Modelling the impact of Optional Firm Access in the NEM

Final report to the Australian Energy Market Commission

9 January 2015

Building a better working world

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9 January 2015

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Dear Victoria,

In accordance with our agreement dated 30th October 2014 (the Engagement Agreement), Ernst & Young (we or EY) has been engaged by the Australian Energy Market Commission (the AEMC, you or the Client) to conduct modelling on the impact of the introduction of Optional Firm Access (OFA) to the National Electricity Market (the Services).

Purpose of our Report and restrictions of its use

The results of our work, including the assumptions and qualifications made in preparing the Report, are set out in the enclosed report (Report). You should read the Report in its entirety. A reference to the Report includes any part of the Report. We understand that this Report will be used by the AEMC for the purpose of informing the AEMC's assessment of the Optional Firm Access framework (the Purpose). It will also be made public principally by posting it on the AEMC website.

This Report was prepared on the specific instructions of the AEMC for the Purpose and should not be used or relied upon for any other purpose.

EY has not been engaged to act, and has not acted, as advisor to any other party and EY owes no duty of care to any recipient of the Report other than AEMC (Recipient) in respect of any use that the Recipient may make of the Report.

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To the fullest extent permitted by law, the Recipient of the Report shall be liable for all claims, demands, actions, proceedings, costs, expenses, loss, damage and liability made against or brought against or incurred by EY arising from or connected with the Report, the contents of the Report or the provision of the Report to the Recipient.

Scope and nature of our work

The scope and nature of our work, including the basis and limitations, are detailed in our Engagement Agreement and in this Report.

This study considers a number of scenarios developed by the AEMC and EY. These scenarios do not necessarily represent EY's view of likely or possible future conditions. In particular, some scenarios were explicitly constructed to test the sensitivity of benefits under OFA rather than to represent probable scenarios, as agreed with the AEMC.

Limitations

All modelling, particularly for long-term planning studies, requires approximations and simplifications which may impact on the modelling results. The relevant limitations of EY's models are detailed in this Report, and should be read in the context of our analysis and conclusions.

The scenarios considered in this Report may not consider the full range of possible futures, and do not necessarily represent EY's view of likely future conditions. Rather, they are designed to test the sensitivity of benefits under OFA to various key parameters.

This final Report was completed on 9th January 2015. Our Report does not take into consideration any other event or circumstances arising after the date it was first completed.

This letter should be read in conjunction with our detailed Report, which is attached.

Thank you for the opportunity to work on this project for you. Should you wish to discuss any aspect of this Report, please do not hesitate to contact Ben Vanderwaal on 07 3227 1414 or Michael Fenech on 07 3243 3753.

Yours sincerely

Ben Vanderwaal
Executive Director

Michael Fenech
Partner

Executive Summary

The Australian Energy Market Commission (AEMC) is currently considering the design and testing of the optional firm access (OFA) model that was proposed as part of the now completed Transmission Frameworks Review (TFR). As part of the current review, EY has been tasked with both refreshing and expanding on the work conducted by ROAM Consulting (recently acquired by EY) in assessing the potential economic benefits delivered by the impact of OFA on generation and transmission development in the National Electricity Market (NEM).

Since the completion of the TFR, there have been a number of developments in wholesale market conditions and in the design of OFA that have lead the AEMC to commission EY to further investigate the potential impact of OFA. In particular, the continued reductions in forecast demand growth and the removal of carbon pricing have materially changed the outlook for the development of the generation sector. Furthermore, the AEMC in consultation with EY has developed a set of scenarios to test the potential for OFA to deliver economic benefits given a range of possible future developments. The modelling timeframe has been extended from 2030 to 2040 in this study.

Methodology

The methodology applied in this study is comparable to that which was used in the TFR modelling: conducting long-term planning studies to determine the economic savings from planning methodologies that more closely align generation and transmission development. EY has used our sophisticated Long Term Integrated Resource Planning (LTIRP) software to forecast generation and transmission development for each scenario under three alternative planning methodologies:

- RIT-T planning – Reflective of the status quo where transmission follows generation
- Co-optimised planning – A theoretically optimal approach where generation and transmission is fully co-optimised
- OFA planning – A co-optimised approach, where transmission development is required to meet the Firm Access Planning Standard (FAPS) given projected generation development

For each scenario, simulations were conducted to determine the total economic cost, including fixed and variable generation costs and the cost of transmission augmentation, and the co-optimised and OFA scenarios compared to RIT-T.

Results

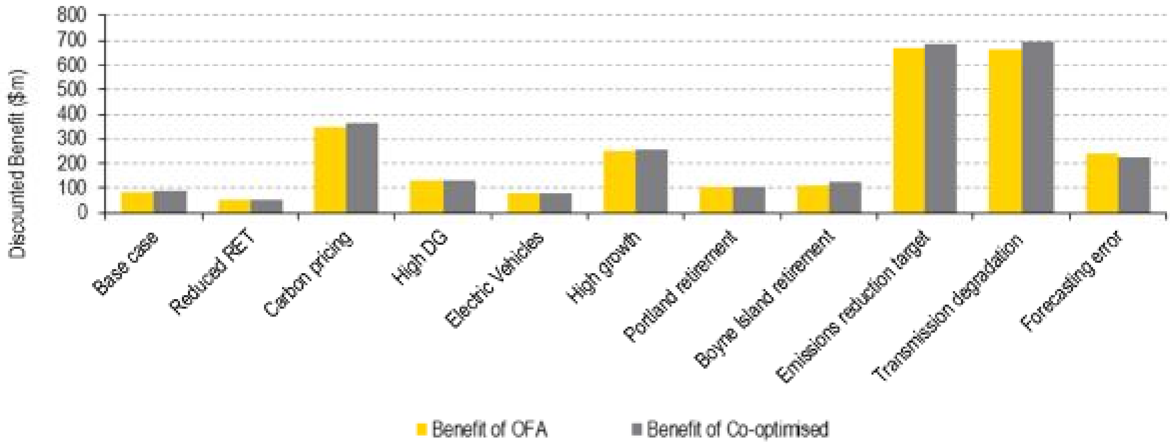
Our key findings are:

- OFA has the potential to deliver substantial economic benefits

- Benefits are highest in scenarios where the electricity generation or transmission fleet undergoes significant transformation, such as in response to strong emissions reduction targets or high demand growth

- Exposing generation to replacement decisions for the existing transmission network could be the source of large savings, and should be investigated further

The figure below illustrates the discounted benefit of both OFA and co-optimised planning for each scenario considered in this study, compared to the RIT-T planning methodology. Our modelling has shown that there is a wide range for the potential benefits of OFA.



The Base case outlook (weak demand growth and no carbon pricing) in this assessment involves relatively muted development in generation and transmission and, consequently, the impact of different transmission planning methodologies is minor. Despite the extended modelling horizon, the economic benefit of OFA in this modelling is comparable to that calculated in the TFR modelling.

The benefits of OFA are larger in scenarios that encourage significant transmission augmentation or transformation of the generation sector. In particular, the pursuit of emissions abatement can be achieved at a substantially lower cost under OFA by effectively exposing generation developers to both resource and transmission considerations. High demand growth, or the expectation of growth, even if it does not eventuate, can also result in OFA benefits.

The modelling found that there are potentially large benefits in exposing generation to the cost of replacing and maintaining existing transmission assets. This issue warrants further investigation given the coarse nature of the input assumptions and approach used in this scenario. A more detailed investigation should consider the need for transmission asset replacement on major generation flowpaths in the next 10-20 years. The AEMC could seek the assistance of TNSPs in developing a more detailed consideration of major transmission asset replacements. The scenario was intended to be illustrative rather than to provide a precise valuation of the impact of OFA on transmission asset replacement.

Modelling limitations

It should be noted that this modelling considers only a single facet of the impact of OFA. Our modelling has not considered many of the other potential benefits of OFA and, similarly, has not considered possible implementation issues, particularly those that are transitional in nature.

Although the scenarios we have described in this Report provide a broad overview of the impact of OFA across many possible futures, there are market development possibilities that have not been considered. For example, the implementation of wide-scale energy storage may potentially be able to significantly reduce the need for both generation and transmission development. Furthermore, uncertainty over future conditions may also lead to different investment decisions that may impact on the benefits of OFA, as demonstrated for demand uncertainty in this Report.

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1. Introduction

In 2012, ROAM Consulting, recently acquired by EY, was engaged by the Australian Energy Market Commission to conduct quantitative modelling to inform the Transmission Frameworks Review. As part of this modelling, ROAM Consulting was tasked with determining the impact of optional financial firm access on both generation and transmission development in the National Electricity Market (NEM) and on the total economic cost of meeting demand until 2030.

Since the completion of the TFR, there have been a number of developments in the wholesale market and in the design of OFA that have lead the AEMC to commission EY to further investigate the potential impact of OFA. In particular, the reductions in demand forecasts and the removal of carbon pricing have a material impact on the development of generation and transmission and therefore, on the potential benefits of OFA. Furthermore, the AEMC has adjusted the application of the Firm Access Planning Standard (FAPS).

In addition to updating the assessment of the impact and value of OFA given existing market expectations, the AEMC has tasked EY with modelling a range of additional scenarios. These scenarios are intended to inform a view on the potential for OFA to significantly impact the development of the NEM given a range of possible futures.

1.1 Background

In April 2013, the AEMC published the outcomes of the TFR. The TFR was a broad and comprehensive review into the interaction between generation and transmission development and operation. The review covered a range of areas that included the behavior of generation in response to network congestion, the potential to better align incentives for efficient generator and network investment and issues with network connection.

As part of this review, ROAM Consulting considered three alternative policy packages defined by the AEMC:

- Package 1 – broadly reflective of the status quo planning standards, with minor rule changes
- Package 2 – the introduction of a congestion pricing mechanism
- Package 4 – provides the option for generators to obtain a specified level of financial access (OFA)[1]

ROAM's task was to determine the impact of each of the packages on the productive, dynamic and allocative efficiency of the NEM. This modelling involved both long-term generation and transmission planning and half-hourly wholesale market modelling. The TFR modelling considered three scenarios, all of which included some form of carbon pricing. The scenarios differed with respect to projected levels of demand growth, the magnitude of carbon pricing and commodity price forecasts.

To determine the impact of the alternative packages on productive efficiency, ROAM conducted market modelling, both historically as a backcast and through forecasting, to determine the impact of the congestion pricing mechanisms on generator incentives in dispatch. The long-term impact of OFA on investment decisions was determined using Long Term integrated Resource Planning (LTIRP).

The overall finding of the modelling was that both congestion pricing and OFA were capable of delivering a greater level of efficiency in both the operation and planning of the electricity market

[1] The AEMC concluded that Package 3 was not suitable during the early stages of the TFR.

relative to the status quo. However, these benefits were not large in magnitude and were generally found to occur towards the end of the modelling timeframe – the TFR forecast modelling was for the period 2012-13 to 2029-30.

The key results of ROAM Consulting's TFR modelling can be seen in Table 1. This table shows the net impact of Package 2 and Package 4, relative to Package 1, on total system cost.

Table 1: ROAM Consulting TFR modelling outcomes

NPV of 2012-13 to 2029-30	Reduction in Total Market Variable, Fixed and Capital Costs from Package 1 ($m)	
	Package 2	Package 4
Scenario 1 – High demand and carbon trajectory	11.2	71.9
Scenario 2 – High demand and moderate carbon trajectory	8.8	92.9
Scenario 3 – Moderate demand and carbon trajectory	4.3	80.0

Since the completion of the TFR, the AEMC has received Terms of Reference from the COAG Energy Council to continue development of the OFA model. The First Interim Report on Optional Firm Access, Design and Testing was released in July 2014.

1.2 Scope of Work

In the TFR, ROAM Consulting assessed the impact of OFA on both long-term market development and on dispatch – in particular, the reduction in the incentive for generation to respond to congestion using 'race to the floor' bidding strategies. It is both EY and the AEMC's view that the impact of OFA on disorderly bidding, and the associated gains in economic efficiency, have not been materially impacted by the OFA design changes that have occurred since the conclusion of the TFR. Therefore, our focus for this assessment is on determining the impact of OFA on the long-term development of generation and transmission and the associated economic savings that may result.

In the TFR, ROAM Consulting's modelling assessed the benefits of OFA until 2030. Generally, it was found that OFA was beginning to drive significant differences in decision making towards the end of this study timeframe. Therefore, the AEMC has requested EY to extend the modelling horizon to 2040 for this piece of work.

We have modelled a range of scenarios in this assessment. The Base case scenario reflects a central view across input assumptions, where possible favouring currently legislated targets and trajectories. Other scenarios have been designed to assess the impact of the following on the benefits delivered by OFA. The different drivers considered in these scenarios include:

- Emissions reduction policies – both carbon pricing mechanisms and the Renewable Energy Target (RET)
- Demand assumptions – major load retirements, growth projections, technology driven demand changes
- Consideration of transmission asset replacement
- The impact of erroneous demand and energy projections

A detailed description of each scenario is provided in Section 3.

In each scenario, EY develops generation and transmission under each of the following planning methodologies:

- RIT-T – a process designed to approximate the current Regulatory Investment Test for Transmission. This is a two-step process whereby generation planning decisions are made with consideration of transmission losses, regional market conditions and locational supply inputs such as fuel costs and resource quality and/or availability. Transmission is then developed using these generation decisions as an input. Transmission investments are only made when found to be beneficial from the perspective of minimising economic cost subject to the projection of generation development over the modelling timeframe.

- Co-optimised – a theoretically optimal method of developing generation and transmission, reflective of an idealized centrally planned model. All investments in generation and/or transmission are made with full consideration of all other investment decisions over the modelling timeframe.

- OFA – the OFA methodology is similar to the co-optimised in that generation investment decisions are made with consideration of their impact on future transmission development. Under OFA, future transmission developments are required to meet the specified level of access for all generation. Therefore, all generator investments are made with complete and perfect knowledge of their impact on the cost of transmission development required to meet the FAPS, subject to the given access levels.

These planning methodologies are described in greater detail in Section 2.2.

The AEMC has requested that EY provide the following outcomes in this Report:

- For each scenario, document the total system cost under each of the three planning scenarios. These results will be presented as both a discounted and undiscounted value and are to be disaggregated into variable generation costs, fixed generation costs and transmission costs.

- Detailed analysis for each scenario of the magnitude and timing of generation and transmission development across the three planning standards. This Report provides qualitative analysis demonstrating the impact of the alternative planning standards on the location of generation development and associated transmission investment.

EY has not been tasked with determining the financial impact of OFA on market stakeholders. Therefore, we have not considered the impact of OFA on market prices and consequently, the impact of OFA on consumers and the generation sector. We have also not considered potential benefits of OFA other than its ability to better align transmission and generation development decisions. These benefits are well documented by the AEMC and in submissions to both the TFR and the current market review. Quantifying these benefits is outside the scope of this work.

1.3 Structure of this Report

This Report details the methodology and input assumptions we have applied in projecting generation and transmission development under the alternative planning methodologies. Additionally, this Report presents the outcomes of our analysis of the impact of OFA on total system cost across all scenarios and describes for each scenario, the locational development of generation and transmission.

This Report is structured as follows:

- Section 2 outlines how the LTIRP has been used in forecasting market development for the alternative planning methodologies.

- Section 3 describes the modelling scenarios and documents the modelling assumptions applied in these scenarios.

- Section 4 summarises the key differences between this modelling and the TFR modelling conducted by ROAM Consulting.
- Section 5 provides the critical results of the modelling across all scenarios, with a particular focus on the impact of the planning methodologies on total system cost.
- Section 6 presents an analysis of generation and transmission development in each scenario.

2. LTIRP – Planning the development of the NEM

2.1 LTIRP – Least cost planning

2.1.1 Introduction

EY has developed the LTIRP model for the purpose of forecasting the development of generation and transmission in the NEM or other regions. The LTIRP uses linear programming techniques to determine the least cost economic expansion plan over the modelling horizon. The LTIRP's development considers how demand will be met within each year and can also therefore be used to analyse utilisation of generation over time. The ability to determine projections of both planning and operation makes it an ideal tool for this assessment.

A key element of the LTIRP approach is that it is a least cost development rather than a market driven development with competing players. Within any optimisation problem in the LTIRP, investments are made based on the concept of a "single player" that controls generation and transmission across all regions.

Typically, the LTIRP co-optimises both generation and transmission investment. However, the LTIRP can be restricted from this such that generation investment decisions are made without consideration of transmission constraints. This feature has been used to approximate the current RIT-T planning approach. This is described in greater detail in Section 2.2.

2.1.2 Model limitations

Although our LTIRP model is one of the most sophisticated of its kind, it does have a number of inherent limitations:

- **Not time sequential:** The LTIRP does not apply time sequential load traces. Rather, demand is represented by "load blocks" that are determined using the load distribution curve. These load blocks provide an accurate representation of regional load shapes in the NEM. However, by their nature, they cannot incorporate a number of market features such as short-term hydro storages and random generator forced outages. We have incorporated the effect of these market features through input data – for example, forced outage rates are applied as a derating to station capacity. The load blocks do incorporate three separate time-of-day categories (day, evening, night) to allow a true representation of the value of solar PV generation. Less sophisticated models allow PV to contribute to meeting peak demand, even if this demand is during the evening.

- **Intermittent generation:** Due to the non-time sequential nature of the LTIRP model, accurate modelling of intermittent generation is challenging. Our approach uses the load blocks (defined above) in conjunction with half-hourly wind traces to develop wind generation for each load block that is representative of the average contribution of wind generation, the variability of wind production and its ability to meet peak demand. This means that wind energy can contribute at high levels of utilisation in some load blocks and provide a very low contribution in others.

- **Non-integer solutions:** The LTIRP is capable of applying generation and transmission development in an integer fashion – that being that generation and transmission is developed in pre-defined discrete blocks. However, this approach significantly increases simulation time. Given the complexity and time horizon of the modelling conducted in this study, EY has not applied integer investments. Therefore, the size of generation and transmission investments or retirements in any year is a continuous number. Furthermore, the size of investment in any year, or in total, can be very low (less than 1 MW). We believe that this approximation is acceptable and that modelling outcomes are representative of long-term market development. The "smoothing" of "lumpy" investment decisions is not an impediment to assessing the impact and potential benefits of OFA.

- **Certainty:** Each individual LTIRP simulation can only model a single projection of demand, emissions abatement policy, commodity and capital cost projection, etc. Therefore, all planning and operating decisions are made with full and complete knowledge of these assumptions. These uncertainties do impact on investment decisions in reality.

2.2 Planning Methodologies

The LTIRP optimisation chooses between a set of available development options to minimise the total economic cost of meeting demand over the modelling timeframe, subject to a set of constraint equations. By adjusting the set of available development options and by applying or removing constraints from the LTIRP, we are able to model alternative planning methodologies.

There are three key planning decision types in these LTIRP studies:

1. Generation development
2. Generation retirement
3. Transmission development – both interconnectors and intraconnectors[2]

The critical difference between the planning methodologies is whether these decisions types are optimised co-operatively and whether they are made with a regional or zonal focus.

In general, generation retirement is assumed to be based on a regional focus without consideration of how the retirement may impact on future transmission development. Generation retirements are driven by cost assumptions and both regional and market supply demand balance. Retirements do not consider the impact of providing additional access to other generation that may result. Retirements do, however, consider the transmission augmentations that would be required if the generator were not to retire in order to maintain its access. An example of this consideration impacting on retirement decisions is described in Section 6.8.

2.2.1 RIT-T planning

The RIT-T planning approach is applied as a two-step application of the LTIRP that is based on the concept that transmission "follows" generation. In the first step of the LTIRP, interconnectors and generation development decisions are developed without consideration of the cost of intraconnector augmentation. Therefore, generation investment decisions are made with consideration of locational fuel costs, resource quality/availability and transmission losses – critically, these decisions are not made with consideration of the cost of achieving sufficient access to load.

The second stage LTIRP simulation of this approach uses this generation development plan, and builds additional intraconnectors where they are found to reduce the total economic cost. This approach is consistent with the RIT-T approach for developing transmission that uses existing generation assumptions and projections of energy growth and generation development to determine the value, and therefore merit, of transmission investment.

2.2.2 Co-optimised planning

The LTIRP models the co-optimised planning approach by considering both the generation and transmission development required to meet demand over the modelling timeframe. Generation retirements are applied as an input to this procedure, having previously been determined using a regional approach, similar to Section 2.2.1. The resulting development projection is the lowest cost method for meeting demand.

[2] Interconnectors are the transmission flowpaths between regions. Intraconnectors are transmission flowpaths between zones within the same region.

2.2.3 OFA planning

OFA is applied in the LTIRP as an additional set of constraint equations in the co-optimised model that apply the FAPS. OFA defines a level of access that must be able to be met by all generation during specified conditions. For this study, and in the current OFA design, the specified conditions have been applied as the time of regional peak demand.

Therefore, given a specified level of access for each generator in each year, EY has applied DC Load Flow techniques (see Section 2.3.1) to determine the capacity required for each intraconnector. These constraints apply the FAPS and force the LTIRP to meet the required capacity for all transmission flowpaths. Therefore, generation decisions in the LTIRP are made with the knowledge that they may require augmentation of one or more intraconnectors to provide sufficient access to all generators.

2.3 Zonal topology and transmission model

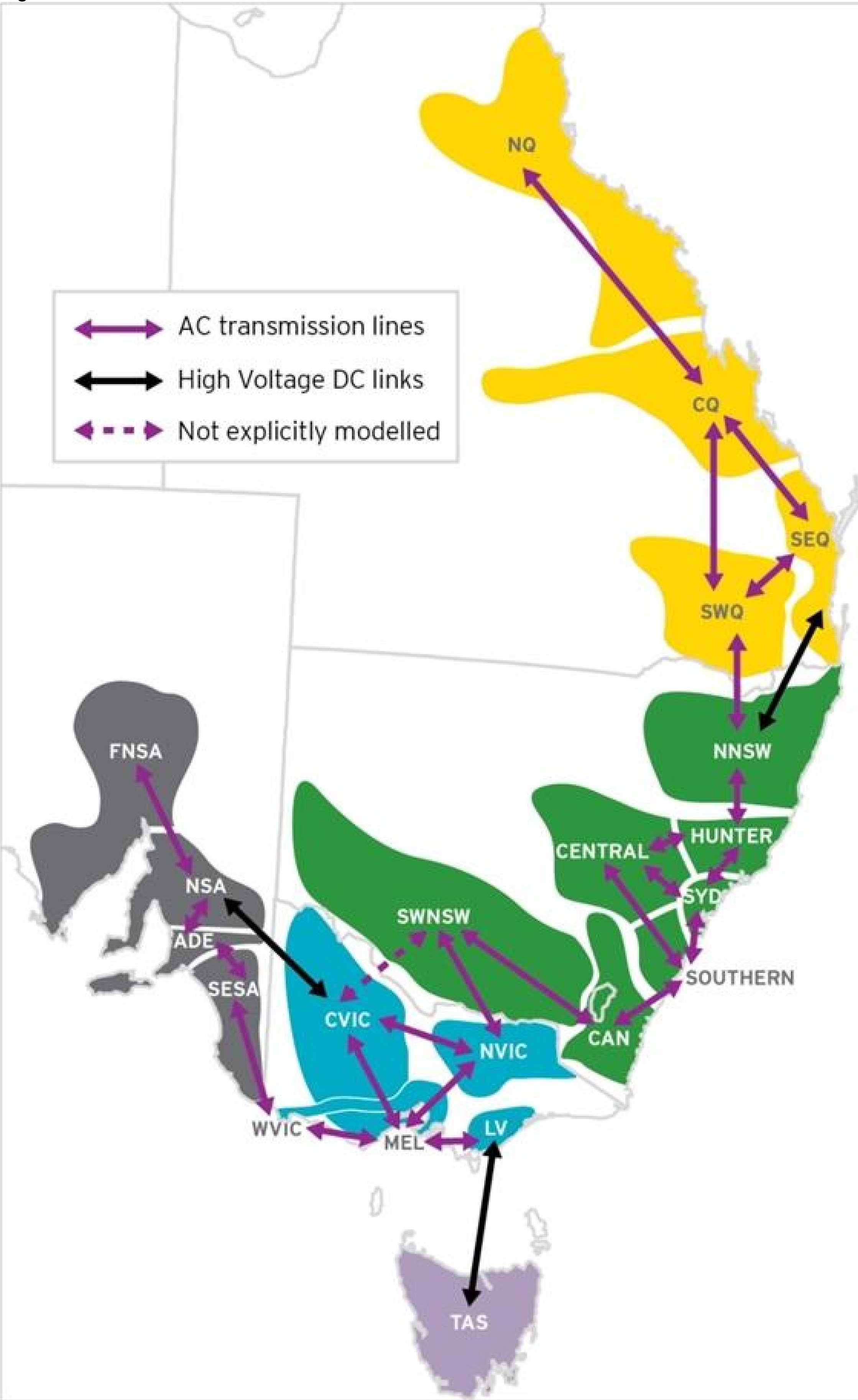
2.3.1 Zonal transmission flowpaths

The transmission model applied in the LTIRP is an approximation of the existing network topology. Modelling the full transmission configuration in a long-term planning study would require simulation time and a level of input data that is beyond the requirements of this study. The zonal approximation allows a consideration of locational decision making and the potential for transmission investment that is computationally feasible.

EY has applied a zonal model that is consistent with that applied in the TFR modelling. Zones are connected by intraconnectors and interconnectors that are represented by a single flowpath limit. This flowpath limit is a proxy for the set of transmission constraint equations that would apply in reality. To refine the transmission model in this study, we have used transmission constraint equation data, historical observations, and additional consultation with AEMO.

The zonal topology is illustrated in Figure 1.

