storage for each region in the model, as sourced .

Table A.5 – Carbon Capture, Transport and Storage Costs

Region	CCS Costs ($/tonne)
Queensland	$20.90
New South Wales	$37.40
Victoria	$7.70
Western Australia (SWIS)	$20.90

90 per cent of emissions are captured and stored in the model for CCS equipped thermal generators. The following figure shows the amount of carbon captured and stored in each of the cases over the forecast period.

Figure A.9 – Annual Carbon Captured and Sequestered (Mt CO_2-e)

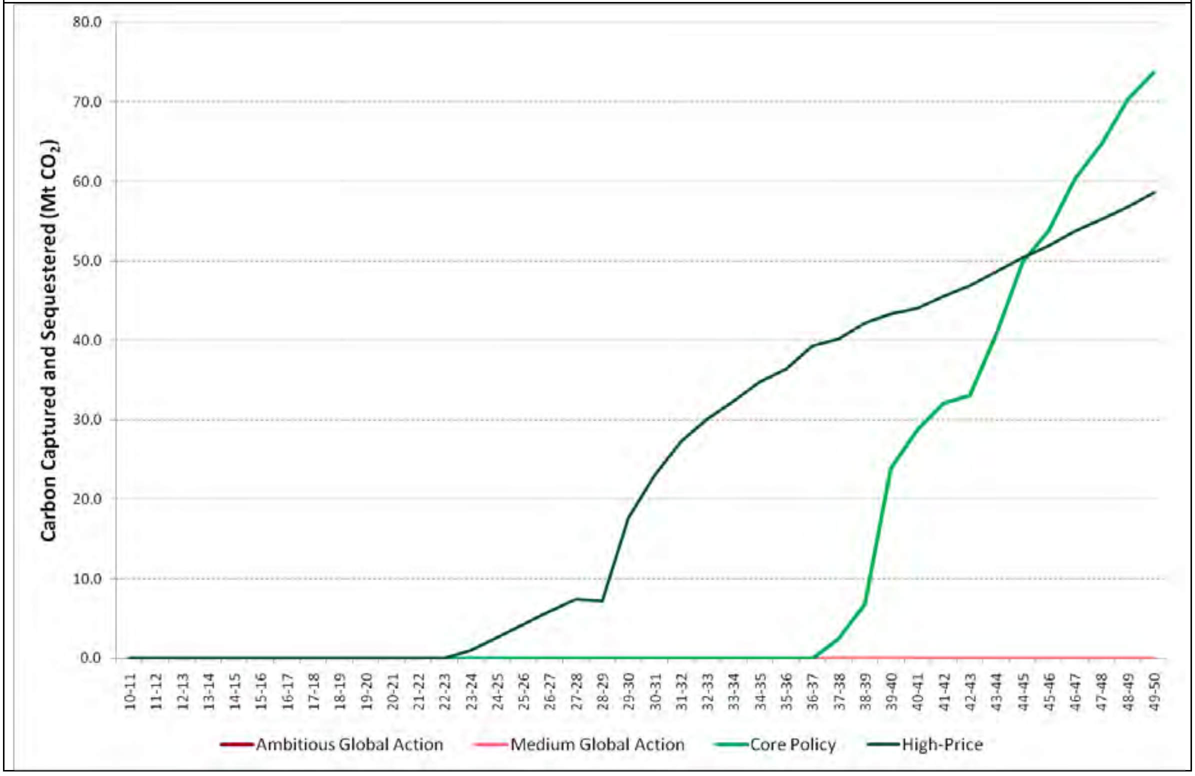
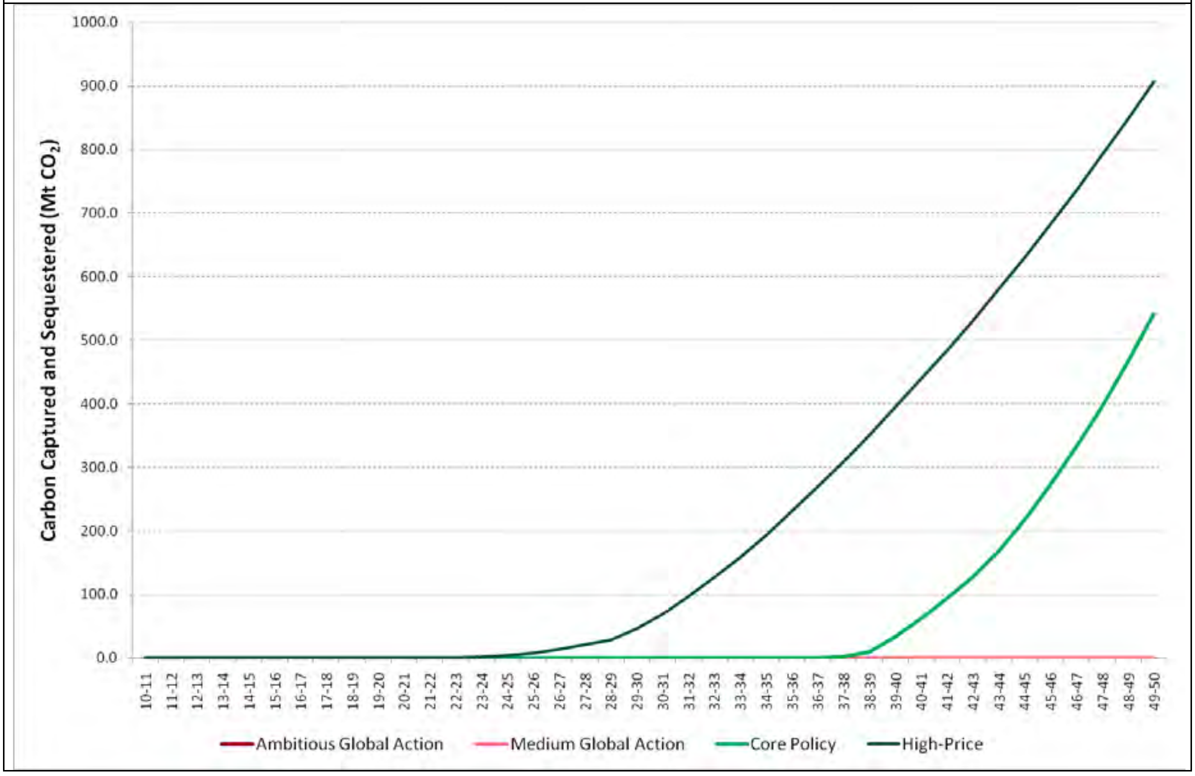


Figure A.10 – Cumulative Carbon Captured and Sequestered (Mt CO_2-e)



Appendix B) Methodology

ROAM has used a Long Term Integrated Resource Planning (LTIRP) software package to plan generation and transmission development in the electricity sector between 2010-11 and 2049-50. The LTIRP software uses linear programming techniques to determine the least cost economic expansion plan by minimising the total cost of servicing the energy demanded for each year. Least cost outcomes are a surrogate for efficient markets which drive development towards the highest level of economic efficiency. The LTIRP is specifically designed for very long range optimisation problems by combining half hourly periods into groups, or load blocks, and assigning weightings to these periods such that the resulting load blocks are representative of the full load duration curve.

ROAM has then used the results from the LTIRP modelling as an input into 2-4-C, ROAM's comprehensive time sequential model, to allow an enhanced level of detail and accuracy for pricing, generation dispatch and interconnector flow forecasts.

The combination of the two models allows the least cost plan to be quickly and accurately determined. This combination of generation and interconnections is then dispatched at a half hourly granularity to calculate detailed market outcomes including wholesale pool prices, transmission flows and generation. The time sequential modelling takes into consideration the intermittent nature of various renewable technologies such as wind and solar and Monte Carlo random forced and partial outages on generators.

For the Non-NEM ROAM has used only the outcomes from the LTIRP.

B.1) *ELECTRICITY DEMAND CONVERSIONS*

Treasury has supplied annual electricity demand for each State of Australia. ROAM has converted this demand for use in the models as follows:

1. Convert the PJ energy targets as supplied by Treasury to GWh
2. Using the 2010 AEMO Statement of Opportunities (SOO), create peak summer and winter demand by applying the forecast load factor in the SOO to the supplied targets
    I. For the Policy scenarios, the peak demand targets of the relevant reference case have been used – that is, the load factor deteriorates in the policy cases as peak demands stay level with the reference scenarios but energy reduces. This is consistent with reductions in energy use but with demand spiking on occasions of extreme weather.
3. Adjustments to the electricity demand as follows
    I. QLD: Mt Isa (Approximately 3400GWh of CCGT and OCGT gas fired generation at Mica Creek)
    II. WA: East and West Kimberley, Esperance (Approximately 1000GWh of Hydro (Ord River 40MW), Natural Gas (pipeline) and Trucked LNG and diesel generation)
    III. NT: Various off grid loads outside the DKIS, including Macarthur River, Borroloola, Tennant Creek and Alice Springs (Allowing approximately 2000GWh in 2011)

4. Using the energy and peak demand and the 2009-10 half hourly load trace as a reference year, forecast the 'as consumed' half hourly load traces for each region modelled, using ROAM's 'LTS' load forecasting software package.
5. Apply an uplift to the resulting half hourly traces to convert from 'as consumed' to 'sent out', thereby matching the supply side which is modelled as 'sent out' also.

The adjustments in Step 3 above have been done to ensure that remote, off grid loads which are currently met through small, local gas, diesel and other small scale renewables persist with that mix of energy supply as these loads are unable to fundamentally change their energy supply. Effectively by isolating these loads (approximately 6400GWh in 2011 increasing to approximately 9000GWh by 2050) and excluding them from the analysis we assume the emissions intensity of the local generation solutions currently serving these loads persist into the future irrespective of Government policies. These loads are excluded from the analysis – no adjustment has been made to generation or emissions to account for these loads.

Appendix C) Benchmarking of the Long Term Integrated Resource Planning (LTIRP) model

Various methodologies are used for modelling investment in electricity markets, and these different methodologies give rise to a variety of model outcomes. We provide in this section a comparison of the outcomes from ROAM's LTIRP model to those from other models which have been used in the past for modelling of this nature and are generally well accepted.

C.1) *Comparison of LTIRP to Energy White Paper models*

As an example, ROAM has conducted preliminary benchmarking for Scenario 2 from the previous Australian Government modelling exercise. Investments in the Australian electricity sector in this scenario were modelled by two different consultants (ROAM and IES) using two different models:

1. ROAM's Integrated Resource Planning (IRP) model;
2. IES's MARKAL model.

The outcomes from these models based upon the same input data (Scenario 2) are illustrated in Figure C.1 and Figure C.2. It is apparent that there are differences between these results, particularly around retirement of plant. Retirements were modelled differently in the two models, giving rise to different outcomes. In ROAM's IRP model plant was retired when it was determined to be no longer profitable on an individual basis (revenue was insufficient to cover costs over a sufficient timeframe). Figure C.1 shows that this lead to substantial retirement of coal-fired plant by 2030 (particularly brown coal).

By contrast, in IES's MARKAL model plant was retired only when it was determined to be the least cost outcome for the whole system. Since existing coal-fired plant are considered to have a sunk capital cost it is rare to be the least cost solution to retire an existing plant (fixed operations and maintenance costs are minimal). This leads to minimal retirement of coal-fired plant in the IES model (Figure C.2).

However, the outcomes of the two models do exhibit some important similarities. When new plant is required both models select a mixture of CCGT and OCGT (peaking) plant. New coal-fired plant is not installed in either model due to the application of a carbon price[13]. Both models also install a moderate level of renewable technologies, in a mixture of wind, geothermal, biomass and solar. ROAM's IRP model selects mostly wind to fulfil the requirements of the Renewable Energy Target (with a small contribution by other renewable technologies), whereas the IES MARKAL model selects a more even mixture of renewable types, with geothermal featuring strongly from 2020.

Note that minor differences between the total installed capacity and total generation between model outcomes are due to IES model outcomes being illustrated for all regions (Australia-wide),

[13] Scenario 2 features a low carbon price equivalent to a -5% by 2020 trajectory.

whereas ROAM's outcomes from the IRP and LTIRP are for the NEM only. Since the NEM constitutes the majority of the Australian electricity sector this provides an adequate comparison.

Figure C.1 – Scenario 2 outcomes (Installed Capacity) - ROAM's IRP model

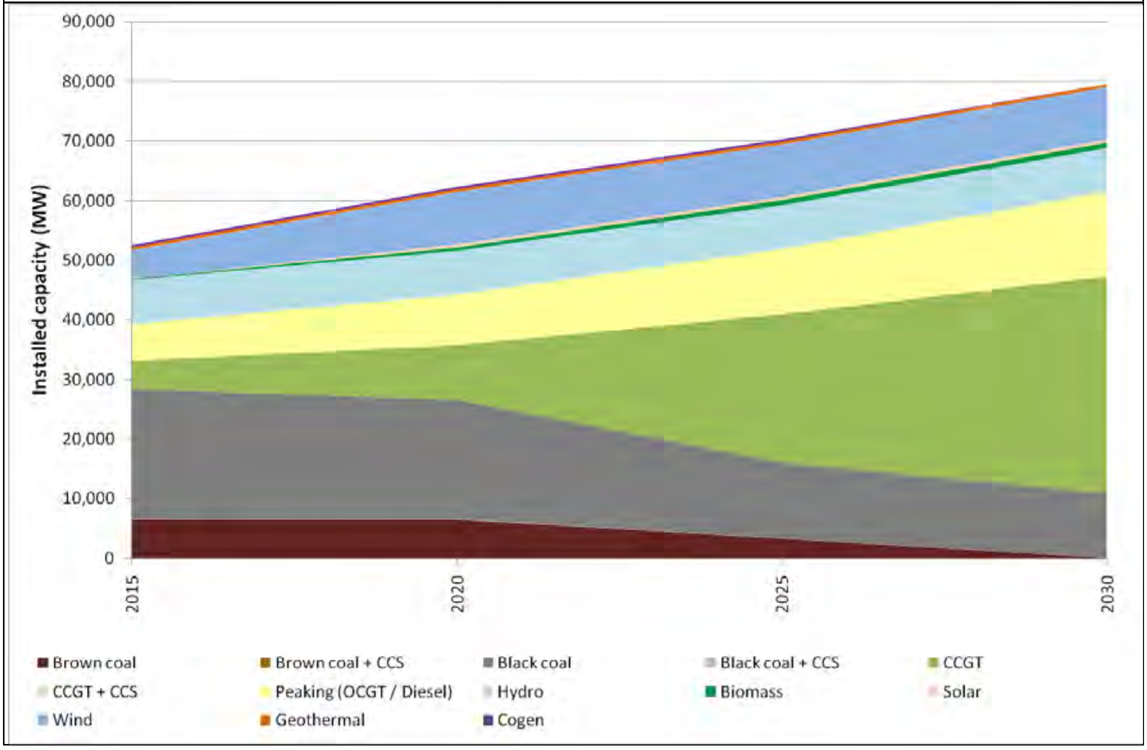
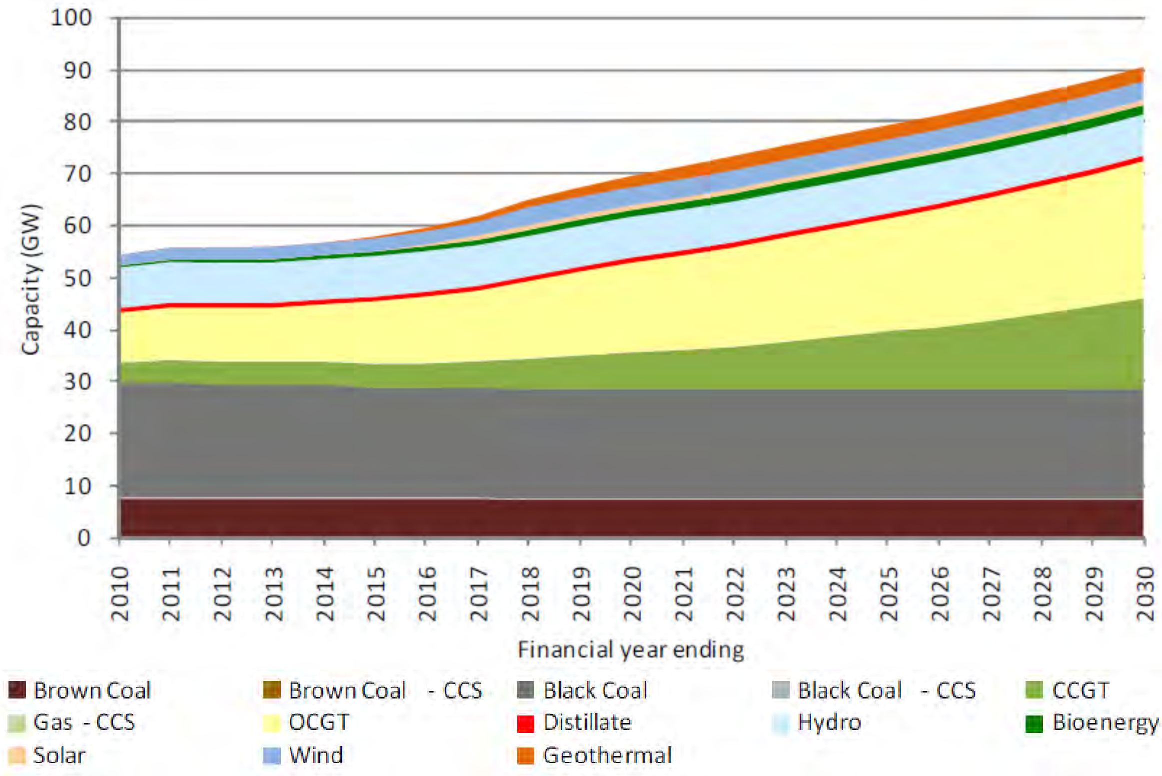


Figure C.2 – Scenario 2 outcomes (Installed Capacity) - IES Markal model[14]



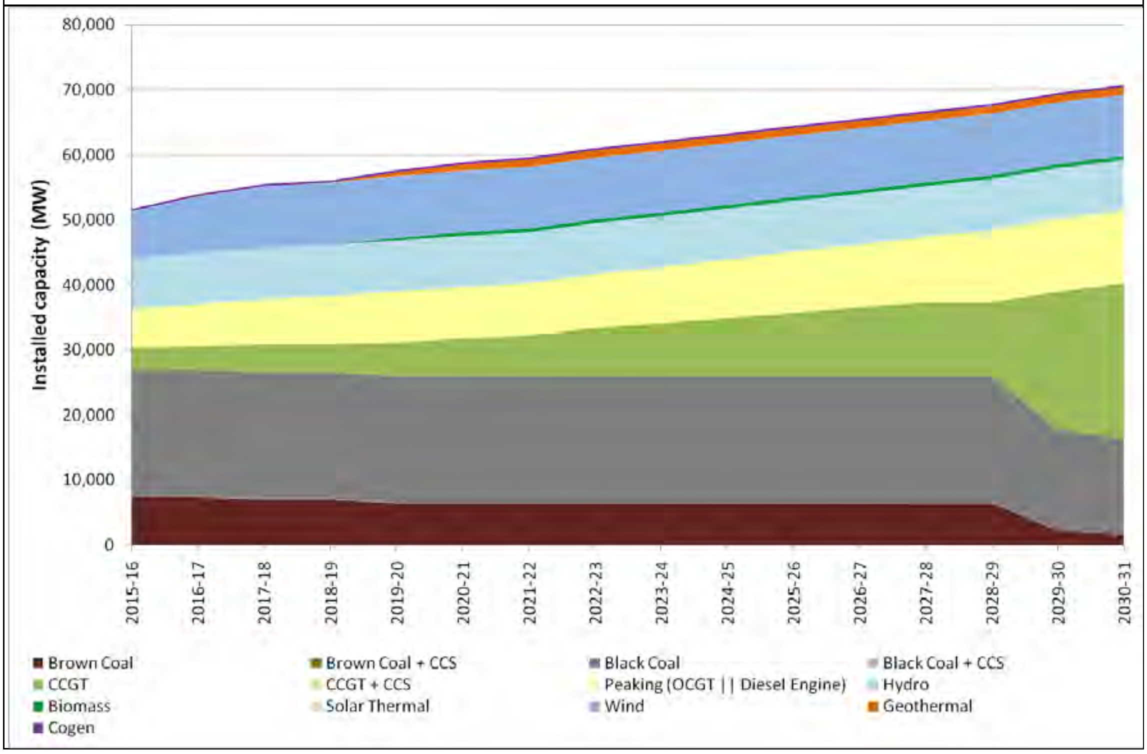
The demand and energy targets used for the original Energy White Paper modelling (IRP and MARKAL model outcomes shown above) were not made public. ROAM has therefore used different demand targets (published by AEMO in the 2010 Electricity Statement of Opportunities) for the later LTIRP modelling. This changes the absolute quantity of plant installed and electricity generated, but is expected to minimally affect the choice of new plant where it is required, and the proportion of generation by various plant types.

