Market Benefits for Solar Enablement

Victoria Power Networks and United Energy

Final Report

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Contents

Executive Summary

This report provides an analysis of the available market benefits of the CitiPower, Powercor (Victoria Power Networks, or VPN)) and United Energy (UE) Solar Enablement project. As part of the Solar Enablement project the DNSPs will be investing in the distribution network to unlock capacity for additional export of power generated by distributed rooftop solar PV that otherwise would have constrained due to overvoltage issues.

Jacobs' market modelling has been conducted by calculating the market benefits in response to the Solar Enablement project. For the purpose of this analysis, market benefits are defined as the reduction in total generation costs (fuel and operating and maintenance costs) and the value of carbon abatement.[1] A baseline market model was specified in PLEXOS and the total baseline cost of generation over the project period (2020-2029) was established, as well as an alternative market model where the distributed solar generation is fully enabled and exportable to the grid. These results were then compared to the baseline model outputs and used to calculate the difference in total generation costs and carbon emissions against a set carbon price.

The key assumptions underlying the wholesale market modelling outputs are included in Table 1 below:

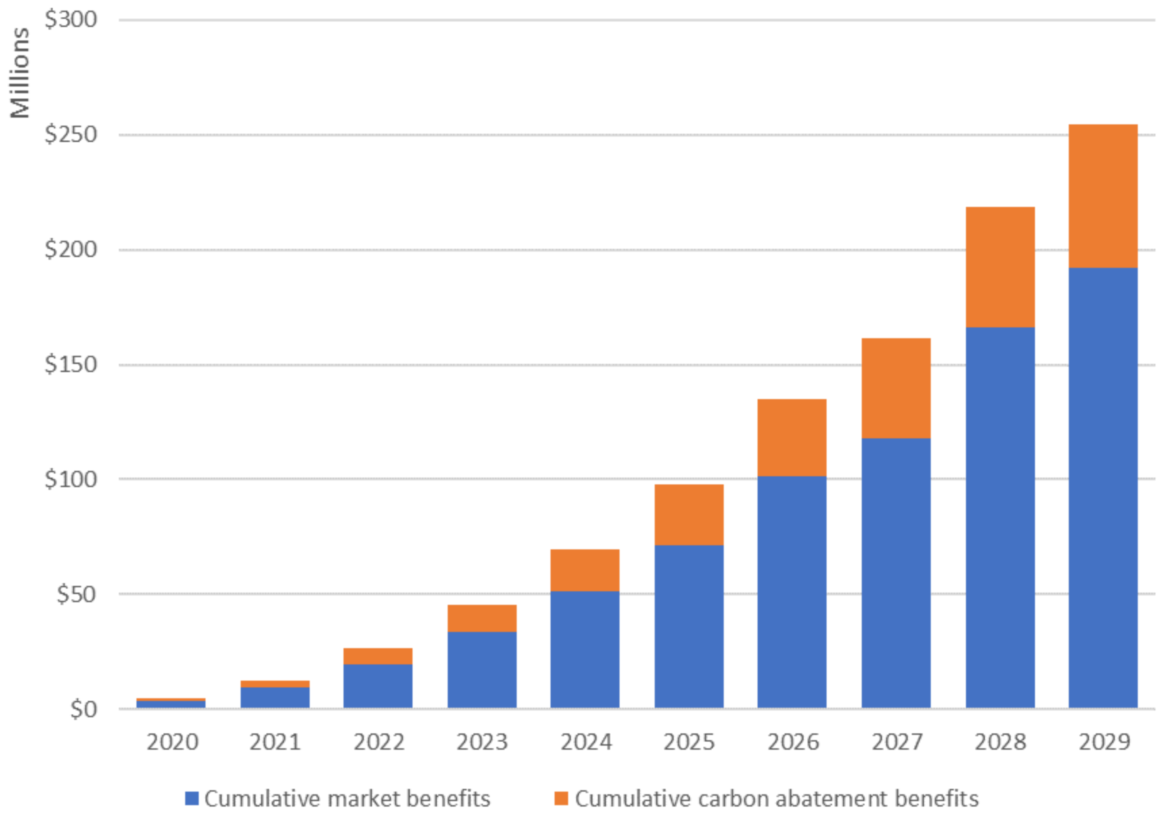
Table 1: Key Scenario Assumptions

Parameter	Base Scenario
Demand growth (including electric vehicle use)	AEMO ESOO 2018 Neutral demand forecast, Jacobs-VPN-UE rooftop PV forecast.[2]
Gas Price	NEM region average starting from $10.6/GJ in 2019. Prices decline in the midterm to $9.7/GJ and then commence an upward long-term trend to $11.1/GJ by 2035.
Federal Emissions Policy	26 per cent emission reduction policy by 2030 on 2005 levels.[3]
LRET/ VRET/ QRET	LRET continues operation in current form. 1st stage and 2nd stage of VRET and QRET included.
Utility scale wind learning rates	Steadily declining growth rate from 1.9% in 2019 to 1.4% in 2050.
Utility scale solar learning rates	Compound Annual Growth Rate of 5.0% p.a. up to 2021, 1.1% p.a. thereafter.
Retirements of coal fired power stations[4]	All power stations retire when they can no longer recover their non-avoidable costs. Planned retirements up to 2030 are: Liddell retires in 2022. Vales Point retires 2028/29. Tarong retires 2029-2034. Gladstone retires 2028-2030,
Interconnectors	Group 1 and Group 2 upgrades under the ISP to proceed (refer to section 2.9.4 for details) excluding Marinus link
Snowy Hydro	The Snowy Hydro Expansion (Snowy 2.0) is operational by 2025/26, assumed to be a pumped storage generator that adds capacity to the NEM without additional energy generation.

[1] Additional network benefits can be considered such as reduction in network losses and/or other network augmentation benefits. These benefits are outside the scope of work for this project and/or have been (partially) covered through other initiatives and not included here to avoid any potential double counting.
[2] The rooftop PV forecast is based on input data provided by VPN and United Energy and adjusted by Jacobs to include the rooftop PV projections from the other networks: Jemena and AusNet.
[3] Emission target trajectories as per AEMO ISP 2018 - 28% Emissions Reduction Target.
[4] Higher levels of renewable generation create an oversupply during certain periods of the day, displacing conventional generation and resulting in earlier retirement. This phenomenon is amplified in a high load growth scenario, with correspondingly higher levels of renewable energy generation.

The resulting gross cumulative market and carbon abatement benefits are included in Figure 1. The total estimated cumulative benefits of Solar Enablement for FY2020-2029 are just over $250 million with roughly $190 million from generation cost reductions (fuel and all other variable costs) and $60 million from carbon abatement benefits.

Figure 1: Cumulative market and carbon abatement benefits



Based on the information in the table above the weighted average market benefit is $35.22/MWh and the weighted average carbon abatement benefit is $11.48/MWh, which makes the total benefit approximately $47 per MWh over the FY2020-2029 project period.

Table 2: Solar Enablement differences

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Additional **rooftop PV generation in GWh/a - VIC**	96	173	289	433	530	626	709	790	875	927
Generation costs *reduction* $m/a	3.77	5.45	10.06	14.56	17.50	20.20	29.98	16.65	47.88	25.88
Generation costs reduction per MWh additional rooftop PV generation ($/MWh/a)	$39	$32	$35	$34	$33	$32	$42	$21	$55	$28
Carbon emission *reduction kilo*-tonnes/a	80.7	149.4	243.0	301.5	413.9	524.1	467.4	640.7	600.9	654.2
Carbon emission benefit at ACCU of $15.35 (March 2019) in $m/a	1.24	2.29	3.73	4.63	6.35	8.05	7.17	9.83	9.22	10.04
Carbon emission benefits per MWh additional rooftop PV generation ($/MWh/a)	$13	$13	$13	$11	$12	$13	$10	$13	$10	$11
Total benefits in $m/a	5.01	7.74	13.79	19.19	23.9	28.3	37.2	26.49	57.10	35.92
Total benefits in $/MWh/a	$52	$45	$48	$45	$45	$45	$52	$34	$65	$39

Disclaimer

The sole purpose of this report and the associated services performed by Jacobs is to assist in the understanding of the wholesale power markets and the impact of the development of rooftop solar PV on the total cost of generation in the National Electricity Market (NEM) in accordance with the scope of services set out in the contract between Jacobs and CHED Services, representing the Victoria Power Networks and United Energy (the Client).

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Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAGR	Compound Annual Growth Rate
CCGT	Combined cycle gas turbine
CPI	Consumer Price Index
DLF	Distribution loss factor used to adjust price received according to losses in the distribution and sub-transmission system relative to the transmission connection point.
DWP	Dispatch weighted price
EIS	Emissions Intensity Scheme
ESC	Energy Efficiency Certificates
ESOO	Electricity Statement of Opportunities, documents published annually by AEMO to provide information on the demand and supply situation in the NEM
ISP	Integrated System Plan (AEMO)
LGC	Large generation certificates (formerly REC) under LRET
LRET	Large-scale Renewable Energy Target
MLF	(Transmission) Marginal Loss Factor applied to adjust price received according to network power losses relative to the regional reference node.
NEFR	National Energy Forecast Report
NEG	National Electricity Guarantee
NEM	National Electricity Market
NSW	New South Wales, a state of Australia
POE	Probability of Exceedance
PV	Photo-voltaic
RECs	Renewable Energy Certificates
REMMA	Jacobs' renewable energy market model for Australia's large-scale renewable energy target
RET	(Expanded) Renewable Energy Target
RIT-D	Regulatory Investment Test for Distribution
SA	South Australia, a State of Australia
SRES	Small-scale Renewable Energy Scheme under MRET
SWIS	South-West Interconnected System
TAS	Tasmania, a State of Australia

UE	United Energy
QLD	Queensland, a State of Australia
QRET	Queensland Renewable Energy Target
VIC	Victoria, a State of Australia
VPN	Victoria Power Networks (CitiPower and Powercor)
VRET	Victorian Renewable Energy Target

1. Introduction

VPN and United Energy are in the process of developing their 2021-2025 Revenue Reset submission to the Australian Energy Regulator (AER). As part of this submission VPN & UE will submit a Solar Enablement business case, detailing the forecast of the costs and benefits associated with enabling the electricity networks to meet anticipated solar exports, known as Solar Enablement.

Furthermore, new Victorian Government policy relating to solar PV installation rebates (the Solar Homes initiative) is to significantly increase penetration of residential customer solar generation on VPN and UE electricity distribution networks.

Therefore, to support and inform the Solar Enablement business case, Jacobs has developed a market model to estimate the potential market benefits of the Solar Enablement Project should the constrained solar be unlocked over a 10-year analysis period.

Jacobs has based the market benefits on the preferred technical options from the Solar Enablement project for the period 2020-2029 in accordance with the following market benefit classes published in the RIT-D.

- Potential changes in fuel consumption arising through different patterns of generation dispatch, covering:
  - Facilitation of substitution of high-fuel cost plants with low-fuel cost plants (merit order dispatch change); and
  - The direct reduction in overall generation dispatch.

We note that in addition there may be an impact on the cost of generation other than resulting from fuel, including reduction of capital investment for new plant, and/or operating and maintenance cost. Jacobs has included the operating and maintenance cost reductions in the results but did not include any reduction in capital investment for deferral of new generation plant. The latter would require a dynamic long-term market assessment, beyond the agreed scope of work.