Figure 1: Zonal NEM Model



From the above chart it can be seen that there are a number of meshed areas in the NEM – the Sydney ring is an example of a mesh in the zonal transmission model. To model transmission flows in these meshed areas, EY has applied DC load flow equations. These equations result in flow splits that are reflective of the current transmission configuration. These flow splits do not change during the study – augmentations only influence the capacity of each flowpath.

For simplicity, we have not explicitly modelled the transmission line between CVIC and SWNSW that comprises part of the VIC-NSW interconnector. This approach is consistent with that applied in the TFR. The capacity of this transmission line is captured in the transfer capability between NVIC and SWNSW.

2.3.2 Inter-zonal transmission considerations

Our approach only considers the development of transmission between zones. In reality, localised transmission issues within zones can limit generator access. For example, the transmission constraint equation "S>>V_NIL_SETX_SETX" is applied to avoid overloading the 275/132 kV transformer in south east South Australia (SESA). This constraint limits the access of some generators in SESA to the ADE zone. However, this transmission constraint is not a limitation on the ability to transfer energy from SESA to ADE; rather this is a limitation on transmission within the SESA region. Therefore, this limitation will not be captured in our zonal network model.

There are a number of other recent examples of inter-zonal transmission limitations that have had a high impact on both generator access and market pricing outcomes, e.g., the "Q>>NIL_855_871" constraint equation in central Queensland.

Furthermore, our model does not capture inter-zonal transmission developments that are built to meet local load requirements. For example, there is continuing development in south west Queensland of the infrastructure required for the coal seam gas industry. These investments are not captured in our model. As a result, the total transmission investment determined in this modelling is not equivalent to the expected investment by TNSPs over the modelling timeframe. However, the zonal transmission model does capture the augmentations that are strongly related to the impact of OFA.

2.3.3 Zonal disaggregation

Regional demand forecasts were developed as described in Section 3.2.2. To develop zonal load forecasts, EY estimated the distribution of load across each zone in each region based on our previous experience with NEM wide demand distributions. Table 2 shows the average share of regional energy in each reference node.

Table 2: Reference node share of regional load

Node	Share of regional load
SEQ (Queensland)	37%
SYD (New South Wales)	45%
MEL (Victoria)	67%
ADE (South Australia)	60%

Initial zonal distributions were further adjusted according to peak demand. A greater share of regional peak demand was concentrated in the reference node, reflecting the contribution of residential load to peak. Similarly, more energy was allocated to regional nodes during off-peak periods reflecting industrial loads and other base loads that are insensitive to diurnal or seasonal trends. This better reflects real-world load distributions.

In general, load growth in each region was assumed to be shared on a pro-rata basis between zones, with two exceptions. To account for the growth of rooftop PV over time, daytime zonal energy distributions of regional energy forecast were modified to be consistent with the assumed distribution of PV systems (Section 3.2.3). Additionally, short-term Queensland demand growth was driven by growth in LNG loads in the SWQ node. Therefore, zonal load distributions were adjusted to reflect a baseload growth of approximately 1000 MW in SWQ over the first five years of the study.

3. Scenarios and Modelling Assumptions

3.1 Overview of modelling scenarios

EY and the AEMC have developed a range of scenarios to test the potential for OFA to impact decision making. Some of these scenarios represent possible futures and therefore provide an assessment of the effect of OFA on the market. A number of these scenarios are more appropriately characterised as sensitivities in that the assumptions are not necessarily a likely possible future – these scenarios are intended to determine what market factors are strongly related to the magnitude of OFA's impact. EY did not examine other scenarios, or combinations of scenarios, that might have shown higher or lower benefits.

A brief overview of these scenarios is presented in Table 3.

Table 3: Scenario descriptions

Scenario	Description
Base case	Base case scenario inputs, with "moderate" forecasts and legislated policies.
Reduced RET	RET reduced to target 26,000 GWh in 2020, with the target then held constant to 2030.
Carbon pricing	The Base case with the Treasury Core carbon price trajectory applied from 2021-22.
High DG	An additional 50% growth in penetration of distributed generation (i.e. rooftop PV).
Electric Vehicles	Electric vehicles (EVs) are adopted from 2020 onwards, leading to increased energy and peak demand requirements. A moderate carbon price was also applied.
High growth	Demand and energy forecasts with an additional 1.5% annual growth applied to any growth in the base case trajectories.
Portland retirement	Retire the Portland Aluminium Smelter in western Victoria in 2017-18.
Boyne Island retirement	Retire the Boyne Island Aluminium Smelter in central Queensland in 2017-18.
Emissions reduction target	An aggressive emissions reduction scenario that targets a 40% reduction on 2000 levels by 2025 and an 80% reduction by 2040.
Transmission degradation	Applies a 2% annual reduction in transmission capacity.
Forecasting error	Incorporates a 2% forecasting error in demand and energy growth over subsequent five year periods, starting in 2020.

1. Base case

The base case considers a "medium" or "moderate" outlook for demand and energy growth by applying the Medium Trajectory in the AEMO 2014 National Electricity Forecasting Report (NEFR). The Base case applies the legislated RET and no carbon price. These assumptions represent a "business as usual" outlook for the NEM.

2. Reduced RET

There is considerable debate about the level of the RET. There is a strong likelihood that the RET, which is currently legislated to target 41,000 GWh of additional renewable generation by 2020, will be modified in some way. The Federal Government's Review of the Renewable Energy Target proposed two potential modifications the RET. ***Option 2- Share of growth in electricity demand*** proposes to amend the scheme such that the target is only increased annually by 50% of projected demand growth until 2020. We have used this as a basis for setting a reduced RET target of 26,000 GWh in 2020, with the target then held constant to 2030.

3. Carbon pricing

The Base case does not incorporate carbon pricing of any kind in its outlook for the NEM. In this scenario, a carbon price is applied from 2021. When introduced, the carbon price follows the original Treasury Core trajectory (details of this trajectory can be seen in Section 3.2.6).

4. High DG

Long-term penetration of rooftop PV was increased by 50% as a sensitivity to the Base case. This has been applied in all regions, with a faster ramp-up of capacity in the first 10 years of the study.

5. Electric Vehicles

Electric vehicles are adopted from 2020 onwards, leading to increased energy and peak demand requirements. In addition, we apply a moderate carbon price from 2021 – this carbon price trajectory is half as large as the trajectory applied in the carbon pricing scenario.

6. High growth

Both energy and peak demand increase significantly over the study period. In addition to the underlying demand and energy growth in the AEMO Medium projection, we have applied an ***additional*** 1.5% annual growth to both annual energy and peak demand. The resulting demand and energy projections exceed those that result from the addition of EVs in the EV scenario.

7. Portland retirement

In this scenario, the Portland Aluminium Smelter is retired in 2018-19. This retirement is applied as a 500 MW reduction in demand in western Victoria in all periods from 2018-19 onwards. This scenario (and the following Boyne Island retirement scenario) is used to test the effect of OFA given major load retirements. This scenario is not intended to be a likely possible future.

8. Boyne Island retirement

In this scenario, the Boyne Island Aluminium Smelter is retired in 2018-19. This retirement is applied as a 950 MW reduction in demand in central Queensland in all periods from 2018-19 onwards.

9. Emissions reduction target

In this scenario, the market is required to meet aggressive emissions reduction targets. These targets result in a more rapid decarbonisation of the NEM than that which results from the application of the Treasury Core carbon price trajectory. This scenario targets a 40% cut in electricity sector emissions (from 2000 levels) by 2025 and an 80% reduction by 2040[3]. For comparison, the Carbon pricing scenario delivered an emissions reduction (from 2000 levels) of approximately 18% by 2025 and 78% by 2040. The Emissions reduction scenario therefore represents a more rapid reduction in emissions.

[3] Australian Government Department of the Environment, ***Australia's emissions reduction targets***: http://www.climatechange.gov.au/climate-change/greenhouse-gas-measurement-and-reporting/australias-emissions-projections/australias

10. Transmission degradation

The AEMC requested that EY consider the potential impact of transmission asset replacement on the effect of OFA. We have therefore developed a transmission degradation scenario. In this scenario, all transmission flowpaths incur a 2% annual reduction in transmission capacity. This annual decrease approximates the need for assets to be replaced in lumps and is based on a general assumption of a 50 year asset live for transmission infrastructure. This degradation can be replaced at a cost that is 25% of the full cost of transmission augmentation. A description of how transmission degradation and replacement is modelled in the alternative planning methodologies is provided in Section 3.2.9.

11. Forecasting error

In the forecasting error scenario, we have assumed that generation and transmission investment decisions are made with the expectation of demand and energy growth that is 2% in excess of actual growth. This process is reset every five years and starts in 2020. This scenario is described in greater detail in Section 3.2.8.

The quantitative details underlying each of the scenarios are provided throughout this section.

3.2 Modelling input assumptions

3.2.1 General Input Assumptions

All modelling results in this Report are presented in real June 2014 Australian dollars. Unless otherwise stated, all results are also discounted to June 2014 using a pre-tax real Weighted Average Cost of Capital (WACC) of 8.78%.[4]

The LTIRP does not enforce a specified reliability standard. Rather, new capacity or transmission is installed to improve reliability if the cost of the augmentation is less than the reduction in unserved energy valued at the Value of Customer Reliability (VCR). We have assumed a VCR of $33,460/MWh; this value was calculated as the Aggregate NEM wide value of VCR in AEMO's ***Value of Customer Reliability Review*** published in September 2014.

EY fixed the currently installed capacity at the commencement of the study. As a result, recent changes such as the decommissioning of the second unit of the Wallerawang Power Station have not been implemented. We have assumed that all currently mothballed plant, with the exception of the Playford Power Station, return to service and have been provided with transitional firm access.

All scenarios apply the committed Heywood interconnector upgrade from 2016.

3.2.2 Demand and Energy Projections

Figure 2 and Figure 3 show the modelled annual NEM energy and coincident peak demand in the Base case, Electric Vehicles, High growth and High DG scenarios. The two load retirement scenarios are described separately, and are relative to the Base case.

[4] Private correspondence, Australian Energy Market Operator (2012)

Figure 2: Annual energy in Base case and sensitivities

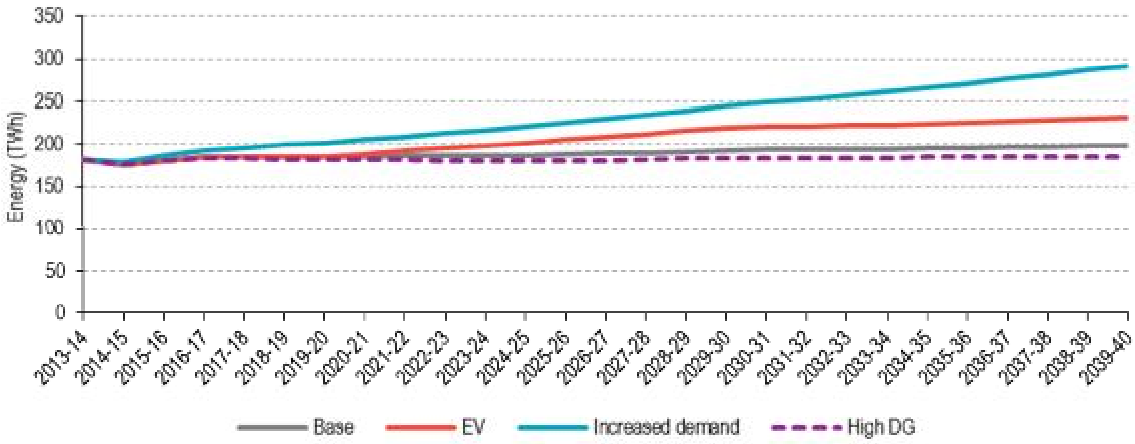
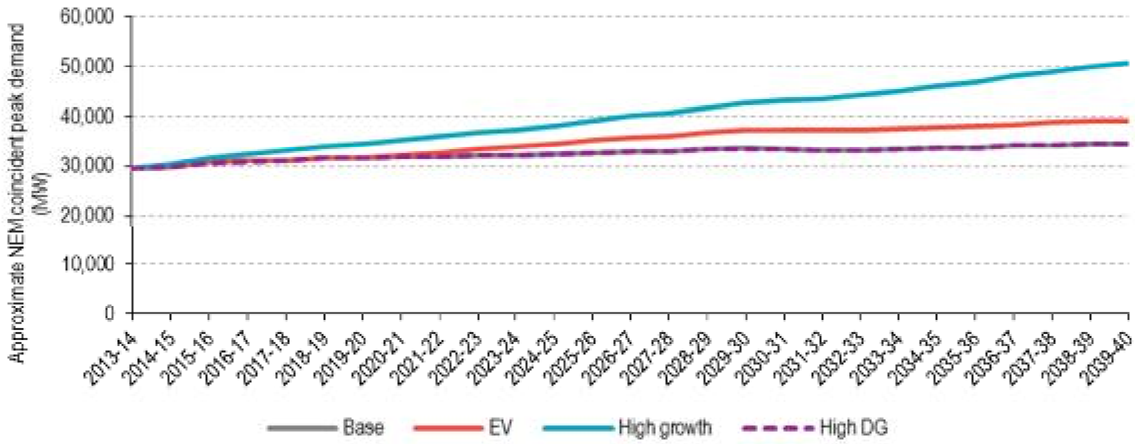


Figure 3: NEM coincident peak demand in Base case and sensitivities



The Base case demand and energy assumptions for this study were taken from the Medium scenario of the AEMO 2014 NEFR. This scenario features relatively little growth in NEM operational energy over the study period, driven by a combination of growth in PV generation and subdued underlying electricity demand growth.

The Increased demand scenario features an additional 1.5% of energy and demand growth in each year, above the underlying growth in regional targets in the AEMO projections.

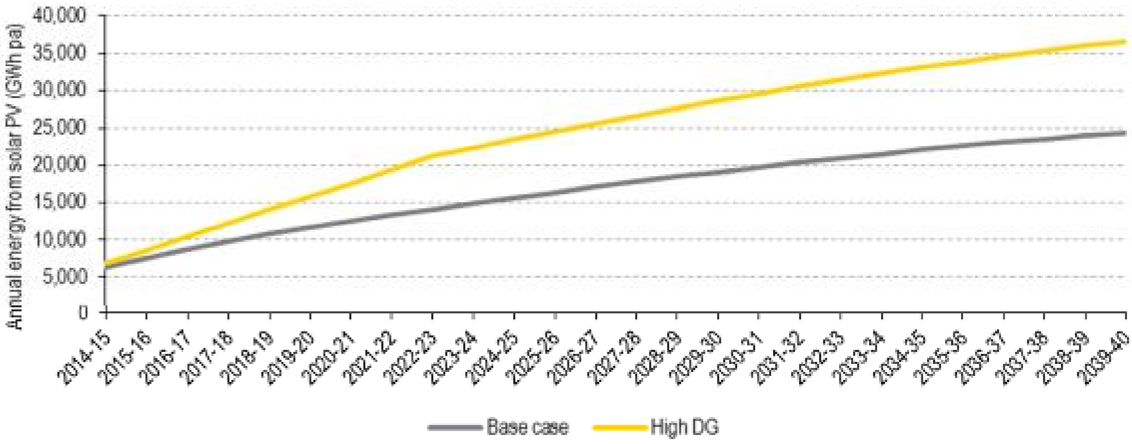
Assumptions for the High DG and EV scenarios are detailed in the sections below. The High DG scenario features an increased penetration of rooftop PV that does not significantly reduce the long-term system peak in this modelling – regional peaks are generally in the afternoon or evening when PV contribution is relatively low or zero.

Demand traces for each region were developed using EY's Trace Extrapolation Tool (TEX) which takes a reference year (2012-13) of 17,520 half-hour demand periods and grows the annual energy and peak demand according to the specified targets. This ensure that realistic load duration curves are used, taking into account changing demand conditions, including penetration of rooftop PV.

3.2.3 Solar PV assumptions

The penetration of rooftop solar PV across the NEM is shown in Figure 4. For all scenarios except High DG, the AEMO 2014 NEFR Moderate rooftop PV trajectory was used. Under the High DG scenario, the long-term penetration of rooftop PV was modelled to be 50% higher than the Base case, with more rapid growth in the first years of the study.

Figure 4: NEM rooftop PV generation in Base case and sensitivity



Solar PV generation traces were modelled on a regional basis using EY's Solar Energy Simulation Tool (SEST) which incorporates satellite derived hourly solar insolation maps from the Bureau of Meteorology and the National Energy Research Laboratory's System Advisor Model to develop representative solar traces for distributed rooftop generation.

Regional generation traces were then allocated to each zone within the region based on the current distribution rooftop PV generation, derived from the Australian PV Institute (APVI) Solar Map[5] and data published by the Clean Energy Regulator. This ensured that future growth of rooftop PV was modelled in appropriate population centres.

3.2.4 Generation and Transmission Cost Assumptions

Generation cost assumptions are sourced from a variety of publications. The relevant datasets for generation cost assumptions are as follows:

- Technology cost data presented by the Bureau of Resources and Energy Economics (BREE) in their ***Australian Energy Technology Assessment 2012***[6] (AETA 2012).
- The 2013 coal fuel cost estimates from ACIL Tasman, provided as part of AEMO's Planning Assumptions.[7]
- Gas fuel cost projections based on ACIL Allen Consulting's report on NSW Coal Seam Gas[8] in 2013 and Intelligent Energy Systems report on the Australian domestic market[9].
- Additional data as available from AEMO in the ***National Transmission Network Development Plan*** in 2010[10] and 2012[11].

[5] Funded by the Australian Renewable Energy Agency, accessed from pv-map.apvi.org.au on 1 November 2014.

[6] Available at: http://www.bree.gov.au/publications/australian-energy-technology-assessments.

[7] Available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions. Updated data in the 2014 NTNDP showed only minor changes from the 2012 data set.

[8] Available at: http://www.appea.com.au/wp-content/uploads/2013/06/27303-NSW-CSG-Report-20130529.pdf.

[9] Available at: http://www.industry.gov.au/Energy/EnergyMarkets/Documents/IESStudyontheAustralianDomesticGasMarket.docx.

[10] ***NTNDP Modelling Assumptions: Supply Input Spreadsheets***, Available at: http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/2010-National-Transmission-Network-Development-Plan-Consultation.

[11] ***2012 NTNDP Assumptions and Inputs***, Available at: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs.

We have applied the same assumption from the TFR that the capital cost of developing generation at the reference node has a 10% premium relative to other zones within each region.

The LTIRP model applies a single WACC to all categories of cost and to all technologies. In collaboration with the AEMC, we have applied a 20% increase to the capital cost of new entrant coal-fired generation in all scenarios to reflect the higher financing costs faced by these plant in reality (the LTIRP itself assumes perfect foresight in all scenarios for planning purposes).

EY has applied retirement costs for existing generation. Reliable input data on retirement costs is scarce and is likely to be highly variable amongst the fleet of existing generators. Therefore, we applied a high level retirement cost approach based on station size and technology. Retirement costs range from $15m – $300m for coal-fired generation and up to $16m for gas-fired generation.

We have also maintained the transmission cost assumption that was applied in the TFR modelling. Transmission upgrades have a cost of $2,000/MW/km. In reality, the cost of augmenting transmission between two locations is dependent on a range of factors such as terrain, access to easements, existing transmission infrastructure and configuration etc. The assumed cost is generally consistent with the capacity and cost of high voltage transmission augmentations and is inclusive of any substation costs which may be associated with transmission augmentation.

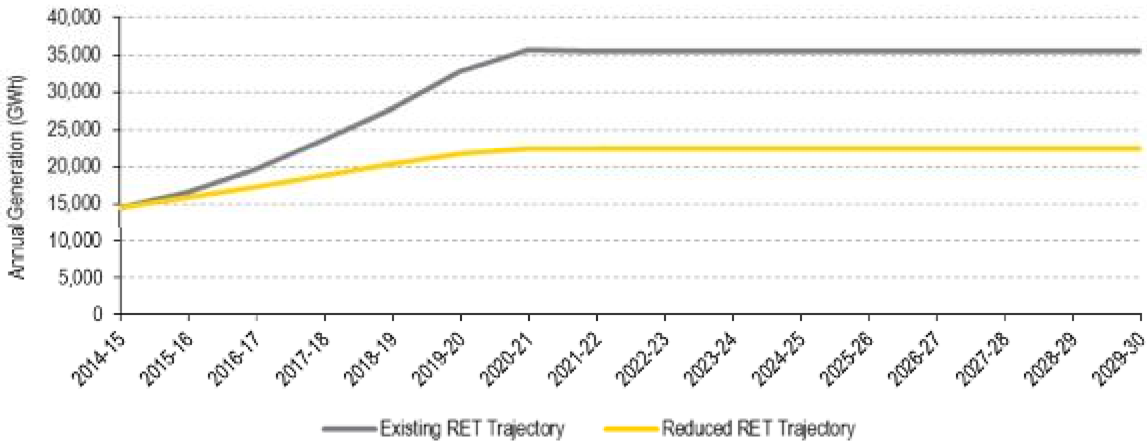
Interconnectors in this modelling represent the transmission flowpath between neighbouring zones on each side of regional boundaries. The capital cost of augmenting these interconnectors is based on the same $/MW/km methodology applied to intraconnector costs. Augmentations of existing DC interconnectors (Murraylink, Terranora and Basslink) are assumed to cost 100% more than AC interconnectors.

3.2.5 Renewable Energy Target

We have applied two alternative levels of the RET in this study. The base RET assumption is the existing legislated target. A reduced RET that targets 26,000 GWh of renewable energy by 2020 has been applied as a sensitivity. These two trajectories are illustrated in Figure 5.

These trajectories show the contribution required from scheduled and semi-scheduled NEM generation, and therefore incorporate assumptions related to the proportion of generation sourced from outside the NEM, as well as non-scheduled generators (e.g., small wind farms as well as landfill gas, etc.) and estimated long-term average hydropower LGC production. These assumptions are drawn from our extensive database of historical certificate generation and creation, as well as our previous modelling studies of the Australia-wide market. These trajectories also assume additional certificates are required to be produced to meet annual GreenPower liabilities.

Figure 5: RET trajectories



Typically, we would allow market forces to determine if the RET were able to be met. The RET applies a nominal, pre-tax penalty price of $93/MWh. If this penalty price (which is decreasing in real value over the duration of the RET) is insufficient to justify further investment in renewable generation, then the RET may not be met and the price of certificates will hit the penalty price.

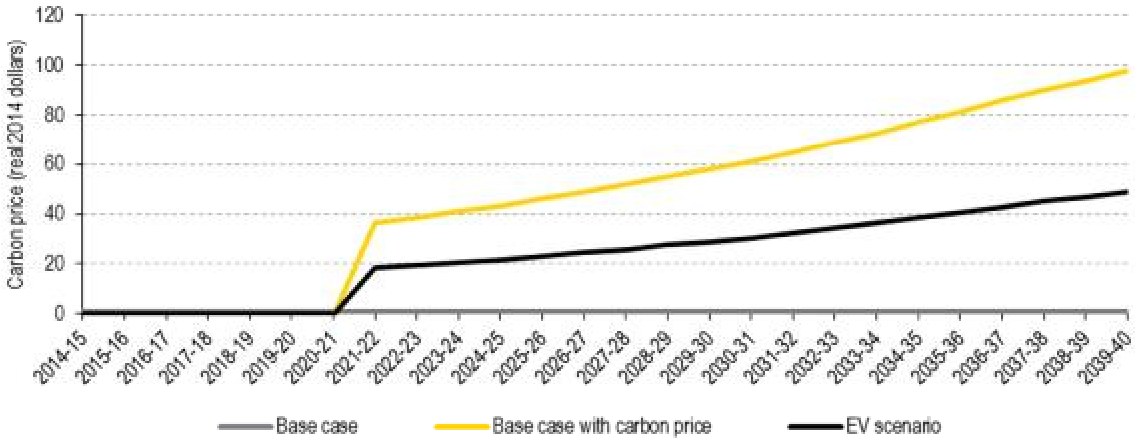
However, the LTIRP style modelling applied for this study is not necessarily appropriate for assessing the ability of the RET to be met. The market driven component of the value of installing additional renewable generation is lower than expected prices in the NEM: dispatch in the NEM allows for strategic withholding of generation to increase wholesale prices. Therefore, the required value of certificates in the LTIRP is higher than would be expected in the real market. Furthermore, there is an argument that the RET price staying at the penalty price for extended periods would not be sustainable in reality, and would necessitate a change to either the target or to the penalty price.

Therefore, the RET applied in this modelling has been forced to meet the target by applying an artificially high penalty price – this applies to both the legislated target and to the Reduced RET scenario. The effect of the high penalty price is identical to forcing the targeted level of renewable generation in each year, accounting for banked certificates.

3.2.6 Carbon Pricing

Figure 6 shows the carbon price trajectories applied in the Carbon pricing scenario, Electric Vehicles scenario and in the Base case (and all other scenarios).

Figure 6: Carbon price trajectories



3.2.7 Electric Vehicles

Projections for EV uptake were derived from Scenario 4 of the Future Grid Forum: change and choice for Australia's electricity system report[12]. This scenario considered a moderate to high growth in electric vehicles, such that EVs are responsible for 31% of total road kilometres by 2050. This results in an annual energy requirement of approximately 43 TWh Australia wide by 2050.

