

UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE  
ELECTRIC POWER INDUSTRY

Master's Thesis

**LONG-TERM MODELLING OF AUSTRALIA'S  
NATIONAL ELECTRICITY MARKET**

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**Madrid, 3<sup>rd</sup> July 2018**



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# ABSTRACT

Nowadays, energy utilities are becoming more and more international, expanding their business to other countries. Before doing so, they must assess the risks that they may face, for example at investing in new generation units, since they affect profitability of new projects. Among others, risks may include future electricity prices, uptake of renewables, governmental supports, demand growth, etc.

This Thesis evaluates, from a utility's perspective, how might electricity fundamentals evolve in the future, such as: electricity prices, installed capacity mix and generation mix in Australia's National Electricity Market. For achieving this objective, a long-term capacity expansion planning model which minimises system's costs has been used.

Two scenarios are simulated: the first one, called *high renewables scenario*, is based on a neutral scenario published by the system operator. The second scenario, which is called *very high renewables scenario*, is based on economical rationales: it considers that the minimum uptake of renewables is the one presented in the former scenario and more and more renewables are iteratively added in those states of Australia in which the profitability of renewable projects is positive. As renewables are installed into the system, their expected margins erode. Hence, the iterative process is stopped whenever the internal rate of return of a photovoltaics or wind project is lower than 7% in that state, which is considered the threshold under which utilities would not continue investing.

The results show that coal generation will tend to disappear after plant decommissioning: it will be replaced by more modern and cheaper gas-fired power plants and renewable generators. Under the high renewables scenario, additional renewable capacity is not profitable until the year 2030.

After 2030, new additional projects might be built in some states where their profitability is higher, thus increasing the uptake in the second scenario of very high renewables. In this scenario, cannibalisation is visible not only in the states where more renewables are installed (to reduce the internal rate of return until a value slightly lower than 7%), but also in the other states, meaning that the installation of more renewables in one state affects the whole market.

As a conclusion, revenues received by renewable generators only from the energy market seem, in most of the cases, to not be enough to cover their investment, operation and maintenance costs. Therefore, they need other kind of supports so that utilities consider investing in more projects if Australia's governmental institutions desire to have more renewable generators in the system.



## ACKNOWLEDGEMENTS

The present master's Thesis is part of the master's degree in the Electric Power Industry, program taught at Universidad Pontificia Comillas in Madrid. To study it, I received a scholarship from Fundación Iberdrola for the academic year 2017/2018.

From February to June 2018, as part of the study program, I continued attending classes and I did an internship at Iberdrola. During my stay at the company, not only I developed the present Thesis, but I also learnt how an international company, Iberdrola, works. Moreover, I've had the chance to make some contacts among employees from different departments who have transmitted a bit of their knowledge to me, which will be for sure very valuable in my professional future.

I strongly think that to perform a job properly, good material and conditions are necessary, but they aren't enough. There must be something else: people. Without the help, discussions and support from people around me, I would have never been able to develop this Thesis.

Therefore, I would like to first thank the team with which I've worked during these months: Alejandro L., José Antonio S. and Pablo G. Thanks for all the discussions we've had, your infinite patience and good ideas to make progress.

I'm also grateful to those Iberdrola's employees who have done their bit to help me feel more integrated and comfortable at work. Among others, I'd like to mention the following employees: Ernesto, Óscar B., Patricia B. and Sergio P. Thanks for your goodwill and for the discussions that we've had.

I can't forget about those people who have supported me during this time. First, I want to say thanks to my family and especially my parents and my brother, to whom I'm infinitely thankful for all they've done for me and who have always been there no matter what happened.

Secondly, to my friends Aitor C., Carlos G. and Phillip C., with whom I enjoy discussing not only about the energy sector, but almost about every kind of topic; and to Kasia C., for always giving me her support when trying to accomplish new challenges.

Before finishing, I would like to acknowledge the support from Fundación Iberdrola's employees, from some university researchers, and the support received from AEMO's (Australia's system operator) employees, who I needed to contact a few times and who kindly replied me with relevant information.

Basically, to everyone who accompanied me and did their bit during this important period of my life, thank you very much. This is in some way not only my Thesis, but our Thesis.





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## ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
AUD	Australian Dollar
CAPEX	Capital expenses
CCGT	Combined Cycle Gas Turbine
CIMP	Imported Coal (black coal produced in the country but whose prices vary according to international markets)
CNAC	National coal (black coal produced in the country but whose prices do not vary according to international markets)
EES	Energy Spillage
ENS	Energy Not Served
EOLON	Onshore wind energy
EV	Electric Vehicle
GAMS	General Algebraic Modelling System
HHV	High Heating Value
HIDRO	Hydroelectric energy
HVDC	High Voltage Direct Current
IRR	Internal Rate of Return
JKM	Japan Korea Marker
LF	Load factor
LHV	Low Heating Value
LIG	Lignite or brown coal
LNG	Liquefied Natural Gas
MAIO	Modelo de Análisis de Inversión Óptima (name of the model used)
NEM	National Electricity Market
NSW	New South Wales
NT	Northern Territory

O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
PV	Photovoltaics
QLD	Queensland
RES	Renewable Energy Sources
SA	South Australia
TAS	Tasmania
USD	United States Dollar
VIC	Victoria
WA	Western Australia

# Chapter 1. General introduction

In this Chapter, an introduction of the present Thesis is done in order to allow the reader to get acquainted with the topic, present the objectives that will be addressed and the structure of the report.