The outcome of ROAM's LTIRP model for the same input assumptions (Scenario 2 from the Energy White Paper modelling), with new energy and demand targets is illustrated in Figure C.3. The outcome of this model lies between the outcome of ROAM's IRP model and that from the IES MARKAL model. Some retirement of coal-fired plant occurs (more than observed in the IES MARKAL model), but only occurs late in the study period, and not in the quantity observed in the ROAM IRP model. The LTIRP is a least cost planning model (similar to the IES MARKAL model), but implements minimum capacity factors for plant based upon technical requirements. Plant is retired if it does not meet these minimum capacity factors (or if it cannot meet its annual fixed costs), which produces the retirements observed here.

[14] Reproduced from IES report "Scenario Modelling for Energy White Paper, Modelling Results", 6 December 2010.

As observed in both previous models, the replacement plant is a mixture of CCGT and OCGT. There is also growth in renewable technologies in response to the Renewable Energy Target. The LTIRP model selects mostly wind technology (in line with the IRP model), but also features a significant capacity of geothermal (in line with the IES MARKAL model).

Figure C.3 – Scenario 2 outcomes (Installed Capacity) - ROAM's LTIRP model



Generation outcomes for the same scenarios are illustrated in Figure C.4 (ROAM's IRP model), Figure C.5 (IES's MARKAL model) and Figure C.6 (ROAM's LTIRP model). OCGTs feature less prominently on these energy charts since they typically provide substantial capacity but little energy to the system. The differences in retirement of coal-fired generation between the two models (IRP and MARKAL) are again clearly apparent. However, in both models the majority of energy comes from a growing capacity of CCGT plant, and the coal-fired plant that remains in service. Renewable plant makes a moderate contribution in both models. As for the capacity outcomes, geothermal and biomass technologies make a significant contribution in the IES MARKAL model, whereas ROAM's IRP model sources a larger proportion of energy from wind (with the other renewable technologies contributing a relatively smaller amount).

Figure C.4 – Scenario 2 outcomes (Generation) - ROAM's IRP model

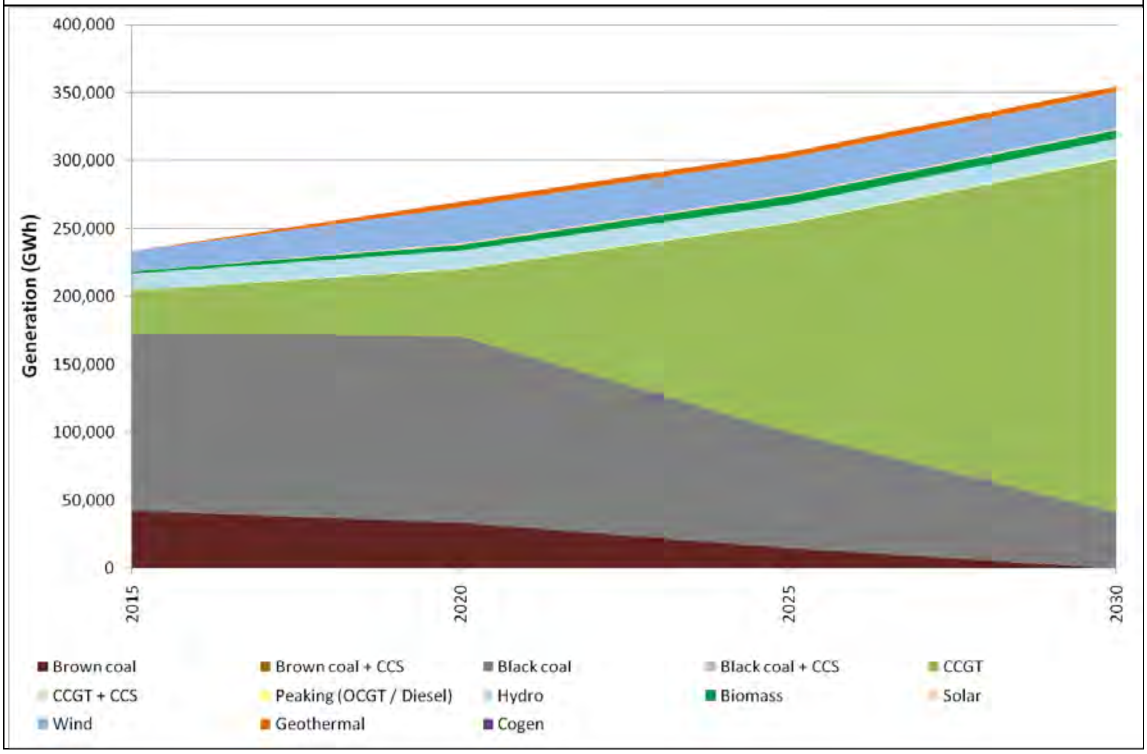
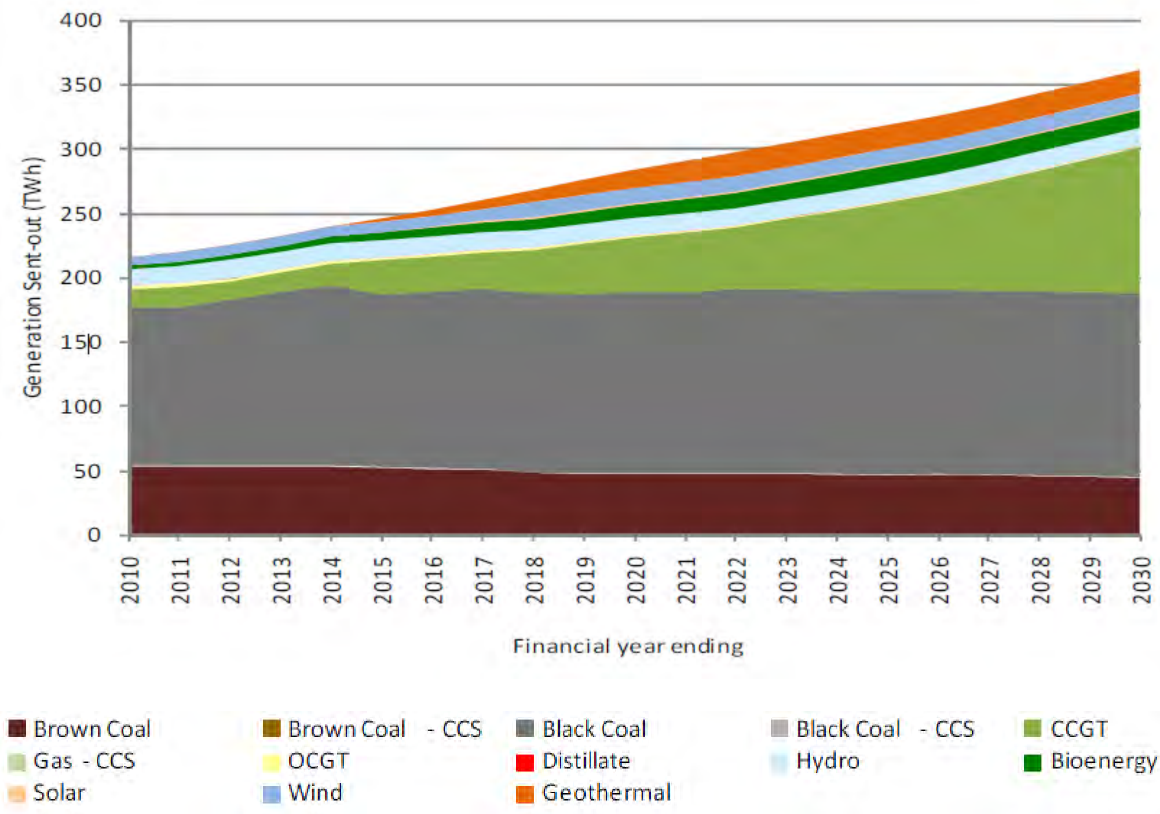


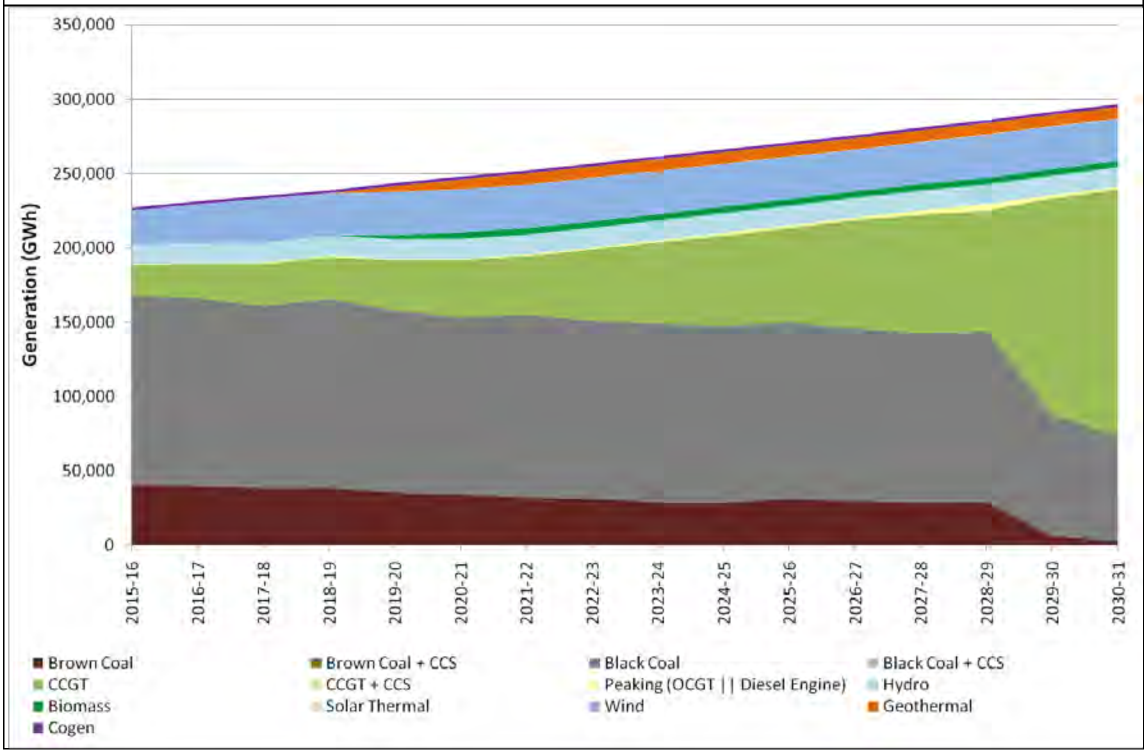
Figure C.5 – Scenario 2 outcomes (Generation) - IES Markal model[15]



The comparative outcome for ROAM's LTIRP model is illustrated in Figure C.6. Again, this outcome is between that observed for ROAM's IRP model and IES's MARKAL model.

[15] Reproduced from IES report "Scenario Modelling for Energy White Paper, Modelling Results", 6 December 2010.

Figure C.6 – Scenario 2 outcomes (Generation) - ROAM's LTIRP model



This benchmarking serves to indicate the differences that can occur in model outcomes due to different modelling methodologies. However, both models in the Energy White Paper modelling exercise were in agreement about the majority of key features observed.

ROAM's LTIRP model produces model outcomes that are consistent with those from the Energy White Paper modelling. This indicates that the LTIRP model is an appropriate tool for modelling of this nature, and is expected to be well accepted in the same way that ROAM's IRP model is.

C.2) *MODEL LIMITATIONS*

ROAM's LTIRP model is the most sophisticated of its kind available. However, like all models of this nature it has limitations. The most important limitations are:

Not time sequential

This model utilises "load blocks", which are determined based upon the load duration curve. Each load block is simulated only once, and the results from each load block are weighted according to the load duration curve to produce realistic annual outcomes. This approach significantly reduces the amount of simulation time required, allowing a much larger number of variable parameters to be co-optimised. However, it is not time sequential in nature, and this means that certain features of the market are captured through averages only. For example, generator forced outages are captured as a reduction in availability spread across all load blocks (generator scheduled outages are included via annual maximum capacity factors for each station such that maintenance can be scheduled during the most appropriate load blocks).

Intermittent generation

Due to the non time sequential nature of the LTIRP model (and all similar models) the modelling of intermittent generation is a key challenge. Many previous modelling studies have assumed a constant average output from intermittent generators in all load blocks. This dramatically over estimates the contribution of intermittent generation to reliability. ROAM's approach, by contrast, is as follows:

1. Determine load blocks from the load duration curve.
2. Determine the generation duration curve for wind farms in each NTNDP zone.
3. Use the previously defined load blocks to split up the intermittent generation duration curve into equivalently weighted blocks. These are forced to be in a different order to the load blocks to ensure diversity (and ensure that the model doesn't always have high wind at times of high demand, and low wind at times of low demand).
4. The wind is considered to contribute these varying amounts in each load block. This means that wind contributes a large quantity of energy in some load blocks, and very little in other blocks, and the weighting of periods is determined from actual wind farm output data. This forces the model to include sufficient other firm capacity when it is economical to do so (to avoid the cost of unserved energy in periods where there is no contribution from wind).

This methodology appears to effectively capture the intermittency of wind and its impacts upon market and network operation. It is a large improvement over previous modelling approaches that utilise a constant output from intermittent generators.

Regional Model

This modelling will only capture network augmentations between the 5 regions of the NEM, but will not capture network augmentation within these regions. The model is configured this way to maximise the detail available to the generation development options. The 'solution space' of a problem of this magnitude is limited, particularly given simulation time constraints, and therefore ROAM has invested the majority of this simulation space to include details on efficiency improvements, renewable generator intermittency and other generation details. In any model, some assumptions will need to be made to the transmission network details – whether it is modelled to the regional level or the NTNDP zonal level, assumptions regarding the underlying nodal network must be made in order to successfully model the market to the timeframe required.

Non-integer solutions

For this study ROAM has used a linear programming approach. This allows incremental network upgrades (installation of small pieces). Often the network is augmented in response to a new generator or other market development, in which case interconnector augmentations will enter in realistic capacities. However, in some cases small increments can be installed in each year, which is not realistic. This can be addressed through the application of additional constraints in a follow-up iteration (restricting all upgrades to whole sizes), however this has no post process moderation has been performed for this study. However, testing has shown the difference to be almost immaterial in a large scale study allowing many upgrade options as in this case.

Appendix D) Modelling details

This appendix provides further details on some specific aspects of ROAM's modelling, data handling and software tools.

D.1) *FORECASTING WITH 2-4-C*

2-4-C is ROAM's flagship product, a complete proprietary electricity market forecasting package. It was built to match as closely as possible the operation of the AEMO Market Dispatch Engine (NEMDE) used for real day-to-day dispatch in the NEM. However, it is capable of modelling any electricity network, and is used to model systems ranging from the small North-West Interconnected System (NWIS) of Western Australia to the large 4000 node CalISO system of California.

2-4-C implements the highest level of detail and bases dispatch decisions on generator bidding patterns and availabilities in the same way that the real NEM operates. Simulations include modelling of generator outages (full, partial and planned), intermittent or inflexible generators and inter-regional transmission capabilities and constraints. Generator bidding strategies are derived from real bid profiles and operational behaviours taken from generators in the relevant system, adjusted over time for any changing market conditions. Such conditions might include water availability, changes in regulatory measures or fuel availability.

These processes and features are central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on projects ranging from week-ahead price forecasts to long term (20-30 year) studies of the whole of Australia, in combination with ROAM's other software tools and expertise. In particular, it has been used on behalf of AEMO since 2004 to estimate the level of reliability in the NEM and consequently set the official Minimum Reserve Levels for all regions of the NEM.