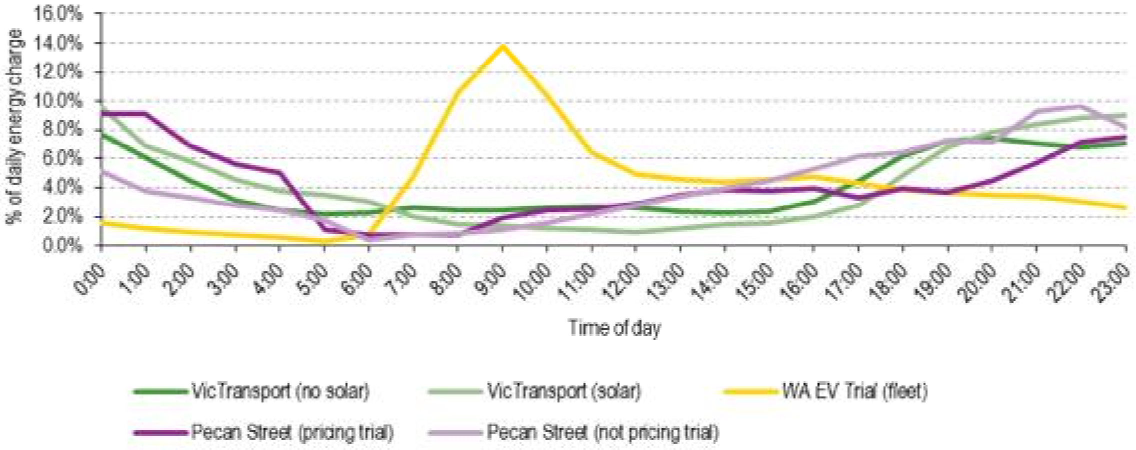
EV demand was distributed between regions pro-rata with population. Within each region, EV uptake was concentrated at the reference node (70-85% of energy, depending on the population and load distribution in that region), with the remainder distributed between other zones using rooftop PV penetration as a proxy for potential residential customers.

Significant uncertainty exists around future EV charging behaviour, with some analysts expecting a low level of customer participation (i.e., EVs plugged in on arriving home for immediate charge), and

12 http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure.aspx

others expecting a combination of price signals and customer engagement to lead to charging being scheduled for off-peak periods or even “vehicle-to-grid” behaviour. For example, Figure 7 shows the EV charging behaviour in a number of trials we have surveyed. This highlights the sensitivity of customer behaviour to key parameters and consumer groups and is not intended to represent an exhaustive review.

Figure 7: Examples of EV charging behaviour trials



High levels of customer responsiveness will minimise the impact on the network, and increase the utilisation of existing capacity, potentially delaying retirements. Conversely, charging coincident with daily peaks will increase the need for new peaking capacity.

For this study, 18% of EV energy was assumed to be demanded during the evening peak hours (6pm to 9pm), 36% of energy during daytime hours, and the remainder overnight. Within these time periods, EV demand was assumed to be insensitive to actual demand conditions, representing customer tariffs that are provide price signals but are not real time.

3.2.8 Forecasting Error

The forecasting error scenario has been designed to determine whether erroneous demand and energy projections impact on the potential for OFA to improve the efficiency of generation and transmission investment. For this scenario, we have assumed that demand and energy projections overstate the growth that actually occurs. We have assumed that the forecasting error is an assumption that growth will be 2% higher than actual growth across all regions.

For this scenario, the projection of generation and transmission investment is made by joining together consecutive LTIRP outcomes, each time fixing only five years of investment decisions. The step are as follows:

1. Run and LTIRP with actual demand and energy projections.

2. Run a second LTIRP that fixes the planting outcomes for the first five years of the first LTIRP, then projects development over the remainder of the forecasting period assuming a compounding forecasting error of 2%. This forecasting error begins in 2020.

3. Fix the planting from the subsequent five years of this second LTIRP (and the first five years from the first LTIRP). Run another LTIRP assuming a forecasting error of 2% that begins in 2025 – therefore the demand projection until 2025 is the same as actual demand.

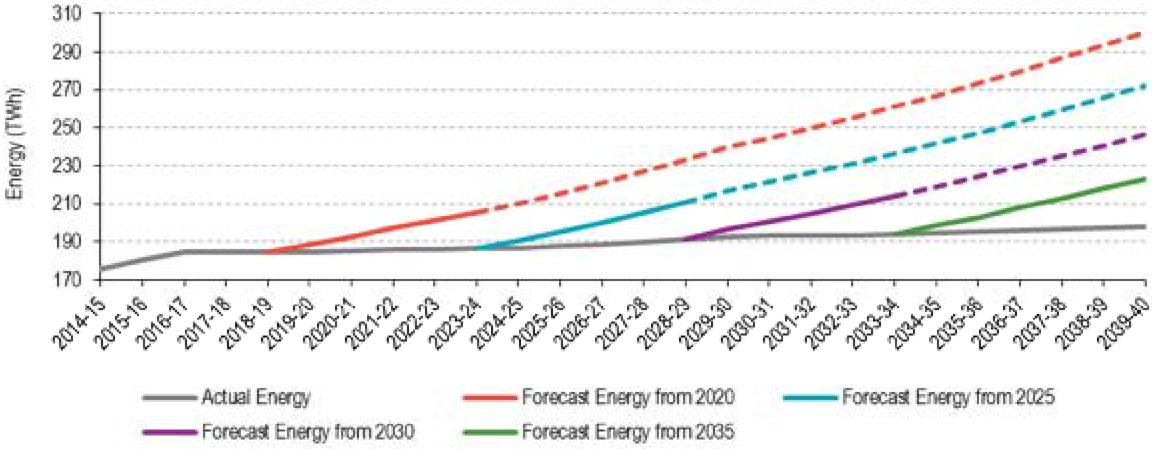
4. Repeat this process until planting assumptions are fixed for the entire scenario.

5. Rerun the study, fixing these planting outcomes but with actual demand and energy.

6. Repeat this process for the remaining planning methodologies.

The demand projections for this approach are shown conceptually in Figure 8. The solid coloured lines show the years where planting outcomes are fixed into the final market development in each forecasting error LTIRP simulation. The dotted lines impact on the decisions made during this five year period, but the planting outcomes that occur after this five year period are not reflected in the final development plan.

Figure 8: Conceptual representation of forecasting error demand assumptions



3.2.9 Transmission Degradation

EY has considered the potential impact of OFA on transmission replacement decisions. Under the current transmission planning framework, transmission replacement does not require a RIT-T. The AEMC requested EY to consider a scenario whereby the treatment of asset replacement is different under the OFA model. We have made the following assumptions:

- Under the RIT-T model, transmission replacement always occurs without any regard for benefit or cost.
- Under co-optimised, transmission replacement only occurs when the benefit exceeds costs, giving consideration to the impact on future generation and transmission development.
- Under OFA, transmission replacement occurs only if it maintains a level of access for existing and new entrant generation that minimises the economic cost of dispatch.

In this modelling, we have applied an annual degradation of intraconnector capacity as a long-term approximation of the need for asset replacement. All intra-connectors reduce their capacity by 2% annually. This degradation can be replaced at any time after it occurs (including during the year of degradation) at a cost that is 25% the cost of full augmentation. These assumptions are conceptual in nature as in practice, these costs would be highly dependent on the characteristics of each transmission asset that comprise a transmission flowpath.

The intention of this scenario is to determine:

a) Does OFA have the potential to drive more efficient asset replacement decisions that the current transmission framework?
b) Does this result in a significant improvement in efficiency?

This scenario is predicated on the principle that OFA will change the process by which transmission asset replacement is conducted. For OFA and co-optimised planning, this modelling assumes that transmission replacement only occurs when generation is willing to continue to pay to procure a level of firm access that requires this asset to be replaced. The continuing cost of asset replacement is considered by all generation for investment and retirement decisions. The RIT-T modelling assumes that the replacement of assets on existing flowpaths will be conducted outside of the RIT-T framework (i.e., no cost-benefit analysis is applied) and that all flowpaths are maintained to at least their existing capacity in all years.

3.3 Firm access assumptions

3.3.1 Establishing access for incumbent generation

The AEMC's review of OFA includes a detailed assessment of the range of issues related to the allocation of transitional access to incumbent generation. The design of transitional access is not critical to our modelling that is focused on the impact of OFA on the long-term development of the NEM. However, in modelling firm access, all generation, both new entrant and existing must be allocated a specified level of firm access. For incumbent generation, we have applied a similar method to that applied in the TFR modelling which requires a calculation of the existing level of access for all incumbent generation.

AEMO have conducted a detailed analysis that considers all dispatch transmission constraint equations to determine a view on the level of access for existing generation. Our approach is less complex than AEMO's in that it uses the zonal approximation of the transmission system.

Our approach is to determine the maximum access that can be allocated across the NEM such that no transmission flowpath requires immediate augmentation. This analysis considers the level of installed capacity in each zone, the load during the regional peak and the capacity of the existing transmission flowpaths. The DC load flow equations determine the resulting flow across each intraconnector. Interconnectors are only allocated access if all generation that uses the flowpaths between the interconnector and the regional reference node have 100% access and there is still capacity remaining on each intraconnector. This approach is generally comparable with that applied by AEMO. The results of our transitional access calculation and a comparison with AEMO's outcomes are provided in Table 4, noting that the EY and AEMO zonal representations are not identical.

Table 4: Transitional access allocation		
Zone	EY Transitional Allocation	AEMO Transitional Allocation
NQ	98%	100%
CQ	98%	99%
SWQ	98%	84%
SEQ	100%	100%
NNSW	100%	100%
Hunter	97%	100%
Central	100%	100%
Southern	72%	100%
SYD	100%	100%
CAN	72%	100%
SWNSW	72%	63%
NVIC	95%	87-100%
CVIC	100%	
LV	100%	95%
MEL	100%	86%
WVIC	100%	100%
ADE	100%	100%
SESA	100%	90%
NSA	83%	97%
FNSA	83%	97%
QNI (QLD)	0%	0%
QNI (NSW)	0%	0%
Terranora (QLD)	100%	0%
Terranora (NSW)	0%	0%
VIC-NSW (NSW)	0%	0%
VIC-NSW (VIC)	0%	Possible
Heywood (VIC)	100%	Possible
Heywood (SA)	54%	0%
Murraylink (VIC)	0%	0%
Murraylink (SA)	0%	0%
Basslink (VIC)	100%	95%
Basslink (TAS)	100%	

There are a number of differences between AEMO and EY in the calculation of existing access. For example, in both our model and the AEMO model, generation is constrained in southern NSW by flows into Sydney. However, in the AEMO model this lack of access is attributed to Snowy Hydro's generation in New South Wales – this is based on a dispatch outcome observed by AEMO in their modelling. In the approach we have used, all generation that equally uses that flowpath (SOUTHERN, CAN and SWNSW generation) is allocated an equal level of access.

Many of the other differences are a result of the treatment of transmission limits. For example:

- AEMO applied a limit of 4500 MW between SWQ and SEQ. This limit has since been alleviated.
- AEMO's application of Hazelwood transformer constraints results in a slightly lower level of access for LV generation.
- EY does not apply the South East transformer constraints in SESA (described in Section 2.3.2) as these are intra-zonal limitations. AEMO's application of these constraints limits the access of SESA generation to ADE. This also allows our model to allocate access to Heywood's import into South Australia.
- We have allocated full access to Terranora's import into Queensland and Basslink's import in Tasmania as both these interconnectors are connected to the reference node in those regions. AEMO model the transmission limitations within the reference nodes.

The level of transitional access shown above is in some cases, significantly different than that calculated in the TFR modelling. These changes are primarily a result of the following:

- Refinements in the zonal transmission model
- Removal of off-peak considerations in the FAPS
- Generator build and/or retirement
- Industrial load retirements and general differences in regional load assumptions and zonal disaggregation

The AEMO transitional allocations in Table 4 are based on the AEMC's allocation method that was presented in the First Interim Report. We understand that the method that the AEMC is recommending for the allocation of transitional access has changed since that time. The changed method is outlined in their draft report. Under the recommended process, each generator within a region would be allocated transitional access for free pro-rata to capacity and regional peak demand. The remainder of the network capacity would be auctioned to generators and firm interconnector right holders as transitional access. Consequently, the values in Table 4 may not represent the outcome of the transitional access allocation method that is now recommended by the AEMC.

3.3.2 Access assumptions for new entrant generation

In the TFR modelling, ROAM Consulting modelled a variety of different scenarios for new entrant firm access. For this modelling, we have applied the new entrant firm access scenario that was found to be optimal in the TFR modelling. This is shown in Table 5.

Table 5: New entrant access allocation

Wind	Solar PV	CCGT	OCGT	Coal
30%	30%	60%	60%	60%

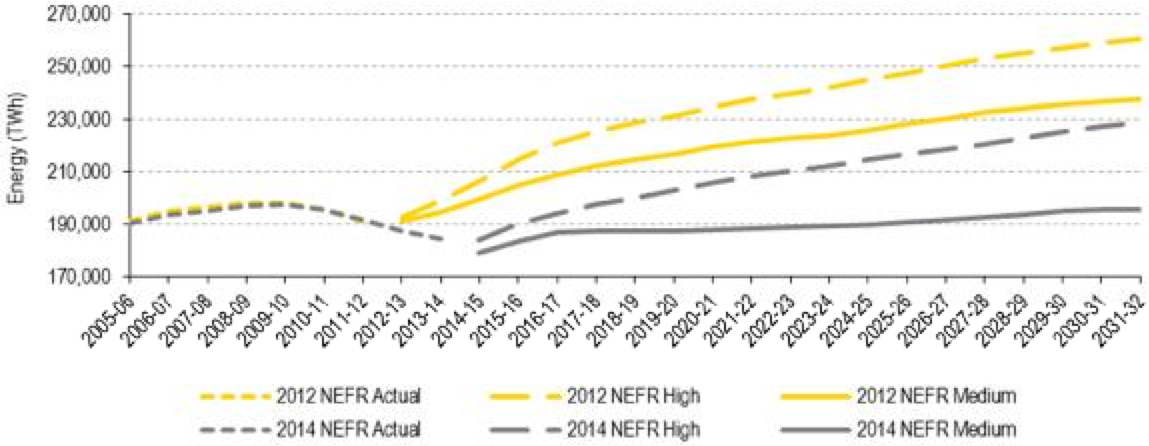
The objective of firm access is to drive market development towards a co-optimised outcome. Therefore, we have used the co-optimised LTIRP outcomes to guide possible changes in the allocation of incumbent generation. The allocation for incumbent generation is based on the access they currently have, not the level that would be optimal given the cost of access. When this level of access is found to be driving inefficient outcomes – such as generator retirements or over-investment in transmission augmentation – we have transitioned the access for existing generation to levels that are comparable to those provided in Table 5.

4. Summary of key differences between OFA and TFR modelling

This section summarises the key differences in input assumptions and methodology between this study and the modelling conducted as part of the TFR. This section provides context when comparing the results of this study with those of the TFR modelling with regards to generation and transmission investment and the value of OFA.

The key difference in input data is the significant reduction in the forecast growth in demand and energy projections. TFR modelling was based on the projections of demand and energy produced by AEMO in the 2012 NEFR. The 2014 NEFR projections incorporate both a lower baseline level of demand and a reduced growth rate over time. The reductions in the forecast annual NEM energy consumption are illustrated in Figure 9 and have the potential to materially alter the market development projections produced by the LTIRP. Forecasts of peak demand exhibit a similar trend.

Figure 9: Comparison between 2014 and 2012 NEFR



Similarly, the removal of carbon pricing from the Base case reduces the transition of the generation sector that was beginning to occur in the later years of the TFR study. However, the inclusion of a carbon pricing scenario that applies the same trajectory as that used in the TFR Base case allows for a more direct comparison between the modelling outcomes.

The extension of the modelling timeframe from 2030 to 2040 also impacts on the modelling outcomes presented in this Report. Extending the modelling timeframe allows the modelling to capture a period where greater transition may be occurring in the generation section, through continued demand growth and/or carbon pricing. Furthermore, all capital cost investments are annualised over their financial life. Only the annualised costs that occur within the modelling timeframe are considered in determining the total cost of meeting demand; this is true of both discounted and undiscounted totals. Therefore, an investment that occurs in 2029 for example would only have provided two years of annualised costs in the TFR modelling. With the extended modelling timeframe, an additional ten years of annualised costs is considered. This allows for the more efficient investments that may result due to OFA in the later years of the study to be more fully considered in determining the benefit of OFA.

There have been a number of other minor changes in input data and modelling methodology since the completion of the TFR. These include:

- Enhanced wind modelling capabilities that more accurately capture correlation between wind in different locations in the NEM

- Adjustments to load distributions based on recent observations, load retirements and a more detailed assessment of the penetration of PV in each zone
- Improved accuracy in the transmission model through further review and collaboration with AEMO
- Recent generator retirements
- The removal of off-peak firm access in the FAPS
- Updates to assumptions relating to capital costs, particularly the large increase in the improvement rate in the cost of solar PV

5. Key results – Impact of planning methodology on total system cost

5.1 Introduction

This section presents the economic impacts of the alternative planning methodologies across all scenarios. These results are provided as both discounted and undiscounted values. Undiscounted results should be interpreted with caution as the market development calculated by the LTIRP inherently incorporates a discount rate in assessing the benefits and costs of investments over the modelling timeframe. Undiscounted values are provided to demonstrate that the efficiency impact of the planning methodologies can be significant in the later years of the study but that these differences are heavily discounted.

All additional generation and transmission capacity that is built in the LTIRP has an associated capital cost. These capital costs are annuitized over the assumed financial life of each asset. Only the annualised payments that occur within the study timeframe are accounted for in both the discounted and undiscounted total economic cost of meeting demand. Therefore, an investment that occurs in 2038 in this study will only contribute two years of annualised payments to the cost totals. This approach is critical in ensuring that decisions that are made later in the study are not influenced by “end effects” which may reduce the incentive to make investments in the later years of the study.

These results do not incorporate other benefits and costs that may result from the introduction of OFA. We have not considered benefits such as the ability for OFA to provide greater certainty to market participants which may reduce the cost of capital, increase willingness to contract, etc. The benefits provided by OFA in discouraging disorderly bidding were quantified in ROAM Consulting’s TFR modelling and have not been considered in this work. Furthermore, this study does not consider the impact of OFA on the operation of the network by TNSPs. Quantification of these benefits is outside the scope of this study.

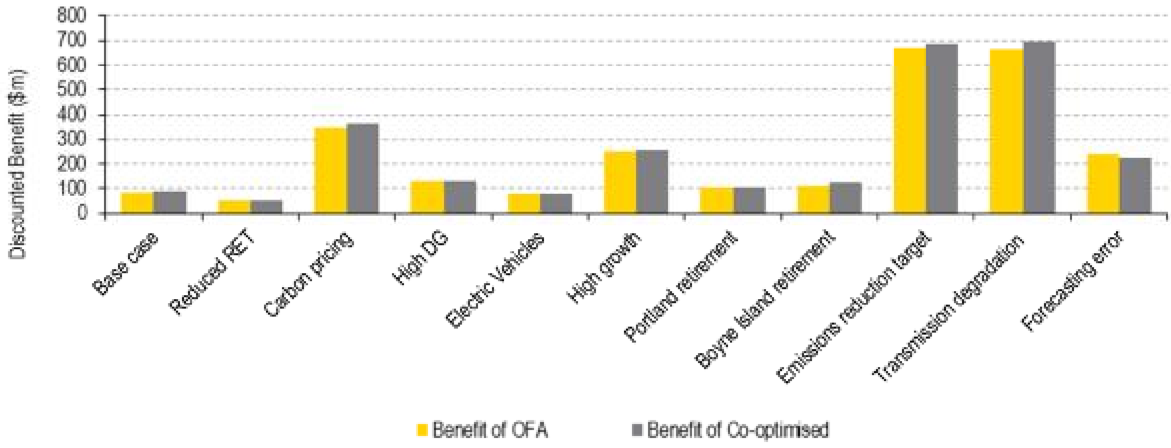
The results presented in this section quantify the benefits of OFA through its ability to better align generation and transmission investment decisions. These benefits result from the potential for OFA to incentivise greater efficiency in generation investment, particularly with respect to locational signals and therefore, result in more efficient network investment.

In addition to the results presented in this Report, EY has provided the AEMC with an Excel Workbook with more detailed annual results.

5.2 Comparison between scenarios

Figure 10 illustrates the discounted benefit of both OFA and co-optimised planning relative to the RIT-T planning approach. Across all scenarios, the economic costs under the OFA and co-optimised planning methodologies are very similar. This is reflective of the ability for OFA to result in a close alignment between generation and transmission investment if each generator procures an efficient level of access. We have configured the level of access of new entrant generation and the ability for incumbent generation to increase or decrease their level of transitional access to reduce any inefficiencies in market development.

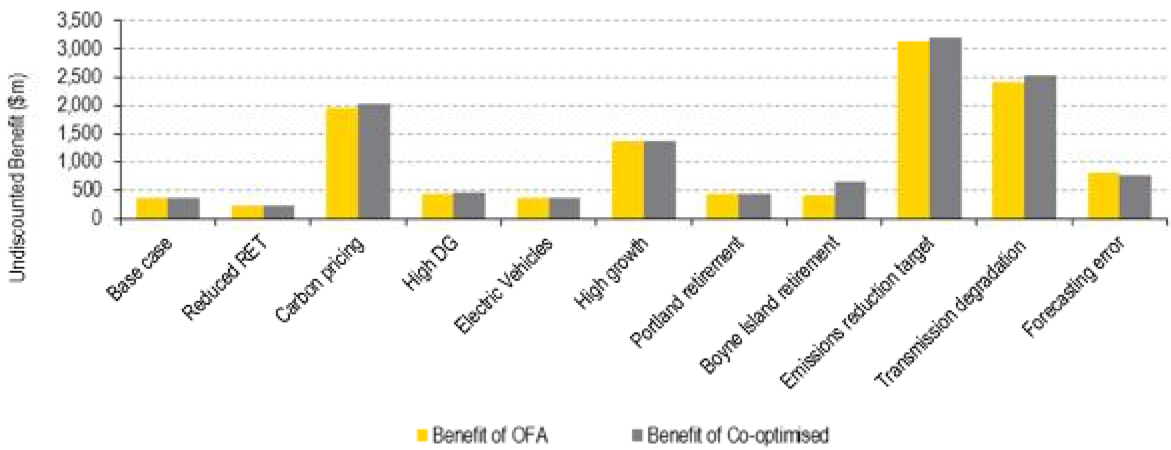
Figure 10: All scenarios – Discounted benefit



From these results, it is evident that those scenarios that result in a significant need for the generation sector to grow (e.g. the High Growth scenario, Forecasting error) or transition (Carbon pricing and Emissions reduction target) exhibit the highest benefit of OFA. The transmission degradation scenario also provides significant cost savings as a result of reduced transmission asset replacement under OFA and co-optimised planning. For the majority of the other scenarios, the benefit of OFA ranges from $50m to $150m. The benefit of OFA in the Base case is $86.6m (the benefit of fully co-optimised planning is $88.2m).

Section 5.3 provides further detail on the breakdown of costs in each scenario. Section 6 describes the generation and transmission development differences between the planning methodologies that drive these benefits. Undiscounted values for all scenarios are provided in Figure 11.

Figure 11: All scenarios – Undiscounted benefit



5.3 Cost breakdown

Table 6 shows the breakdown of cost between the three planning methodologies in the Base case on a discounted and undiscounted basis. (Note that some costs may not add to their totals, due to rounding.) These results demonstrate that in this scenario, both OFA and co-optimised planning increase both variable generation and fixed generation costs. However, the reduction in the cost of transmission exceeds the increase in generation cost. This is consistent with the general concept of OFA in that it has the potential to incentivise generation to choose a location that considers both generation and transmission costs. This decision could result in generation choosing a location where although generation costs are higher, the lower transmission costs associated with the generator location result in a lower total cost.

Table 6: Cost breakdown – Base case ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	25,795	25,806	25,806	70,097	70,112	70,112
Fixed Generation	34,125	34,203	34,203	94,708	95,032	95,033
Transmission	1,201	1,024	1,023	4,370	3,669	3,667
Total	**61,120**	**61,034**	**61,032**	**169,175**	**168,813**	**168,812**
Benefit relative to RIT-T		**86.6**	**88.2**		**361.1**	**362.9**

Table 7 shows the discounted and undiscounted costs for the Reduced RET scenario. The benefit of OFA in this scenario is lower than the Base case due to the reduction in generation investments that are required to meet the RET.

Table 7: Cost breakdown – Reduced RET ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	26,927	26,933	26,939	74,053	74,058	74,071
Fixed Generation	27,666	27,719	27,720	73,978	74,163	74,162
Transmission	904	795	784	3,267	2,850	2,830
Total	**55,498**	**55,447**	**55,443**	**151,298**	**151,071**	**151,062**
Benefit relative to RIT-T		**50.9**	**54.9**		**226.8**	**235.9**

The Carbon pricing scenario is comparable to the Base case (or Scenario 2) in the TFR modelling. The breakdown of total costs for this scenario on a discounted and undiscounted basis are shown in Table 8, noting that these cost figures reflect all costs that are incurred up to 2040.

Table 8: Cost breakdown – Carbon pricing ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	58,738	59,230	59,205	192,551	195,466	195,264
Fixed Generation	43,085	42,767	42,797	146,976	144,910	145,118
Transmission	1,787	1,261	1,245	7,864	5,050	4,974
Total	**103,610**	**103,259**	**103,247**	**347,391**	**345,425**	**345,356**
Benefit relative to RIT-T		**350.7**	**362.5**		**1,965.7**	**2,035.0**

For comparison, Table 9 shows the cost breakdown for the Carbon pricing scenario for all costs incurred by 2030. Table 10 shows the cost breakdown from Scenario 2 of the TFR modelling which is over a similar period; the modelling has two additional years at the start of the modelling and also ends at 2030. The benefits of OFA between these two scenarios are relatively similar. These results also illustrate that a large proportion of the full benefit of OFA in this scenario (provided above) occurs during the 2030 to 2040 period. The total variable generation cost is significantly higher in the TFR modelling. This is driven by higher demand growth and because carbon pricing was in effect from the commencement of the study whereas in this modelling, carbon pricing is introduced in 2021.