Jacobs has also included potential benefits from NEM-wide carbon abatement through increased small-scale rooftop PV output.

Market modelling has been a core part of Jacobs' energy markets team in Australia for more than 20 years.

All monetary values in this report, unless stated otherwise, are in December 2018 dollars (FY2019).

The following sections are provided in this report:

- Chapter 2 describes the market modelling assumptions for the NEM at a moderate level of detail, and the methodology used to simulate the medium-term development of the National Electricity Market. It describes the modelling system used and how they are integrated together to combine the modelling of thermal and renewable energy markets.

- Chapter 3 provides the approach to the calculation of the Solar Enablement benefits.

- Chapter 4 Includes the outputs and results of Solar Enablement market benefits.

2. Market Modelling Approach and Assumptions

2.1 Scenario

Amidst recent political uncertainty surrounding energy policy[5], this study assumes that the Paris Agreement on emission targets, as ratified by the Australian Government, will be upheld. The Paris Agreement provides a requirement for Australia to achieve a 26% reduction in national emissions by 2030 relative to 2005 levels. This is in line with the Neutral emissions trajectory from AEMO ISP 2018 used in this study which suggests a 28% decrease on 2005 emissions by 2030/31.

No federal or state level emissions policies have been assumed up to 2030 in the used market model. Renewable capacity for State-level renewable policies up to 2030 are assumed to be fulfilled through reverse auctions (reverse auctions for stage one of the VRET and QRET have been completed).

Our approach requires creation of a baseline and alternative market model to assess market pricing associated with each. The scenario specific assumptions are summarised in Table 3 with an overview of the approach displayed below.

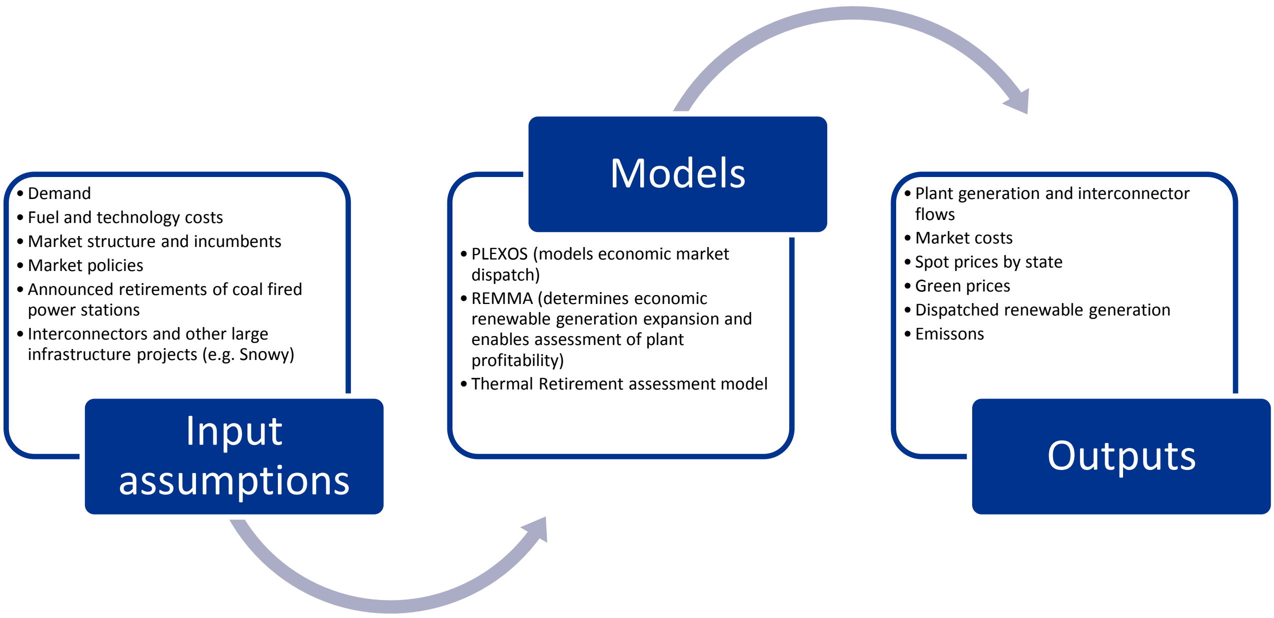


Table 3: Key Scenario Assumptions

Parameter	Base Scenario
Demand growth (including electric vehicle use)	AEMO ESOO 2018 Neutral demand forecast, Jacobs-VPN-UE rooftop PV forecast.[6]
Gas Price	NEM region average starting from \$10.6/GJ in 2019. Prices decline in the midterm to \$9.7/GJ and then commence an upward long-term trend to \$11.1/GJ by 2035.
Federal Emissions Policy	26 per cent emission reduction policy by 2030 on 2005 levels.[7]
LRET/ VRET/ QRET	LRET continues operation in current form. 1st stage and 2nd stage of VRET and QRET included.
Utility scale wind learning rates	Steadily declining growth rate from 1.9% in 2019 to 1.4% in 2050.

[5] The present Commonwealth Government now no longer supports a National Energy Guarantee policy.
[6] The rooftop PV forecast is based on input data provided by VPN and United Energy and adjusted by Jacobs to include the rooftop PV projections from the other network jurisdictions: Jemena and AusNet.
[7] Emission target trajectories as per AEMO ISP 2018 - 28% Emissions Reduction Target.

Parameter	Base Scenario
Utility scale solar learning rates	CAGR of 5.0% p.a up to 2021, 1.1% p.a. thereafter.
Retirements of coal fired power stations[8]	All power stations retire when they can no longer recover their non-avoidable costs. Planned retirements up to 2030 are: Liddell retires in 2022. Vales Point retires 2028/29. Tarong retires 2029-2034. Gladstone retires 2028-2030,
Interconnectors	Group 1 and Group 2 upgrades under the ISP to proceed (refer to section 2.9.4 for details) excluding Marinus link
Snowy Hydro	The Snowy Hydro Expansion (Snowy 2.0) is operational by 2025/26, assumed to be a pumped storage generator that adds capacity to the NEM without additional energy generation.

The alternative Solar Enablement scenario is mostly the same, with the rooftop small-scale solar PV forecast as the only difference between the two scenarios.

2.2 Modelling approach

The modelling timeframe covers financial year 2020 to financial year 2029 inclusive. All monetary values are in December 2018 dollar terms unless otherwise stated. All years are referring to the end of a financial year, except where noted.

The market forecasts consider regional demand forecasts, generating plant performance, timing of new generation including embedded generation, existing interconnection limits, and the potential for interconnection development. Jacobs used its PLEXOS model to develop total generation costs from 2020 to the year 2029 for the Neutral Scenario.

Future wholesale electricity prices and related market outcomes are essentially driven by the supply and demand balance, with long-term prices being effectively capped near the cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and capital costs of new plant and emissions intensity threshold will have a noticeable impact on long-term price forecasts. Year-to-year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power. Key assumptions used in the modelling include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation of assets. It is assumed that this is already included in the demand forecasts provided by AEMO.
- Wind generation is based on observed wind power generation profiles for each region.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. This is a conservative assumption as there have been short periods when prices have exceeded new entry costs when averaged over 12 months.
- Infrequently used peaking resources are bid near Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low. Torrens Island A capacity is an example when some plant is never indicated to be required for median peak demand.

[8] Higher levels of renewable generation create an oversupply during certain periods of the day, displacing conventional generation and resulting in earlier retirement. This phenomenon is amplified in a high load growth scenario, with correspondingly higher levels of renewable energy generation.

- The LRET target is for 33,000 GWh of renewable generation by 2020.
- Additional renewable energy is included for expected GreenPower and desalination purposes.

2.3 Market modelling

Jacobs used its PLEXOS model to develop forecasts for electricity generation costs and wholesale prices in the NEM. Electricity price projections are subject to variance based on factors including changes to government policy on emission abatement mechanisms, and therefore reliance on these projections must be qualified by the recognition of this uncertainty.

2.3.1 PLEXOS

The PLEXOS market simulation model is used to forecast the evolution of the wholesale price and generation levels.

PLEXOS is a sophisticated stochastic mathematical model developed by Energy Exemplar which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.

Detailed modelling simulations using PLEXOS are typically run one year at a time to more accurately model system dispatch and pricing. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on a half hourly or hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, inter-connector constraints and any other operating restrictions that may be specified.

Expected hourly (or even shorter time intervals if needed) electricity prices for the NEM are produced as output, calculated either on a marginal cost bidding basis, or if desired, by modelling strategic behaviour, based on gaming models such as the Cournot equilibrium, long-run marginal cost recovery (or revenue targeting) or shadow pricing. Jacobs uses a combination of user-defined bids and long-run marginal cost bidding to produce the price forecasts and has benchmarked its NEM database to historical market outcomes using this algorithm to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes.

There are four key tasks performed by PLEXOS:

- Forecast demand profiles over the planning horizon, given a historical load profile, expected energy generation and peak loads.
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models
- Calculate hourly or half-hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and price impacts of abatement schemes.

Jacobs approach to determine the future system reliability is through the expected Unserved Energy (USE) in the NEM, which is the amount of customer demand that cannot be supplied in a region of the NEM due to a shortage of generation or interconnector capacity. These events are experienced by customers as blackouts. USE is calculated in GWh and is expressed in terms of percentage of customer demand (i.e. AEMO’s reliability standard is that USE in a region should be less than 0.002% of the region’s demand). Also, since PLEXOS’ simulations and optimisation are done hourly (or even shorter than that), the model ensures that enough flexible capacity is installed in the NEM to respond to large fluctuations in demand reliably and rapidly.

2.3.2 General Participant Behaviour

2.3.2.1 Market structure

We assume the current market structure continues under the following arrangements:

- Victorian and New South Wales generators are not further aggregated.
- The generators' ownership structure in Queensland remains as public ownership.
- The South Australia assets continue under the current portfolio groupings.
- The following plants have been decommissioned: Wallerawang Power Station in NSW, Northern Power Station in South Australia and Hazelwood Power Station (from the end of March 2017), and Liddell will be decommissioned in financial year 2023 as per AGL's announcement.

2.3.2.2 Contract position and bidding

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed for operational reasons or bid at its marginal cost to ensure the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out. This strategy maximises profit in the short-term, excluding any long-term flow on effects into the contract market.

Bidding strategies chosen in the modelling are typically benchmarked to what is considered to be a representative historical year, and then projected forward with the calibrated PLEXOS bidding parameters locked in. In our most recent modelling we have found that NEM projected prices fall well short of forward curve prices if we use our typical strategic bidding parameters. These are benchmarked to achieve average price outcomes that were achieved in 2017/18.

2.3.3 Generation Expansion in PLEXOS

The model selects new capacity from a range of available fossil fuel and renewable technologies. Parameters for technologies not presently commercially available are included where an estimate can be made of their performance and costs for use in the modelling. In each scenario the least cost mix of plant is dispatched to meet demand, based on fuel and capital costs, and any policy constraints.

Hence:

- Technologies included as new plant options are wind, solar PV, solar thermal, hydro-electric systems, biomass-based generation, simple and combined cycle gas turbines, super and ultra-supercritical coal fired steam turbines, integrated gasification combined cycle plant with carbon capture and storage (utilising coal as a fuel), geothermal, battery storage and pumped storage.
- Technologies excluded are nuclear generation, tidal and wave technologies.