D.2) *PEAK ELECTRICITY DEMAND AND ENERGY FORECASTS*

As discussed, ROAM has used the energy forecasts as supplied by Treasury, produced using the MMRF model. For each region, a bulk load consumption facility has been modelled to represent the cumulative, time-sequential, load consumption profile anticipated at each of the five regions used in the study.

The regional load trace forecasts (that is, the half-hourly load data) have been developed using the 2009-10 financial year load traces for each region as the reference. The peak demand is derived by using the load factors calculated from the published 2010 AEMO Electricity Statement of Opportunities and the 2010 IMO Statement of Opportunities published peak demand and energy targets. The application of these load factors to the Treasury electricity demand data provide annual peak demand targets for summer and winter. The historic half hourly load data has then been grown to meet both the energy and peak demand forecasts.

D.3) *BIDDING OF EXISTING AND NEW ENTRANT THERMAL PLANT*

Generator bids are derived using actual price bands derived from bidding used by the generators in 2010. An quadratic programming algorithm was developed to analyse generation for each existing unit of each station in the NEM for peak (7am to 10pm) and off-peak (10pm to 7am) times on weekdays and weekends (four distinct periods). Bids are generated by ROAM's algorithm to produce the best fit of the simulated generation to the actual generation over the last twelve months, while also respecting other constraints such as historical bidding profiles and minimum generation levels. Extreme peakers are bid at or above estimated short run marginal costs at all times to ensure a close match to historical generation trends.

The bids of new stations are based on the predicted bids of existing stations of the same type, or at estimated marginal costs if appropriate. This approach is in line with the methodology used by AEMO in the Forward Looking Loss Factor calculation.

D.4) *MODIFICATION OF BIDS UNDER A CARBON PRICE*

Under a carbon price, the carbon cost for each generator (in \$/MWh) is given by each generator's emissions factor (tCO_2-e/MWh), multiplied by the carbon price (in \$/tCO_2-e). Since the electricity market in Australia is not internationally trade exposed, it is anticipated that generators will largely increase their bids by the amount of their respective carbon costs. Hence, the effect of a carbon price on the NEM was modelled by adding the carbon cost (\$/MWh) to the bids of each generator. The resulting merit order and competitiveness of each plant changes as the carbon price increases over time.

D.5) *UNIT OUTAGES*

2-4-C utilises independent schedules for each unit of:

- Planned maintenance, and
- Randomised forced outage (both full and partial outage) distribution.

These schedules have been constructed based on information in the public domain and historical generator availabilities - in particular, the following six key parameters are used in the development of outage schedules and are detailed in the table below. A total of twenty five Monte Carlo iterations have been modelled such that the results presented are the average of many different random outage influenced market outcomes.

Table D.1 – Generator outage modelling assumptions	
Full forced outage rate	Proportion of time per year the unit will experience full forced outages.
Partial forced outage rate	Proportion of time per year the unit will experience partial forced outages.

Table D.1 – Generator outage modelling assumptions	
Number of full outages	The frequency of full outages per year.
Number of partial outages	The frequency of partial outages per year.
Derated value	Proportion of the unit's maximum capacity by which the unit will be derated in the event of a partial outage.
Full maintenance schedule	Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).

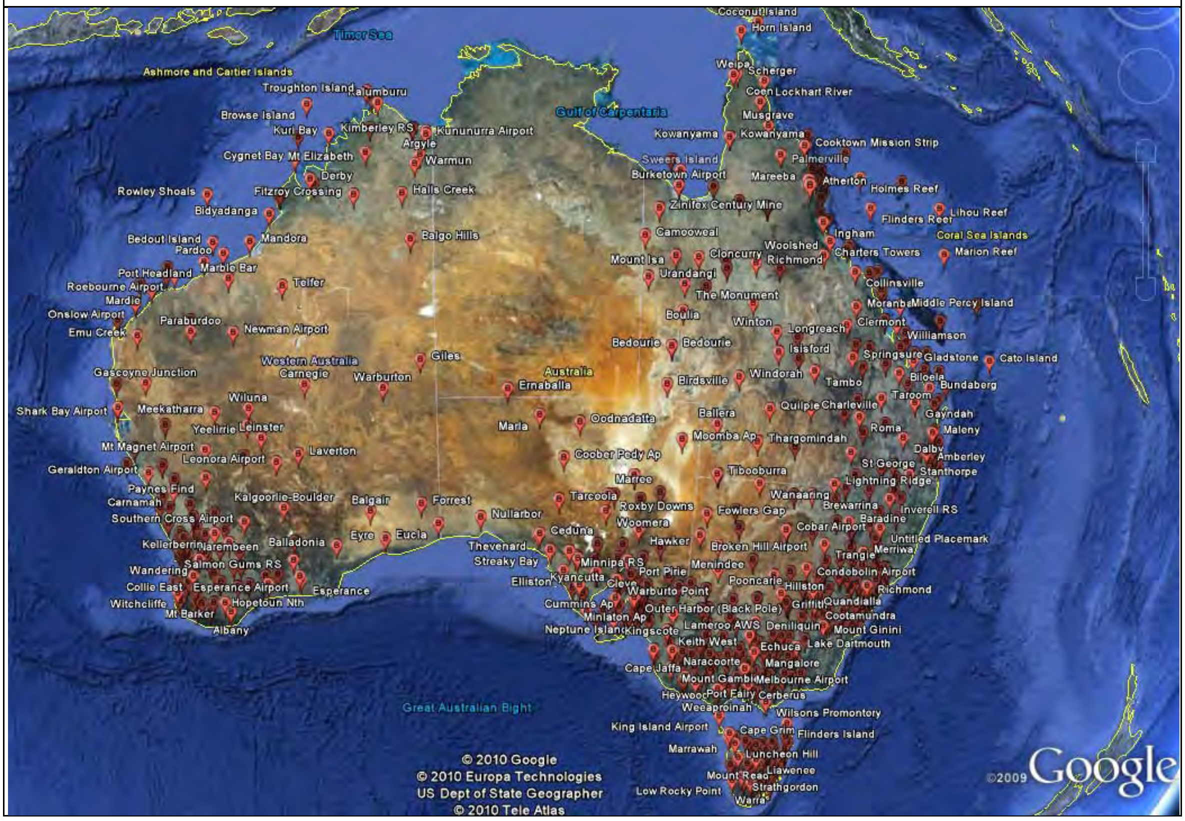
Appendix E) Modelling renewable generators in 2-4-C

E.1) *WIND MODELLING*

To model the output of wind farms, the average wind speed at the wind farm site is required for each half hourly period, which can then be converted into generator output using turbine power curves.

Historical data was sourced from automatic weather stations around Australia from the Bureau of Meteorology (BOM). The locations of the weather stations in eastern Australia are shown in the figure below.

Figure E.1 – Locations of BOM weather stations



The wind data from the BOM weather stations was taken at a variety of elevations from 1m to 70m above the ground. Elevation strongly affects wind speeds. The wind at the height of a turbine hub (from 50m to 80m) will be much faster than the wind at ground level, and the amount of the increase in speed is strongly dependent upon many factors, including the type of ground cover (rock, grass, shrubs, trees) and the nature of the weather pattern causing the wind. In addition, the local topography affects wind speeds very strongly (winds tend to be focused by flowing up hillsides, for example).

Therefore, the wind speed at a weather station perhaps 30km distant from a wind farm is likely to be correlated strongly in time with the wind at the site of the turbines, but the absolute scaling of the speeds is highly uncertain. Therefore, ROAM uses data from the Renewable Energy Atlas of Australia[16] to assess absolute wind speeds. The Atlas contains modelling data provided by Windlab Systems giving the mean annual wind speeds, at a typical turbine height of 80m, at 3km resolution for most of Australia. The mean wind speed at the wind farm site is used to scale the data from the closest weather station to provide an estimate of the wind speed time series at turbine height.

Finally, the wind speeds are adjusted (reduced) to account for turbulence and shading (reduction in wind speed due to extracted energy) across the wind farm (the 'park effect'), calibrated by historic data from existing wind farms.

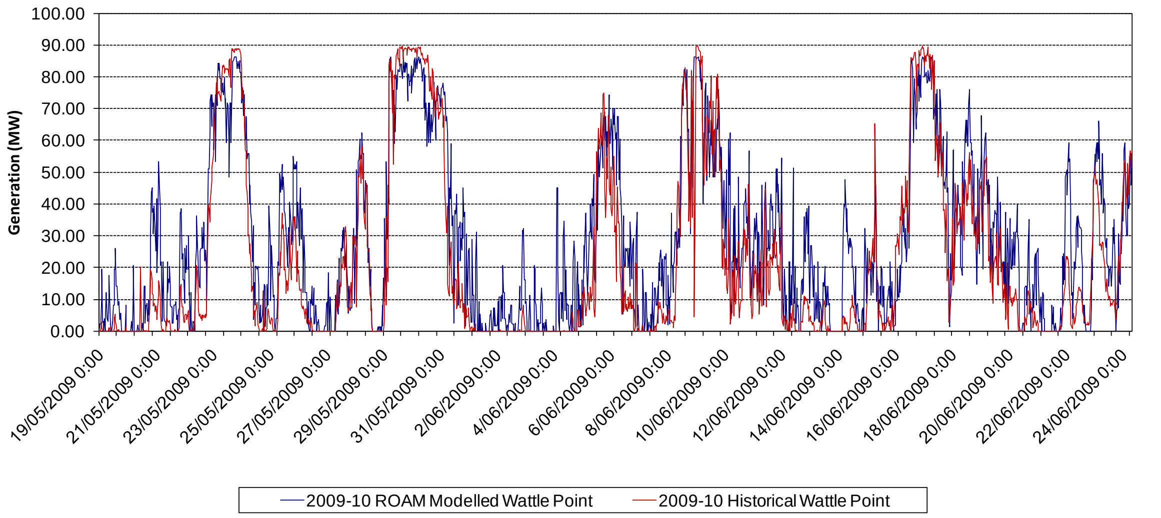
A turbine power curve is then applied to convert the wind speeds into actual generation (this accounts for the fact that the efficiency of turbines varies strongly with wind speed). The annual time of day average generation is compared to historic data, and the output adjusted if necessary to achieve an appropriate time of day average generation curve. This accounts for qualitative differences between time of day wind speed distributions at hub height versus the BOM stations. As a final step, generation for existing wind farms with known historical output levels will be adjusted if necessary to maximise the modelling accuracy; this adjustment is usually small.

This method captures the daily and seasonal variation of wind at different sites, and also the likely correlation in the operation of nearby wind farms, which is highly material for assessing likely transmission congestion.

There is very good agreement between the results of this method and the known output of existing wind farms. As a benchmarking exercise, ROAM compared the historic generation profile of Wattle Point with a generation profile developed with the procedure described above. The results are shown in a graphical form presented in Figure E.2. The nearest weather station to Wattle Point is the Edithburgh weather station, of which the wind data from 2009-10 was used to develop the generation profile, a subset of which is shown in Figure E.2. The modelled generation provides a very good approximation to the historic generation profile, with a strong correlation of 0.83.

[16] http://www.environment.gov.au/settlements/renewable/

Figure E.2 – Wattle Point Generation Benchmark



E.2) *SOLAR MODELLING*

ROAM's modelling uses a detailed meteorological model to produce solar availability traces that vary by time of day, by time of year and by location.

The clear sky solar radiation incident on a location in the absence of any atmospheric effects is forecast by a solar model used by the National Oceanic and Atmospheric Administration (NOAA), part of the United States Department of Commerce. This models the position of the sun and incident radiation on Earth's atmosphere for any given date and location, and takes into account the local elevation.

ROAM then uses an atmospheric model developed by Bird and Hulstrom[17] that estimates the incident solar radiation, both direct (line of sight to the sun) and diffuse (sunlight reflected from the ground or from clouds), based on a number of atmospheric parameters, including type of local terrain, ozone thickness, water vapour present in the atmosphere and atmospheric pollutants. This produces a 'clear sky' (no cloud) solar insolation trace, at the half hour level, that takes into account local atmospheric effects.

However, solar plant is significantly affected by cloud cover and this must be taken into account in determining the final solar generator availability. Ideally, data at the hourly level (at least) would be obtained for each specific site of interest for a full calendar year. Unfortunately, relatively few sites have to date been monitored in Australia, and those that have been are not located ideally for solar plant.

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[17] *A Simplified Clear Sky model for Direct and Diffuse Insolation on Horizontal Surfaces*, R.E. Bird and R.L Hulstrom, Solar Energy Research Institute Technical Report SERI/TR-642-761, Feb 1991, Golden, CO.

Instead, ROAM has obtained data from the Bureau of Meteorology (BOM) on the total daily (global) solar radiation received at weather monitoring stations around Australia. This data is obtained from cloud cover satellite imagery and uses a sophisticated computer model to estimate daily solar exposure. Calibration tests by the BOM have shown it to be accurate to within 7% on sunny days and within 20% on cloudy days.

The BOM data is used to calibrate ROAM's model by introducing periods of partial or total cloud cover during each half hourly period of each day until the reported daily total global incident radiation is reached.

From this method, ROAM produces a half hourly global solar radiation trace. An empirical model of diffuse solar radiation is employed to separate out the diffuse and direct beam components, calibrated by sites where detailed half hourly data is available.

E.3) *BIDDING OF RENEWABLE GENERATORS*

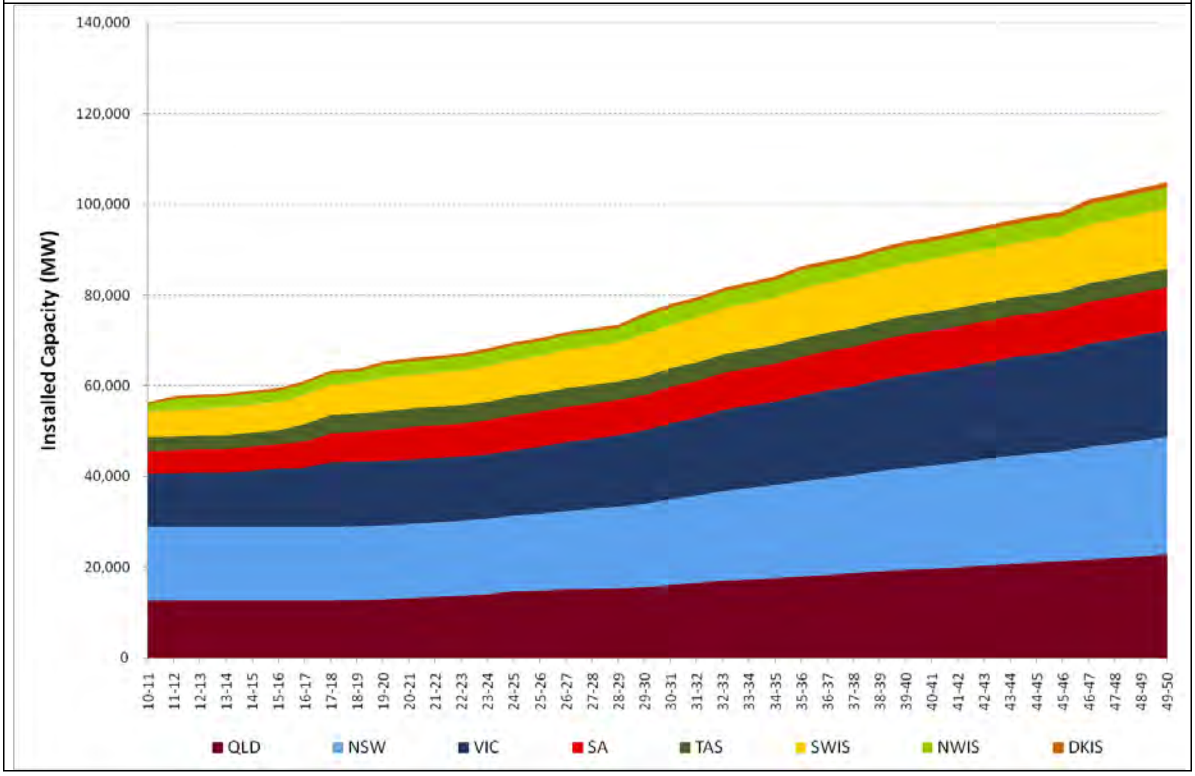
All renewable generators were bid into the market at their short run marginal cost, with the exception of biomass which is bid to conserve fuel during off-peak low priced periods.

Appendix F) Detailed Results: Installed Capacity

F.1) *Medium Global Action*

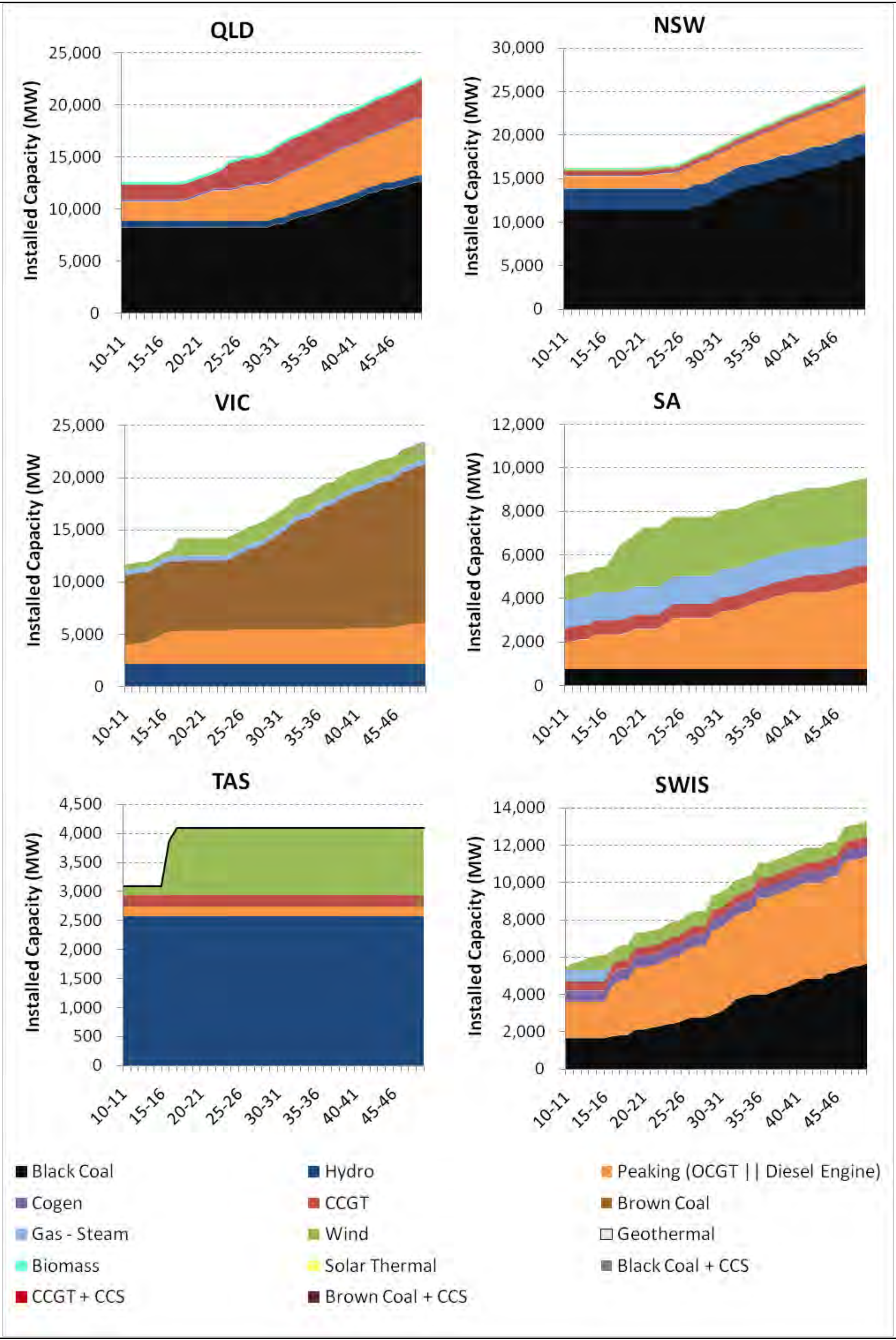
The chart below shows that under medium global action the level of installed capacity increases in line with existing proportions. That is, no single region, or collection of regions, becomes the dominant provider of energy. The coal generating states of Queensland, New South Wales and Victoria all show strong generation development, with the renewable rich Tasmania and South Australia lagging behind.