Table 9: Cost breakdown – Carbon pricing to 2030 ($m - discounted)			
Cost	RIT-T	OFA	Co-optimised
Variable Generation	43,150	43,210	43,208
Fixed Generation	29,032	29,040	29,045
Transmission	869	738	732
Total	**73,050**	**72,988**	**72,985**
Benefit relative to RIT-T		**62.2**	**65.9**

Table 10: Cost breakdown – TFR Scenario 2 ($m - discounted)			
Cost	RIT-T	OFA	Co-optimised
Variable Generation	82,469	82,523	82,503
Fixed Generation	36,227	36,203	36,199
Transmission	278	163	146
Total	**118,974**	**118,889**	**118,848**
Benefit relative to RIT-T		**85.0**	**126.0**

The effect of a higher penetration of rooftop PV generation is provided in Table 11. This scenario shows a marginally higher benefit for OFA than the Base case.

Table 11: Cost breakdown – High DG ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	24,731	24,753	24,753	65,588	65,634	65,634
Fixed Generation	34,078	34,068	34,068	94,530	94,466	94,465
Transmission	1,134	990	988	3,946	3,517	3,515
Total	**59,943**	**59,812**	**59,810**	**164,064**	**163,617**	**163,614**
Benefit relative to RIT-T		**131.0**	**132.7**		**447.7**	**450.2**

The Electric Vehicle scenario incorporates higher demand growth driven by moderate penetration of EVs and also a moderate carbon price. The total cost breakdown for this scenario is presented in Table 12. This scenario results in a lower discounted benefit of OFA than the Base case. This result shows that the benefits of OFA are not necessarily directly proportional to the level of demand growth. The drivers of this outcome will be described in detail in Section 6.5.

Table 12: Cost breakdown – Electric Vehicles ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	54,684	54,728	54,729	196,415	196,760	196,787
Fixed Generation	35,961	35,998	36,008	104,636	104,611	104,645
Transmission	940	781	768	3,755	3,076	3,009
Total	**91,585**	**91,507**	**91,505**	**304,807**	**304,446**	**304,441**
Benefit relative to RIT-T		**77.7**	**79.3**		**360.8**	**365.9**

The results of the High growth scenario are provided in Table 13. The relatively large benefit of OFA over RIT-T planning here is a consequence of the generation development required to meet load growth expectations in the scenario.

Table 13: Cost breakdown – High growth ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	34,404	34,589	34,586	109,445	110,709	110,701
Fixed Generation	38,530	38,505	38,507	116,606	116,029	116,027
Transmission	1,495	1,085	1,083	6,518	4,465	4,464
Total	**74,429**	**74,179**	**74,176**	**232,570**	**231,202**	**231,193**
Benefit relative to RIT-T		**250.3**	**252.9**		**1,367.1**	**1,376.7**

The Portland retirement provides a relatively marginal additional benefit in comparison with the Base case. The effect of the Portland retirement on the impact of the alternative planning methodologies on generation and transmission development is relatively low. The cost outcomes are provided in Table 14.

Table 14: Cost breakdown – Portland retirement ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	25,083	25,090	25,090	67,566	67,597	67,597
Fixed Generation	34,056	34,140	34,140	94,560	94,875	94,876
Transmission	1,225	1,028	1,027	4,507	3,732	3,730
Total	**60,363**	**60,259**	**60,257**	**166,633**	**166,205**	**166,203**
Benefit relative to RIT-T		**104.6**	**106.1**		**427.5**	**429.2**

The Boyne Island retirement scenario incorporates other modifications to assumptions beyond the retirement of the smelter. This process is detailed in Section 6.8. The cost outcomes provided in Table 15 demonstrate that there is some additional benefit to OFA and co-optimised planning in response to the smelter retirement. There are material differences between generation and transmission development in Queensland under the alternative planning methodologies.

Table 15: Cost breakdown – Boyne Island retirement ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	26,797	26,900	26,876	75,099	75,647	75,551
Fixed Generation	34,733	34,694	34,724	97,359	97,034	97,012
Transmission	1,187	1,012	989	4,667	4,035	3,924
Total	**62,717**	**62,606**	**62,589**	**177,125**	**176,716**	**176,487**
Benefit relative to RIT-T		**110.8**	**127.5**		**409.7**	**637.9**

The Emissions reduction target scenario provides the highest benefit for OFA. The RIT-T planning methodology results in additional transmission investment of over $650m in comparison to both OFA and co-optimised planning. The cost breakdown is provided in Table 16. Note that the total scenario cost is lower than for the Carbon scenario, because the emissions trajectory is applied as an internal constraint rather than an external carbon price, such that carbon costs are not explicitly applied.

Table 16: Cost breakdown – Emissions reduction target ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	34,158	34,147	34,130	99,025	98,794	98,739
Fixed Generation	52,561	52,542	52,574	181,381	181,556	181,681
Transmission	2,319	1,680	1,652	10,090	7,004	6,871
Total	**89,039**	**88,369**	**88,355**	**290,497**	**287,354**	**287,291**
Benefit relative to RIT-T		**669.8**	**683.4**		**3,142.9**	**3,205.7**

The results of the Transmission degradation scenario provided in Table 17 illustrate the potential for OFA to incentivise efficient transmission replacement decisions by imposing the cost of maintaining these assets on generators. These benefits are substantial and are reflective of the assumptions we have applied in this scenario. It should be noted that the vast majority of this benefit could possibly be achieved without OFA in the modelling by applying a RIT-T to all transmission asset replacement rather than enforcing asset replacement. It can be seen in the table below that the investment in transmission asset replacement is far lower under the OFA and co-optimised planning methodologies.

We have run a number of sensitivities on the assumed cost of replacement relative to full augmentation. Generally, we have found that the relationship between the OFA benefit and the cost of transmission replacement is almost linear. For example, if the cost of replacement is increased to be 50% of the cost of transmission augmentation (double the cost applied in the results below), the benefit of OFA increases by approximately 93%.

Table 17: Cost breakdown – Transmission degradation ($m)						
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	25,795	25,833	25,806	70,097	70,186	70,125
Fixed Generation	34,125	34,184	34,239	94,708	95,019	95,182
Transmission Augmentation	1,201	1,044	1,004	4,370	3,734	3,591
Transmission Replacement	815	211	190	3,105	933	853
Total	**61,935**	**61,272**	**61,239**	**172,280**	**169,872**	**169,751**
Benefit relative to RIT-T		**662.7**	**695.8**		**2,407.5**	**2,528.2**

The outcomes provided in Table 18 show that the Forecasting error scenario results in a benefit of OFA that is far greater than in the Base case. In particular, the discounted difference in total transmission investment under RIT-T compared to the other planning scenarios is almost 150% higher in this scenario relative to the Base case. Although the discounted benefits are comparable in magnitude to the High growth scenario, they are driven by different effects, as detailed in Section 6.11.

This scenario also has the unusual feature that the benefit under Co-optimised planning is lower than under OFA. In all other scenarios, OFA is a mathematically “stricter” planning approach than Co-optimised, which leads to close to, but more expensive than, the least-cost outcome. A key assumption to the LTIRP model is that all agents have perfect foresight of future conditions. In this scenario, however, each simulation contains an incorrect assumption about future demand. Therefore, it is possible that an “imperfect” approach (i.e., OFA) in one simulation could in fact produce an outcome that is slightly more efficient overall when the actual (Base case) demand is applied (e.g., if less capacity or transmission is installed in one year under OFA than Co-optimised, due to firm access requirements, this would be preferred when the expected demand growth is lower).

Table 18: Cost breakdown – Forecasting error ($m)

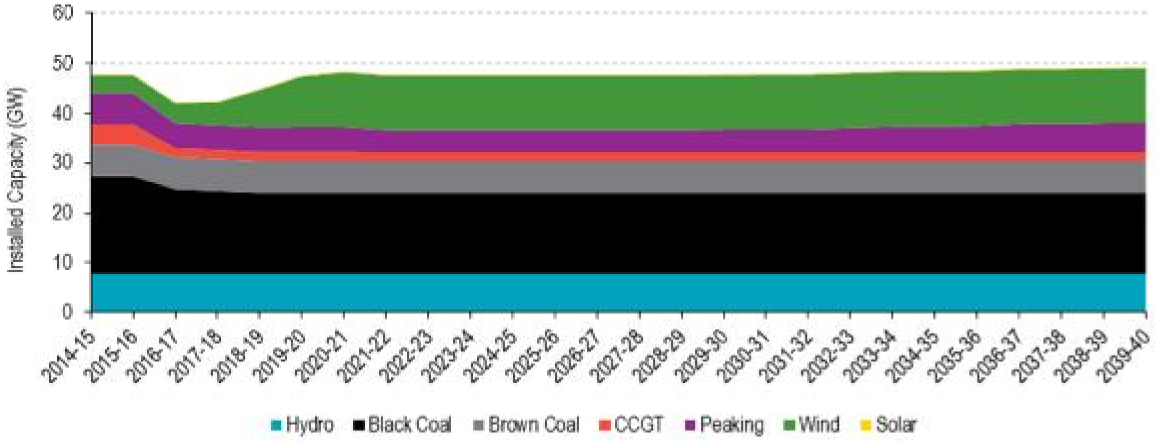
Cost	Discounted			Undiscounted		
	RIT-T	OFA	Co-optimised	RIT-T	OFA	Co-optimised
Variable Generation	25,628	25,620	25,617	69,264	69,186	69,179
Fixed Generation	35,429	35,632	35,647	101,216	102,185	102,240
Transmission	1,684	1,252	1,250	6,006	4,324	4,322
Total	**62,741**	**62,504**	**62,515**	**176,485**	**175,695**	**175,741**
Benefit relative to RIT-T		**237.4**	**226.5**		**790.2**	**744.0**

6. Scenario results – Generation and transmission development

6.1 Base case

The impact of OFA in the Base case reduces the cost of meeting demand by $86.6m (on a discounted basis). This benefit is relatively low, particularly given the extended modelling timeframe. Figure 12 shows the NEM-wide development in generation capacity. It is evident that with the exception of early generation retirements and renewable generation development to meet the RET, there is very little activity in this scenario. This scenario, with no imperative for emissions reduction and muted demand growth, provides relatively little incentive for any capacity development. Without significant development in new generation capacity, there is little scope for OFA to drive more efficient investment decisions and therefore, to increase market efficiency.

Figure 12: Base case – Generation development



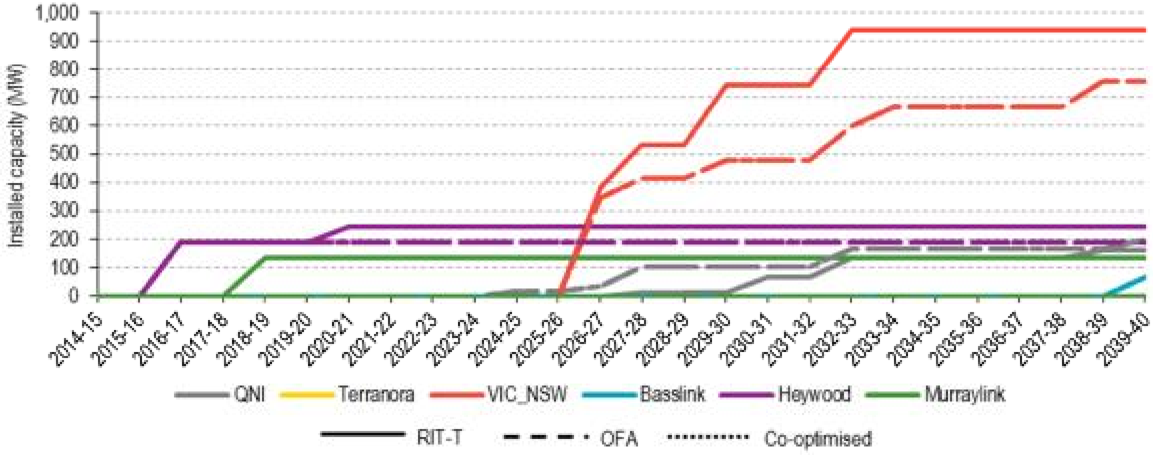
Despite the muted development generally, there are material differences between the location of generation investments and on transmission augmentation between the RIT-T planning methodology and the OFA and co-optimised methodologies. It is important to recognise that the LTIRP is a complex, interconnected model where decisions are not made independently. Therefore, investment decisions that are made as a result of OFA can impact on the development of generation and transmission across all regions of the NEM. Figure 13 illustrates the differences between the generation developments across each region between the three planning methodologies. The remainder of this section will focus on these differences and how they drive differing transmission augmentation projections.

Figure 13: Base case – Regional generation development

The regional differences in generation investment shown above also result in differing projections of interconnector augmentation. The RIT-T scenario results in higher levels of interconnector augmentation in this scenario. This is shown in Figure 14, noting that the OFA and co-optimised lines overlap, as interconnector development was the same in both scenarios in this case.

In the majority of scenarios there is a higher level of interconnector development under RIT-T planning. This is not the result of an inherent characteristic of OFA or co-optimised planning in comparison with RIT-T planning. Rather, differences in interconnector development are a secondary impact of the impact of OFA on locational generation investments.

Figure 14: Base case – Interconnector development



6.1.1 New South Wales

Figure 15 shows the development of new capacity and generation retirements between zones in the New South Wales region. It is evident that there are large retirements of coal capacity in the Hunter region. These retirements drive investment in both capacity and transmission in the later years of the study.

These results show a difference in the level of wind generation installed in the CAN zone – the RIT-T planning installs approximately 600 MW less wind capacity. This difference is driven by the trade-off between installing wind in the NSA zone and the CAN zone. Both of these zones have high quality wind resources. The CAN zone has a slightly lower expected capacity factor in this modelling. However, when the augmentation costs required to provide sufficient access for the NSA are considered, CAN wind is preferred. This is seen in the reduced need for transmission augmentation between NSA and ADE when applying the OFA and co-optimised planning methodologies (see Figure 24).

There are also minor differences in the location of new entrant peaking capacity within New South Wales. Under the co-optimised and OFA methodologies, new entrant peaking generation located in the Hunter region, where access is abundant given the retirement of coal in that zone. Under RIT-T planning, the LTIRP favours the Southern and Central zones.

The existing capacity surplus is not eroded until relatively late in the study. This allows the LTIRP to favour retirement of generation in the early years to save up to 20 years of maintenance expenditure before that capacity would have been required. When further supply is required, the LTIRP builds new gas capacity and augments transmission flowpaths between New South Wales and Victoria. The timing of new generation is shown in Figure 16.

Figure 15: Base case – New South Wales generation development

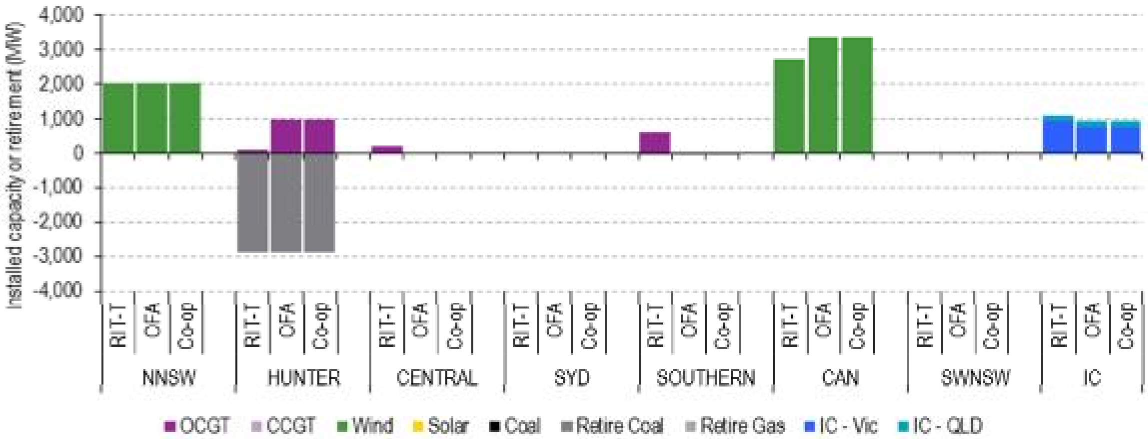
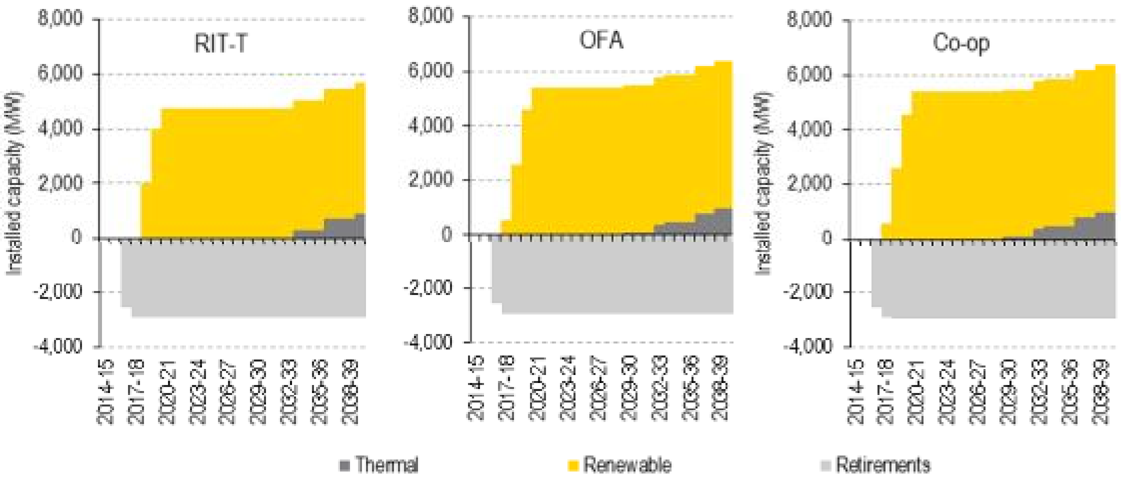


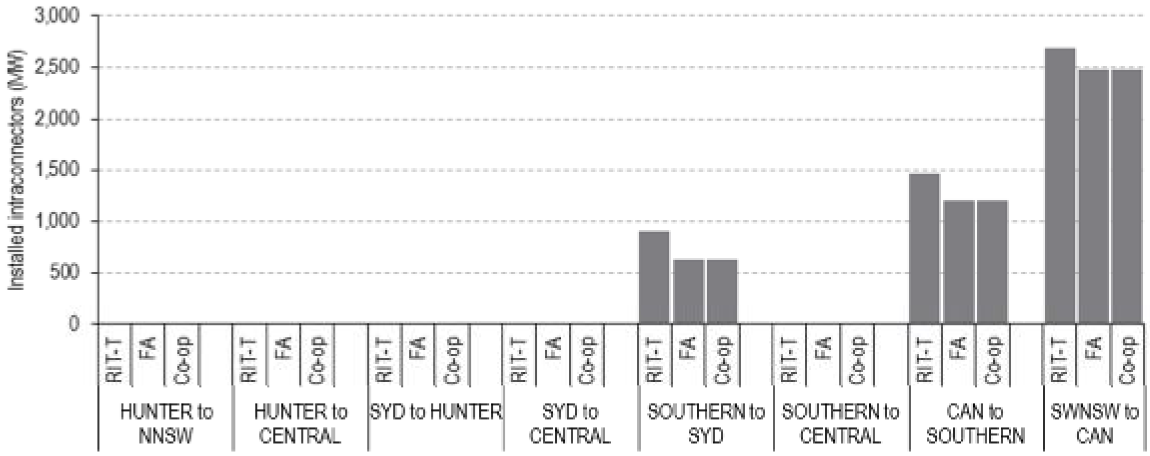
Figure 16: Base case – Timing of New South Wales generation development



Despite the lower installation of wind generation in CAN, the RIT-T planning methodology builds additional transmission capacity across each of the flowpaths from the Victorian border to Sydney (see Figure 17). This is driven by a combination of factors including:

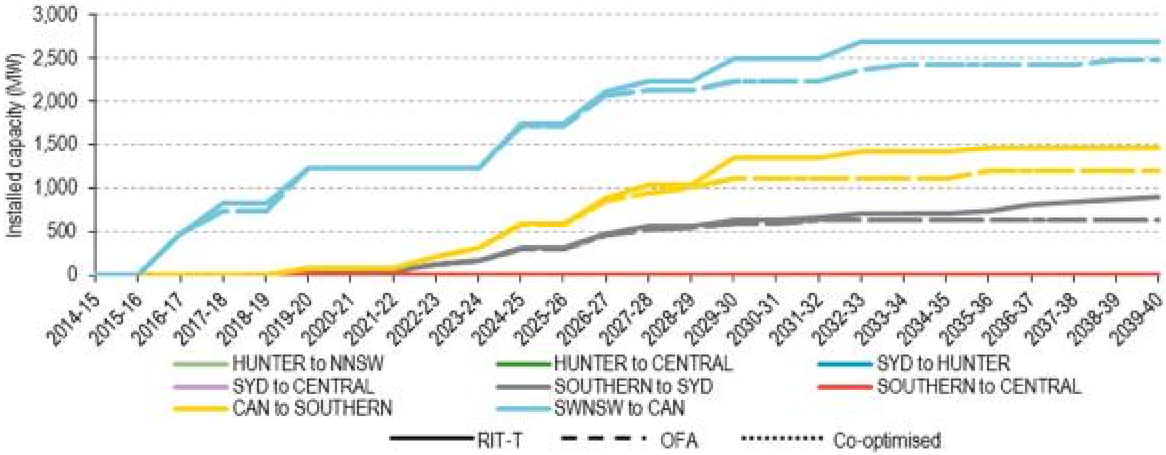
- ► Supporting the additional augmentation of the VIC-NSW interconnector
- ► Building additional peaking capacity in the SOUTHERN zone
- ► The additional wind generation located in South Australia increases the benefits of additional transfer capacity into New South Wales

Figure 17: Base case – New South Wales transmission development



The transmission augmentations in New South Wales occur throughout the study, with the SWNSW to CAN augmentations commencing in 2016. This early transmission augmentation is driven by a high level of retirements in the early years of the study and is also predicated on the long-term certainty provided by the LTIRP in relation to the relative cost of generation between Victoria and New South Wales. The timing of the transmission augmentations are provided in Figure 18.

Figure 18: Base case – Timing of New South Wales transmission development

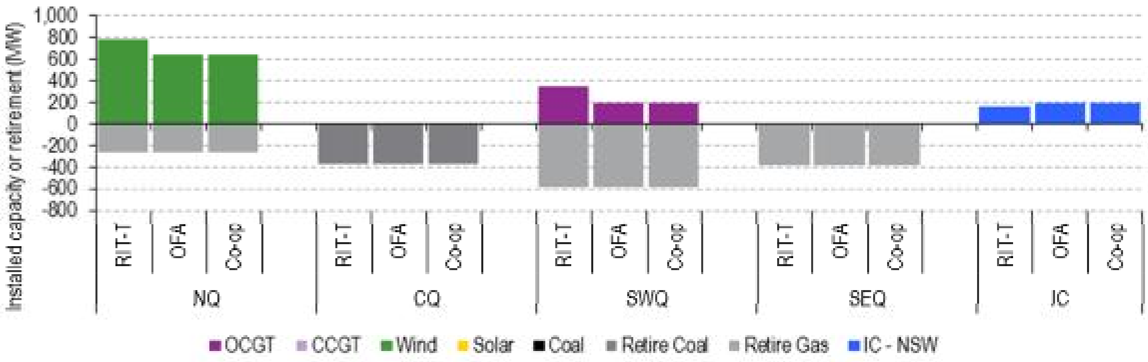


6.1.2 Queensland

Figure 19 shows the development of generation capacity in Queensland over the entire modelling period. It is evident that there is limited need for new generation capacity in Queensland in this scenario, even given the moderate level of retirement. After the initial increase in demand, attributable to the commencement of LNG export, the growth in demand in not of a magnitude that drives a need for large volumes of additional capacity. There is no need for inter-zonal transmission augmentation in Queensland.

There are relatively small differences in installed capacity, such as the additional wind located in NQ and additional OCGT capacity in SWQ under RIT-T planning. These are secondary impacts of the planning methodology, with the differences not being driven by consideration of Queensland transmission issues. Rather, these results are linked with the impact of OFA on the tendency for wind to locate in South Australia or New South Wales. The reduction in installed capacity in the OFA and co-optimised scenarios is partly offset by the marginally higher level of regional import available through QNI augmentation.

Figure 19: Base case – Queensland generation development



6.1.3 Victoria

Figure 20 shows that there is almost no new capacity installed in Victoria in this scenario. There is a relatively large amount of retirement, but all of this retirement is in gas capacity.

Despite the lack of activity in Victoria itself, the surplus of very low cost generation in Victoria (due to the lack of carbon pricing) and Tasmania (during high rainfall years) mean that there are potential benefits in increasing the ability to export energy from Victoria. This drives the transmission augmentations between Melbourne and Sydney across all planning methodologies, including increasing the capacity of the intraconnector between MEL and NVIC. The transmission augmentations required in Victoria are presented in Figure 21.