New entrant technology costs are derived at each applicable point-in-time (generally an estimate of current costs) and future costs are handled within the modelling using learning curves and adjustments for changes in exchange rates.

For gas turbines and conventional Rankine cycle plants (including sub-critical, supercritical and ultra-supercritical, and biomass), Jacobs uses the capital cost estimating tool within the Thermoflow suite of software. This model estimates engineering, procurement and capital (EPC) capital costs based on technical configurations of each plant appropriate for Australian conditions and fuels. Jacobs applies local factors (such as the unit sizing, suitability for Australia's climate and fuel alternatives) for the configuration of the plants and regional factors (such as labour and other costs for Australian construction environments). These factors are based on our experience and judgement.

The cost estimates are refined using adjustment factors where appropriate based on market soundings and information from other projects (including overseas projects).

In addition to the EPC costs, allowances have been made for coal drying costs, connection costs (for electricity and gas where applicable) and owner's costs. Interest during construction costs are handled separately in the modelling.

The cost assumptions are based on AEMO ISP 2018 report.

2.4 South Australian energy plan

On 14th March 2017, the South Australian Government announced its $550 million energy plan, which is designed to stabilise its power system. The plan includes building 275 MW of new high efficiency, fast start, emergency power plant, and conducting a tender for at least 100 MW of battery storage to be installed in time for the summer of 2017/18. The other major aspect of the plan is to initially source 4,500 GWh of electricity from South Australian synchronous scheduled generation in FY2018, growing by 4% p.a. and reaching 6,000 GWh by FY2025. This has been labelled the Energy Security Target (EST) and is expected to have the largest price impact in South Australia.

In the South Australian context, the generation for the EST would be sourced exclusively from conventional gas-fired generation. The latest generation of wind turbines can operate synchronously with the grid and provide frequency ancillary services; However, this class of wind turbine is yet to be deployed in Australia.

We have included the fast start emergency OCGT and battery storage elements of this energy plan and excluded the synchronous generation element in all scenarios to assess the impact of the energy plan to South Australian prices. This is because South Australian government has announced that since they proposed the EST a number of significant changes have occurred in the energy market (i.e. AEMO's requirement to have a sufficient number of synchronous units connected, the potential for synchronous condenser installations in South Australia by ElectraNet, and new batteries installed in that State) and therefore has decided to defer the EST after 2020 and review it again then.

2.5 Snowy hydro expansion

On 15 March 2017, Malcolm Turnbull announced a $2 billion plan to expand the capacity of the Snowy Hydro scheme by another 2,000 MW, which represents almost 50 percent of the current scheme capacity. It is not clear from the announcement whether the additional capacity would increase the net level of hydro generation, or in other words, whether the new capacity would have new hydro inflows that are not diverted from other Snowy generators. We have assumed this is not the case as it would have been an additional selling point of the plan, because additional hydro inflows would put downward pressure on NEM prices. Therefore, we have assumed that the new pump storage generator would only add capacity to the NEM, not energy.

Under this assumption, the price impact of the new Snowy Hydro pump storage scheme would be to slightly raise off-peak prices. It is in these off-peak time periods that Snowy Hydro would generally pump water uphill, enabling it to generate in peak periods. The largest impact would be on the New South Wales and Victorian prices, with a lesser impact expected for South Australia, Queensland and Tasmania. In the future, the scheme may also be pumping in periods of high renewable output, such as the middle of the day when large levels of generation from solar PV are generating or in windy conditions when wind generation provides output.

The impact of the Snowy hydro expansion on LGC prices is expected to be negligible, especially if the scheme does not add energy to the NEM.

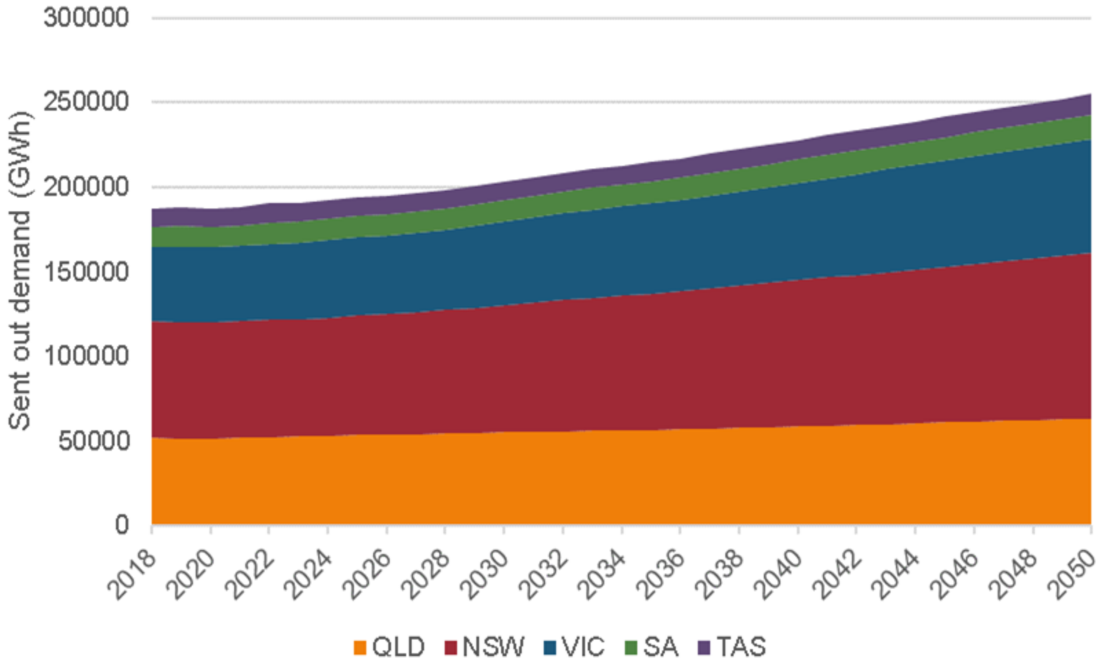
The Snowy Hydro expansion is included in the Neutral scenario.

2.6 Demand

The modelling in this study is based on demand projections contained in AEMO's 2018 ESOO report. The neutral energy demand projections, shown in Figure 2, and the 50% POE peak demand projections are used.

These projections take into consideration population growth, economic growth, and technology uptake (including rooftop PV, electric vehicles, energy efficiency and non-aggregated batteries).

Figure 2: Demand forecast sent out, AEMO neutral scenario



Source: Jacobs' analysis of AEMO demand forecasts ESOO 2018

The energy and peak demand forecast were applied to the 2014/15 actual half-hourly demand profile. The 2014/15 regional load shapes have been used as it reflects demand response to normal weather conditions and captures the observed demand coincidence between regions. Furthermore, the wind profiles for each wind farm in the NEM are based on the 2014/15 year, which means that the market model captures the correlation between wind generation and electricity demand.

The use of the 50% POE peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels and generation dispatch.

The impact of the various state-based energy efficiency schemes on the electricity market is to lower the total demand seen by the grid. This in turn has a flow-on impact on prices, as the lower level of demand places downward pressure. The impact of state-based energy efficiency schemes is already incorporated in the AEMO projections.

2.7 Emission reduction policies

2.7.1 Large Scale Renewable Energy Target

The LRET scheme originally enjoyed bipartisan support from Australia's major political parties and was expanded in 2009 from a 9,500 GWh Mandatory Renewable Energy Target (MRET) by 2010 to a 20% target of 41,000 GWh by 2020. Support for the scheme wavered under Coalition Government and in early 2014 the Government commissioned a report on the merits and impact of the Renewable Energy Target. The report recommended that the target be wound back and, while this position largely opposed by industry, business and government, it did result in a downward revision of the LRET target from 41,000 GWh to 33,000 GWh. The LRET contributed to the Federal Government's 2030/31 commitment to a 28% reduction in emissions relative to 2005 levels and it presently enjoys strong support. In the model the LRET is fixed to 33,000 GWh from 2020 to 2030 and after that the scheme ends.

2.7.2 Commonwealth emission reduction policies

The Federal Government has committed to achieving a 26% emission reduction on 2005 levels by 2030.

The assumed Commonwealth emission reduction target on 2005 levels for the Neutral scenario is the minimum commitment, which is 28 per cent by 2030/31 and 70 per cent by 2050.

2.7.3 Victoria's renewable energy policy

In June 2016, the Victorian Government committed to Victorian renewable energy generation targets of 25 per cent by 2020 and 40 per cent by 2025, also known as the VRET. The VRET was recently announced to be expanded with a state target of 50 per cent renewable generation by 2030.

As a result, the Victorian Government had established the Victorian Renewable Energy Auction Scheme (VREAS) to support achievement of the VRET and called for bids for up to 550 MW of large scale, technology neutral renewable energy, and up to 100 MW of large scale solar-specific renewable energy.

The 2017 VREAS has now been closed and the Victorian Government has already awarded commercial contracts in support of up to 650[9] MW of new renewable energy generation to successful proponents. These proponents will be awarded a 'Support Agreement' with the State of Victoria to ensure revenue certainty for renewable energy projects.

A carbon price mechanism in the form of an EIS has been introduced in the modelling in order to achieve the VRET emissions targets as discussed above.

2.7.4 Victorian Solar Homes Package

Through the Solar Homes Package the Victorian Government will help Victorian households cut their electricity bills through subsiding the rooftop PV and battery installations. Eligible households can claim a rebate up to $2,225 on the cost of a solar PV system or a $1,000 rebate for the replacement of hot water systems with solar hot water. The Solar Homes program promises $1.24 billion in subsidies over 10 years and would roughly triple the level of household solar in Victoria. The rooftop PV forecasts for Victoria have been updated in the model to include the impact of the Solar Homes Program.

2.7.5 Powering Queensland Plan

Even though the modelling focuses on Victorian benefits, the grid is interconnected to other states and therefore cross-regional dependencies exist. The Powering Queensland Plan sets out the Queensland Government's strategy for the short-term and long-term energy transition. The government is investing $1.16 billion on stabilising the electricity prices and transitioning to a low-carbon energy sector (sometimes referred to as the QRET).

The main features of the plan include:

- Provision of electricity price relief by investing $770 million to cover the cost of the Solar Bonus Scheme;
- Direct Stanwell Corporation to undertake strategies to place downward pressure on wholesale prices;
- Investigate the restructure of government-owned generators and the establishment of a 'CleanCo' - a separate generator to operate Queensland's existing renewable and low-emissions energy generation assets and develop new renewable projects;
- Achieve 50% renewable energy by 2030 (referred to as QRET 2nd phase), to reduce emissions with an initial phase of conducting a reverse auction for up to 400 megawatts of renewable energy capacity, including 100 megawatts of energy storage;
- North Queensland energy plan investing $386 million; and

[9] The total capacity of the winning bidders in Victoria was 928 MW but only the 650MW are supported by the Victorian government.

- Maintaining Qld energy system security and reliability.

2.8 Generator cost of supply

2.8.1 Marginal costs

The marginal costs of thermal generators consist the variable costs of fuel supply including fuel transport plus the variable component of operations and maintenance costs. The indicative variable costs for various types of existing thermal plants are shown in Table 4. We also include the net present value of changes in future capital expenditure that would be driven by fuel consumption for open cut mines that are owned by the generator. This applies to brown coal in Victoria.