Figure F.1 – Total Installed Capacity by Region: Medium Global Action



The figure below shows the breakdown of generation expansion in each region by technology type. As mentioned, the regions with coal available tend to develop that resource considerably given the absence of a domestic carbon price. Wind resource development in South Australia encourages peaking plant to support wind during peak periods. Sufficient existing capacity is installed in Tasmania and therefore additional peaking support is avoided in that State despite expansion of the wind resource there.

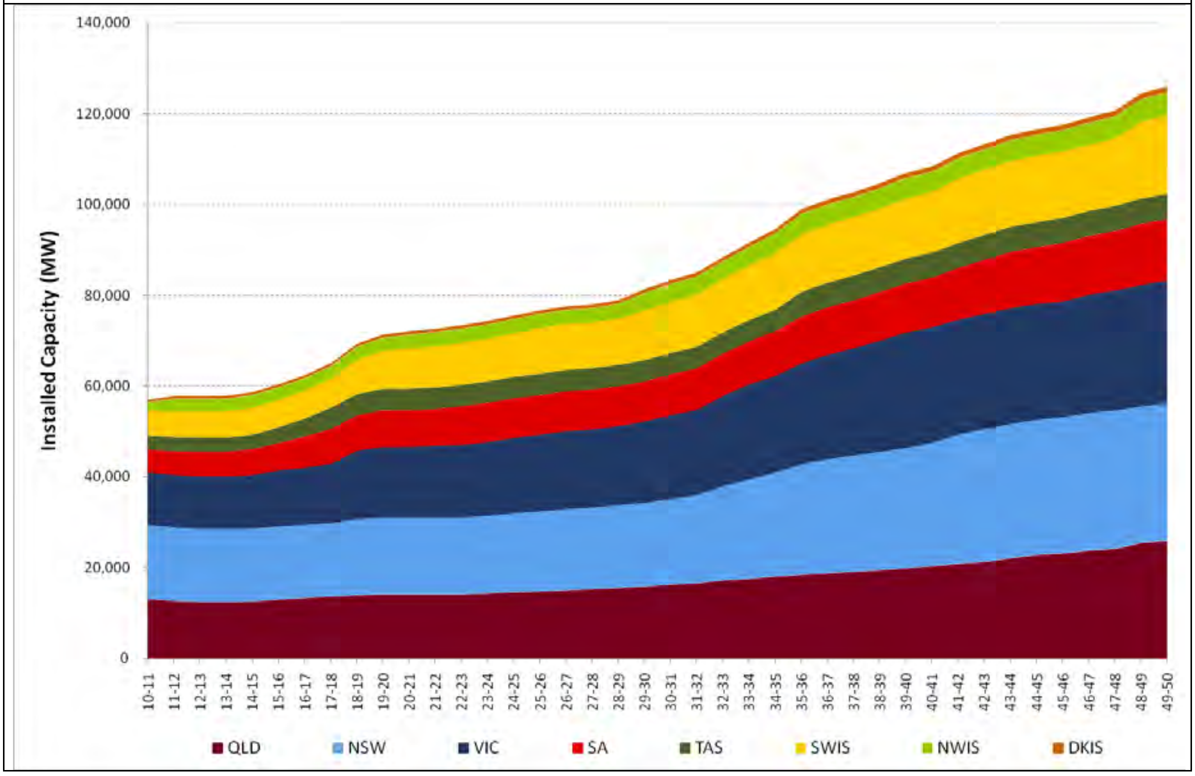
Figure F.2 – Regional Installed Capacity by Technology: Medium Global Action



F.2) *Core Policy*

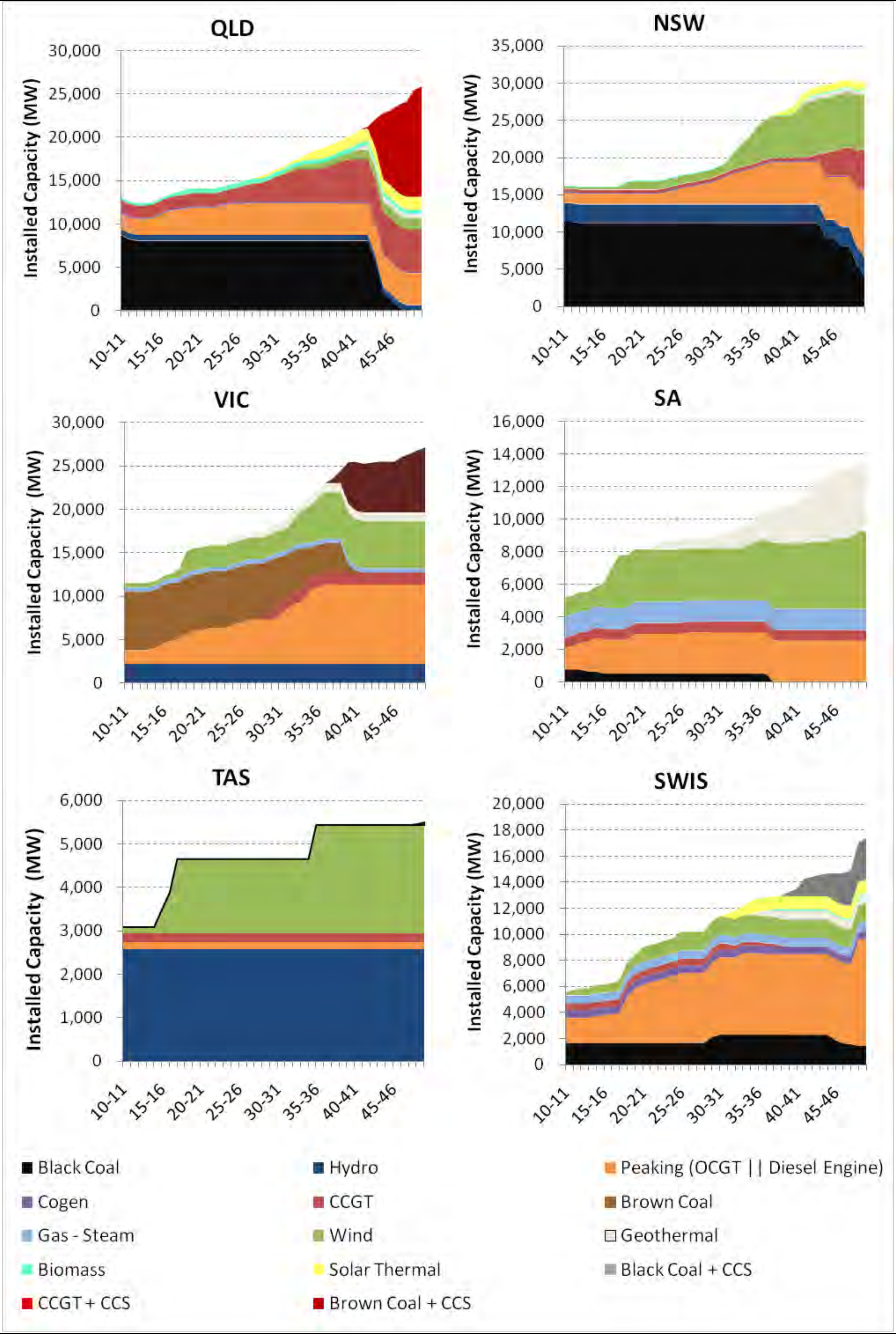
The figure below shows the development of each region under the Core Policy scenario. South Australia in particular in this scenario expands its generation capacity relative to the Medium Global Action scenario, while the lack of wind resources in Queensland slows development in that State.

Figure F.3 – Total Installed Capacity by Region: Core Policy



The figures below show the development of each technology by region in the Core Policy scenario. All States but Queensland show strong development in local wind resources. Brown and black coal are progressively retired in Queensland, New South Wales and Victoria, however by the end of the study period CCS installations in Queensland and Victoria reclaim part of coal's lost market share. Biomass, Solar Thermal and Geothermal all enter in various States, while the SWIS has some expansion of Black Coal before Black Coal + CCS replaces some coal capacity.

Figure F.4 – Regional Installed Capacity by Technology: Core Policy



F.3) *AMBITIOUS GLOBAL ACTION*

Similar to the Medium Global Action scenario, ambitious global action without a domestic carbon price tends to maintain the status quo in terms of regional installed capacity.

Figure F.5 – Total Installed Capacity by Region: Ambitious Global Action

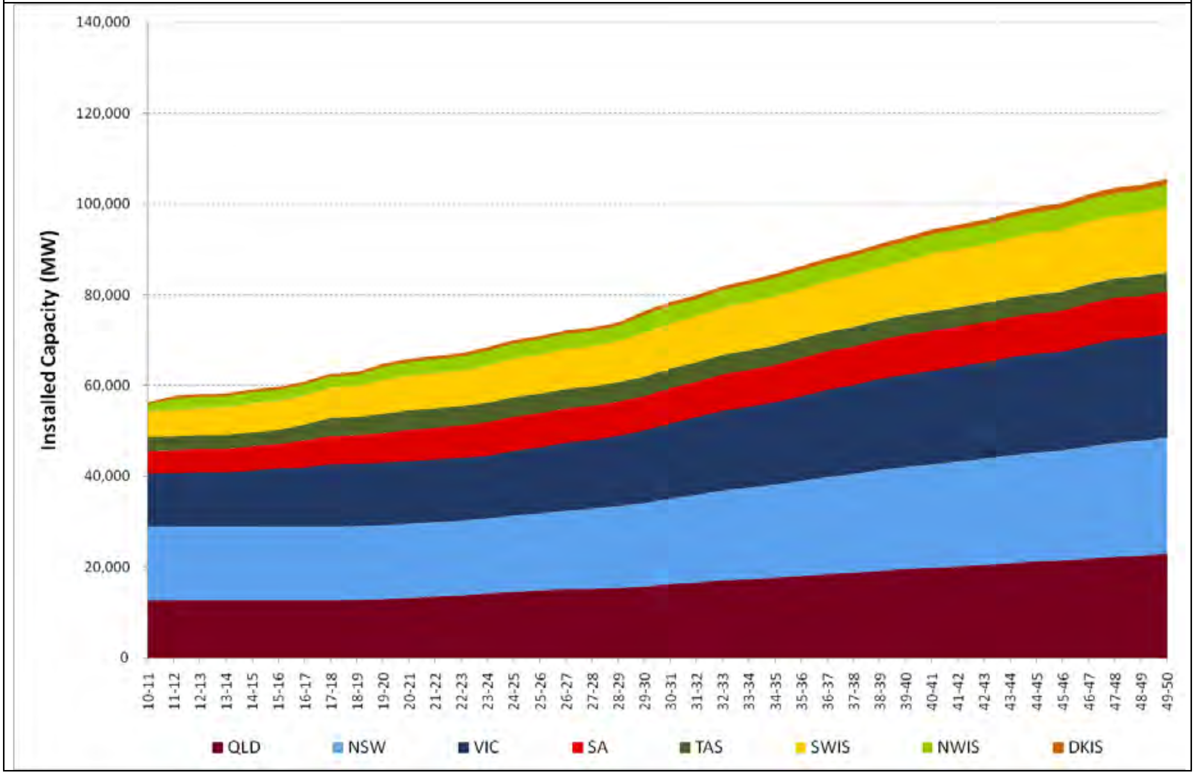
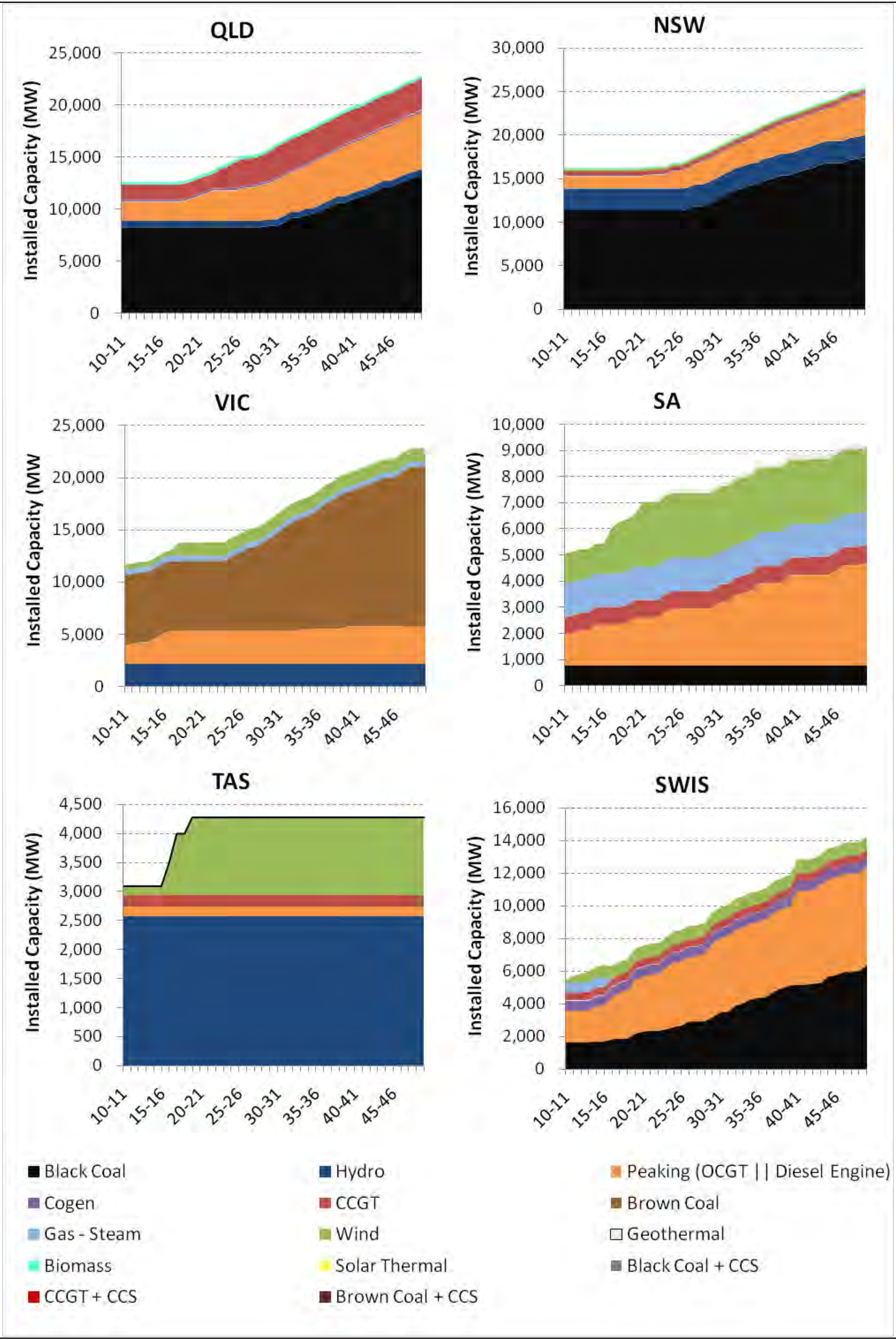