Figure 20: Base case – Victoria generation development

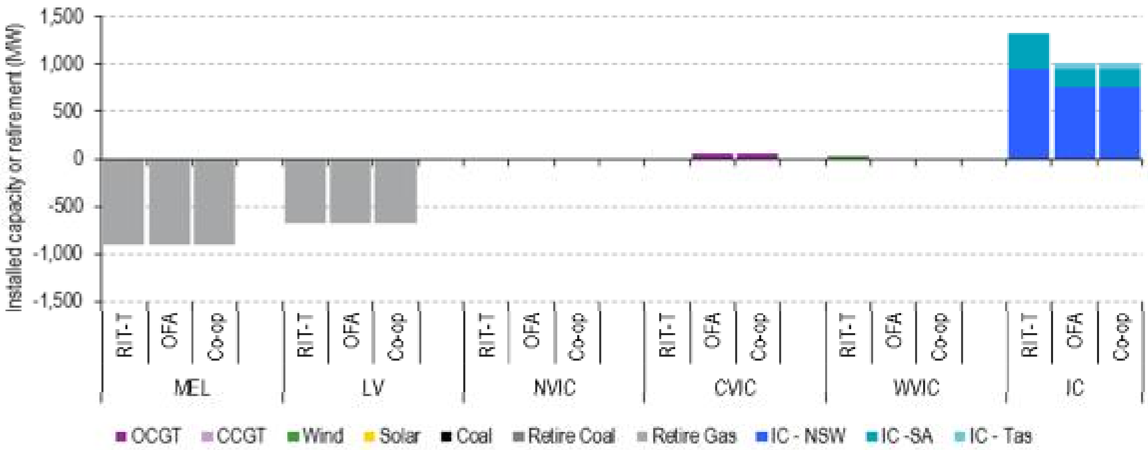
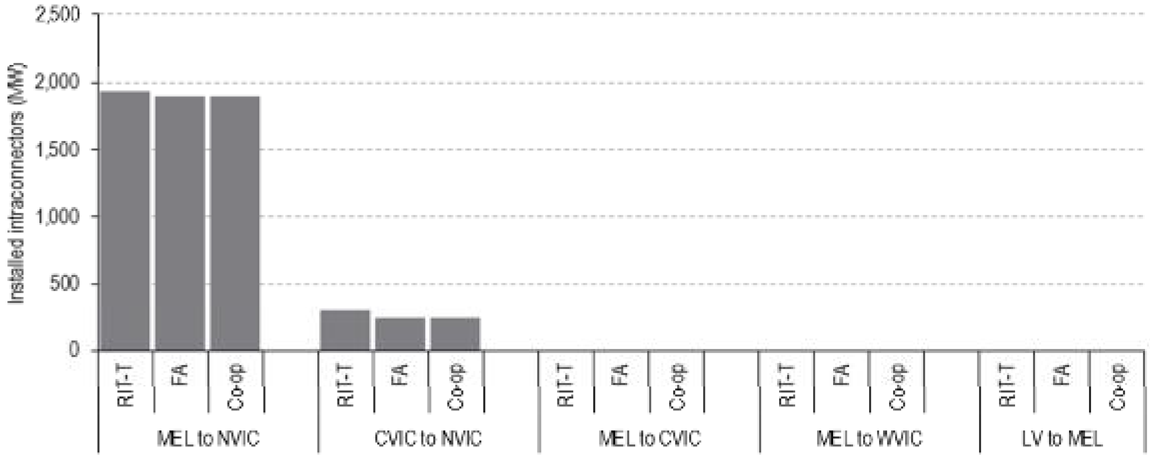


Figure 21: Base case – Victoria transmission development



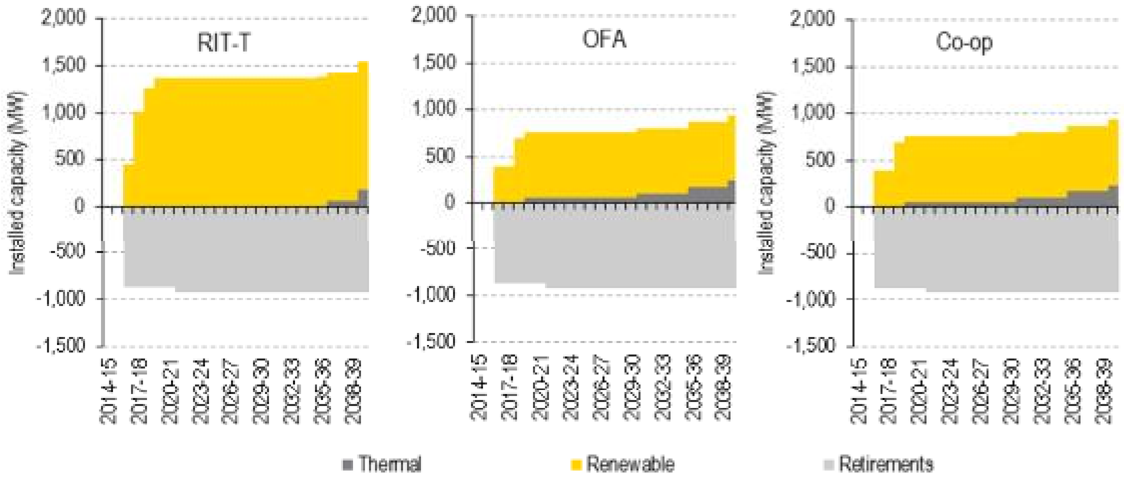
6.1.4 South Australia

As noted above, the RIT-T planning approach resulted in an increase in the installation of wind generation in the NSA zone (see Figure 22). The higher level of wind penetration in South Australia allows for additional interconnector augmentation between South Australia and Victoria.

The activity in South Australia is dominated by the installation of wind generation in NSA. However, approximately 900 MW of excess peaking capacity is retired in the early years of the study. A small amount of peaking capacity is added later in the study (see Figure 23). Under OFA and co-optimised planning, this capacity is located in NSA whereas under the RIT-T methodology, this capacity is located in SESA.

Figure 22: Base case – South Australia generation development

Figure 23: Base case – Timing of South Australia generation development



The impact of the higher level of wind generation on transmission augmentation is shown in Figure 24 where the RIT-T drives substantially higher levels of transmission investment between NSA and ADE. The timing of the ADE to NSA augmentations shown in Figure 25 closely match the addition of NSA wind (see Figure 23). Furthermore, the decision to locate peaking capacity in SESA under RIT-T planning results in a need for augmentation between SESA and ADE.

Figure 24: Base case – South Australia transmission development

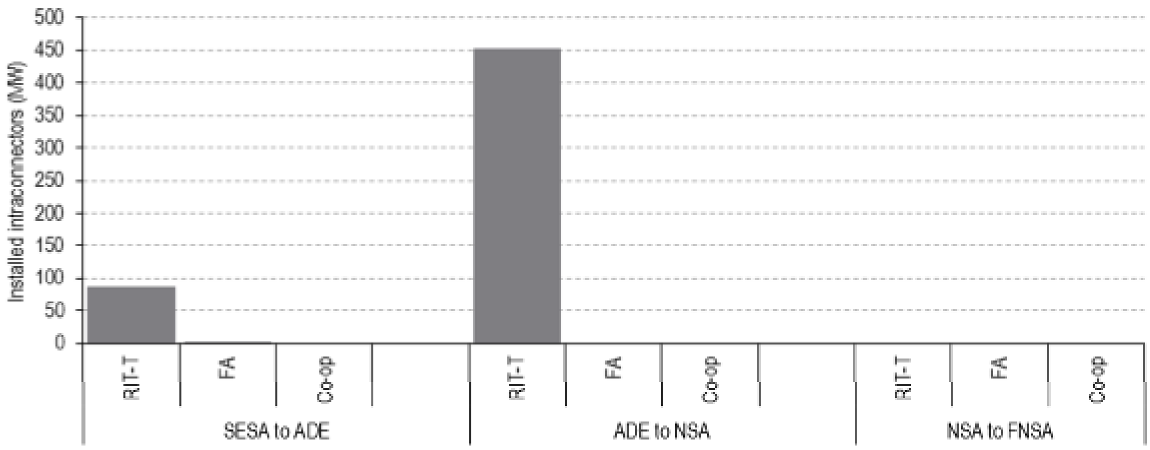
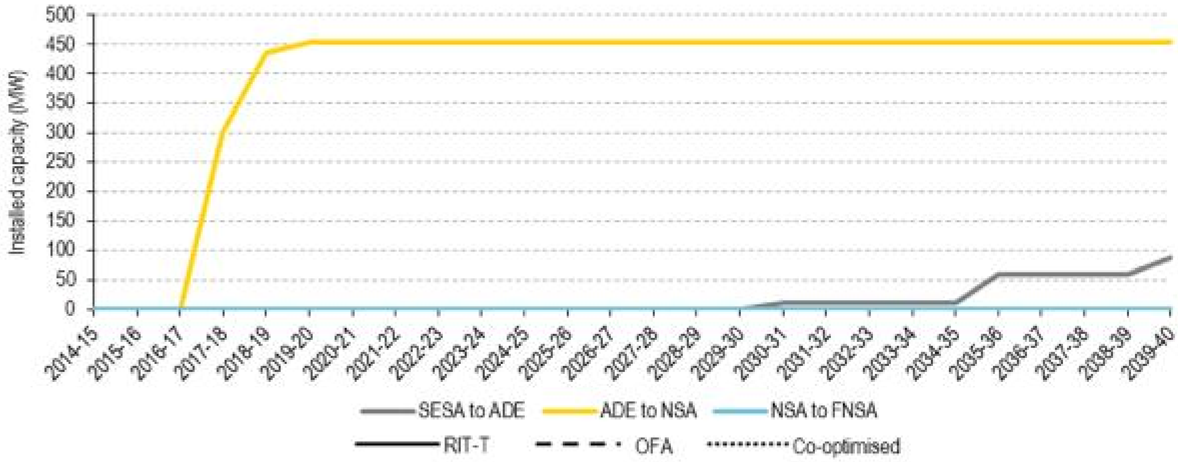


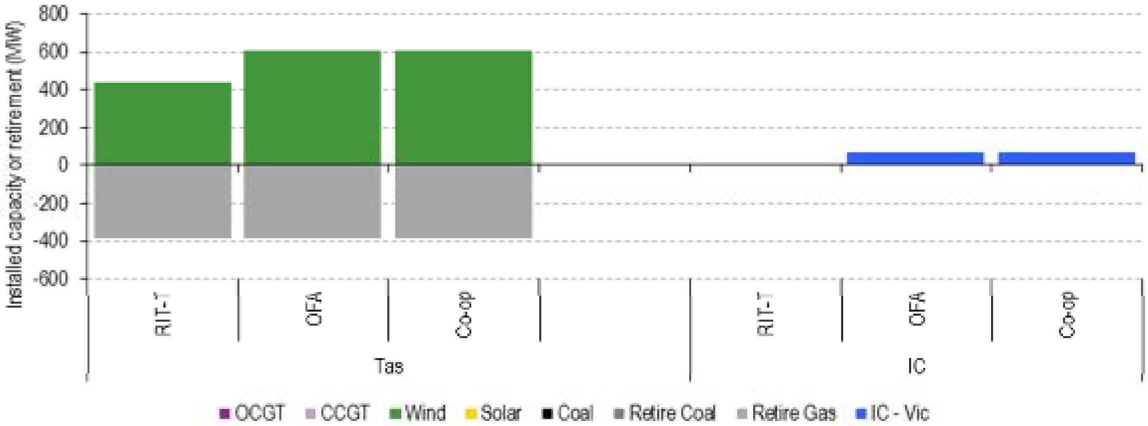
Figure 25: Base case – Timing of South Australia transmission development



6.1.5 Tasmania

Figure 26 shows the generation outcomes for Tasmania. The difference between the planning scenarios is a result of second order effects that drive the regional outcomes described above. Despite the high resource quality, wind development in Tasmania is limited by the need to further augment Basslink, particularly given variable annual hydrological inflows.

Figure 26: Base case – Tasmania generation development



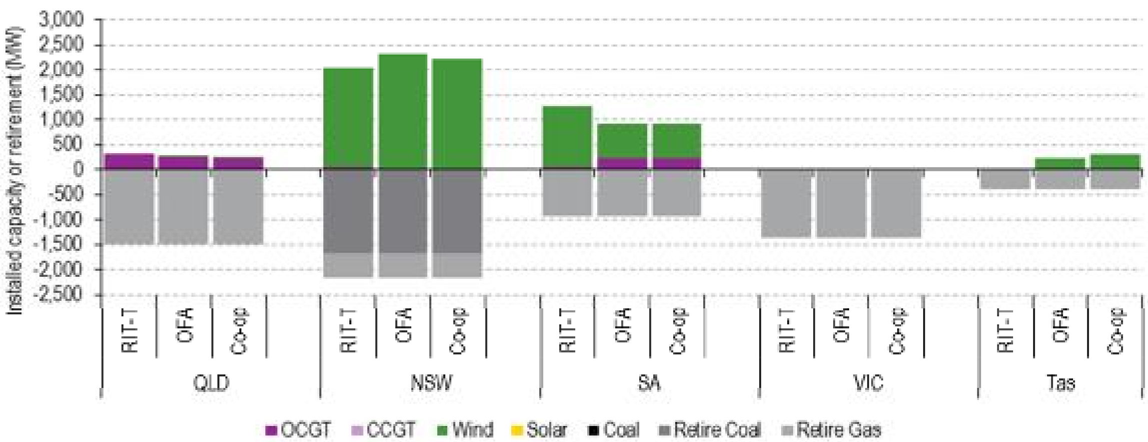
6.1.6 Summary

The impact of OFA on total system cost is relatively small (approximately 0.14% of the total discounted cost). However, figures provided above show that OFA has impacted the location of thousands of MW's of generation and transmission investment. This demonstrates a key outcome of this OFA analysis that was also described in detail in the TFR modelling. However, the decisions being made between locations in the LTIRP are relatively marginal. This means that even when OFA influences a substantial change in market development, the resulting economic impact may be relatively minor in comparison.

6.2 Reduced RET

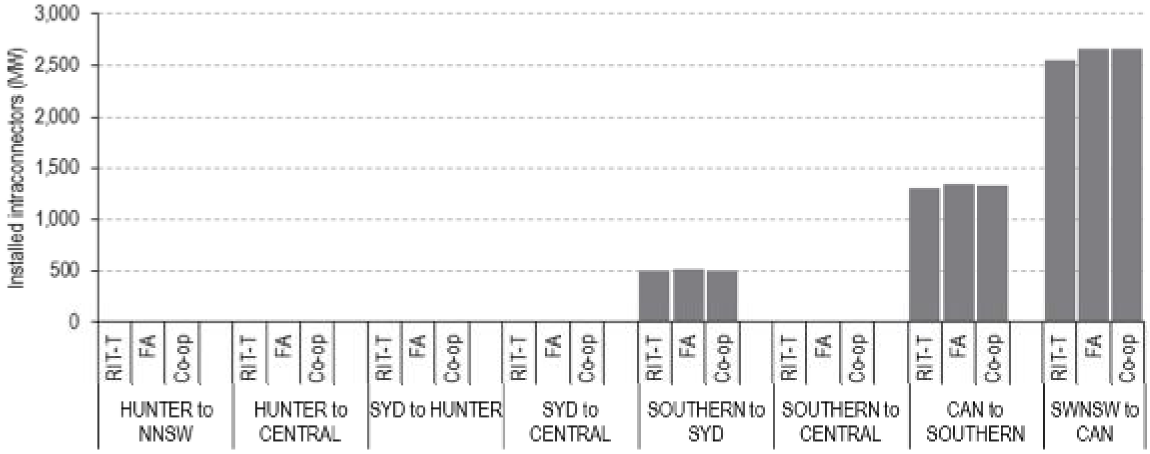
The differences between the Base case and the Reduced RET scenario are relatively minor. In particular, the clearest impact of OFA in the Base case – reallocating wind capacity to CAN over NSA – is still evident in the Reduced RET scenario. This is shown in Figure 27 that presents the generation development between regions in this scenario. The magnitude of this difference is reduced due to the reduction in total renewable investment. This reduction is the primary contributor to the benefit of OFA decreasing from $86.6m to $50.9m.

Figure 27: Reduced RET – Regional generation development



In the Reduced RET scenario, the difference between the quantity of wind installed in South Australia relative to the rest of the NEM is comparable to the Base case. However, the differences in New South Wales transmission investment between the planning methodologies are very different to those that were described in the Base case. Whereas the higher levels of wind generation in SA drove increased augmentation in southern New South Wales in the Base case, Figure 28 illustrates that the difference in augmentations along this flowpath is minimal in the Reduced RET scenario.

Figure 28: Reduced RET – New South Wales transmission development



Generally, the benefits of OFA scale with the level of the RET when compared to the Base case. This is not true of other scenarios where either demand growth, carbon pricing or some other factor drives investment activity in the wholesale market.

6.3 Carbon pricing

The return to the Treasury Core carbon price trajectory results in a scenario with higher levels of coal and gas retirement and an increasing penetration of renewable generation technologies, including large-scale solar PV. The development of the NEM in this scenario is shown in Figure 29. This figure demonstrates that there is continued activity after in the market after 2030 – beyond the timeframe of the TFR modelling. Expanding the modelling timeframe to include the post-2030 period is the primary contributing factor in the increased benefits of OFA in this scenario in comparison to the TFR Scenario 2 result.

Figure 29: Carbon pricing – Generation development

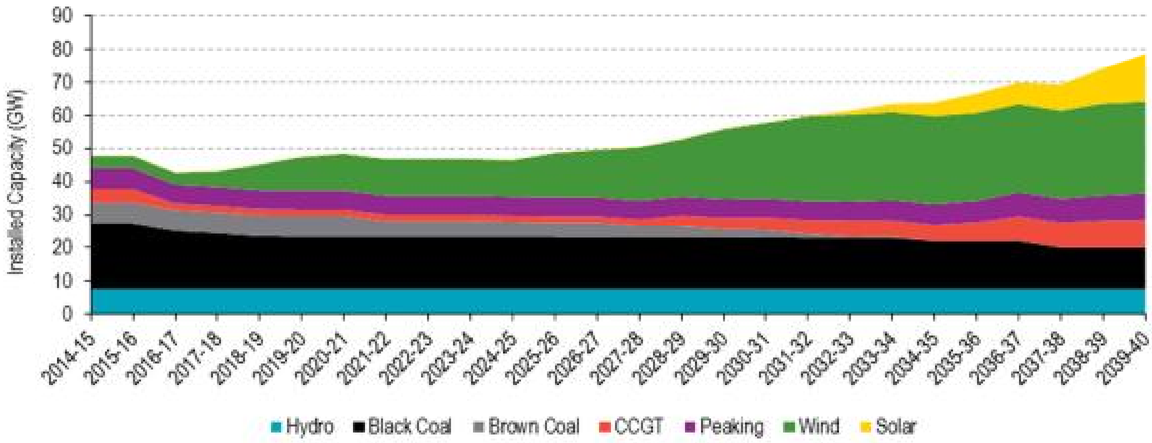


Figure 30 shows the regional generation development for each of the planning methodologies. Compared to the Base case, there are relatively minor differences between the capacities installed within each region. The benefits of OFA in the Carbon pricing scenario are instead driven more heavily by the impact of planning methodology on investment decisions within each region.

Figure 30: Carbon pricing – Regional generation development

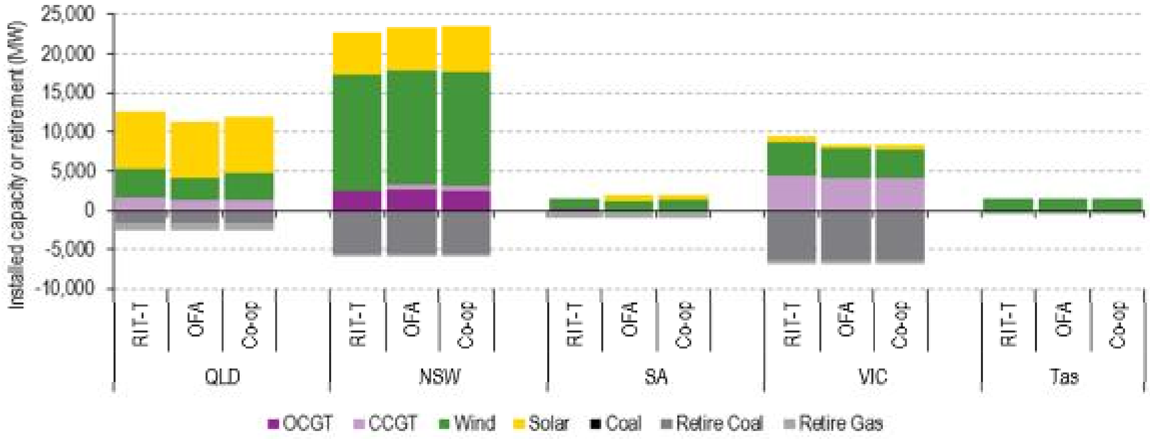
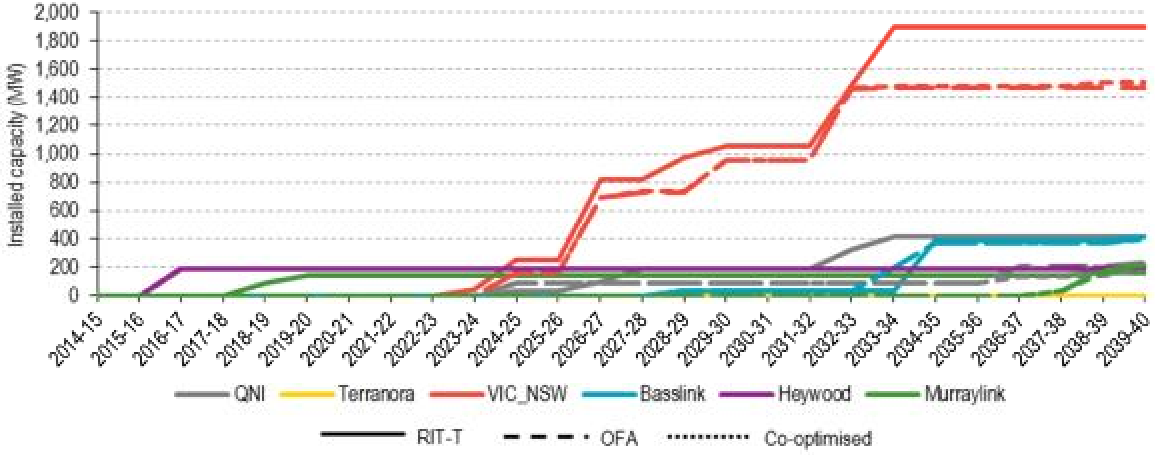


Figure 31 shows the interconnector augmentation in the Carbon pricing scenario.

Figure 31: Carbon pricing – Interconnector development



6.3.1 New South Wales

New South Wales exhibits the most activity of any region in this scenario. In particular, there is approximately 20 GW of new entrant renewable generation located in New South Wales. The zonal location of this generation development is shown in Figure 32.

The balance between the amount of wind built north and south of Sydney is a clear difference between the planning methodologies. Under RIT-T planning, almost 6 GW of additional renewable generation is built in NNSW. This requires large transmission augmentation between Hunter and NNSW – see Figure 33.

Despite the higher level of renewable generation built in zones south of Sydney (particularly SOUTHERN and CAN) under OFA and co-optimised planning, there is less transmission augmentation between the Victorian border and Sydney. This outcome results from the efficient placement of new entrant peaking generation (that requires a higher level of access than renewable generation) in the HUNTER zone, where generators retirements have freed up significant transmission access. The RIT-T method favours placing additional OCGT generation in the SOUTERN zone. This in conjunction with a higher level of VIC-NSW interconnector augmentation drives more investment in transmission along this southern flowpath.

Figure 32: Carbon pricing – New South Wales generation development

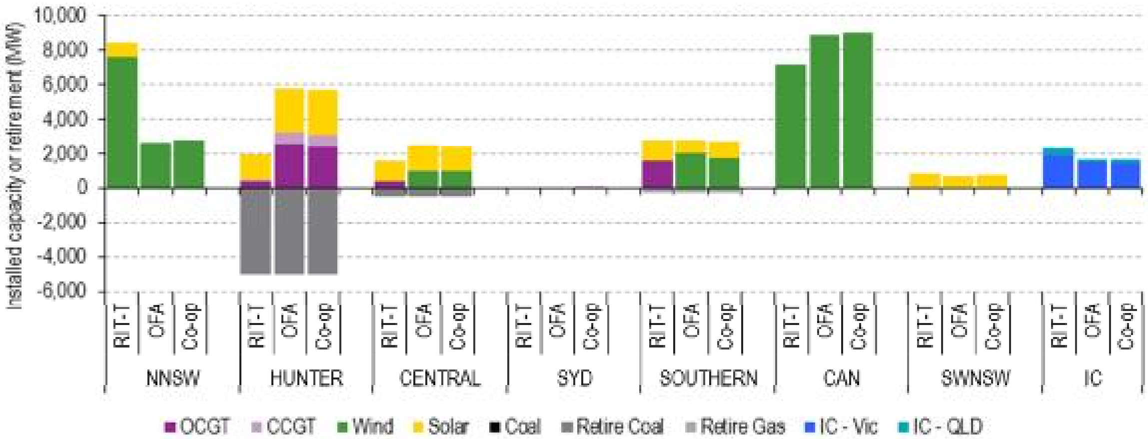
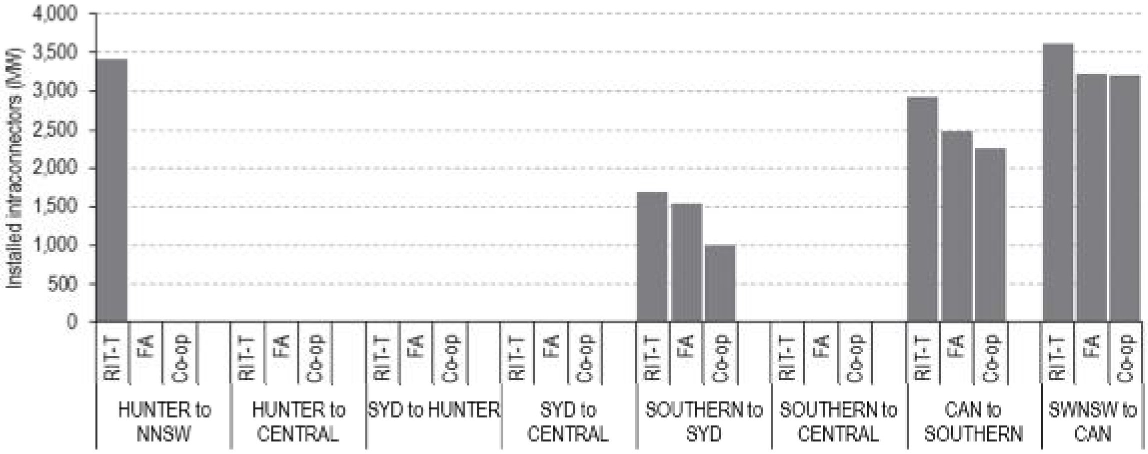


Figure 33: Carbon pricing – New South Wales transmission development



6.3.2 Queensland

Compared to the Base case, there is more investment activity in Queensland in this scenario. This is demonstrated in Figure 34. However, as with the Base case, the differences between capacities installed in each zone are generally not a direct result of OFA and rather a second-order effect of OFA's impact in other regions. The inability of OFA to drive significant differences in Queensland is due to the lack of need for transmission investment; transmission augmentation within Queensland is very low for all planning methodologies in this scenario (see Figure 35). In contrast, the TFR modelling did demonstrate that OFA could drive more efficient investment in Queensland. This result was driven by previous forecasts of high demand growth for the region. The updated demand projections do not forecast the same level of growth. A high proportion of the growth that is projected is located in SWQ, where local generation can be installed without the need for transmission augmentation.