Table 4: Indicative average variable costs for existing thermal plant

Technology	Variable Cost $/MWh	Technology	Variable Cost $/MWh
Brown Coal – Victoria	$8 - $12	Black Coal – NSW	$19 - $26
Gas – Victoria	$51 - $105	Black Coal - Qld	$10 - $24
Gas – SA	$56 - $77	Gas – Queensland	$58 - $144
Oil – SA	$214 - $340	Oil – Queensland	$255 - $285
Gas Peak – SA	$129 - $271		

2.8.2 Plant performance and production costs

The marginal costs of thermal generators consist of the variable costs of fuel supply including fuel transport plus the variable component of operation costs. For brown coal in Victoria, where the open-cut mine is (mostly) owned by the generator, the variable costs also include the net present value of changes in future capital expenditure for the mine. This makes up about 50% of the variable cost. The same principle is used for the Millmerran and Kogan Creek black-coal-fired generators, which are also co-located with mines in Queensland.

Fixed operating cost data are based on available data on operating cost for like plant and data published by the market operators for their planning processes. For the NEM, fixed operating costs are based on publicly available data from AEMO[10]. Fixed operating cost data change over time in accordance with assumptions on projections of growth in wage rates, which are sourced from Treasury budget projections.

Thermal power plants are modelled with planned and forced outages with overall availability consistent with current performance. Coal plants have available capacity factors between 86% and 95% and gas fired plants have available capacity factors between 87% and 95%. Indicative average variable costs for existing thermal plants are shown in Table 4.

For more detail on the thermal plant properties including variable and fixed O&M costs, refer to Appendix A.

2.8.3 Gas prices

Gas prices are based on neutral price projection in AEMO's 2018 Integrated System Plan (ISP) as part of the 2018 National Electrictiy Forecasting Report.

2.8.4 Coal prices

Black coal prices on world markets have recently fallen after a prolonged period of high prices. Coal prices on export markets are likely to stabilise around current levels in the long term. This will impact on domestic coal prices as these generally reflect export parity prices with a discount for higher ash levels and lower fuel

[10] Jacobs uses the Australian Energy Market Operator's publicly available data to develop fixed costs for conventional coal and gas plant as well as renewable energy technologies. This is located at: http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions. Jacobs' database was used as the source for avoidable operating and maintenance costs, which are employed in the decision-making process for plant mothballing and retirement.

contents. Coal prices will generally impact on the power stations not at mine-mouth (NSW coal-fired plant and central Queensland coal-fired plant), or those associated with a mine that also exports coal.

Brown coal prices are insensitive to movements in global coal markets because brown coal is not exported. Brown coal prices are assumed to remain flat in real terms over the forecast period.

Coal prices are based on the Wood Mackenzie outputs published and used by AEMO as part of the 2018 National Electrictiy Forecasting Report.

2.9 Interconnection and losses

Assumptions on interconnect limits are shown in Table 5. These limits are based on the maximum recorded inter-regional capabilities. The Victorian export limit to Snowy/NSW is sometimes up to 1,300 MW. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong.

Table 5: Interconnection limits – based on maximum recorded flows

From	To	Capacity	Summer
Victoria	Tasmania	478 MW	
Tasmania	Victoria	478 MW	
Victoria	South Australia	650 MW	
South Australia	Victoria	650 MW	
South Australia	Red Cliffs	135 MW	
Red Cliffs	South Australia	220 MW	
Victoria	Snowy	1,300 MW	
Snowy	Victoria	1,900 MW	
Snowy	NSW	3,559 MW	3,117 MW
NSW	Snowy	1,150 MW	
NSW	South Queensland	120 MW	
South Queensland	NSW	180 MW	120 MW
NSW	Tarong	589 MW	
Tarong	NSW	1,078 MW	

2.9.1 Basslink

Basslink has a continuous capacity of 478 MW and a short-term rating up to 600 MW. Basslink has been modelled with an optimised export limit that best uses the available thermal capacity of the cable to maximise the value of export trade. The import limit was represented as a function of Tasmanian load according to the equation published by AEMO. This allows 323 MW of import at 800 MW and 427 MW at 1,100 MW of load.

2.9.2 Inter-regional losses

Inter-regional loss equations are modelled in PLEXOS by directly entering the Loss Factor equations published by AEMO. The losses currently applied are those published in the AEMO's report “Regions and Marginal Loss Factors: FY 2018-19”.

Negative losses are avoided by shifting the quadratic loss equation so that the minimum passes through zero loss.

2.9.3 Intra-regional losses

Intra-regional losses are applied as detailed in the AEMO's report "Regions and Marginal Loss Factors: FY 2018-19".

2.9.4 Future developments

There are several possible interconnection developments being considered as outlined in AEMO's Integrated System Plan 2018[11]. We have assumed that the Group 1 and Group 2 upgrades under this plan proceed, as shown in Table 6. In modelling the NEM, we augment the existing interconnections according to these applicable conceptual augmentations as required.

Table 6: Group 1 and 2 AEMO ISP 2018 Interconnector Upgrades

	From	To	Capacity	Indicative Year
Group 1	Queensland	New South Wales	+190 MW	2020
	New South Wales	Queensland	+460 MW	2020
	Victoria	New South Wales	+170 MW	2020
Group 2	New South Wales	South Australia	+750 MW	2022 to 2025
	South Australia	New South Wales	+750 MW	2022 to 2025
	Queensland	New South Wales	+378 MW	2023

Source: AEMO ISP 2018

The latest 2019/20 AEMO's draft MLF numbers are lower for most regions and this should lead to a slower build of solar in those areas and an increase in spot prices. However, in the longer-term transmission investment should assist in improving the MLF's in weaker parts of the network. In scenarios where a national emissions reduction policy exists, lower MLF values may also increase the bundled price required for new plant as a greater volume of capacity will be needed to meet targets.

2.10 Reserve requirements

Jacobs formulates future NEM development ensuring that the reserve requirements are met in each region at least cost. The minimum reserve levels assumed for each state are based on values specified in AEMO's Electricity Statement of Opportunities, summarised in Table 7

Table 7: Minimum reserve levels assumed for each state

	Queensland	NSW	Victoria	South Australia	Tasmania
Reserve Level	913 MW	-1,564 MW	176 MW [12]	-116 MW [14]	144 MW

The minimum reserve level for Victoria and South Australia combined is now adjusted for reserve sharing to minimise the local reserve requirement in South Australia. This means that Victoria must carry 530 MW when South Australia is partially relying on Victoria. The increase in reserve in Queensland reflects both the increase in the size of the largest unit by 300 MW (Kogan Creek) and the support provided to NSW through increased export power flows.

2.11 New generation entry

After selecting new entry to meet AEMO's minimum reserve criteria, Jacobs' pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. A detailed description of the assumptions around new generation entry are included in Appendix A, section A.6.

[11] AEMO, Integrated System Plan, 2018
[12] Adjusted for reserve sharing between regions

2.12 Renewable Energy Zones

The 34 potential zones of good renewable resources (REZs) across the NEM, presented in AMEO ISP 2018 (shown in Figure 9 in Appendix C), are used as reference to locate new renewable projects added to the system. To identify these REZs, AEMO considers resource quality and diversity, diversity and demand matching, transmission development to access a REZ, system strength and network losses.

3. Approach to Solar Enablement Benefits

3.1 Method

Jacobs has applied a simple but robust approach to estimate the market benefits. The steps outlined below enable estimation of the difference in total generation costs between a market model with and without solar enablement:

1. Project the expected solar uptake and applicable solar generation by development of 30-minute interval load traces (in MW) of small-scale rooftop solar PV for CitiPower, Powercor and United Energy (prepared by VPN/UE).

2. Modelling of the expected tripping of solar inverters in the VPN and UE networks and calculation of the potential loss in PV generation to be supplied to the network (prepared by VPN/UE).

3. Specification of two rooftop PV load traces: one Baseline PV load trace and one Solar Enablement load trace.

4. Scaling both load traces to include PV uptake for the other two Victorian network businesses (AusNet Services and Jemena). The added generation is equal for both traces to assure that we capture only the benefits from the solar enablement by VPN and UE.

5. Development of an up-to-date market model in PLEXOS.

6. Run the developed model two times, once with the Baseline and once with the Solar Enablement PV trace, keeping all other thing equal in the PLEXOS model.

7. Extract the total generation cost per annum and the carbon emissions (combustion and fugitive) per annum and compare both model outputs.

The first two steps of this method have been executed by VPN and United Energy and the data has been provided to Jacobs for further adjustment and analysis as per the included further steps.

By comparing the model outputs the reduction in total generation cost between the two models is the main market benefit for the solar enablement project. A secondary benefit is the reduction in carbon emissions resulting from the lower utilisation of conventional power sources (coal and gas). The reduction in emissions can be monetised by multiplying the tonnes of carbon saved by a carbon price (e.g. Australian ACCU or ETS).

The total generation cost is defined as:

Total Generation Cost = Generation Cost + Start & Shutdown Cost + Emissions Cost

> *Where the Generation Cost is the total variable cost of generation which includes the fuel and other variable costs.*

Potential deferral of capital cost from reduction in investment of central generation has not been considered in this project. It is possible that in the long-term solar enablement can result in the deferral of large-scale generation and thus higher benefits, but this requires a more dynamic market long-term modelling assessment that is beyond the scope of this project.

3.2 Solar PV projections

3.2.1 Small scale PV in the NEM

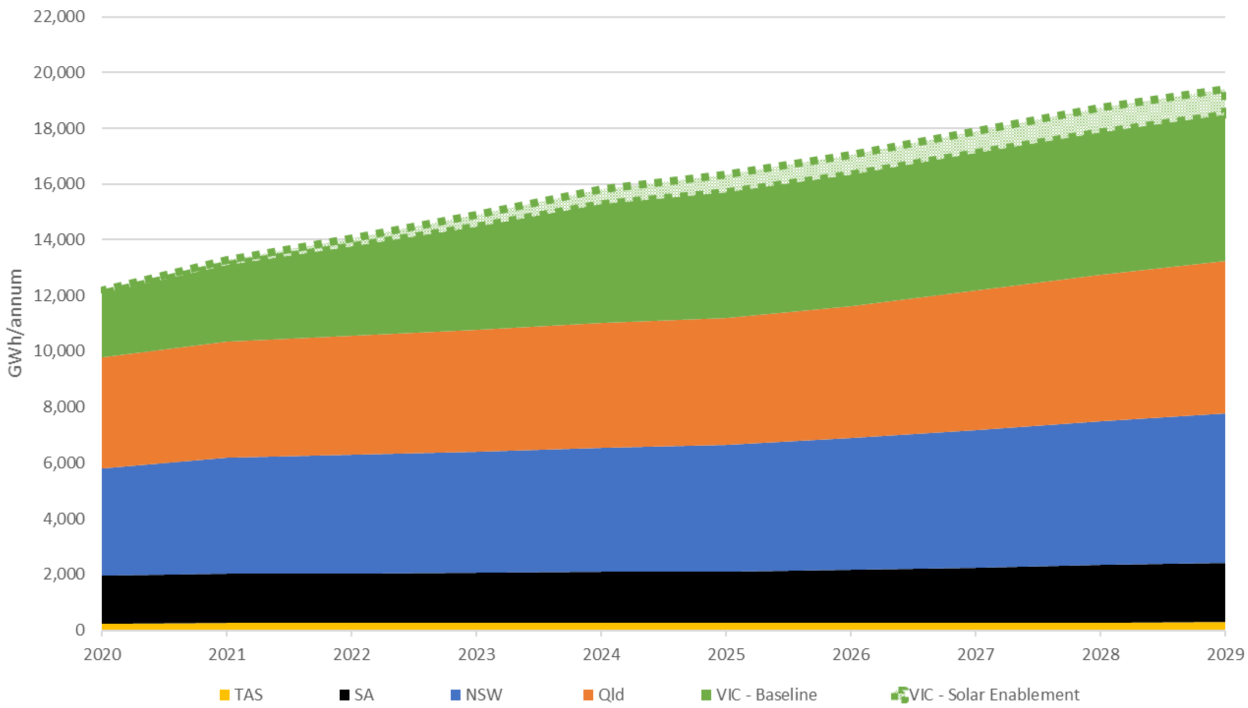
For all NEM states (except for Victoria) we have applied the Neutral 50 POE rooftop solar PV load traces from the ESOO 2018 demand forecast to our modelling. Figure 3 shows the equivalent AEMO projected PV annual generation for the Neutral scenario.