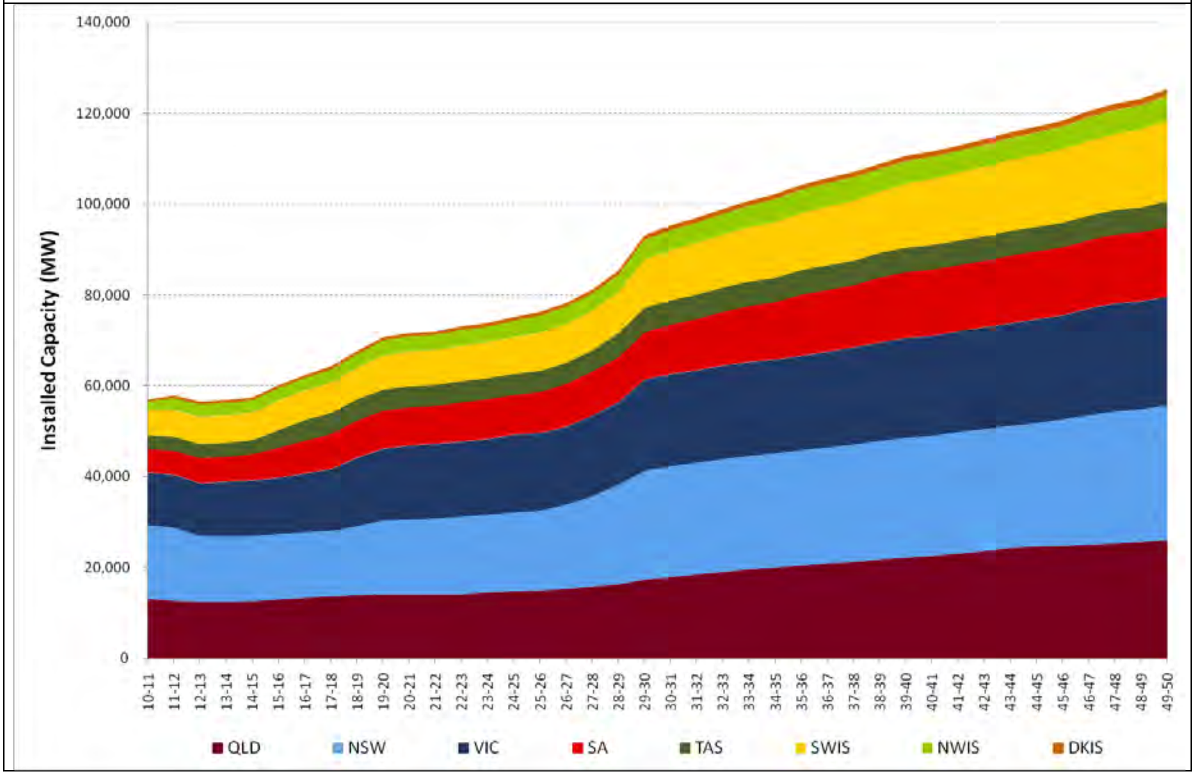
Figure F.6 – Regional Installed Capacity by Technology: Ambitious Global Action



F.4) *HIGH-PRICE*

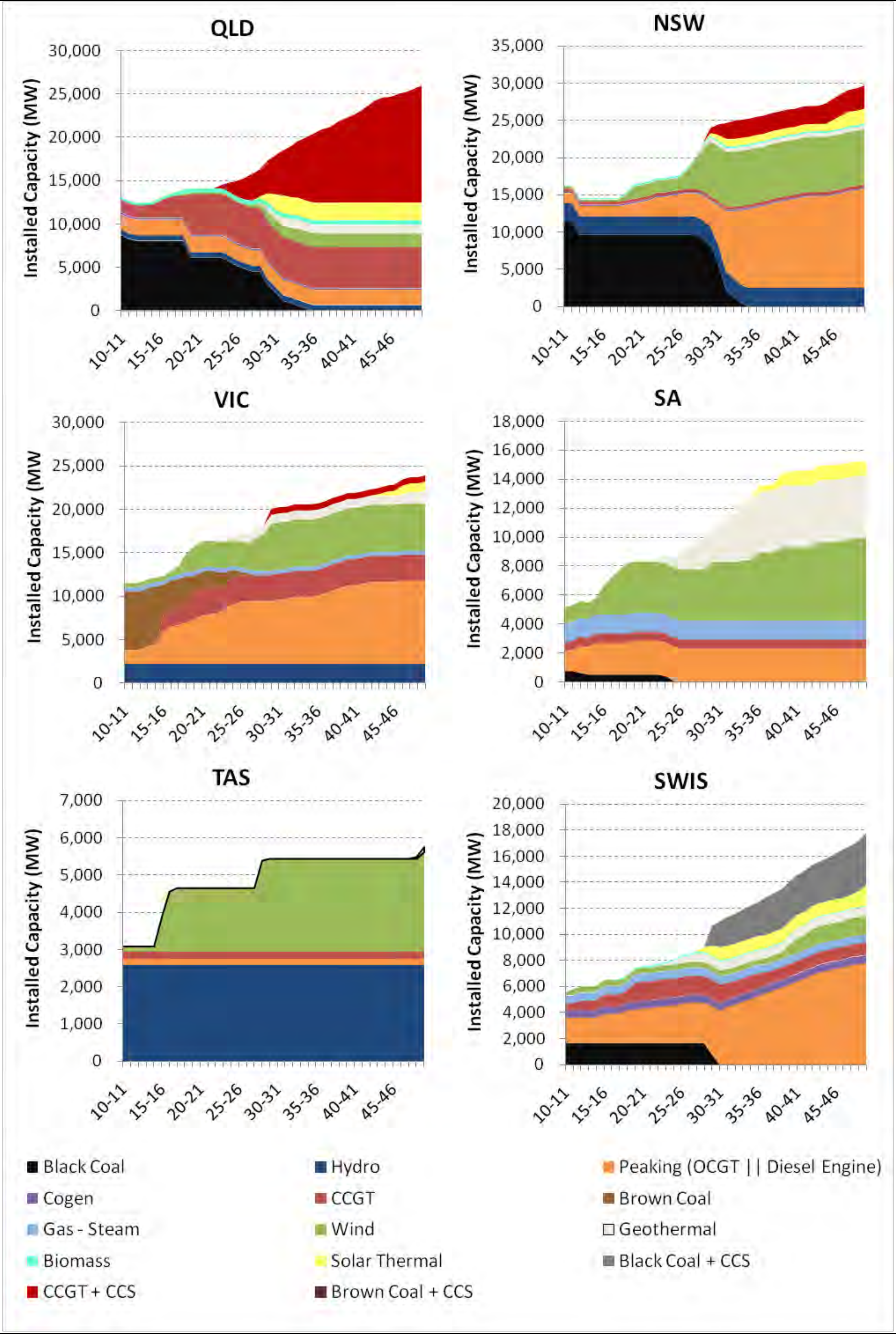
The High Price scenario shows significant development of renewable resources. This tends to favour regions such as South Australia which has an abundance of high quality wind and geothermal resources.

Figure F.7 – Total Installed Capacity by Region: High-Price



The rapid retirement of coal under a high carbon policy hastens the deployment of CCGT + CCS. This particularly favours Queensland, with lower gas prices than other states due to its proximity to existing and new coal seam gas fields and potential sequestration locations. Solar thermal is also gains significant market share in 'the Sunshine State'. South Australia develops primarily renewable resources, as well as supplementary peaking capacity. South Australian wind is also supported through Victorian peaking capacity, as transmission expansion occurs between these two states in response to wind uptake in SA.

Figure F.8 – Regional Installed Capacity by Technology: High-Price

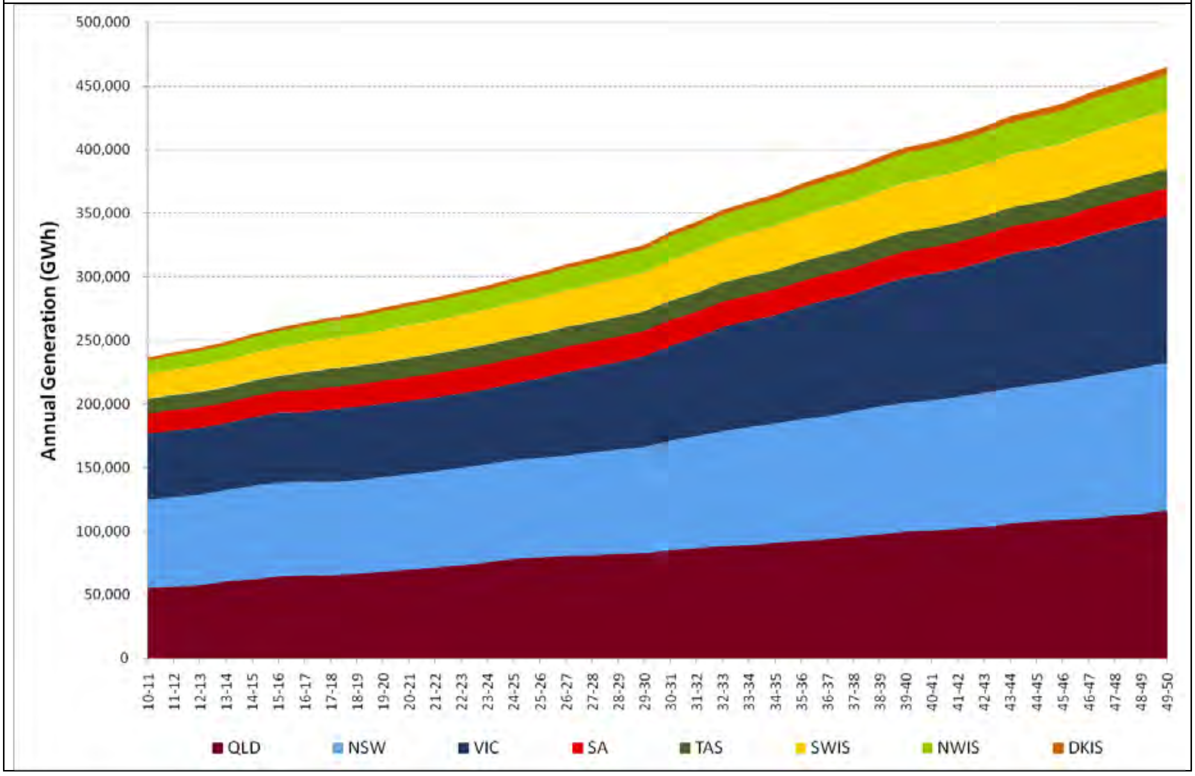


Appendix G) Detailed Results: Annual Generation

G.1) *MEDIUM GLOBAL ACTION*

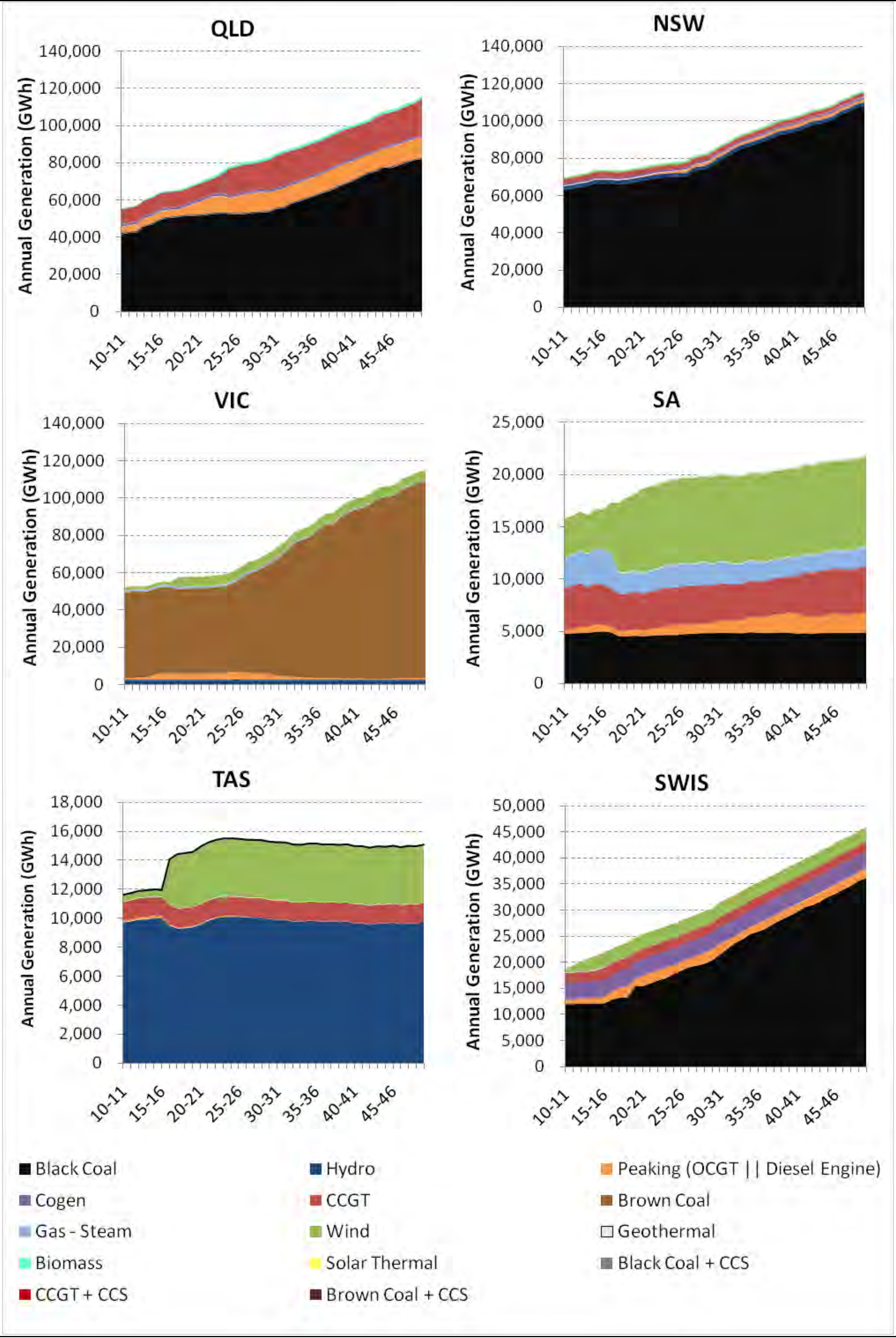
As with installed capacity, the regional shares of energy remain largely in line with existing proportions in the Medium Global Action scenario. South Australia and Tasmania provide two exceptions, with no major growth in their share of energy generation.

Figure G.1 – Total Annual Generation by Region: Medium Global Action



The figure below shows the dominance which coal generation is expected to have in terms of energy generated with the absence of any domestic carbon price. Almost all regional energy in States with coal capacity is produced using the fuel. Tasmania and South Australia, two regions without significant local coal supplies, show growth in renewables to meet the Renewable Energy Target, otherwise existing generators maintain similar generation to current levels.

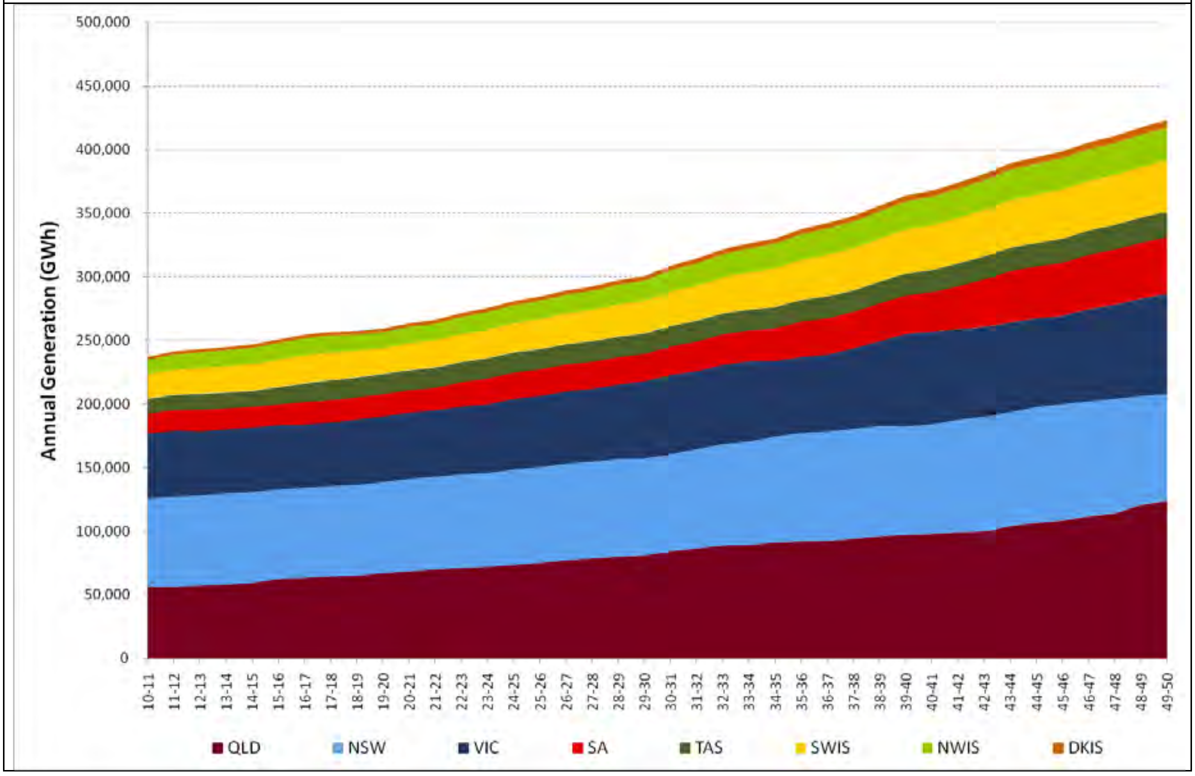
Figure G.2 – Regional Annual Generation by Technology: Medium Global Action



G.2) *Core Policy*

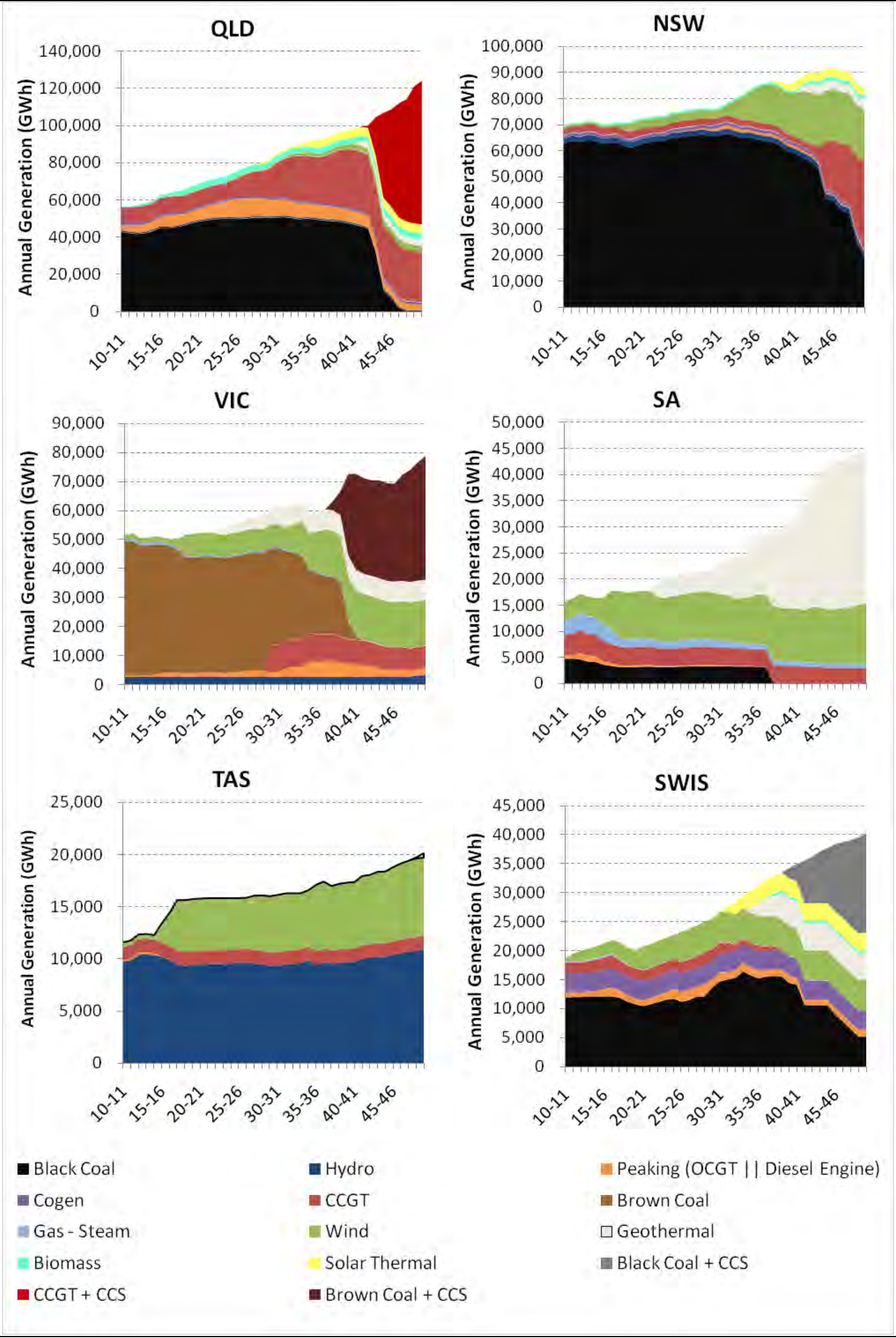
The Core Policy scenario shows significant growth in South Australia's share of energy, particularly after the commencement of geothermal as a large scale commercial technology towards the end of the study period.