The higher level of solar PV penetration in NQ does drive the need for a small NQ to CQ intraconnector upgrade. Under the OFA and co-optimised approaches, this augmentation is avoided by installing higher levels of solar PV in CQ instead.

Figure 34: Carbon pricing – Queensland generation development

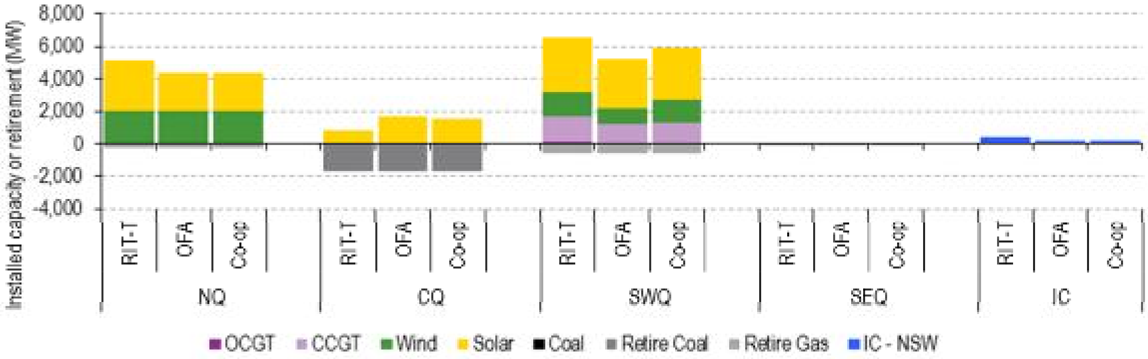
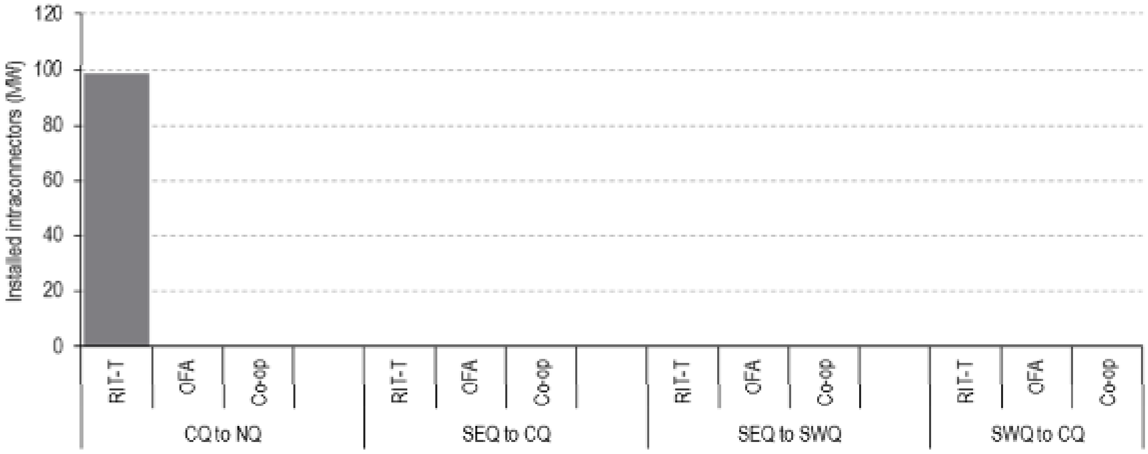


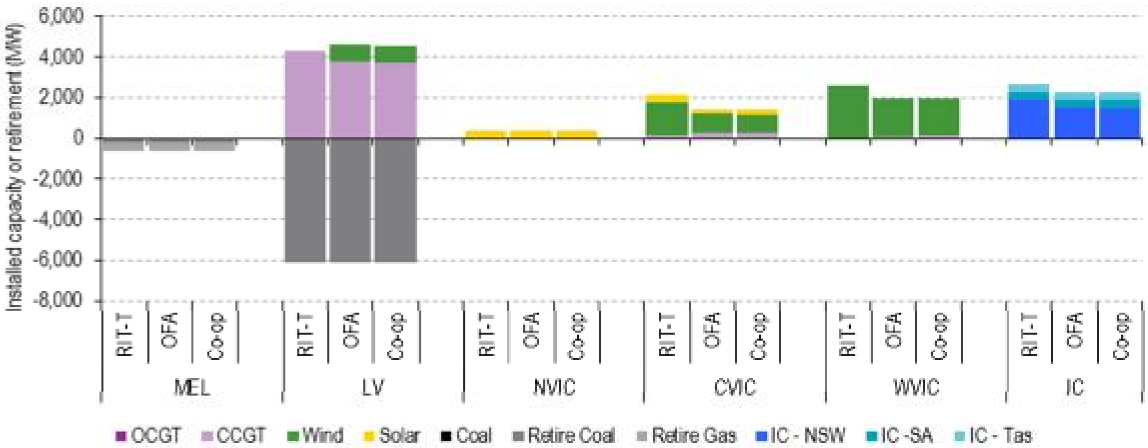
Figure 35: Carbon pricing – Queensland transmission development



6.3.3 Victoria

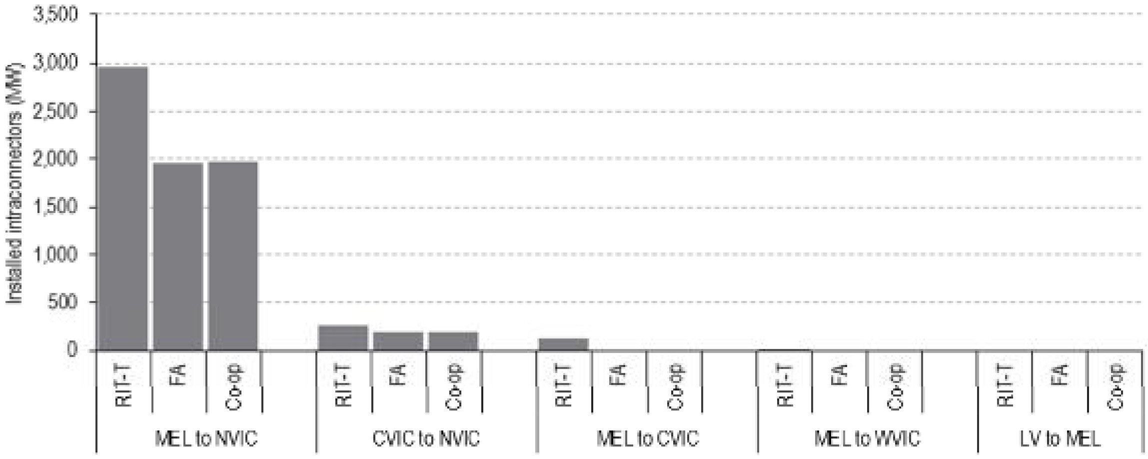
The impact of OFA on generation and transmission development in Victoria is again relatively mild. The increasing carbon price drives over 6 GW of coal retirement in the LV zone. However, this is replaced by new entrant gas generation in that zone across all planning methodologies, reducing any need for transmission augmentation that may have occurred had gas been incentivised to locate elsewhere. The generation outcomes are provided in Figure 36.

Figure 36: Carbon pricing – Victoria generation development



The differences in Victorian transmission augmentation illustrated in Figure 37 are primarily driven by the additional VIC-NSW augmentation under RIT-T planning. This difference in interconnector augmentation is driven by second-order impacts of each planning methodology.

Figure 37: Carbon pricing – Victoria transmission development



6.3.4 South Australia

The impact of OFA in South Australia is relatively unchanged from the effects described in the Base case. This is seen in Figure 38 and Figure 39, showing the increase in new entrant NSA wind and ADE to NSA augmentation under RIT-T planning.

Figure 38: Carbon pricing – South Australia generation development

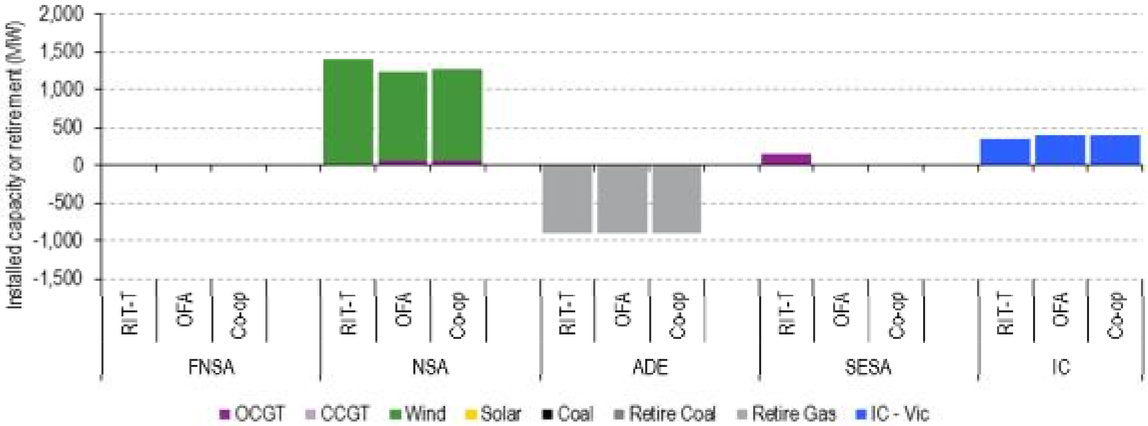
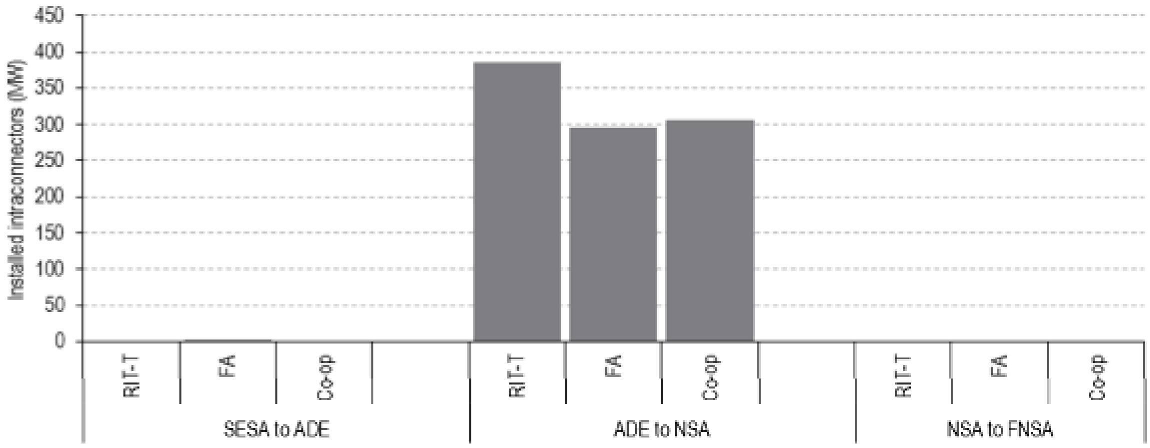


Figure 39: Carbon pricing – South Australia transmission development



6.3.5 Tasmania

There are no material differences in Tasmanian generation outcomes in this scenario.

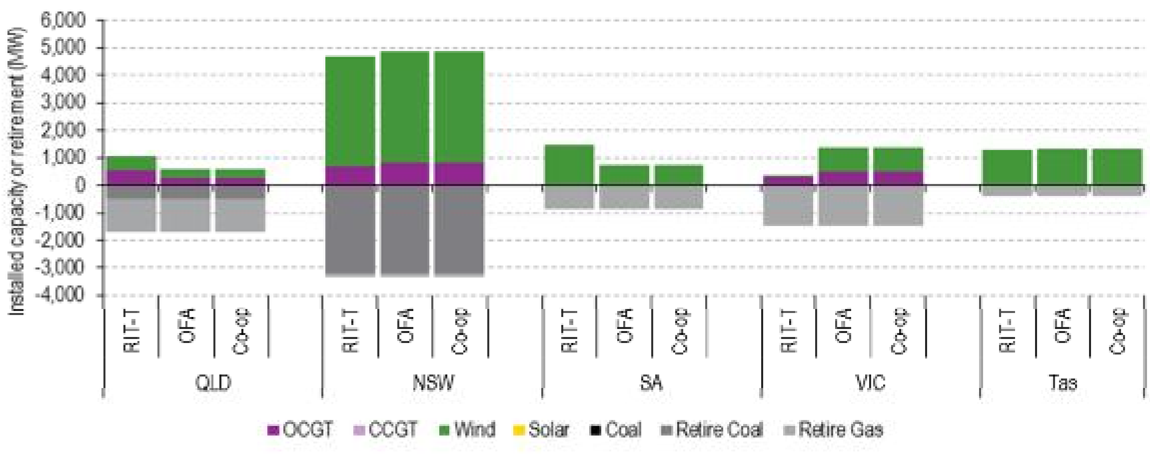
6.4 High DG

The higher penetration of rooftop PV results in a marginal increase in the benefit of OFA. However, the impacts on generation and transmission development are relatively subtle. Figure 40 shows the regional generation development for this scenario.

A key difference between this scenario and the Base case scenario is the additional wind generation that is built in Victoria under OFA and co-optimised planning. The increased penetration of DG and its associated impact on regional load shapes alters the relative value of the energy provided by wind generation between New South Wales and Victoria.

In the Base case, there was no difference in Victorian generation development between the planning standards. In the High DG case, the reduction in wind built in the NSA zone under OFA is compensated by additional wind development in both New South Wales and Victoria. This additional Victorian wind requires no additional transmission augmentations within Victoria and therefore reduces the need for transmission augmentation in New South Wales. The net effect of the High DG assumption results in a slightly higher economic benefit from the impact of OFA on generation development.

Figure 40: High DG – Regional generation development



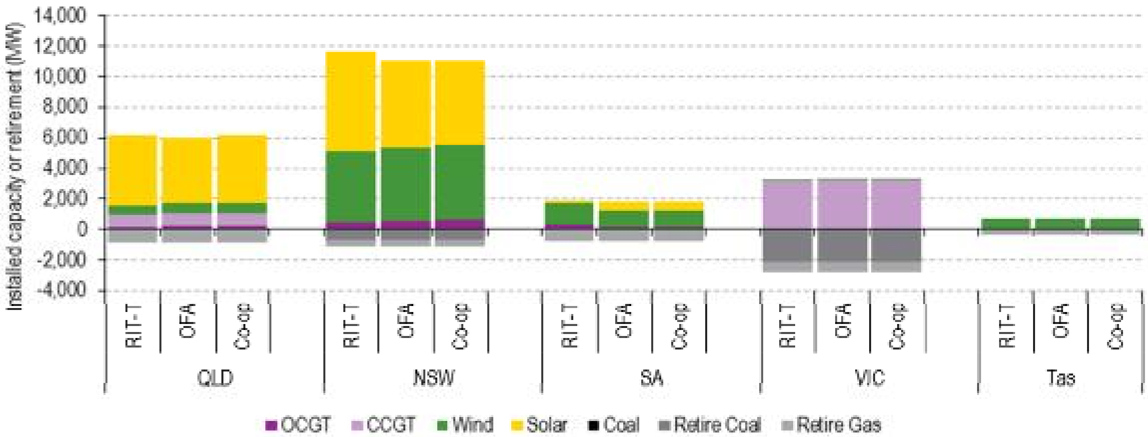
6.5 Electric Vehicles

The results provided in Section 5.3 indicate that the impact of OFA in the EV scenario is slightly lower than in the Base case. This is a surprising result, given that the EV scenario includes both carbon pricing and higher demand growth. However, it is important to recognise that the difference in the impact of OFA (approximately $8.9m discounted) is very low given the total cost is over $91b in the EV scenario. This section describes how the assumptions in the EV scenario do not drive additional OFA benefits.

Figure 41 shows the regional generation outcomes in this scenario. A key observation in this figure is that the volume of retirement in New South Wales and Queensland is far lower than that observed in the Base case. The return of moderate demand growth at an earlier stage in this scenario changes the incentives for generation retirement such that it is preferable to continue to operate generation until EV demand commences ramping up. This limits the need for significant thermal augmentation in these regions which, in the Base case, provided opportunities for OFA to increase market efficiency. Furthermore, the retirements of brown coal in LV are replaced by gas generation at the same location.

Additionally, the quantity of new entrant wind generation installed in this scenario is not higher than in the Base case. By the time the carbon price is sufficiently high to incentivise new entrant renewable generation, the cost of solar PV is lower than the cost of wind generation. The solar PV installed in the NEM tends to be more evenly spread than wind generation given the relatively lower variability in resource quality.

Figure 41: Electric Vehicles – Regional generation development

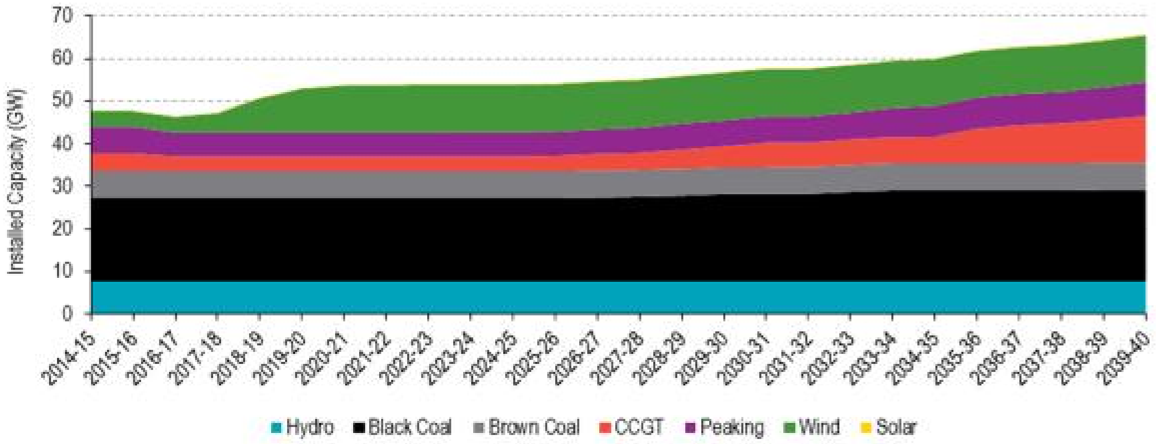


Therefore, both the moderate demand growth and the lower carbon price modelled in the EV scenario are not sufficient to drive significant transition in the generation sector within the modelling timeframe. As with the TFR modelling, what transition that is occurring does so towards the end of the study and is therefore heavily discounted and considers only a few annualised payments. The impacts of OFA in this scenario are similar to those in the Base case.

6.6 High growth

The High growth scenario delivers a projection that results in a benefit of OFA of almost three times that of the Base case. This scenario is characterised by high levels of thermal generation development across each region, including in coal-fired capacity. The development of the generation sector in this scenario is shown in Figure 42. This figure shows that the quantity of early retirement is reduced and that more wind, gas and coal generation is built in comparison with the Base case.

Figure 42: High growth – Generation development



As with the other scenarios, interconnector development is largely a "second order" effect of secondary outcome of the impact of planning methodology on generation locational decision. In this scenario, the total investment in interconnectors is comparable between the three planning methodologies, as shown in Figure 43.

Figure 43: High growth – Interconnector development

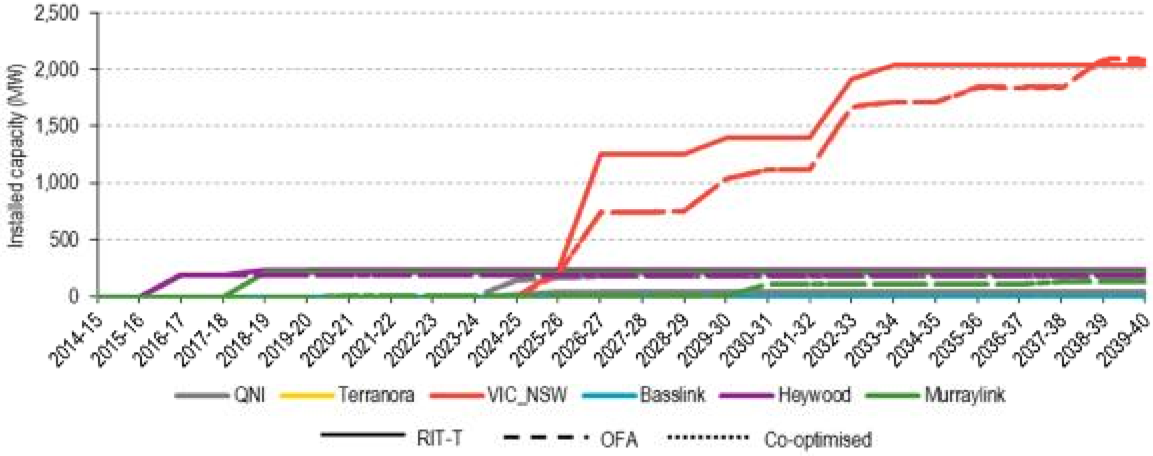
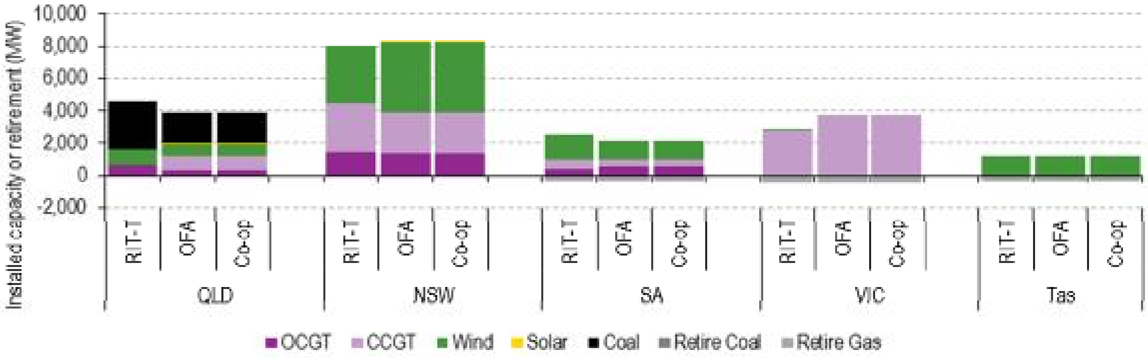


Figure 44 shows the regional generation development in this scenario. There are some differences between the total regional build between the planning methodologies, particularly in Queensland. However, the majority of OFA benefits are driven by decision making within each region.

Figure 44: High growth – Regional generation development



In comparison to the Base case, the High growth scenario has a relatively low level of retirement. Many of the retirements in the Base case are no longer cost effective given the projected growth in demand. If the high demand growth did not occur until later in the study, for example in 10 years, there would be two opposing effects on market development. Firstly, if that growth had not been projected during the first 10 years, there would likely be a higher level of retirements in that period, driving additional transformation of the system and potential benefits under OFA. However, given the later starting point, demand would not grow as significantly as in the modelled scenario. Therefore market development could be delayed and the impact of OFA may reduce.

6.6.1 New South Wales

The effects of OFA on generation development documented in the Base case are generally also true of this High growth scenario. In addition, OFA and co-optimised planning are shown (Figure 45) to also influence the location of approximately 4 GW of gas generation in New South Wales. Under the RIT-T, most of this capacity is located in CAN. However, this requires substantial investment in transmission on the CAN to SOUTHERN and SOUTHERN to SYD flowpaths (see Figure 46). Under OFA and co-optimised planning, it is preferable to incur the 10% capital cost premium to install at the reference node to avoid the need for this transmission augmentation.