The green shaded area represents the Victorian projection of rooftop solar PV. This forecast is not based on AEMOs ESOO 2018 demand forecast but has been constructed specifically for the solar enablement project evaluation as it assumes a higher uptake of rooftop PV resulting from the Victorian Solar Homes program (discussed in more detail in section 3.2.2.

The solid green shaded area is the estimated generation forecast we have used for our baseline rooftop PV projections, assuming VPN and United Energy do not proceed with the solar enablement project (effectively the 'do nothing' option). This forecast is higher than AEMOs rooftop PV forecast for Victoria because of the inclusion of rooftop PV uptake growth due to the Victorian Solar Homes program.

The dotted light-green area is the additional solar PV generation that is expected when VPN and United Energy proceed with the enablement project. The project is expected to significantly decrease the tripping of solar inverters and therefore more GWh's per annum (increasing over time) will be generated, as can be observed in the figure below.

Figure 3: Projected small-scale PV generation by NEM region (GWh)[13]



Source: Jacobs analysis of AEMO rooftop PV projections and VPN/UE projections

The Victorian rooftop PV projections have been developed using several sources, the most important are:

- Projections by CitiPower, Powercor and United Energy of the expected uptake of rooftop PV in their respective network areas.

[13] In recent history NSW, Qld and SA have seen high penetration levels of small-scale rooftop PV, while Victoria's penetration levels have lagged somewhat behind compared to the state's population (2nd largest state in Australia). The Solar Homes program is expected to close this gap in the next decade.

- Increased half hourly generation of rooftop PV resulting from the solar enablement upgrade project.
- Jacobs rooftop PV projections for Victoria specifically considering the impact of the Victorian Solar Homes program, combining analyses and insights from several projects for industry clients and government agencies.
- Information on the average size of the Victorian DNSPs from e.g. the State of the Energy Market report 2018, published annually by the AER.
- Additional market modelling insights and analysis of historical trends.

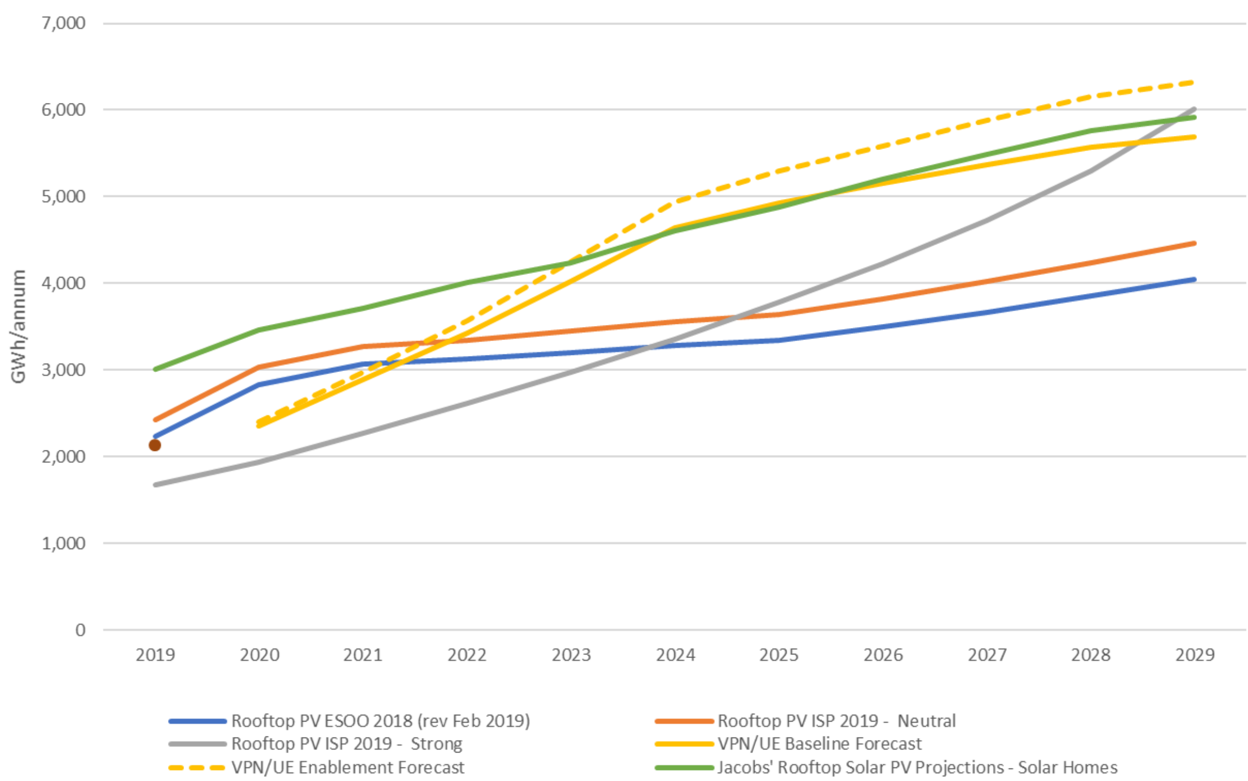
3.2.2 Comparison of rooftop PV projections in Victoria

To put the developed rooftop PV forecast for Victoria in perspective we have included a comparison of rooftop PV forecasts in Figure 4. The yellow and yellow dotted lines are the Baseline forecast and Enablement forecast for VPN and UE. They are significantly above the Neutral AEMO forecasts from the ESOO 2018 and the draft forecast from the ISP 2019—neither of which include the impact of the Solar Homes program. Although the ISP 2019 Strong forecast starts lower the estimated generation from rooftop PV for this scenario in 2029 is comparable to generation projections developed for this analysis (yellow lines).

The green line is Jacobs' rooftop solar PV projection developed for our market modelling activities (not developed in respect to this engagement) as an alternative to the available AEMO forecasts, by including the impact of the Victoria Solar Homes project. From 2024 onwards, this projection is largely in line with developed VPN/UE Baseline forecast. Only in the period 2020 to 2023 the Jacobs' forecast is higher.

The red dot is a PV generation estimated based on the current registered small-scale solar PV resources. This number is likely an underestimation of the actual generation as there is a lag of up to 12 months of registration of new small-scale PV systems.

Figure 4: Comparison of rooftop PV generation forecasts for Victoria



Source: Jacobs' analysis of data from AEMO ISP 2019, ESOO 2018, VPN and United Energy.

As the actual generation from small scale PV in 2019 is likely higher than projected in the ESOO, we believe that the VPN/UE forecasts and therefore the potential solar enablement benefits are likely somewhat underestimated in the short term. The total benefits from the analysis up to and including 2023 can therefore be considered conservative.

4. Results

4.1 Base-line market modelling results

Our market modelling with PLEXOS has been based on an existing Jacobs in-house model developed for our customers to provide wholesale electricity price forecasts. A detailed description of the assumptions used in our market modelling can be found in Section 2.

To estimate the baseline market cost we extracted the annual total NEM generation cost and the total NEM carbon emissions from PLEXOS. The model outputs are included in Table 8.

Table 8: Base-line total generation costs and carbon emissions

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total rooftop PV generation in GWh/a - VIC	2,274	2,745	3,196	3,696	4,273	4,514	4,717	4,922	5,111	5,231
Total generation costs $m/a	3,341	3,311	3,550	3,708	3,671	3,747	3,731	3,569	3,720	3,729
Carbon emissions mega-tonnes/a	141.6	138.4	136.8	135.2	135.7	134.0	128.4	124.0	124.6	118.9

The table values represent the Base-line values to which the benefits are calculated. The Solar Enablement output in the next section will show lower overall generation costs as well as lower carbon emissions, but higher Victorian small-scale rooftop solar PV generation.

4.2 Solar Enablement modelling results

Table 9 includes the results from the market modelling including the generation of the small-scale rooftop PV unlocked through the Solar Enablement project. The higher rooftop solar generation has reduced overall total generation costs and greenhouse gas emissions from combustion and fugitives compared to the baseline.

Table 9: Solar Enablement total generation costs and carbon emissions

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total rooftop PV generation in GWh/a - VIC	2,370	2,918	3,485	4,129	4,803	5,141	5,426	5,712	5,985	6,158
Total generation costs $m/a	3,338	3,306	3,540	3,694	3,654	3,727	3,702	3,552	3,672	3,703
Carbon emissions mega-tonnes/a	141.5	138.3	136.5	134.9	135.3	133.5	127.9	123.4	124.0	118.2

4.3 Solar Enablement analysis

4.3.1 Price and generation cost dynamics

The basis for market benefits from solar enablement is avoided centralised generation during the day in the NEM. The principle is that for each MWh of additional solar PV exported an equivalent amount of generation by conventional thermal power can be avoided. Therefore, it is important to understand the evolving market generation mix to be able to interpret the veracity of the market benefit estimated by the model.

The benefits are related to the variable costs of thermal generation with the price of fuel as the largest component. Therefore, if gas fired generation is displaced by solar PV the variable generation costs can be as high as $274/MWh (maximum average variable cost of gas fired generation in the NEM, refer to Table 4), while in a far less beneficial case additional rooftop PV export would only displace Victorian coal fired power which has an average variable cost of only $8 to $12 per MWh.

The worst case includes periods of overcapacity of renewable generation with zero to very low variable costs in the market (wind and solar), in this case the benefit of additional rooftop PV export will be close to zero.

Conversely, energy storage like batteries and pumped hydro can support the market benefits of additional PV exports by charging during the day (off-peak periods) and discharging at times of the day when prices and generation costs are higher (peak periods). This is called 'load shifting' as the storage virtually shifts load from peak to off-peak periods. By shifting load, the increased demand from storage assets will put upward pressure on the daytime prices, increasing the value of solar PV generation. Additional market benefits will materialise through storage taking advantage of higher prices during the evening peak. This reduces overall generation costs, as storage generation (charged using cheap solar power) displaces expensive gas peaking generation and puts downward pressure on the peak prices.[14]

The dynamics discussed above are captured in Figure 5. This figure shows the unlocked generation from the Solar Enablement project set against the interval prices for three years (2020, 2023 and 2029). The prices during the day are decreasing into the future (dotted lines) as the base amount of rooftop PV and the enablement grows (solid lines). The large single dot indicates the average variable generation cost reduction per MWh unlocked solar (Solar Enablement benefit $/MWh). It shows that the Solar Enablement benefit in $/MWh is below the average day-time interval price levels in their respective years. This is as expected because the variable costs are only partially driving the prices.