Figure G.3 – Total Annual Generation by Region: Core Policy



The figure below shows that each State has growth in a number of technologies over the forecast period. Queensland shows strong growth in combined cycle gas with and without CCS. Solar and Biomass also contribute to its overall energy landscape. New South Wales replaces part of its black coal with wind, a mix of other renewables, and combined cycle plant. Victoria shows strong growth in wind, geothermal and then brown coal plant with CCS, as its brown coal plant retire. South Australia, as mentioned previously, shows strong growth in wind and in particular geothermal generation.

Figure G.4 – Regional Annual Generation by Technology: Core Policy



G.3) *Ambitious Global Action*

In terms of annual energy, no major differences between the Medium Global Action and Ambitious Global Action scenarios are visible in the charts below. Coal is a dominant provider of energy without a domestic carbon price, irrespective of the ambition of global emissions abatement.

Figure G.5 – Total Annual Generation by Region: Ambitious Global Action

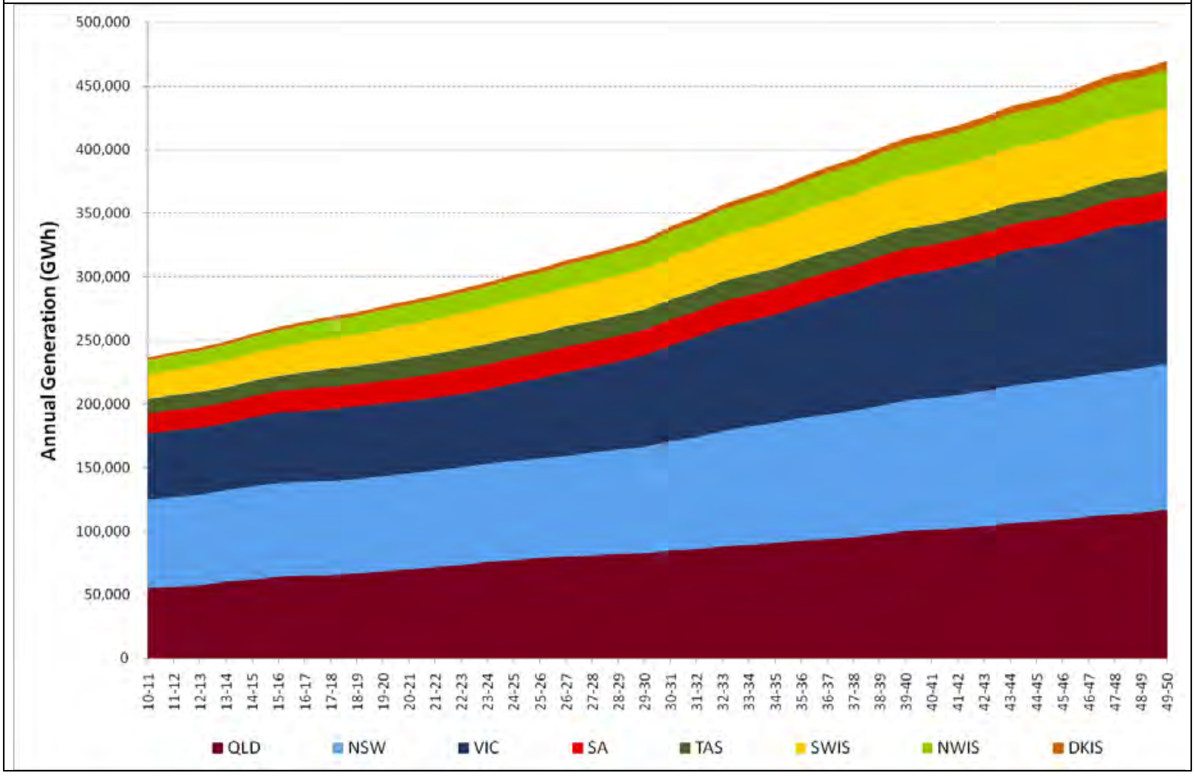
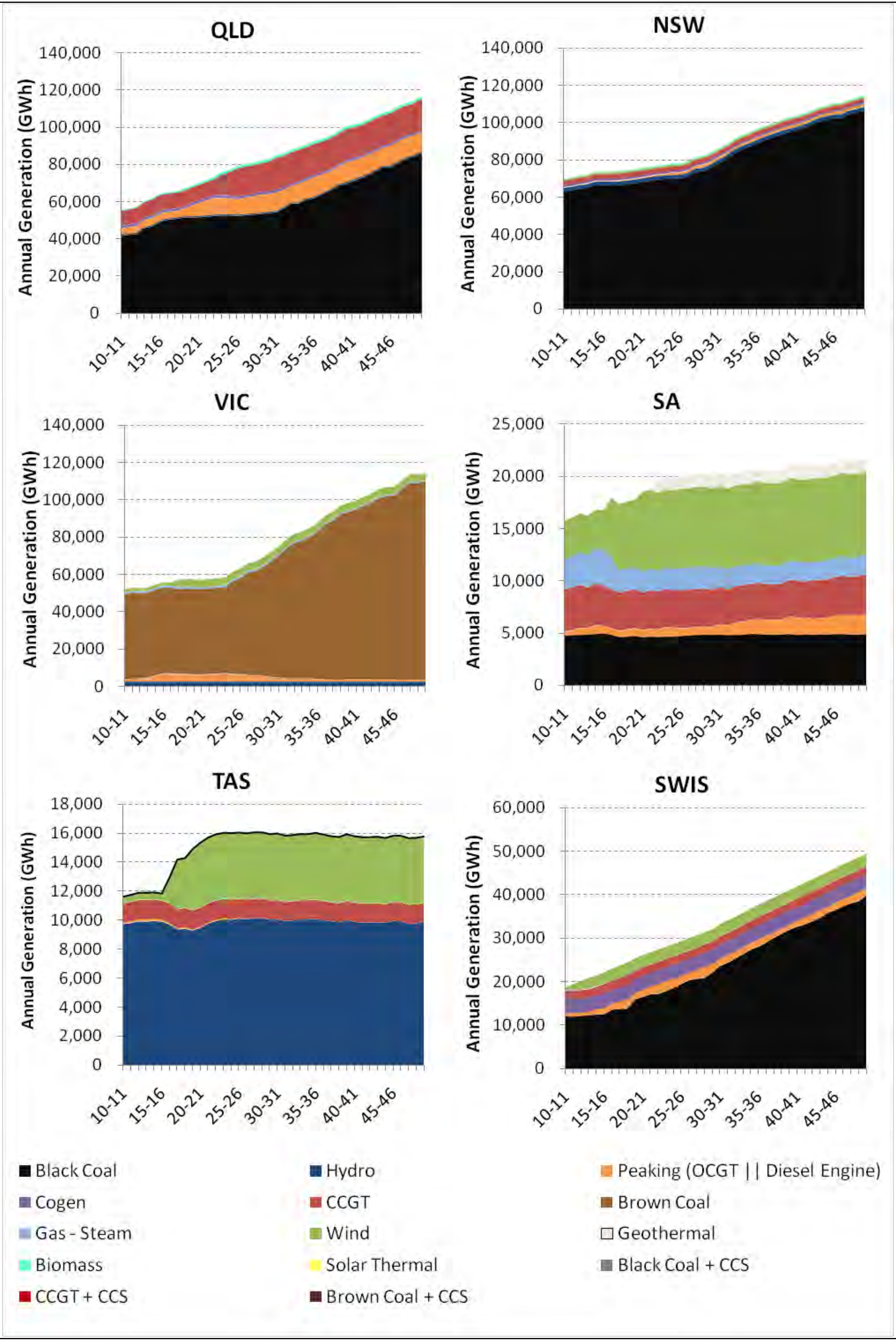


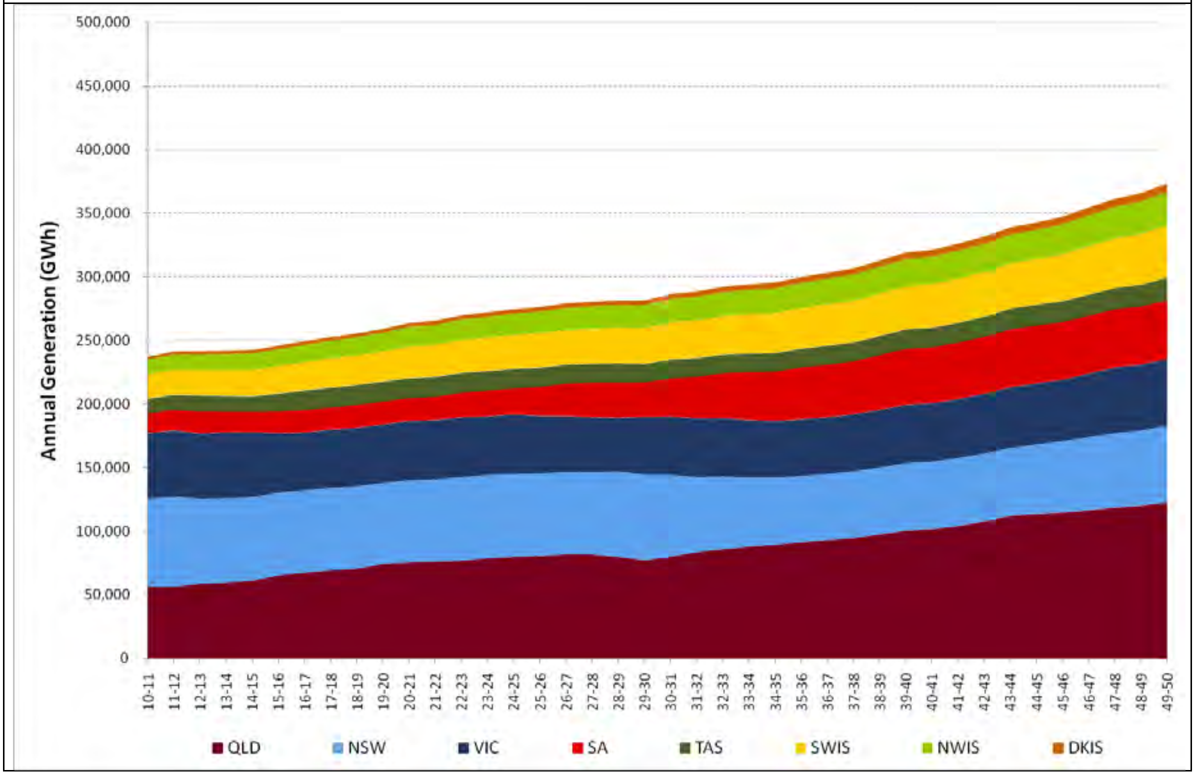
Figure G.6 – Regional Annual Generation by Technology: Ambitious Global Action



G.4) *HIGH-PRICE*

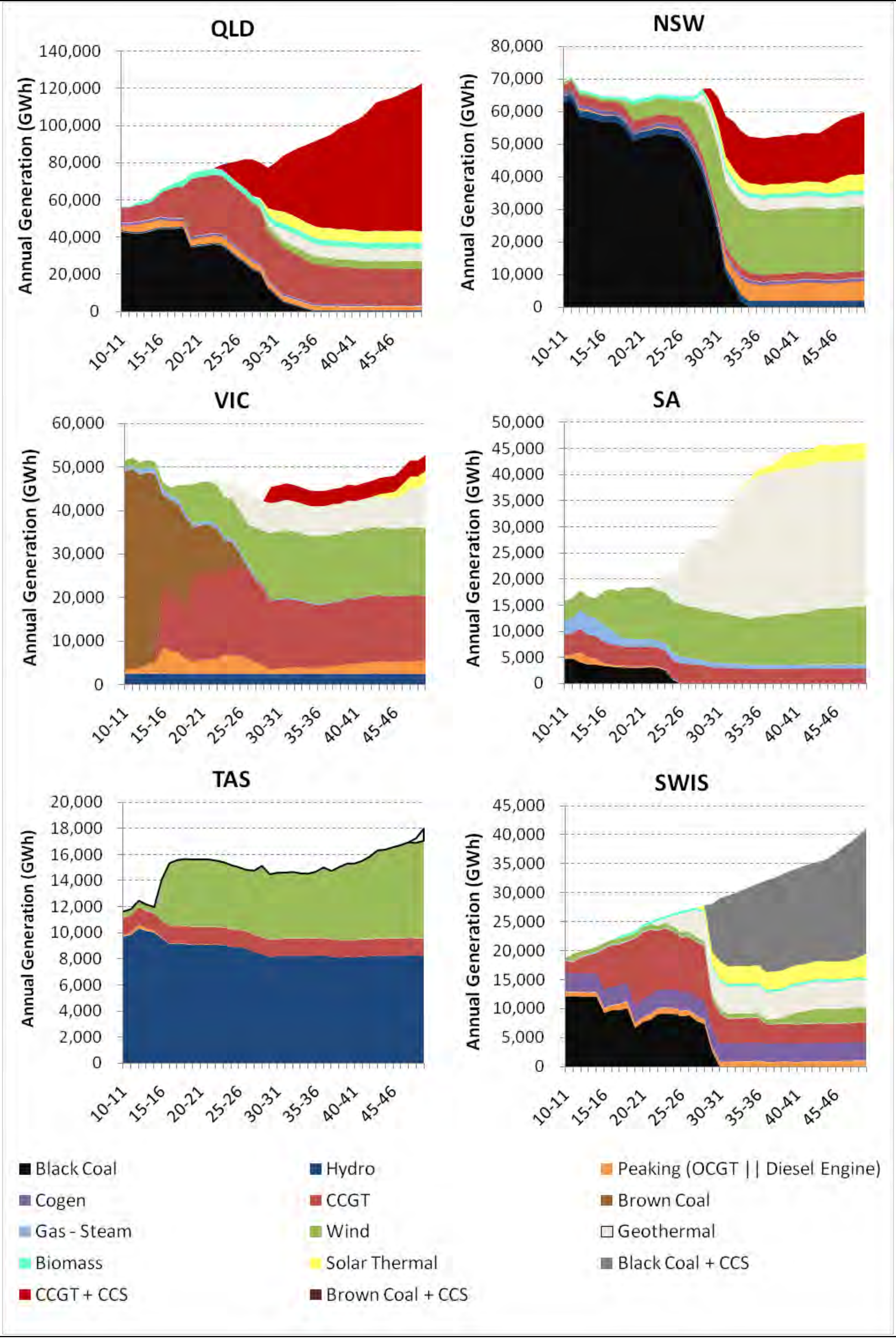
The High Price policy scenario shows gradual growth in Queensland and South Australia as major providers of energy, while New South Wales and Victoria decline as their coal fleets retire without sufficient low cost local replacement options.

Figure G.7 – Total Annual Generation by Region: High-Price



The figures below reinforce the above chart. The retirement of New South Wales and Victorian coal generators to 2030 are replaced by local wind and combined cycle gas, however each State's market share declines during that period. Queensland coal is replaced with combined cycle gas in the same period, which combined with South Australian wind claim much of the load growth in that time. From 2025 low and zero emissions alternative become commercially viable – in particular CCGT + CCS, geothermal and solar thermal generators in Queensland, New South Wales, Victoria and South Australia. Black coal +CCS is the preferred energy generator in the SWIS from 2030, with support from renewables including wind, geothermal and solar thermal.