Figure 45: High growth – New South Wales generation development

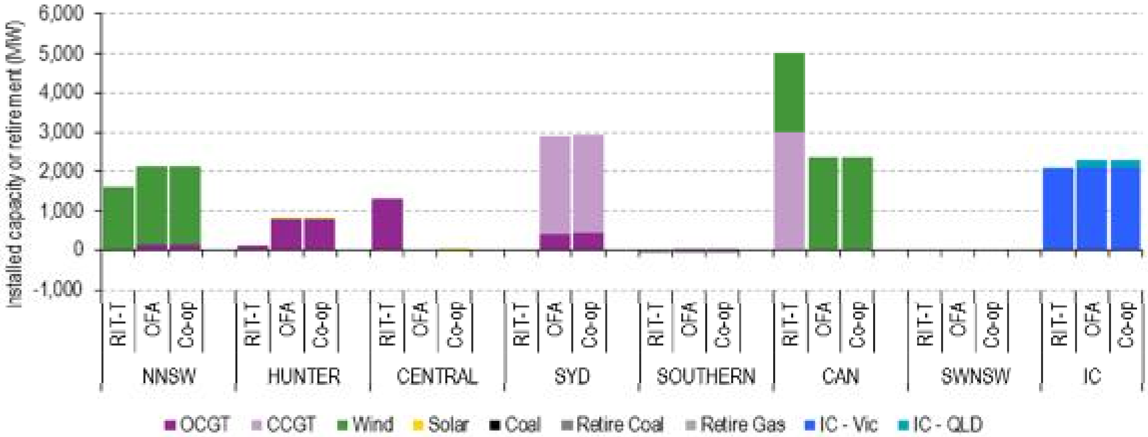
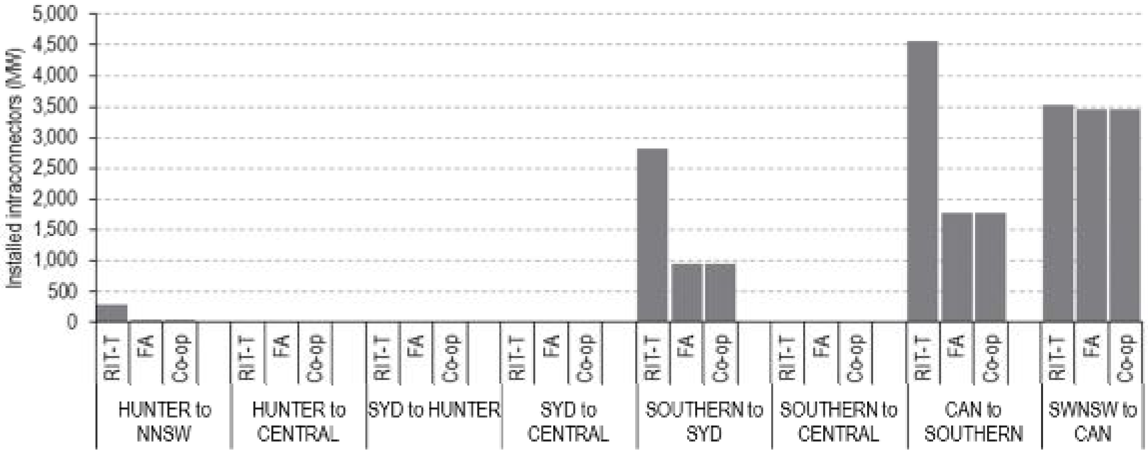


Figure 46: High growth – New South Wales transmission development



6.6.2 Queensland

Figure 47 shows the zonal generation development in Queensland. The quantity of coal installed in CQ under OFA or co-optimised planning is lower than in the RIT-T scenario. This reduction in coal capacity is compensated by additional CCGT generation in SWQ. The benefit of this decision is that it prevents the need for transmission augmentation between central and southern Queensland. This is illustrated in Figure 48.

Figure 47: High growth – Queensland generation development

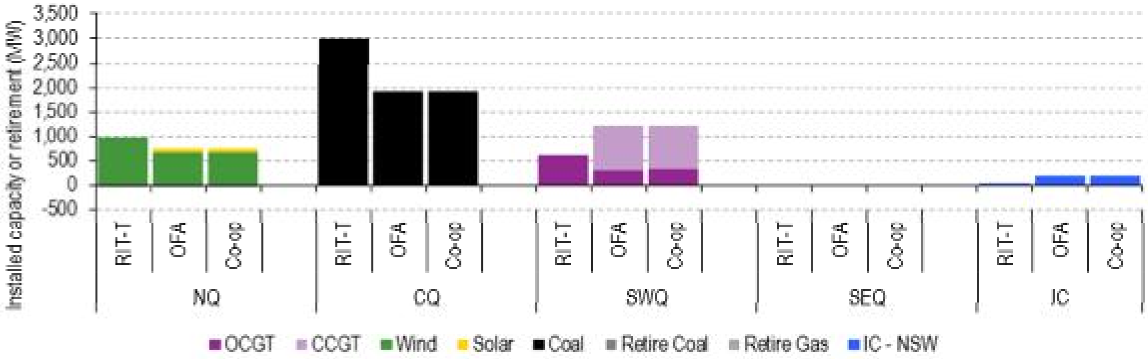
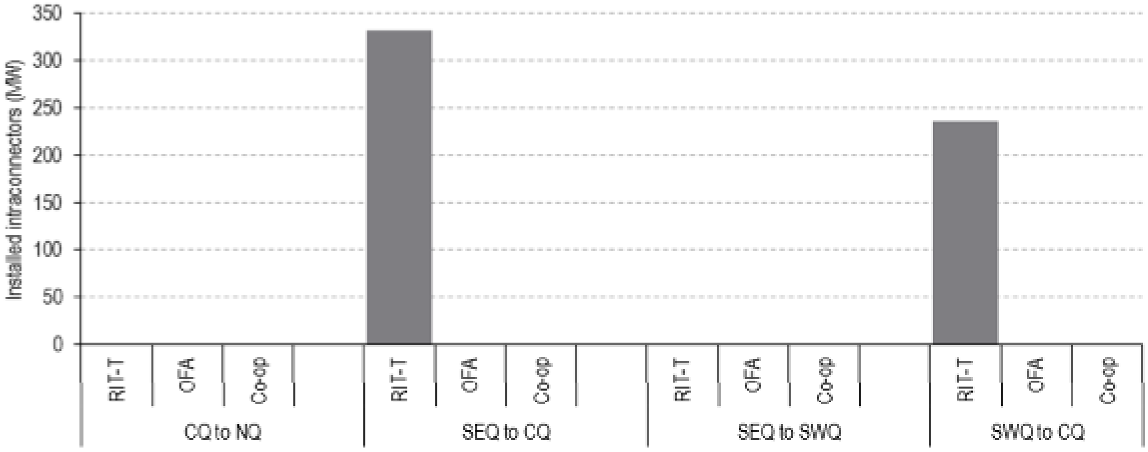


Figure 48: High growth – Queensland transmission development



6.6.3 Victoria

The effect of OFA in Victoria is relatively low in comparison to the impacts described above for Queensland and New South Wales. However, there are observable impacts in Figure 49 and Figure 50 that show generation and transmission development respectively. Under RIT-T, more new entrant CCGT is installed in the LV zone and this requires a small augmentation on the LV to MEL flowpath. This is not necessary under OFA and co-optimised planning where some of this capacity is shifted to CVIC and WVIC.

Figure 49: High growth – Victoria generation development

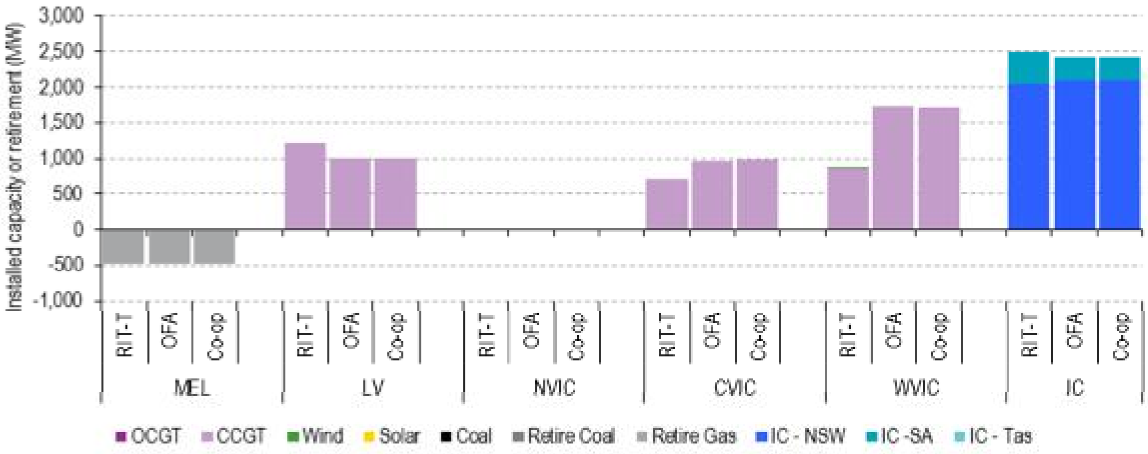
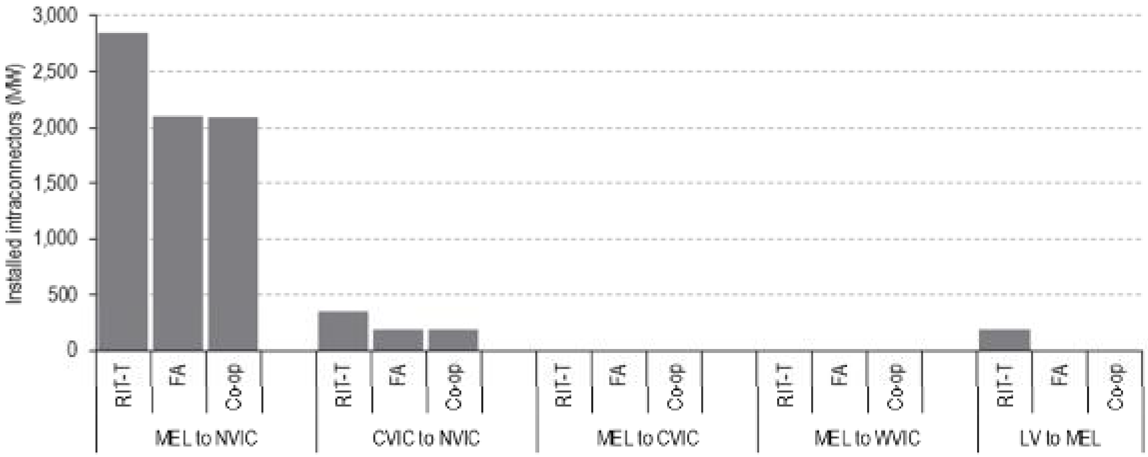


Figure 50: High growth – Victoria transmission development

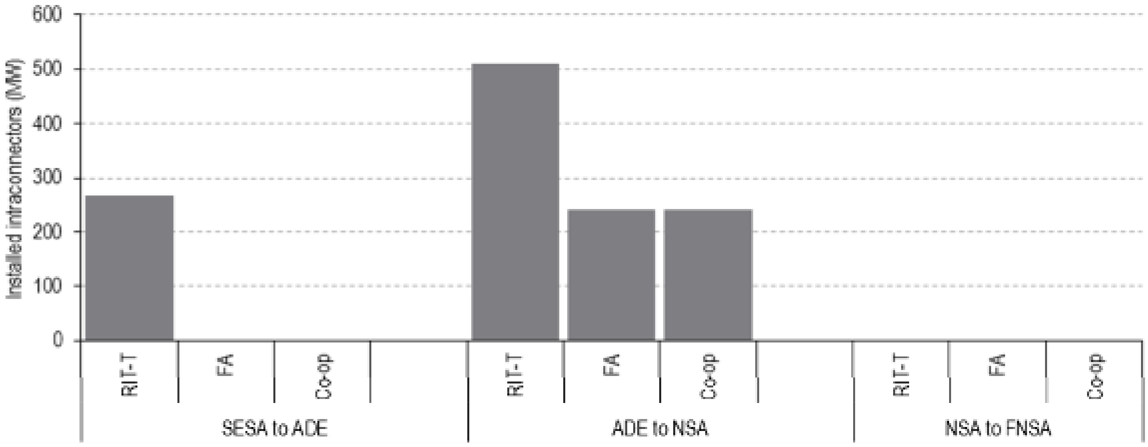


6.6.4 South Australia

The impact of OFA on the installation of NSA wind and on NSA to ADE transmission augmentation is also evident in this scenario. Furthermore, OFA and co-optimised planning favours additional peaking generation being located in NSA as opposed to under the RIT-T where new entrant peaking is located in SESA. The NSA peaking generation does not require additional access, noting that peaking generation and wind are rarely required during the same period, particularly in South Australia. The SESA peaking generation does require a transmission augmentation between SESA and ADE. Generation and transmission results are provided in Figure 51 and Figure 52 respectively.

Figure 51: High growth – South Australia generation development

Figure 52: High growth – South Australia transmission development



6.6.5 Tasmania

The planning methodology has no material impact on Tasmanian generation development in this scenario.

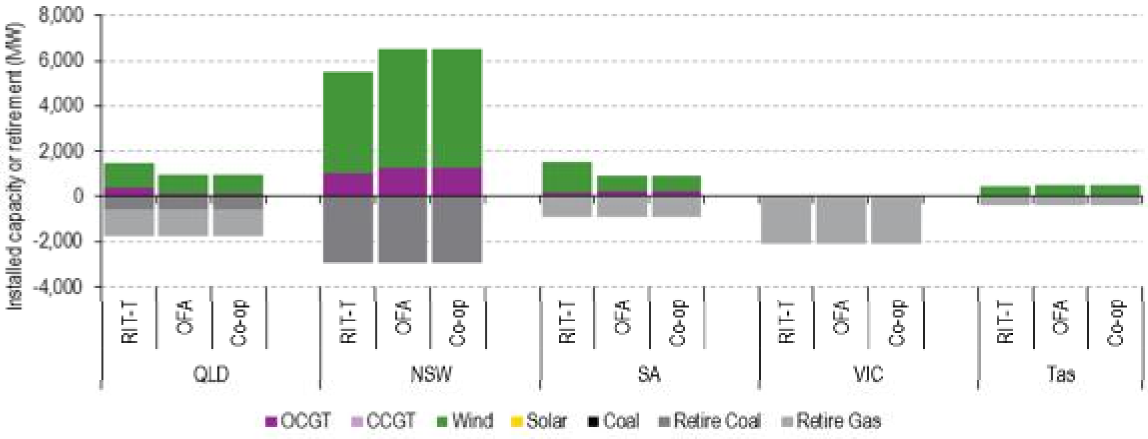
6.7 Portland retirement

The industrial load retirement scenarios were designed to determine whether OFA could more efficiently allocate generation retirements and future investments in response to a significant load reduction outside the reference node. The Portland retirement scenario considers whether the reduction in load in the WVIC zone impacts generation retirement and development in Victoria.

In general, the retirement of the Portland smelter has very little impact on the effects of OFA. This is in part due to the lack of activity required in Victoria generally. The retirement of Portland results in a commensurate increase in Victorian gas retirements, primarily in WVIC. Even if these retirements had occurred elsewhere, the transmission capacity between MEL and WVIC is sufficiently high that the retirement of the Portland load does not require augmentation on this flowpath.

The impact on the rest of the NEM is immaterial. Regional generation outcomes are shown in Figure 53.

Figure 53: Portland retirement – Regional generation development



6.8 Boyne Island retirement

The Boyne Island smelter is a large energy user that represents a significant proportion of CQ load. It was hypothesised that the retirement of this load may create a need for transmission augmentations between central and southern Queensland, particularly if Gladstone were to continue operating. OFA could potentially deliver benefits in this scenario by incentivising generation in CQ and NQ to retire to avoid the need for transmission augmentation. Under RIT-T planning, the retirement decisions of CQ and NQ generation does not consider the cost of this transmission augmentation if retirements do not occur.

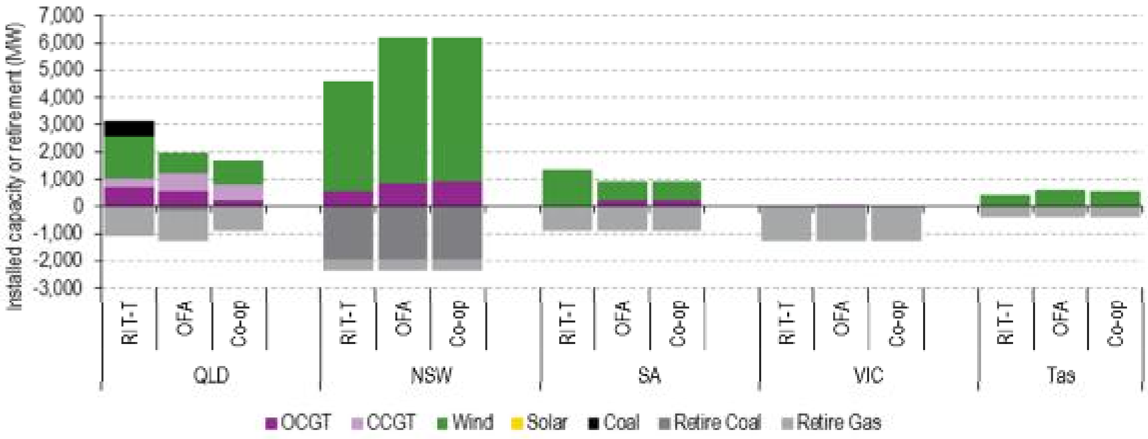
However, in the LTIRP forecasts it was found that even if Gladstone were restricted from retiring, there was no imperative to upgrade transmission in Queensland. As a result, in modelling this scenario it was found that a similar quantity of CQ and NQ retirements occurred under each planning methodology.

EY and the AEMC determined that it was appropriate to modify the scenario to illustrate conceptual benefits of OFA in more efficiently responding to major load retirements. This scenario is therefore for the purposes of illustration, rather than valuation. The scenario demonstrates the potential for OFA to impact on market development in response to major changes in load distribution.

The critical factor that is limiting the ability of OFA to impact on market development in this scenario is the lack of need for additional transmission into southern Queensland. Therefore, as a modification to this scenario, the Boyne Island retirement occurs concurrently with an equal increase in baseload in the SEQ zone. This additional load in SEQ increases at a moderate rate throughout the study.

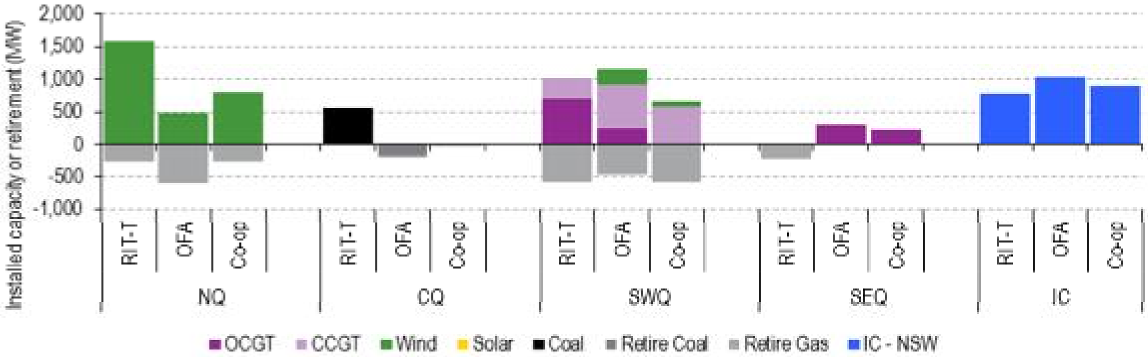
Figure 54 shows the regional generation development in this scenario. It is evident that under RIT-T planning, a higher level of capacity is developed in Queensland. Under OFA and co-optimised planning, generation development is moved to New South Wales.

Figure 54: Boyne Island retirement – Regional generation development



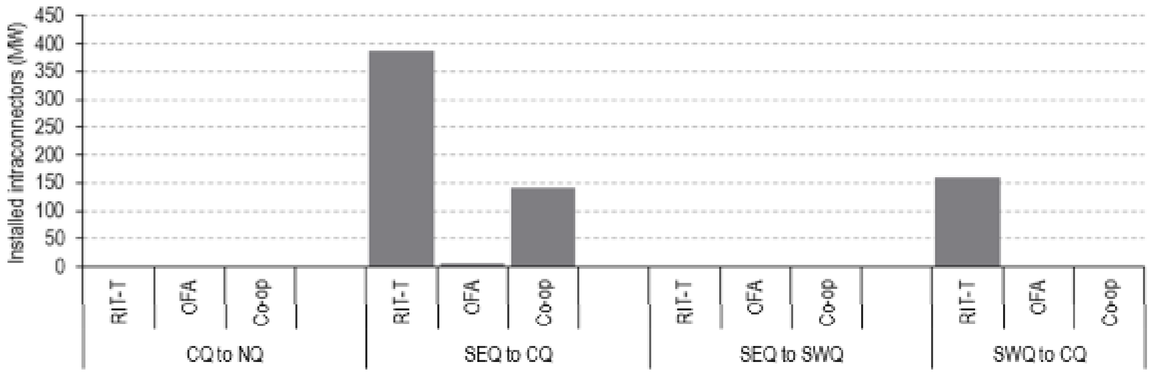
The impact of planning methodology on generation and transmission development in Queensland in response to the Boyne Island retirement is the focus of this scenario. Queensland zonal generation development is provided in Figure 55. This shows that the generation development outcomes different materially between the planning scenarios, with the RIT-T approach in particular influencing a very different planting outcome. Under RIT-T planning, there is significantly more development in NQ and CQ, including new entrant coal generation in CQ. Under co-optimised and RIT-T planting, retirements in SEQ are reduced, new entrant capacity is built in SEQ and QNI augmentations are increased.

Figure 55: Boyne Island retirement – Queensland generation development



The differences in Queensland transmission augmentations are clearly evident in Figure 56. This shows the impact of both reduced retirements and additional new entrant capacity in CQ and NQ under RIT-T planning. The generation development under OFA and co-optimised planning is able to reduce the need for transmission augmentation within Queensland. The result is that the additional total system cost reduction due to the OFA and co-optimised planning methodologies is $24m and $39m respectively when compared to the Base case.

Figure 56: Boyne Island retirement – Queensland transmission development



The generation development provided above showed that in comparison to the other scenarios described, generation development between the co-optimised and OFA planning approaches was not closely aligned. These differences are driven by the firm access allocated to incumbent generators. The level of access provided to these generators could not be maintained after the retirement of the Boyne Island load. To demonstrate this impact, EY has not allowed generation in CQ and NQ to reduce their level of access. This means that generators in these zones must either remain online and build transmission augmentation or retire. Under co-optimised planning, some of the generation that chooses to retire in OFA can more efficiently operate with a lower level of effective access. This difference drives the relatively large difference in total system cost between OFA and co-optimised planning in this scenario (see Table 15). If the CQ and NQ generation had been allowed to procure a lower level of access in response to the Boyne Island retirement, the OFA and co-optimised outcomes would have been more closely aligned.

This demonstrates a key point in that the duration of transitional access could potentially impact on the ability of OFA to drive efficient investment. Generally, shorter terms in access arrangements, particularly for existing generation assets, allows greater flexibility for generation and transmission to share price signals and achieve lower cost outcomes. Conversely, longer periods of transitional access may result in otherwise unnecessary transmission augmentation and an inability for the TNSPs to respond to changing market conditions, such as retirements, in the future.

6.9 Emissions reduction target

The Emissions reduction target scenario delivers a market structure in 2040 that is broadly similar to the Carbon pricing scenario. The primary difference between these scenarios is the speed at which emissions abatement occurs. This scenario incentivises a more rapid reduction in carbon emissions. This brings forward the transition of the generation sector and therefore results in a larger benefit of OFA; this scenario yielded the highest benefit of OFA of all the scenarios considered in this study. The generation development is shown in Figure 57.

Figure 57: Emissions reduction target – Generation development

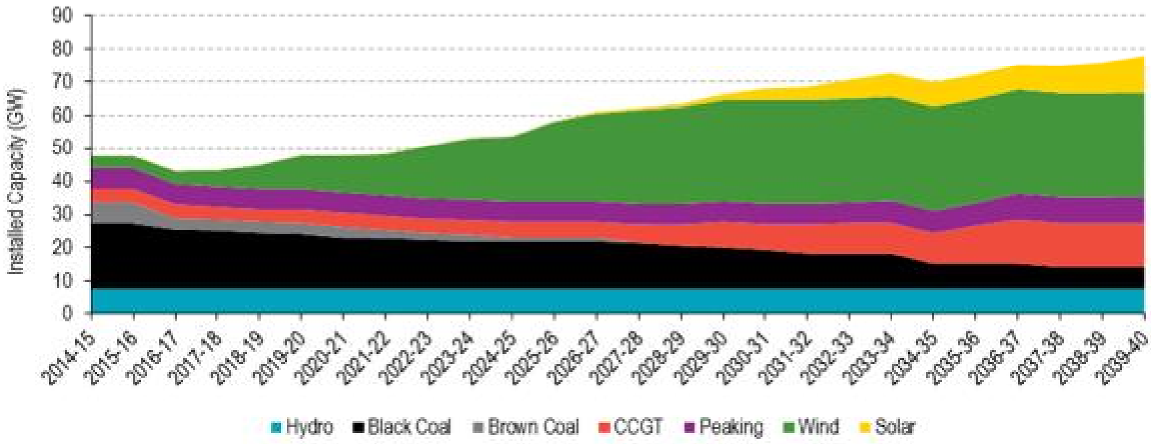
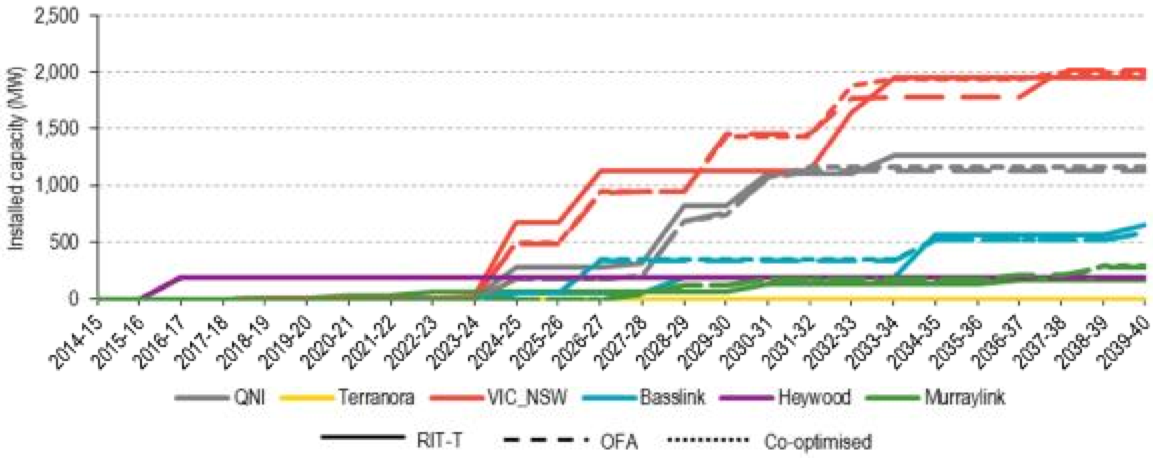
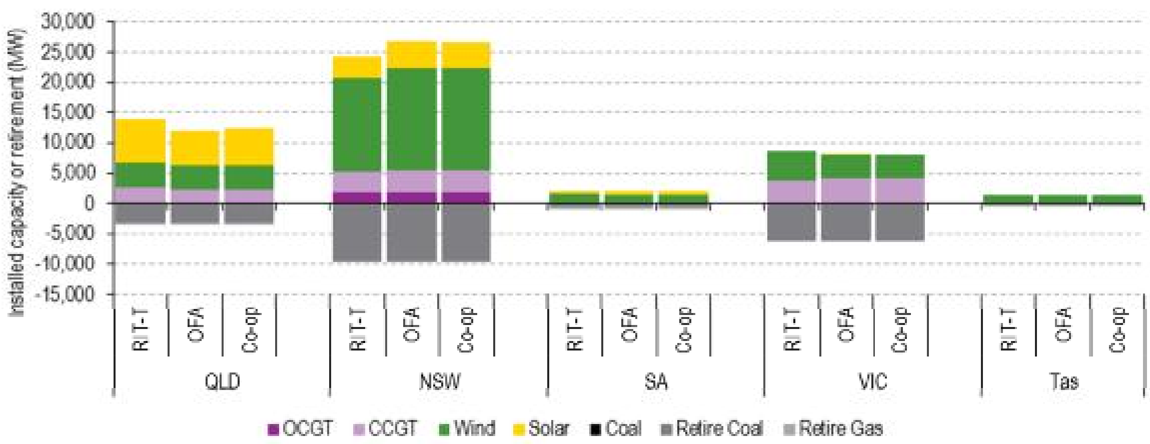


Figure 58: Emissions reduction target – Interconnector development



The regional generation development in this scenario is illustrated in Figure 59. In comparison to the Carbon pricing scenario, there are more coal retirements and a higher level of renewable investment, particularly wind. In the earlier years of the study, wind has a significantly lower LRMC than solar PV. Therefore, this scenario, that requires large emissions reduction before 2025, utilises a higher proportion of wind in meeting emissions targets. Generally, the regional differences are very similar to the carbon pricing scenario.