Figure 5: Solar Enablement additional export in VIC and interval price levels

Source: Jacobs' analysis of PLEXOS outputs

Furthermore, it can be observed that while day-time price-levels drop significantly from 2020-2023 the decrease in interval price levels between 2023 and 2029 is far less pronounced, while the evening peak price levels show a significant drop from 2023 to 2029. As discussed previously this is the effect of higher penetration levels of energy storage in the market. Among other storage projects, Snowy 2.0 is expected to start operations in 2025/26, shifting cheap solar energy generation from daytime (supporting daytime prices) to evening peak, lowering evening price levels.

[14] This benefit is not captured in the market benefits for Solar Enablement as it is dependent on storage to materialise and therefore only partially attributable to additional rooftop PV export.

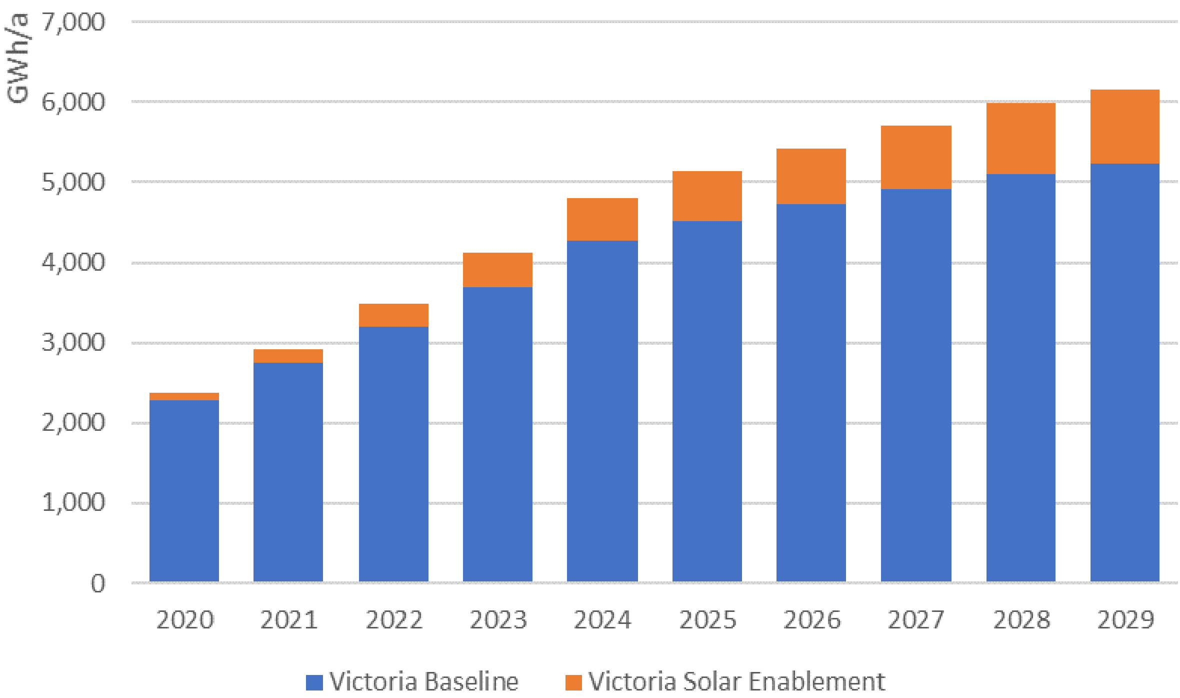
4.3.2 Solar Enablement benefits

Projected development of small-scale rooftop solar PV generation over the ten-year project period is included in Figure 6. Enabled solar PV generation shows growth over the ten-year period from approximately 100 GWh in 2020 to almost 1,000 GWh in 2029, approximately 15% additional generation that can be unconstrained.

The associated generation cost reductions and carbon emission reductions are included in Table 10. The cumulative total generation cost reduction is $192 million for the FY2020-2029 period, as well as a total emissions reduction of 62.6 mega-tonnes of carbon for the same period.

We have also calculated the $/MWh additional rooftop PV generation resulting from the Solar Enablement project. This cost reduction over the project period ranges from approximately $21 to $55 per MWh (refer to Table 10).

Figure 6: Small scale rooftop PV generation in Victoria



Furthermore, the $/MWh benefit from carbon emissions reduction are estimated from roughly $10 to $13 per MWh. For calculating the benefit of reduced carbon emissions, we have used the March 2019 ACCU price of $15.35, which is a conservative assumption considering that other carbon trading schemes have much higher price levels e.g. the current EU ETS (29 July 2019) is trading at about 28 euro (~A$45).

Table 10: Solar Enablement differences

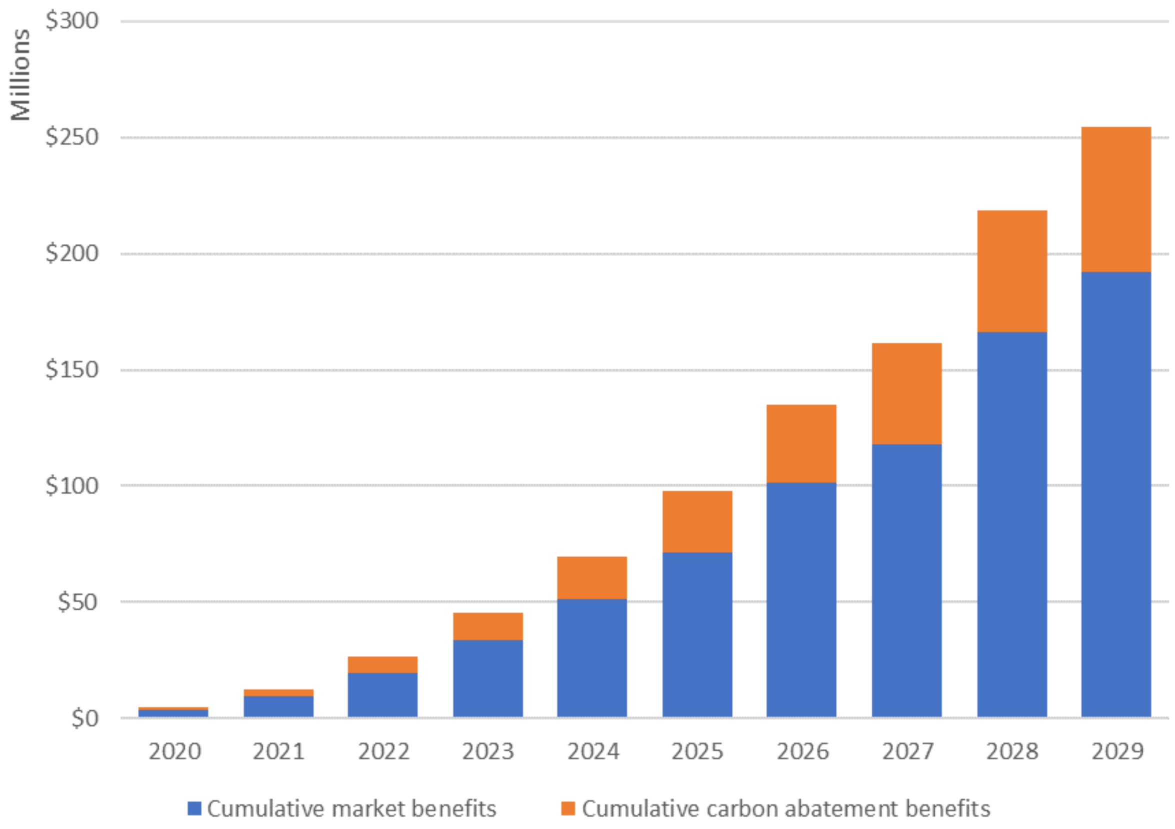
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Additional **rooftop PV generation in GWh/a - VIC**	96	173	289	433	530	626	709	790	875	927
Generation costs *reduction* $m/a	3.77	5.45	10.06	14.56	17.50	20.20	29.98	16.65	47.88	25.88
Generation costs reduction per MWh additional rooftop PV generation ($/MWh/a)	$39	$32	$35	$34	$33	$32	$42	$21	$55	$28
Carbon emission *reduction kilo*-tonnes/a	80.7	149.4	243.0	301.5	413.9	524.1	467.4	640.7	600.9	654.2

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Carbon emission benefit at ACCU of $15.35 (March 2019) in $m/a	1.24	2.29	3.73	4.63	6.35	8.05	7.17	9.83	9.22	10.04
Carbon emission benefits per MWh additional rooftop PV generation ($/MWh/a)	$13	$13	$13	$11	$12	$13	$10	$13	$10	$11
Total benefits in $m/a	5.01	7.74	13.79	19.19	23.9	28.3	37.2	26.49	57.10	35.92
Total benefits in $/MWh/a	$52	$45	$48	$45	$45	$45	$52	$34	$65	$39

Based on the information in the table above the weighted average market benefit is $35.22/MWh and the weighted average carbon abatement benefit is $11.48/MWh, which makes the total benefit approximately $47 per MWh over the FY2020-2029 project period.

Figure 7 depicts the cumulative benefits for the project period reaching just under $200 million for market benefits only and just over $250 million for both market and carbon abatement benefits.

Figure 7: Cumulative market and carbon abatement benefits



The results as discussed in this section have been provided to VPN and United Energy to be included in their financial models.

Appendix A. Modelling techniques and forecasting performance

The wholesale market price forecasts were developed utilising Jacobs NEM model having regard to the renewable and abatement markets for the Renewable Energy Certificates (LGC). This model is based on the PLEXOS market modelling software, licensed from Energy Exemplar. The Jacobs Renewable Energy Market Model REMMA was used to prepare the Large Generation Certificate price projection. This Appendix discusses these tools and how they were applied.

A.1 PLEXOS Model[15]

PLEXOS is a sophisticated stochastic mathematical model developed by Energy Exemplar (formerly Drayton Analytics) which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming that co-optimises generation dispatch, transmission power flow and ancillary services and integrates them with optimisation of hydro-electric generation and emissions abatement.

The long-term capacity expansion model in PLEXOS is called "LT Plan". The purpose of the LT Plan model is to find the optimal combination of generation new builds and retirements and transmission upgrades that minimises the net present value of the total costs of the system over a long-term planning horizon. That is, to simultaneously solve a generation and transmission capacity expansion problem and a dispatch problem from a central planning, long-term perspective. Planning horizons for the LT Plan model are user-defined and are typically expected to be in the range of 20 to 30 years.

Once the capacity expansion plan has been determined, PLEXOS can then perform more detailed simulations, typically one year at a time, to more accurately model system dispatch and pricing. Prior to optimising dispatch in any given year, PLEXOS schedules planned maintenance and randomly pre-computes a user-specified number of forced outage scenarios for Monte Carlo simulation. Dispatch is then optimised on an hourly basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, inter-connector constraints and any other operating restrictions that may be specified.

Expected hourly (or half-hourly) electricity prices for the NEM are produced as output, calculated either on a marginal cost bidding basis, or if desired, by modelling strategic behaviour, based on gaming models such as the Cournot equilibrium, long-run marginal cost recovery (or revenue targeting) or shadow pricing. Jacobs uses a combination of user-defined bids and the Nash-Cournot game to produce the price forecasts and has benchmarked its NEM database to 2015/16 market outcomes using this algorithm to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes. There is no guarantee that such bidding behaviour and contracting levels will continue in the future but there is evidence of stable bidding behaviour for similar market conditions that supports this approach.