Figure G.8 – Regional Annual Generation by Technology: High-Price

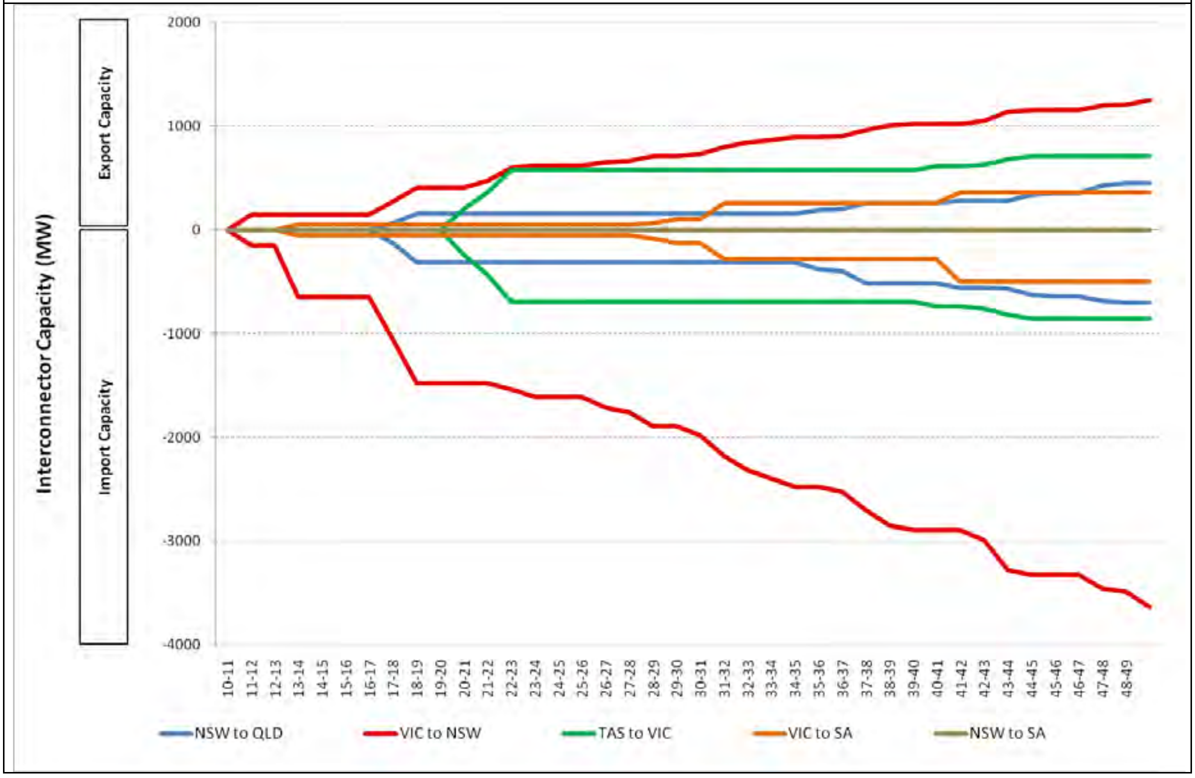


Appendix H) Detailed Results: Interconnector Expansion

H.1) *MEDIUM GLOBAL ACTION*

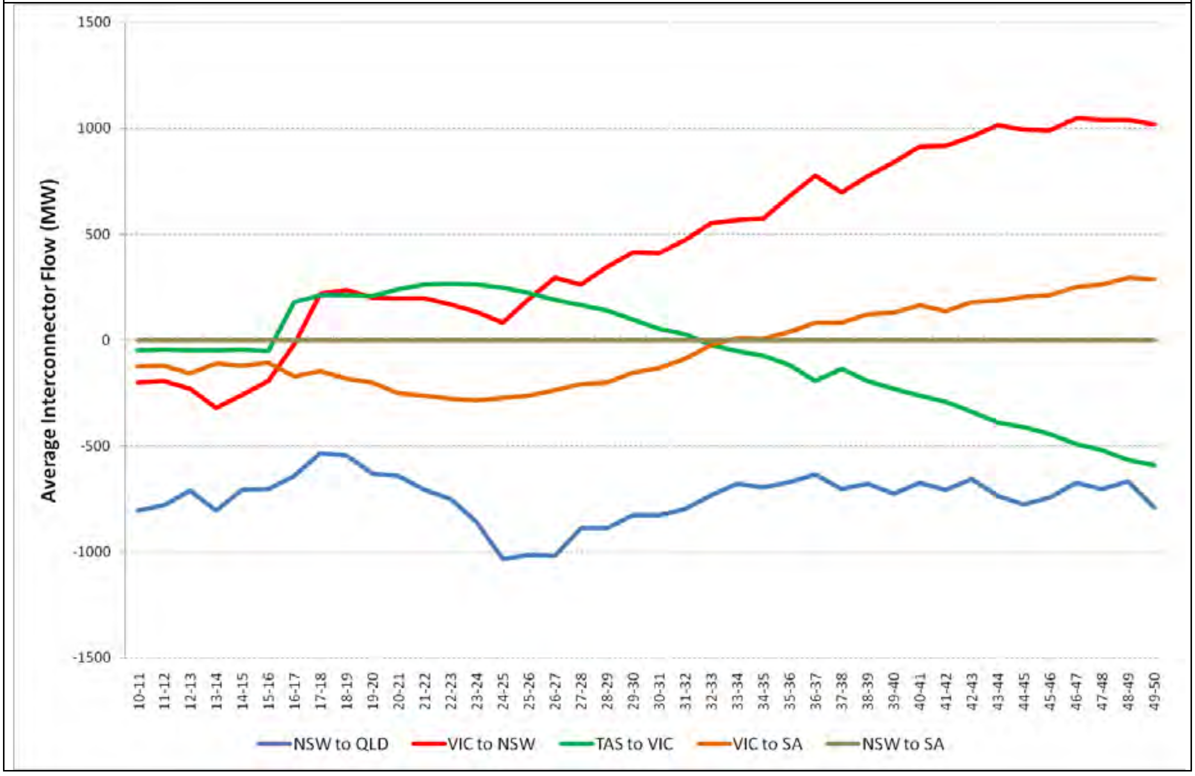
Key to the deployment of a mixture of generation alternatives is the expansion of the existing transmission networks, particularly between regions of the NEM. Two of the largest load centres are the States of Victoria and New South Wales, and expansion of the link between these two states is an early priority to share black and brown coal generation between the States. All existing flow paths are expanded in the Medium Global Action scenario, including a duplication of the existing undersea Basslink DC link.

Figure H.1 – New Interconnector Capacity: Medium Global Action



As the figure below shows, flows between Queensland and New South Wales are forecast to continue their existing tendency to flow south, exporting Queensland coal and gas fuelled energy. Victoria will tend to export energy to New South Wales, while Tasmania is forecast to become more reliant on Victorian coal.

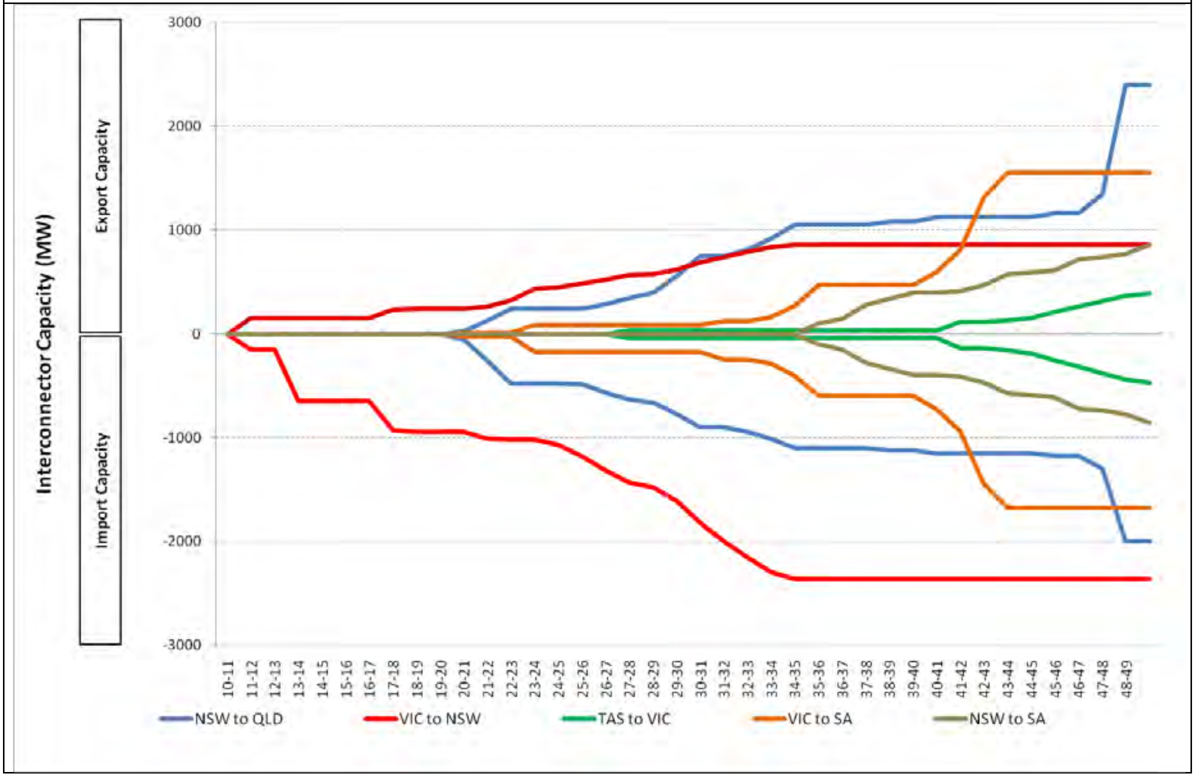
Figure H.2 – Interconnector Flows: Medium Global Action



H.2) *CORE POLICY*

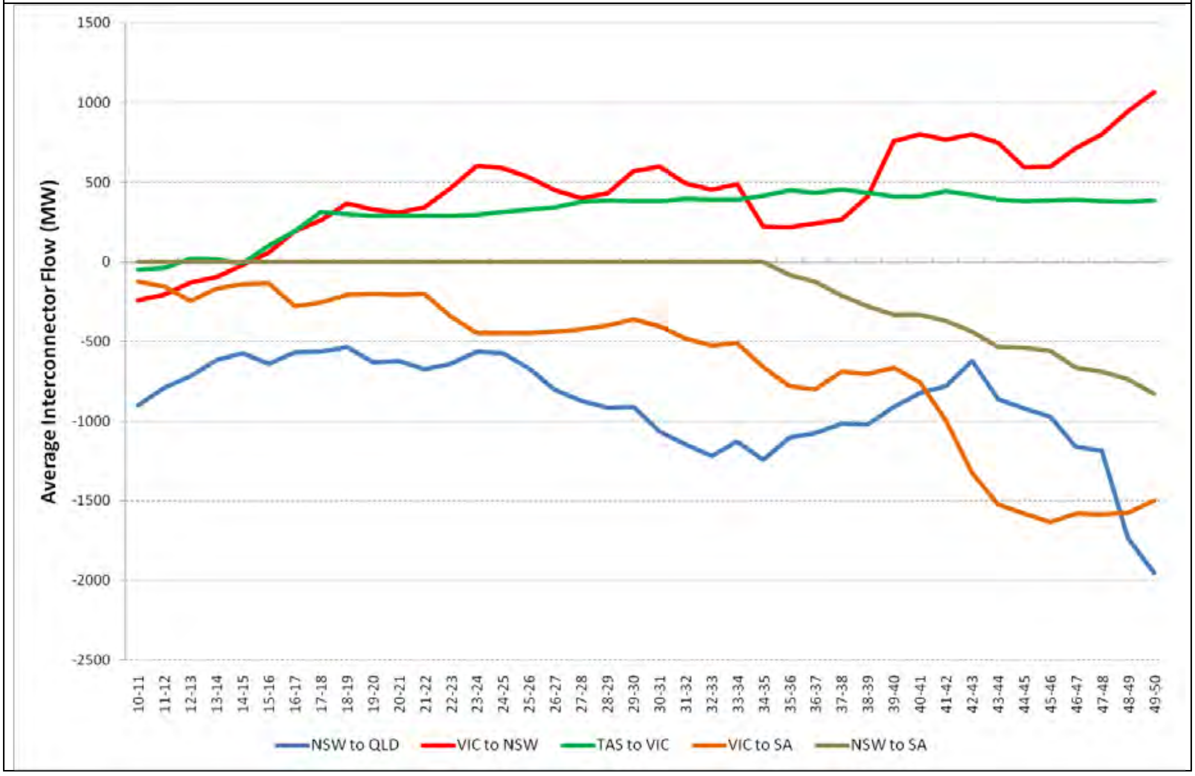
Under the policy scenarios, the geographic diversity of renewable and low emissions technologies will put significant impetus on expanding existing links between NEM regions, as well as provide incentive for the creation of a new flow path. Rapid expansion, particularly for upgrades to expand the import capacity of Victoria from New South Wales, is seen along the VIC-NSW flow path. From 2020, it is least cost to expand the link between NSW-QLD and VIC-SA also is expanded around this time. The carbon policy and interconnector costs promote diversification of wind resources, and therefore South Australia's connection options do not rapidly increase until the large scale deployment of geothermal resources, which also serves to promote the creation of a new link between NSW and SA.

Figure H.3 – New Interconnector Capacity: Core Policy



Average annual flows between regions show that Tasmania will increase its tendency to export its renewable resources to Victoria, particularly as the brown coal fleet loses its competitiveness after the carbon policy commences. Renewable resources in Victoria and South Australia will flow towards New South Wales (via Victoria for SA renewables at the beginning, and also along a new direct path from approximately 2035). Queensland will maintain its export orientation.

Figure H.4 – Interconnector Flows: Core Policy



H.3) *AMBITIOUS GLOBAL ACTION*

The Ambitious Global Action scenario does not experience significant transmission expansion or annual average flow differences than the Medium Global Action scenario.

Figure H.5 – New Interconnector Capacity: Ambitious Global Action

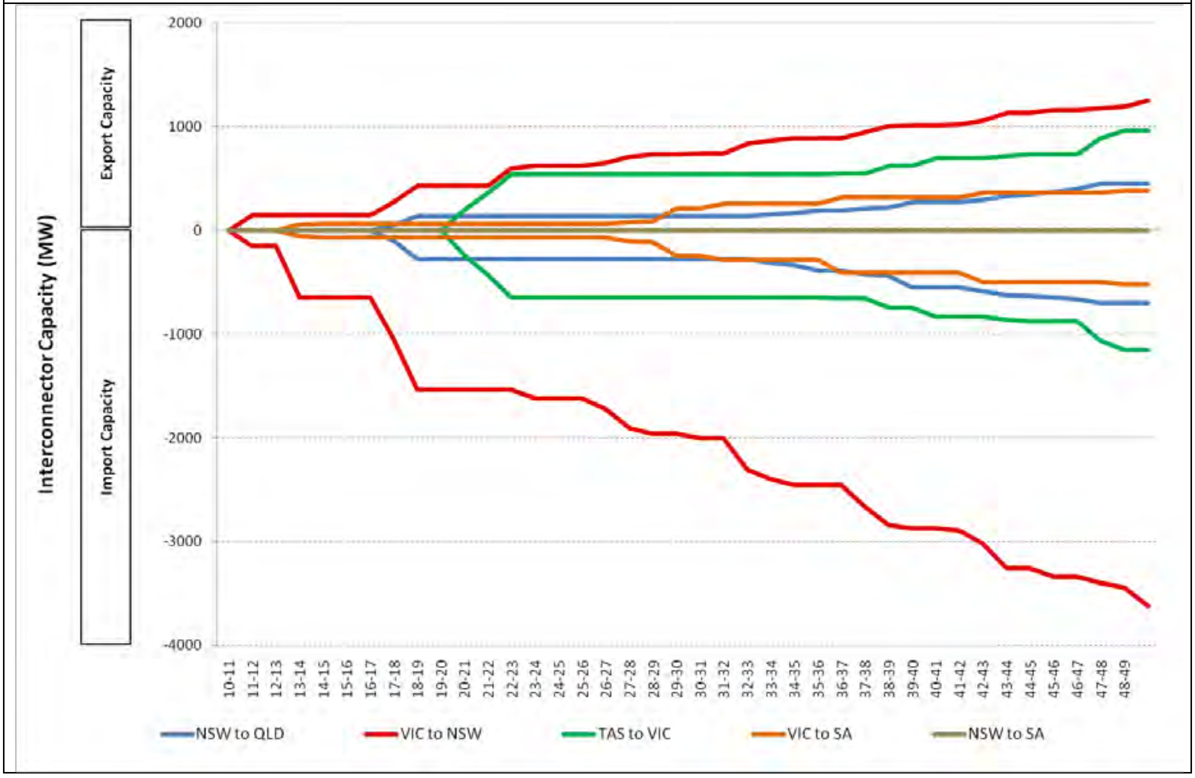
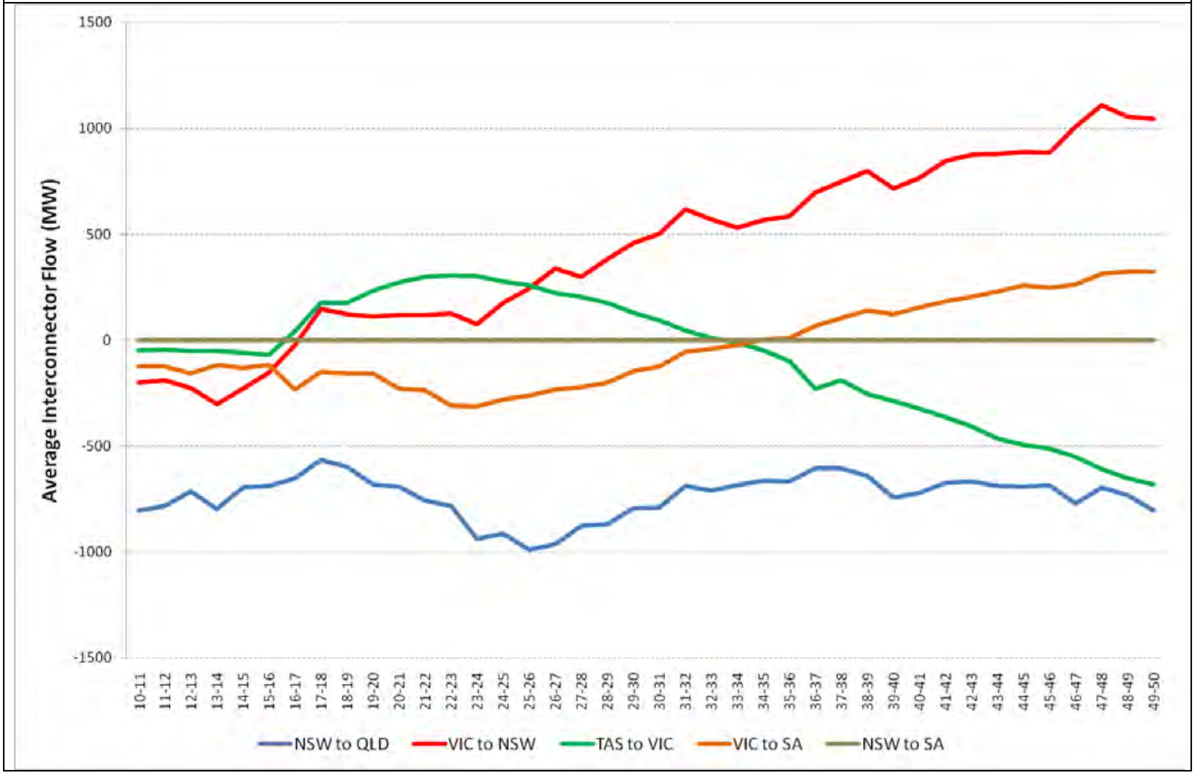