Figure 59: Emissions reduction target – Regional generation development



Within each region, the impact of planning methodology on generation and transmission development follows the same patterns as those that were observed during the Carbon pricing scenario. In some cases, the magnitude of the differences is increased. However, it is the timing of these developments in comparison with the Carbon pricing scenario that drives the increase in the relative benefit of the OFA and co-optimised planning approaches. Figure 60 and Figure 61 show the timing of generation development in New South Wales in the Carbon pricing and Emissions reduction target scenarios respectively. It is evident that the development of generation in the Emissions reduction scenario occurs at a higher rate in the early years of the study. Due to the effects of discounting, this results in a greater overall benefit from OFA relative to RIT-T.

Figure 60: Timing of NSW generation development – Carbon pricing

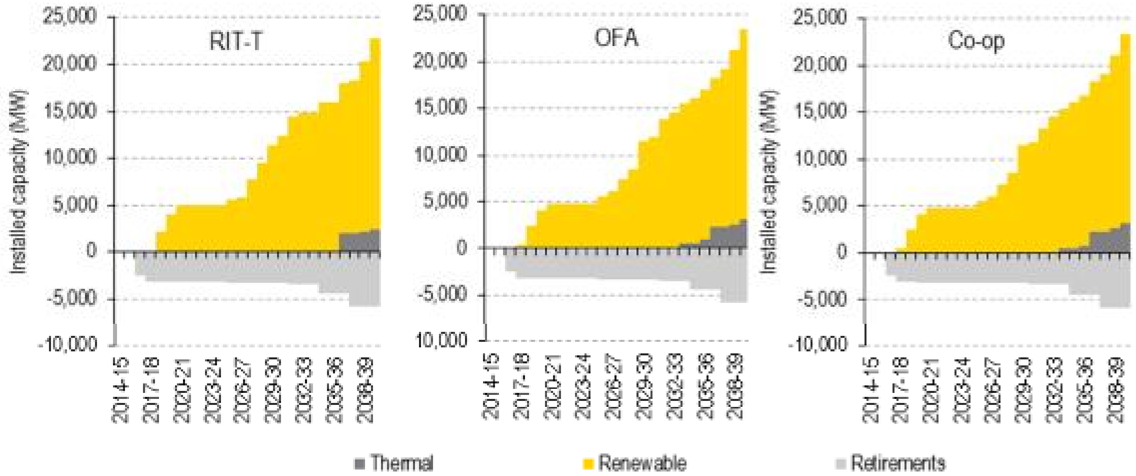
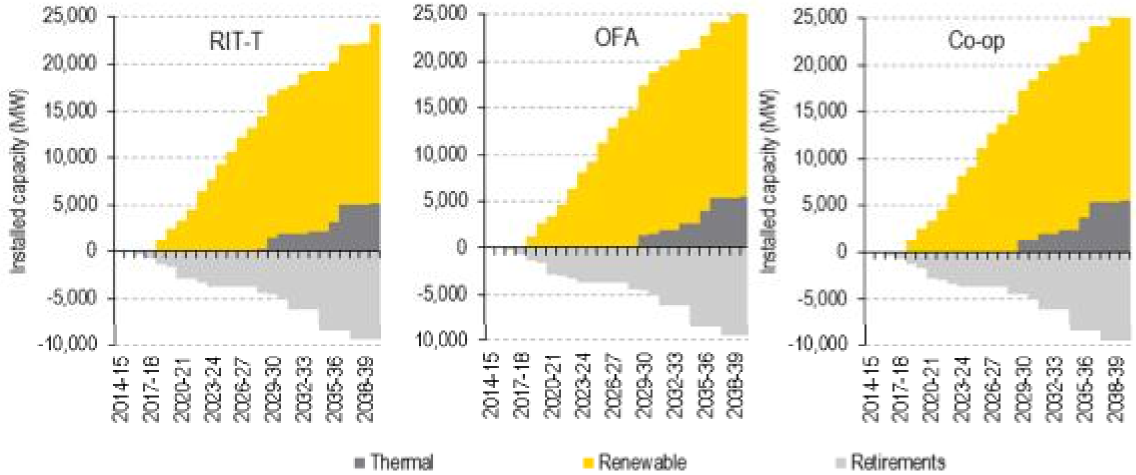


Figure 61: Timing of NSW generation development – Emissions reduction target



Similarly, Figure 62 and Figure 63 show the increase in magnitude and the earlier commencement of augmentations to the HUNTER to NNSW intraconnector for the Carbon pricing and Emissions reduction target scenarios respectively.

Figure 62: Timing of transmission development – HUNTER to NNSW – Carbon pricing

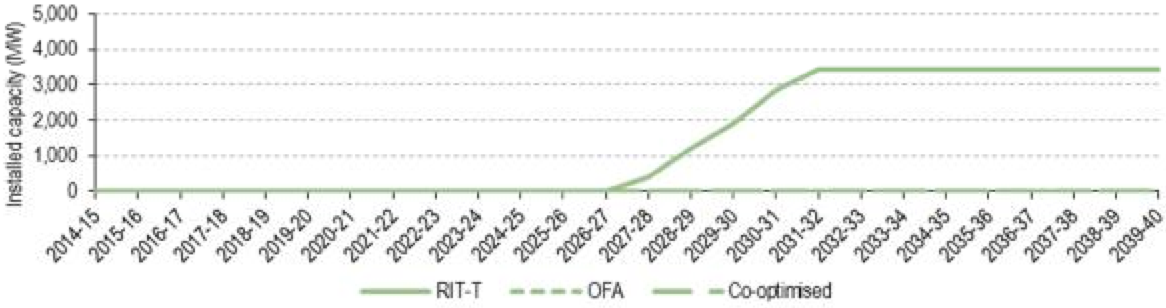
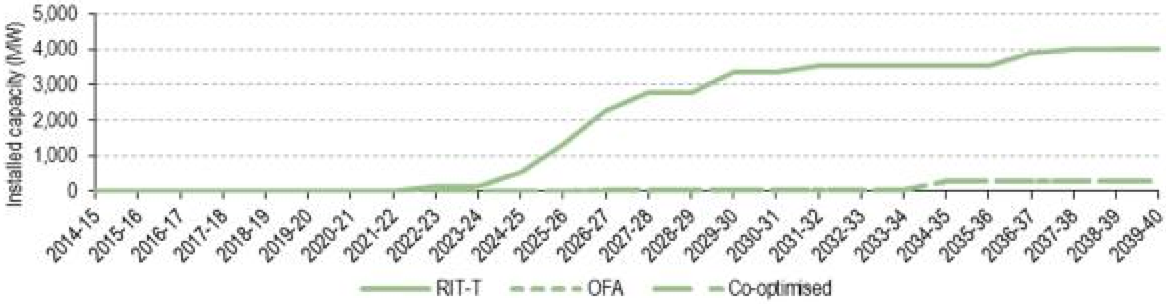


Figure 63: Timing of transmission development – HUNTER to NNSW – Emissions reduction target

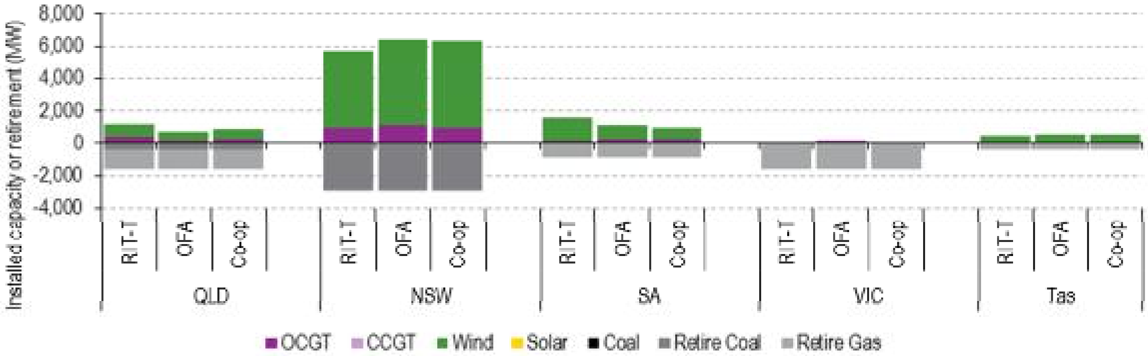


6.10 Transmission degradation

The differences between the total economic costs between the three planning methodologies in the Transmission degradation scenario are substantial. However, the majority of this benefit is a consequence of delaying or not completing asset replacement in the LTIRP. Section 3.2.9 describes how the three planning methodologies apply transmission replacement.

The effects on generation outcomes are comparable to the Base case, with a number of small differences. Regional generation development is shown in Figure 64.

Figure 64: Transmission degradation – Regional generation development



The reductions in transmission flowpath capacity applied in this scenario have impacted on the location of new entrant peaking generation in New South Wales, Queensland and South Australia. The zonal generation development in these three regions is provided in the following figures. In comparison to the Base case, new entrant peaking generation under OFA and co-optimised planning is more likely to be located in zones with higher loads, more abundant transmission access or at the reference node. This decision allows the LTIRP to defer replacement on flowpaths that would have been constrained had new entrant peaking generation been built according to the Base case projection.

Figure 65: Transmission degradation – New South Wales generation development

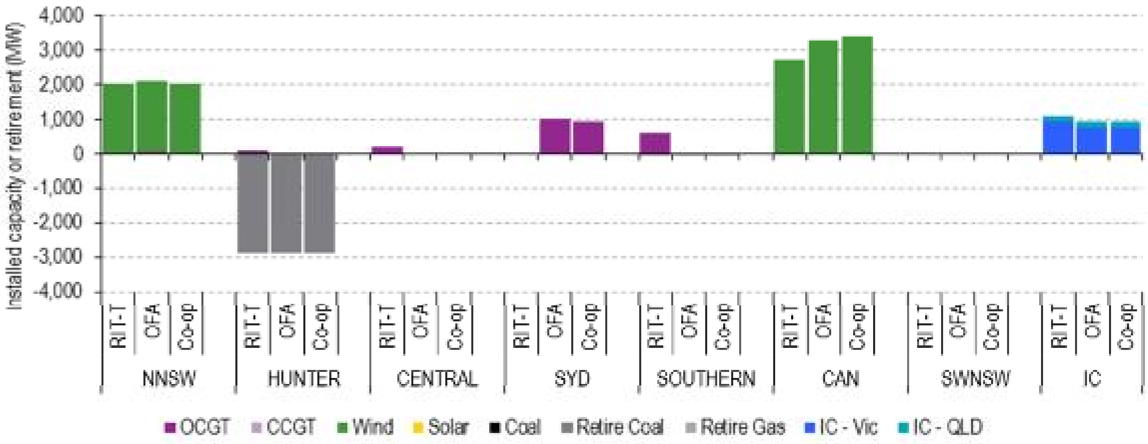


Figure 66: Transmission degradation – Queensland generation development

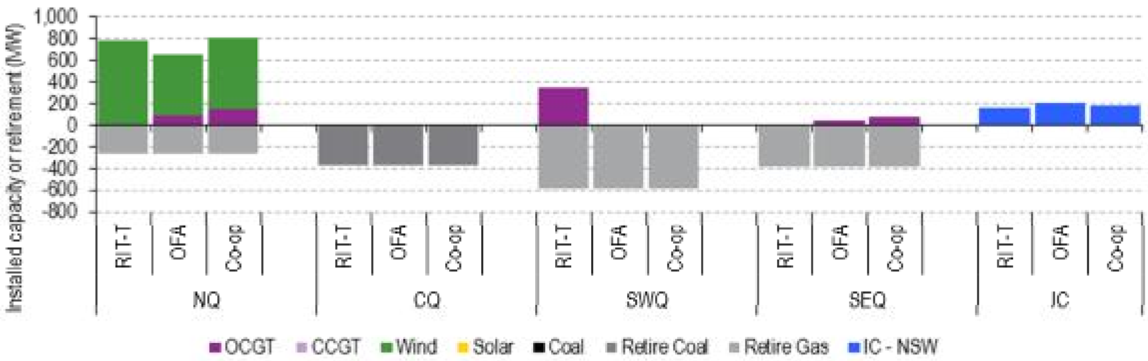
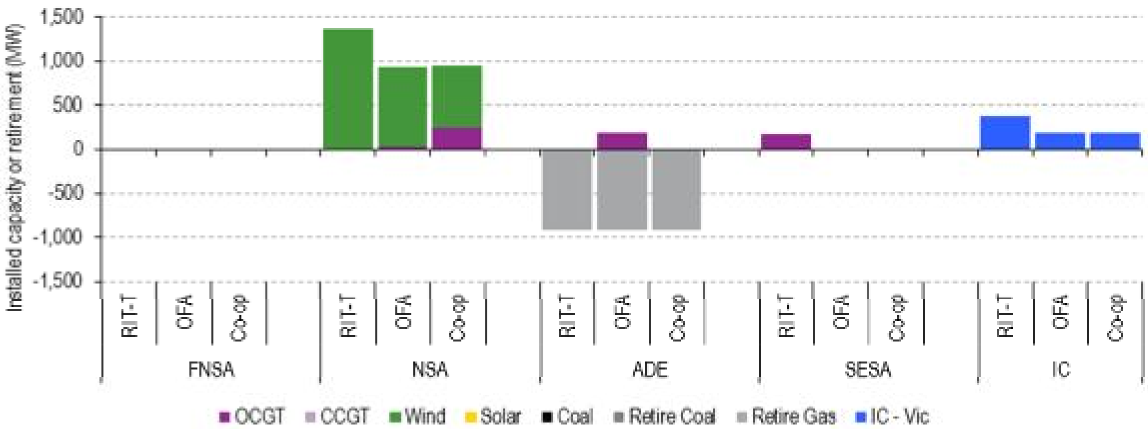


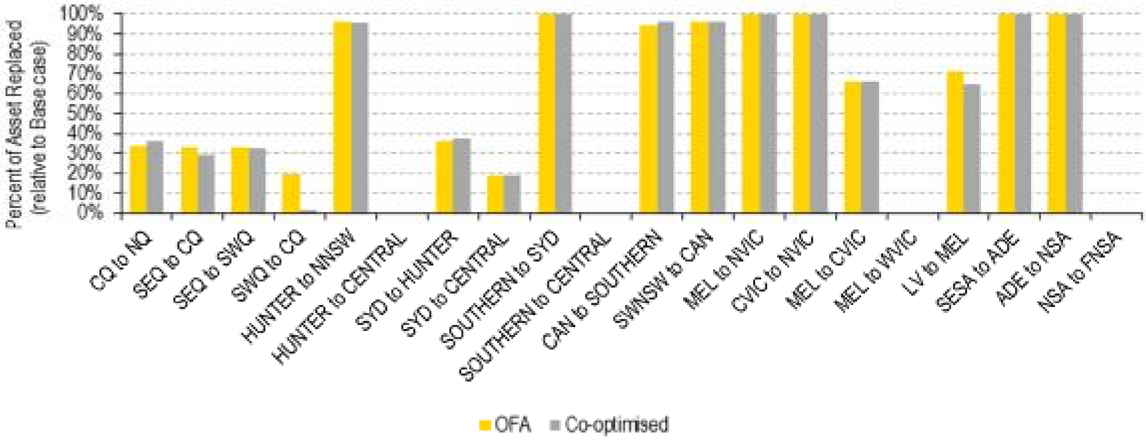
Figure 67: Transmission degradation – South Australia generation development



The majority of the increase in the benefits of OFA and co-optimised planning in this scenario result from not being forced to replace degraded flowpaths. A proportion of the replacements that are forced under RIT-T planning do not deliver benefits in excess of their cost. It was shown above that the impact of OFA on generation development in response to transmission degradation is of a similar magnitude to that observed in the Base case.

Figure 68 shows the percentage of asset replacements that were considered to be viable under OFA and co-optimised planning; the RIT-T planning approach completes 100% of asset replacement. There are a number of flowpaths that both OFA and co-optimised planning maintain at full capacity, particularly between Melbourne and Sydney and flowpaths into Adelaide. However, there are a number of flowpaths that are allowed to reduce in capacity throughout the study. This is evident in Queensland, around the Sydney ring, between MEL and WVIC and between NSA and FNSA. The increase in generation costs from not replacing the reduced capacity on these flowpaths was not sufficient to justify the replacement expenditure. Consequently, the OFA and co-optimised approaches are able to deliver economic savings.

Figure 68: Transmission degradation – Replacement



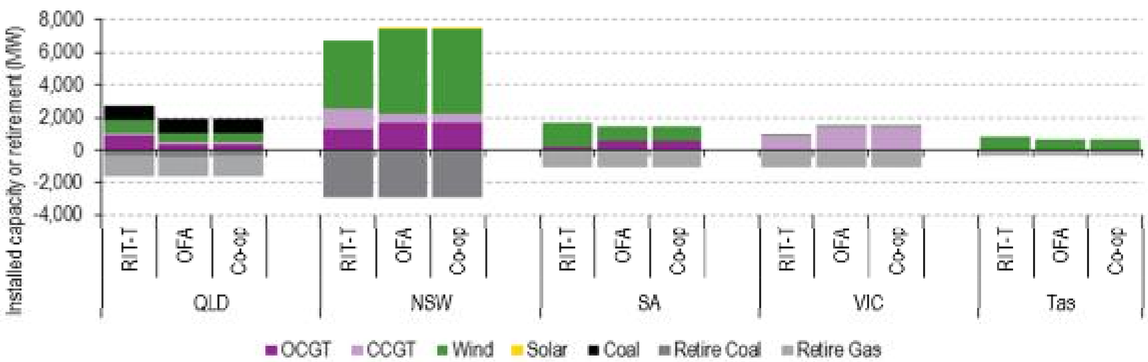
It should be noted that the approach applied to transmission replacement is coarse and will not be reflective of true asset replacement decisions. This is particularly true of flowpaths with a low number of high voltage transmission lines where any reduction in flowpath capacity would need to be large. The LTIRP allows relatively small reductions in flowpath capacity; this is unlikely to be possible for flowpaths with high capacity transmission lines. Furthermore, some transmission flowpaths have a high capacity due to relatively recent augmentations or transmission lines. Consequently, transmission replacement decisions are likely to not be required within this study timeframe.

A scenario whereby transmission replacement decisions are required to meet a RIT-T (under RIT-T planning) would deliver a significant fraction of the benefits attributed to OFA in this scenario, but would still likely deliver a benefit under OFA that is marginally higher than the Base case. Under such a framework, OFA is able to deliver additional benefits by considering the need for asset replacements in determining the location of generation development.

6.11 Forecasting error

The Forecasting error scenario continues to oversupply the market for the duration of the study. The quantity of new entrant capacity in this scenario in all mainland regions exceeds the quantity installed in the Base case. Regional generation development is shown in Figure 69.

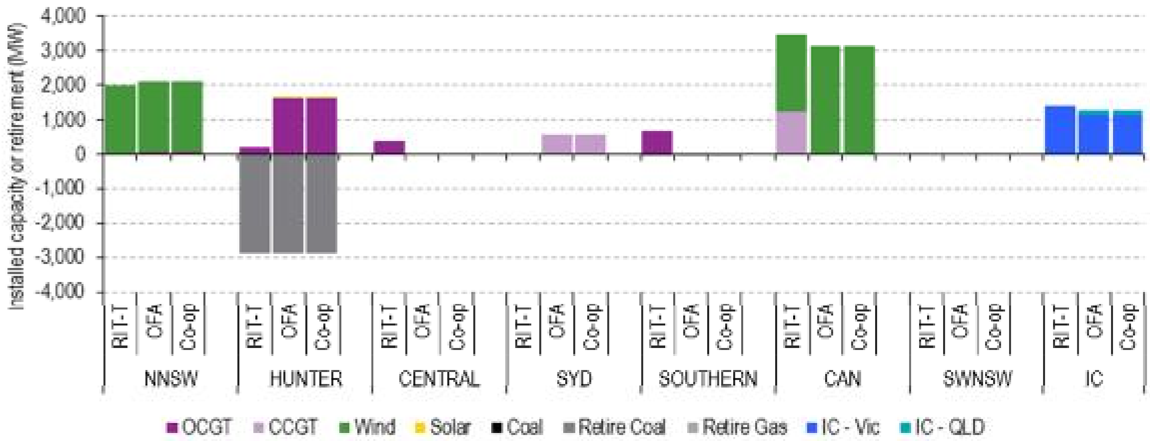
Figure 69: Emissions reduction target – Regional generation development



Queensland and Victoria are able to support this additional thermal generation development without the need for transmission augmentation. Therefore, the impact of OFA and co-optimised planning in these regions is comparable to the impacts observed in the Base case.

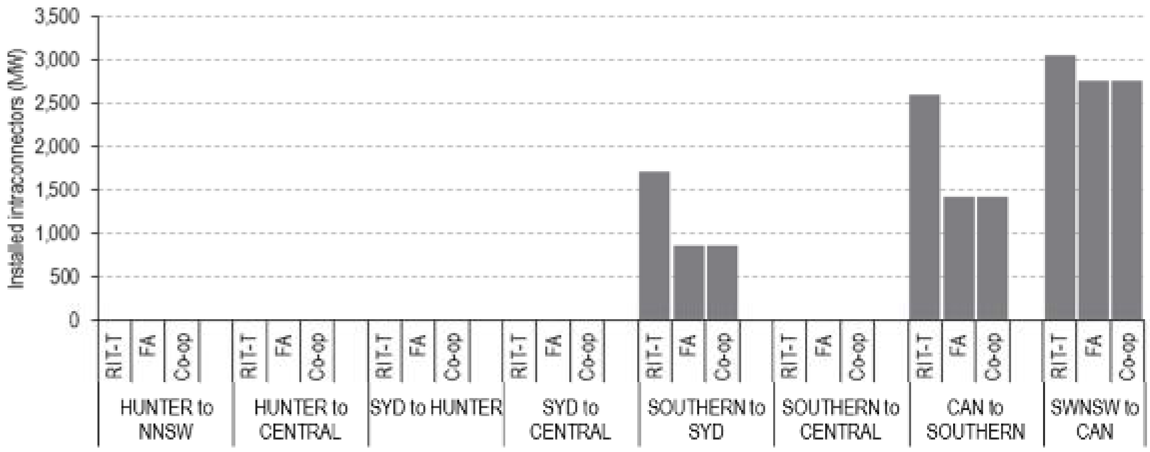
Within New South Wales, the increase in generation development does exacerbate the inefficiencies caused by RIT-T planning. In particular, the RIT-T planning outcomes feature a higher level of generation that is installed in the SOUTHERN and CAN zones, rather than in the HUNTER zone where access is more abundant. The generation outcomes in New South Wales are shown in Figure 70.

Figure 70: Forecasting error – New South Wales generation development



The effect of this generation on transmission development is shown in Figure 71, demonstrating that the locational development under RIT-T planning results in a greater need for augmentation on the CAN to SOUTHERN and SOUTHERN to SYD intraconnectors.

Figure 71: Forecasting error – New South Wales transmission development



The magnitude of the impact of OFA on total system cost in this scenario is far larger than in the Base case. The extent to which inefficient developments occur under the RIT-T planning approach comprises only a proportion of this increase. Given that these assumptions were made based on erroneous demand projections, the negative effect of the inefficient investments made under RIT-T planning are exacerbated.

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