The impact of financial contracts on the bidding strategy of market participants can be incorporated either explicitly through specification of volumes and prices of individual contracts, or implicitly by specifying a proportion of a portfolio's output that is typically contracted, and hence restricting strategic bidding to the uncontracted proportion.

There are four key tasks performed by PLEXOS:

- Forecast demand over the planning horizon, given a historical load profile, expected energy generation and peak loads.
- Schedule maintenance and pre-compute forced outage scenarios.
- Model strategic behaviour, if desired, based on dynamic gaming models

[15] PLEXOS the model used by the Australian Energy Market Operator (AEMO). Since AEMO operates and maintains the model several input variables (e.g. network constraints, historical wind and solar profiles) are developed and maintained by AEMO, these are used by Jacobs as well. It is used by energy modellers in many countries.

- Calculate hourly unit dispatch given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, other operating restrictions (such as spinning reserve requirements) and variable operating costs including fuel costs and price impacts of abatement schemes.

The model can estimate:

- Hourly, daily, weekly and annual generation levels, SRMC, fuel usage and capacity factors for individual units.
- Regional generation and prices for each trading period.
- Flows on transmission lines for each trading period.
- Total costs of generation and supply in the NEM including capital costs of generation, fixed and variable fuel costs, and fixed and variable non-fuel operating costs. This can be done for the system as a whole, for generation companies operating in the system and for each generating plant.
- Reliability, which can be measured in terms of expected energy not served and expected hours of load shedding.
- Company and generator costs and operating profits.
- Emissions of greenhouse gases. Emissions for each fuel type are modelled to get total system emissions.

One of the key advantages of this model is the detail in which the transmission constraints of electricity grids can be modelled. The PLEXOS NEM model includes 5 regions: Tasmania, South Australia, Victoria, New South Wales, and Queensland. Inter-regional transmission constraints and the dispatch impacts of intra-regional transmission constraints are modelled using the constraint set provided by AEMO as used in the 2015 NTNDP[16]. These constraints are dynamic with the limits typically being a function of regional demand, flows on other lines, inertia, number of units generating, and generation levels of relevant units. AEMO currently provides parameters for these constraints to 2050.

The PLEXOS model interacts with REMMA to produce a holistic projection including thermal and renewable capacities for the NEM and WEM. REMMA provides renewable supply curves for the PLEXOS model by region by technology type, and PLEXOS optimises the timing of renewable resources to satisfy the LRET at least cost. PLEXOS will also use these curves to build renewable energy plant if and when it is competitive against conventional thermal generation technology.

A.2 PLEXOS modelling assumptions

The basic assumptions that underpin the modelling include the following:

- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the long run marginal cost of new entry.
  - In the modelling of energy market impacts, intra-regional marginal loss factors are assumed to be unchanged from those set by AEMO in 2017/18. That is, the loss factors are assumed to be the same across all years and across all scenarios.
  - Losses across the inter-regional interconnects are modelled directly in the PLEXOS model using equations that mimic the transfer equations used in AEMO dispatch algorithms.

The modelling of uptake of renewable energy generation under the RET target is based on data available on the individual projects. Each new solar project requires about 12 to 18 months of construction time, whereas other generation technologies require around 2 years of construction time.

The PLEXOS NEM model includes 5 regions: Tasmania, South Australia, Victoria, New South Wales, and Queensland. Inter-regional transmission constraints and the dispatch impacts of intra-regional transmission constraints are modelled using the constraint set provided by AEMO as used in the 2017 National Transmission

[16] See http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities

Network Development Plan (NTNDP). These constraints are dynamic with the limits typically being a function of regional demand, flows on other lines, inertia, number of units generating, and generation levels of relevant units.

New wind farms in Jacobs' PLEXOS NEM database are modelled as multiple units, each with a maximum capacity of 1 MW. Wind projects in the Jacobs renewable energy database are mapped to wind bubble locations provided in the 2017 NTNDP.

The wind projects for each bubble are aggregated into cost tranches of around 600 MW each. Each tranche has construction costs by year, maximum capacity built by year and marginal loss factor specified. The new entrants use the wind availability profile specified by AEMO in the NTNDP for that location.

These new entrant wind farms are included within transmission constraints, specified in the 2017 NTNDP, by way of their connection point.

A.3 Price and revenue factors

Future wholesale electricity prices and related market outcomes are essentially driven by the supply and demand balance, with long-term prices being effectively capped near the long run marginal cost of new entry on the assumption that prices above this level provide economic signals for new generation to enter the market. Consequently, assumptions on the fuel costs, unit efficiencies, and costs of new plant and carbon prices will have a noticeable impact on long-term price forecasts. Year-to-year prices will deviate from the new entry cost level based on the timing of new entry. In periods when new entry is not required, the market prices reflect the cost of generation to meet regional loads, and the bidding behaviour of the market participants as affected by market power.

A.4 Structural assumptions

Key assumptions used in the modelling include:

- Capacity is installed to meet the target reserve margin for the NEM in each region. Some of this peaking capacity may represent demand side response rather than physical generation assets.
- Medium demand growth projections, with annual hourly shapes for underlying demand consistent with the relative growth in summer and winter peak demand. The load shape was based on 2014/15 load profile for the NEM as this is most recent year with normal weather patterns. This hourly load pattern has been adjusted to take into account the generation profile for the historical uptake of small-scale roof-top PV generation.
- Wind generation is modelled as:
  - All individual wind farms throughout the NEM are modelled with their 2014/15 wind profiles.
  - New wind farms are allocated by the model to AEMO's wind bubbles, where the profiles for these have been sourced from AEMO's NTNDP studies, which are publicly available.
- Generators behaving rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.
- Infrequently used peaking resources are bid near Market Price Cap (MPC) or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- Additional renewable energy is included for expected greenpower and desalination purposes, as well as for the ACT target.
- The assessed demand side management for emissions abatement or otherwise economic responses throughout the NEM is assumed to be included in the NEM demand forecast.

A.5 Participant behaviour

Market structure

We assume the current market structure continues under the following arrangements:

- Victorian and New South Wales generators are not further aggregated.
- The generators' ownership structure in Queensland remains as public ownership.
- The South Australia assets continue under the current portfolio groupings.
- Swanbank E power station was mothballed in 2015 and will be brought back in line with the recent announcement in 2018. The remaining half of Pelican Point's capacity is also back from mothballing from 1 July 2017. The following plants have been decommissioned: Wallerawang Power Station in NSW, Northern Power Station in South Australia and Hazelwood Power Station (from the end of March 2017), and Liddell will be decommissioned in financial year 2023 as per AGL's announcement.

Contract position and bidding

Bidding of capacity depends on the contracting position of the generator. Capacity under two-way contracts will either be self-committed[17] for operational reasons or bid at its marginal cost to ensure that the plant is earning pool revenue whenever the pool price exceeds the marginal cost. Capacity which backs one-way hedges will be bid at the higher of marginal cost and the contract strike price, again to ensure that pool revenue is available to cover the contract pay out. This strategy maximises profit in the short-term, excluding any long-term flow on effects into the contract market.

Bidding strategies chosen in the modelling are typically benchmarked to what is considered to be a representative historical year, and then projected forward with the calibrated PLEXOS bidding parameters locked in. In our most recent modelling we have found that NEM projected prices fall well short of forward curve prices if we use our typical strategic bidding parameters, which are benchmarked to achieve average price outcomes that were achieved in 2014/15. We could only replicate the 2017/18 forward curve by benchmarking the model to 2016/17 price outcomes.

A.6 New generation entry

After selecting new entry to meet AEMO's minimum reserve criteria, Jacobs' pool market solution indicates whether prices would support additional new entry under typical market conditions and these are included in the market expansion if required. We assume that:

- Some 75% of base load plant capacity will be hedged in the market and bid at close to marginal cost to manage contract position.
- New entrants will require that their first-year cash costs are met from the pool revenue before they will invest.
- The next new entrants in Victoria will be either peaking plant to meet reserve requirements or new combined cycle plant when such plant can achieve at least 50% capacity factor. Jacobs does not expect that new brown coal without carbon capture and storage capability is ready to be the price setter for new entry in Victoria until after 2029/30, and even then, only with high gas prices.
- Infrequently used peaking resources are bid near MPC or removed from the simulation to represent strategic bidding of such resources.

The new entry cost for Tasmania is based upon the lower of the cost of imported power through new transmission capacity from the mainland on a new link or a new combined cycle gas fired plant in Tasmania. As

[17] "Self-committed" means that the generator specifies the timing and level of dispatch with a zero-bid price. If generators wish to limit off-loading below the self-commitment level, a negative bid price down to -$1,000/MWh may be offered. This may result in a negative pool price for generators and customers.

gas price rises, the cost of imported power becomes cheaper than local CCGT generation, particularly as lower emission generation becomes available on the mainland.

Cost and financing assumptions used to develop the long-term new entry prices are provided in Table and are applicable to the financial year 2017/18 in December 2016 dollars. The real pre-tax equity return applied was 13% and the CPI applied to the nominal interest rate of 8% was 2.1%. The capital costs are generally assumed to remain flat over the modelling horizon. The debt/equity proportion is assumed to be 60%/40%. This gives a real pre-tax vanilla WACC of 8.42% pa.

Table A1: New entry cost and financial assumptions ($ December 2016 for 2017/18)

State	Type of Plant	Capital Cost $/kW	Capacity Factor	Fuel Cost $/GJ	WACC (% real)	WACC (% nominal, vanilla)	Interest Rate (% nominal)	Debt Level	LRMC $/MWh
SA	CCGT	$1,423	89.7%	$10.95	8.42%	10.52%	8.0%	60%	$109
SA	OCGT	$1,127	93.4%	$10.95	8.42%	10.52%	8.0%	60%	$133
VIC	CCGT	$1,339	89.7%	$10.94	8.42%	10.52%	8.0%	60%	$99
VIC	OCGT	$915	93.4%	$10.94	8.42%	10.52%	8.0%	60%	$121
NSW	CCGT	$1,339	89.7%	$11.16	8.42%	10.52%	8.0%	60%	$100
NSW	OCGT	$915	93.4%	$11.16	8.42%	10.52%	8.0%	60%	$126
QLD	CCGT	$1,339	89.7%	$9.55	8.42%	10.52%	8.0%	60%	$88
QLD	OCGT	$915	93.4%	$9.55	8.42%	10.52%	8.0%	60%	$117

Note: fuel cost shown as indicative only, AUD/USD exchange rate assumed at 0.75.

The above Table A1 assumes an exchange rate of AUD/USD at 0.75. A lower exchange rate would drive the overall costs higher as the investments costs increase.

The availability factors are applied as capacity factors in Table to allow us to approximate a time-weighted new entry price in each state that can rapidly be compared to the time-weighted price forecasts to determine whether or not new entry would be encouraged to enter the market.

New entry prices include hybrid options such as wind supported by gas generation as well as solar supported by gas generation. Over the longer term this means that growing carbon prices are offset by improved capacity factors of renewable generation and that gas prices have a reduced impact over long term prices in a world where higher levels of renewable generation are plausible when combined with firming arrangements.