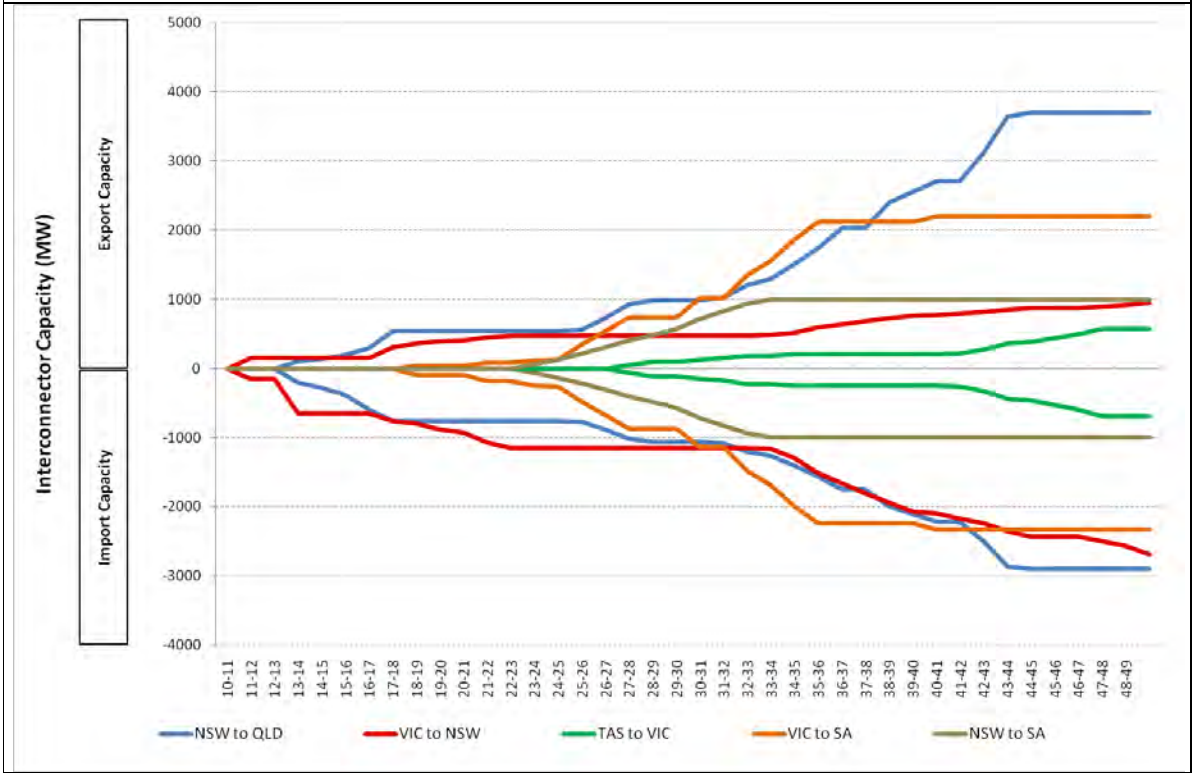
Figure H.6 – Interconnector Flows: Ambitious Global Action



H.4) *HIGH-PRICE*

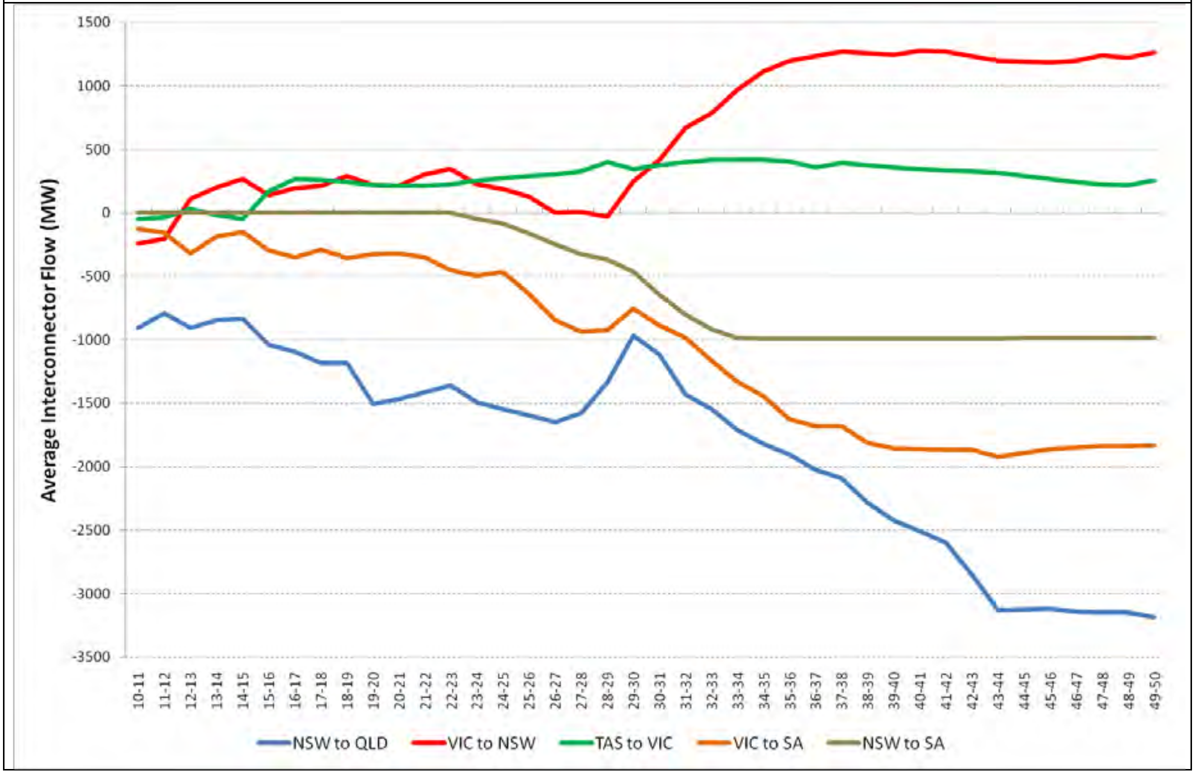
In terms of network development, the High Price scenario provides far greater incentive to more rapidly expand the transmission interconnections in order to support the uptake of renewables, particularly in the southern States. The new NSW-SA flow path is developed earlier than the Core Policy, from 2025 approximately. The replacement of brown coal generators in Victoria with local renewables slows the exports of this State, and therefore delays the expansion of the VIC-NSW transmission path.

Figure H.7 – New Interconnector Capacity: High-Price



The figure below shows that the VIC-NSW flow path on average will be relatively neutral for the next three decades under this High Price scenario. The retirement of Victorian brown coal provides opportunities for Tasmanian renewables to export to the mainland, while Queensland and South Australia become significantly export oriented, due to the abundance of local wind (SA), gas (QLD), geothermal, solar thermal (QLD) and CCGT+CCS generation.

Figure H.8 – Interconnector Flows: High-Price

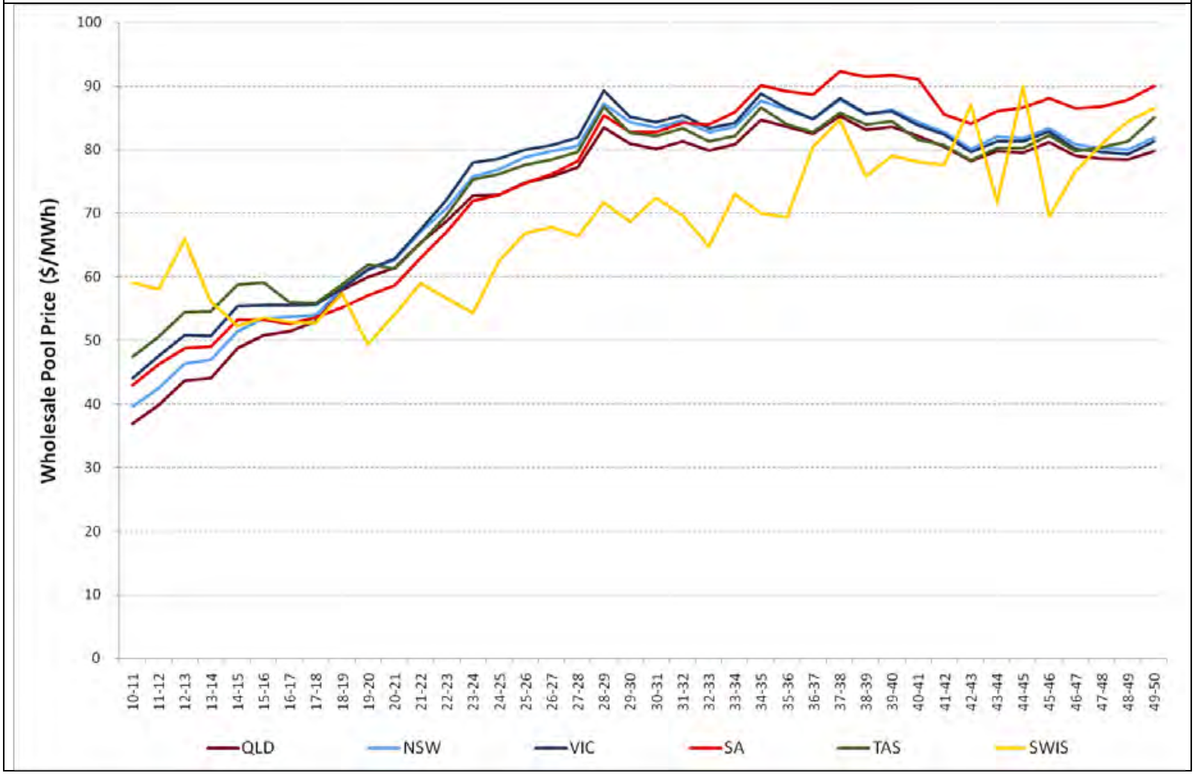


Appendix I) Detailed Results: Wholesale Pool Prices

I.1) *Medium Global Action*

The Medium Global Action scenario shows a strong rise in national electricity wholesale prices by the end of the study period. This is particularly apparent in the eastern NEM states, as a large increase in gas prices is passed through to the market. Prices tend to settle around $80/GWh in the longer term as gas prices plateau. SWIS prices are forecast to increase, however as the gas prices on the west coast are already near international price parity, and prices there are forecast to fall during the first decade, the rate of growth is not as severe as the NEM.

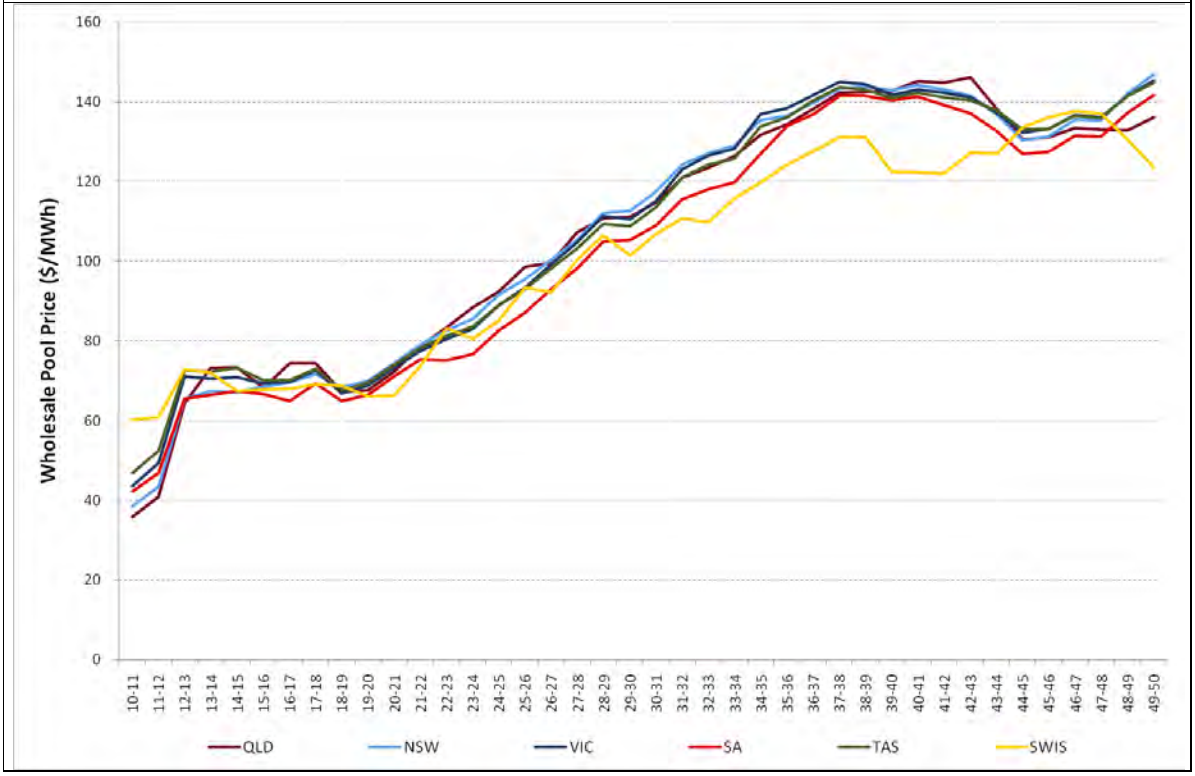
Figure I.1 – Wholesale Pool Prices: Medium Global Action



I.2) *CORE POLICY*

The Core Policy scenario shows a similar trend in wholesale pool prices, with prices increasing rapidly due to the rising price of natural gas, and the introduction of a carbon price. Penetration of renewables and low emissions alternatives such as CCS results in prices levelling out at approximately $140/MWh, or approximately 175% of the price in the Medium Global Action scenario. Of significance is the jump of approximately $20/MWh in 2012-13 as the carbon price is passed through to consumers.

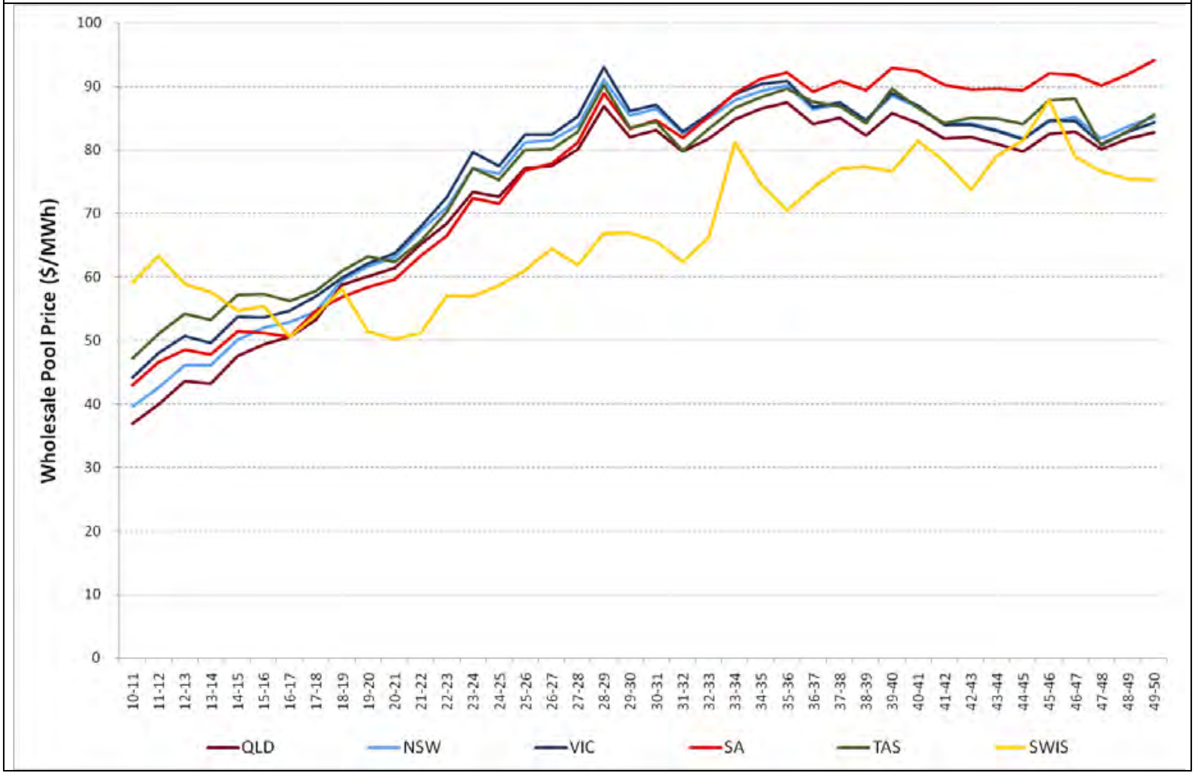
Figure I.2 – Wholesale Pool Prices: Core Policy



I.3) *AMBITIOUS GLOBAL ACTION*

The Ambitious Global Action scenario shows very similar trends to the Medium Global Action scenario, as only minor load growth differences separate the two scenarios.

Figure I.3 – Wholesale Pool Prices: Ambitious Global Action



I.4) *HIGH-PRICE*

The High Price scenario shows substantial growth in wholesale pool prices. A significant carbon price, together with increasing gas prices, cause a doubling of wholesale prices by 2015 in all NEM regions. Wholesale prices initially increase by more than the carbon price, as the carbon price immediately retires some black coal plant in New South Wales and Queensland, thereby reducing the amount of baseload generation. From 2027 to 2030 there is a brief reprieve as the remnants of the brown coal fleet is retired and replaced with renewable technologies, which serve to suppress price (as discussed in Section 3.6). However load growth and an increasing carbon price forces prices to further increase, beyond \$200/MWh in some States by 2050 – more than four times the 2010-11 level.

Figure I.4 – Wholesale Pool Prices: High-Price