New entry costs do not have an impact on market prices for energy until after 2030 due to the initial supply surplus, the expected contribution from renewable energy projects, and the low forecast demand growth. There will be very limited additional GT capacity after 2030.

A.7 REMMA

REMMA is Jacobs' renewable energy market model. It was used to provide an indication of the future contract price for Large Generation Certificates (LGCs) for each market scenario.

The Australian renewable energy market was modelled in REMMA, which is Jacobs' renewable energy model. REMMA is a tool that estimates a least cost renewable energy expansion plan and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality).   REMMA is an Excel application based on a database of nearly 900 existing, committed, proposed and generic projects across Australia.

It is Jacobs' practice to run Strategist in tandem with the renewable energy market model to determine that the wholesale market solution is also compatible and most efficient with regard to renewable energy markets. Additional renewable generation has the effect of reducing wholesale prices while reduced wholesale prices typically have the effect of reducing investment in renewable generation. Iteration of these models in tandem typically allows the overall solution to converge to a stable model of consistent wholesale and renewable energy markets.

Projecting LGC prices with the REMMA model is based on the assumption that the price of the LGC will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the LGC provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the LGC target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource availability and regulatory limits on uptake. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects. Jacobs has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the LGC price path. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects.

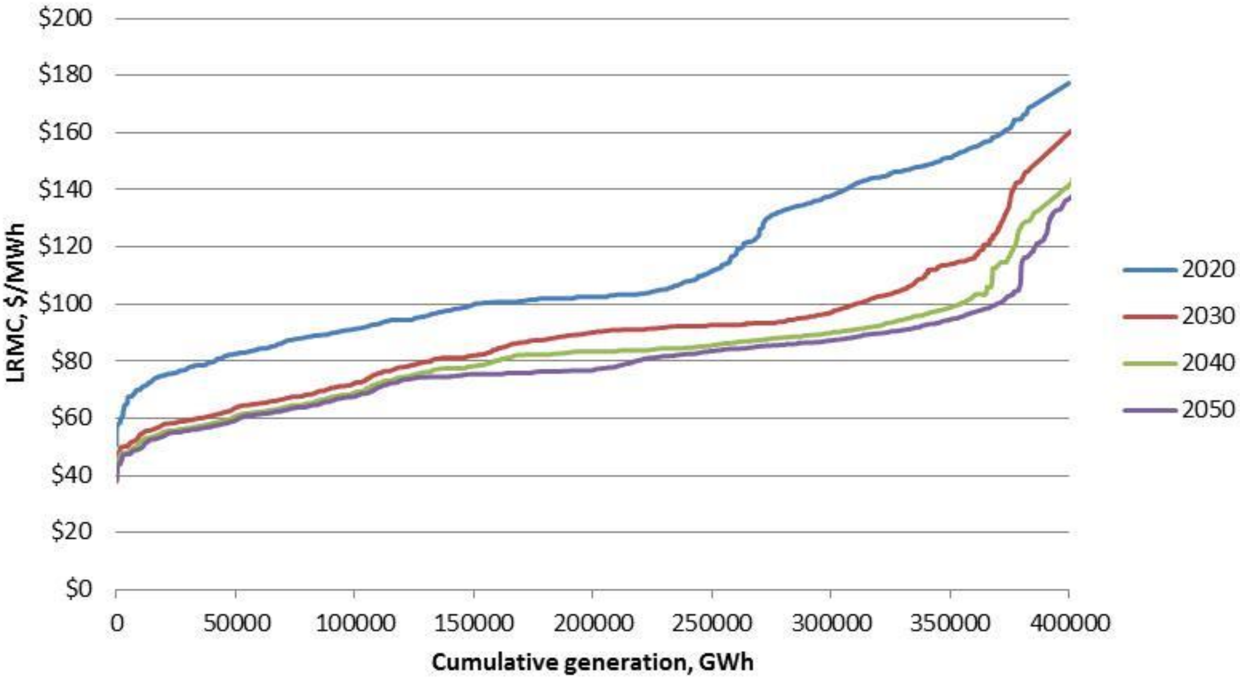
The prices calculated by REMMA represent the price for a new LGC contract in each year. Thus, if a project's LGC output is contracted over 20 years at the real price in the first year of service, it will meet its project life costs from the LGC revenue and the projected energy market revenue. If the project's LGC output were traded in contracts over shorter periods or on the spot market, it may earn more if LGC price is rising or less if LGC price is falling over life relative to the first-year contract price. The financial analyst should determine the renewable energy project revenue having regard to the contracting strategy that would describe the mix of short and long-term contracting. The annual contract price may be taken as an indication of spot price, although in reality, spot prices would be more volatile than indicated by the LGC contract price profile over time.

A.8 Renewable energy database

For the purposes of forecasting renewable energy prices, a critical requirement is the database of potential renewable energy projects. Jacobs has developed a database which includes existing, committed, and prospective projects including some allowance for generic projects based on projections by industry organisations. With the continuing aftermath of the global financial system, we have maintained the financial parameters with debt level to 60%, and the 1% premium to return on debt, reflecting the increased scarcity of capital funding, bringing to it 5.4% in real terms. The resulting pre-tax real WACC is now 7.8% for renewable energy projects.

Figure **8** shows the cumulative renewable energy supply curve developed from the database for all proposed renewable plants. The supply curve includes all proposed resources expected to be available until 2030. The figure illustrates how the higher the LRMC of additional plant added in a particular year increases due to less favourable conditions such as location. The lowering over the curve over the years shown is indicative of the learning curve of renewable technologies.

Figure 8: Renewable Energy Supply Curve to 2030, all proposed renewables ($ December 2016)



Most of the available wind projects are in the cost range of $60 to $95/MWh. Since the window for development of new resources is now 2018 to 2020, it can be reasonably expected that the candidate projects for development in this period have mostly been identified publicly, and so we would not expect large changes in the cost curve, at least until 2020.

Appendix B. Costs and performance of thermal plants - NEM

The following Table A2 shows the proposed parameters for power plants. Costs are reported in December 2017 dollars for 2017/18. The impact of carbon price on variable costs is not included in the Table A2.

Plant	Full Load Heat Rate SO (GJ/MWh)	Total Sent Out Capacity (MW)	Available Capacity factor (%)	Variable O&M ($/MWh)	Fixed O&M ($/MW/year)	AUX LOSSES %
Tasmania						
Bellbay Three	13.5	119.4	93.90%	$4.60	$15,178	0.50%
Tamar Valley CCGT	7.8	201.8	93.00%	$3.07	$15,178	3.00%
Tamar Valley GT	11.5	57.7	93.90%	$4.60	$15,178	0.50%
Victoria						
Somerton	13.5	161.7	83.90%	$3.07	$15,178	0.50%
Bairnsdale	11.5	83.6	93.30%	$4.60	$15,178	0.50%
Jeeralang A	13.75	230.8	95.00%	$9.21	$15,178	0.50%
Jeeralang B	12.85	253.7	95.00%	$9.21	$15,178	0.50%
Laverton North	11.55	338.3	93.90%	$4.60	$15,178	0.50%
Loy Yang A	11.58	2043	88.70%	$1.23	$151,458	10.00%
Loy Yang B	11.7	966	93.10%	$1.23	$119,712	8.00%
Valley Power	13.75	334.3	95.00%	$9.21	$15,178	0.50%
Yallourn	12.91	1361.6	79.80%	$3.67	$157,336	8.00%
Newport	10.33	484.5	93.00%	$3.07	$46,602	5.00%
Mortlake	10.78	550.2	93.00%	$3.90	$15,178	8.00%
Qenos Cogeneration	11	21	93.30%	$2.21	$10,689	2.40%
South Australia						
Angaston	9	49.8	99.40%	$13.16	$15,178	0.50%
Dry Creek	17	147.3	86.10%	$9.21	$15,178	0.50%
Hallett	15	220	88.30%	$10.51	$15,178	0.50%
Ladbroke Grove	11.5	83.6	92.10%	$7.66	$15,178	0.50%
Mintaro	16	89.6	88.10%	$9.21	$15,178	0.50%
Osborne	8.0	185.4	93.90%	$2.98	$10,689	2.40%
Pelican Point	7.71	462.6	91.40%	$3.07	$10,689	2.40%
Port Lincoln	11.67	72.6	91.40%	$9.21	$15,178	0.50%
Quarantine	11.5	217.9	89.10%	$9.78	$15,178	0.50%
Snuggery	15	65.7	88.10%	$9.21	$15,178	0.50%
Torrens Island A	10.8	456	87.70%	$9.21	$45,427	5.00%
Torrens Island B	10.5	760	87.70%	$2.29	$45,427	5.00%
NSW						
Bayswater	10	2592.7	85.80%	$3.07	$57,077	6.06%
Colongra	11.84	720.4	91.90%	$10.58	$15,178	0.50%
Eraring	10.08	2707.2	75.20%	$3.07	$57,077	6.00%
Hunter Valley	23.38	49.8	89.10%	$10.58	$15,178	0.50%
Liddell	10.38	1936.4	54.70%	$2.76	$60,605	6.00%
Mt Piper	9.93	1259.6	86.90%	$2.92	$57,077	6.00%
Tallawarra	7.17	422	92.30%	$3.89	$10,689	3.00%
Uranquinty	10.98	660.7	93.30%	$3.71	$15,178	0.50%
Vales Point B	9.87	1240.8	80.10%	$3.84	$57,077	6.00%
Queensland						
Barcaldine	11.5	36.8	91.40%	$4.60	$15,178	0.50%
Braemar	11	1017.9	94.20%	$3.86	$15,178	0.50%
Callide B	9.88	658	65.90%	$2.21	$57,718	6.00%
Callide C	9	846	81.20%	$1.53	$57,718	6.00%
Condamine	7.8	131.0	94.20%	$3.07	$35,272	3.00%
Darling Downs	7.7	611.1	94.20%	$3.07	$35,272	3.00%
Gladstone	10.22	1579.2	75.20%	$1.35	$60,605	6.00%
Kogan Creek	9.5	699.4	82.30%	$1.38	$68,407	6.00%

Plant	Full Load Heat Rate SO (GJ/MWh)	Total Sent Out Capacity (MW)	Available Capacity factor (%)	Variable O&M ($/MWh)	Fixed O&M ($/MW/year)	AUX LOSSES %
Millmerran	9.88	787.5	87.60%	$1.38	$55,902	8.00%
Moranbah	9	45.6	91.40%	$4.60	$15,178	0.50%
Mt Stuart	11.5	416.9	94.20%	$6.13	$15,178	0.50%
Oakey	11.5	338.3	94.20%	$6.13	$15,178	0.50%
Roma	13.5	67.7	84.00%	$6.13	$15,178	0.50%
Stanwell	9.99	1372.4	89.70%	$1.23	$57,077	6.00%
Swanbank E	8.1	358.9	94.20%	$3.07	$35,272	3.00%
Tarong	10.05	1316	88.20%	$1.27	$57,718	6.00%
Tarong North	9.5	416.4	78.60%	$1.27	$55,902	6.00%
Yabulu	7.44	235.7	92.40%	$3.07	$35,272	3.00%
Yarwun	7.8	156.8	94.20%	$3.07	$35,272	2.00%

Appendix C. Renewable Energy Zones

Figure 9: Renewable Energy Zones identified in AMEO ISP 2018