## 1.1 Related works

Long-term expansion modelling of electricity systems is widely done by many utilities, such as Iberdrola, in electricity markets where they prospect to have or do have businesses, in order to estimate important variables for them like prices of electricity with assumptions that are constantly updated such as prices of commodities. Therefore, in general the models, together with the inputs they use, are confidential so that their competitors do not have an advantage, knowing what the others are doing to make their forecasts.

There are also models developed by universities and research centres which are, in some cases, open source. This is the case of OSeMOSYS, which was developed to allow openness and barriers reduction to new users [1]. For instance, in the literature we can find some examples of the use of these models. This is the case of this model of the Tunisian Power System using OSeMOSYS [2]. With it, they studied the resulted generation mix under two scenarios: business as usual and 30% renewables target in electricity production. They found out that this renewables target may allow more energy independence while system costs would not significantly increase. Knowing this information is important to learn about the challenges this system might face in the next years.

In the case of Australia's National Electricity Market (NEM) only a few references can be found in the literature. There is a study done in 2015 that assesses a long-term generation and transmission expansion using a simulation platform called PLEXOS [3]. Its findings under the only scenario they assessed were that coal generation would still be very relevant in the NEM in the next decades, accounting more than 50% of yearly generation in 2040. This is nowadays discussable because of the lowering of costs of renewable generators and the international desire of CO<sub>2</sub> emissions reduction. Actually, the Australian Energy Market Operator (AEMO) published in 2014 a generation expansion planning report in which they obtained a similar outcome [4].

But now the reality is different. In the last generation outlook report published by AEMO at the end of 2016, they introduce three scenarios in which renewable generators play a much more important role for the next two decades [5]. There are a lot of variables which affect this kind of studies, apart from necessary assumptions. These studies must be repeated from time to time with updated and more recent data. This is due to the uncertainty of the future: we do not have any crystal ball to fully predict it.

## 1.2 Motivation of this Thesis

The liberalization of the Australian electricity sector started in the 90's in its most populated states [6]. The introduction of renewables into the system in the last years, the lack of a very meshed transmission grid in a large territory and the decommissioning of large plants is challenging the country's security of supply.

Actually, there have been recently some blackouts such as the state-wide one that affected South Australia (SA) in 2016, caused by a big storm which affected a transmission line (see Figure 1). Right after this event, protection systems triggered the severing of the interconnector between the latter and the state of Victoria (VIC), as well as the trip of some generators [7]. The previous year the last coal-fired station had been decommissioned, thus obligating South Australia to rely more on the interconnector with Victoria since then [8]. This is an example that demonstrates the challenges that Australia is facing.



Figure 1 – Fallen electricity transmission tower after a storm in South Australia. Source: [8]

Moreover, the Government of Australia has set a target for greenhouse emissions reduction of 26-28% below 2005 levels in 2030 as the international commitment after Paris Agreement [9]. This can only be done by using more environmentally-friendly energy resources for electricity production (for example, solar PV), by enhancing energy efficiency and by electrifying consumption (for instance, heat pumps), among others.

Therefore, big changes are expected to happen in Australia's energy sector. This leads to a lot of investment opportunities (for example in renewables) not only for companies based in the country, but also for foreign enterprises. For investing, companies need to evaluate the options and risks. The fact that future electricity prices (driven mainly by fuel and technology costs, generation mix, demand, inflation, and exchange rates) as well as that governmental supports affect profitability of these investments means that long-term forecasts should be done to estimate future electricity prices.

The scope of this Thesis is Australia's National Electricity Market (NEM), which includes the following states: Queensland (QLD), New South Wales (NSW), Victoria, South Australia,

Tasmania (TAS) and Australian Capital Territory (ACT). Western Australia (WA) and Northern Territory (NT) are not covered due to the fact that they are out from NEM, explained in Chapter 2.

## 1.3 Objectives

The general objective of this Master's Thesis is modelling the generation expansion of Australia's NEM to estimate different generation mixes (installed capacity and energy) and future prices of electricity. This information will be highly valuable for companies willing to invest in the country.

To achieve these goals, an optimisation model in GAMS language already developed by Iberdrola is used for estimating long-term generation expansion (until the year 2050) of this market. The different simulations are done under two scenarios in order to analyse the impact of the uptake of renewables in the future.

### 1.3.1 Specific objectives

For its achievement, the Thesis is structured according to the following secondary objectives:

- Having a general view of the Australian electricity system in order to find out those relevant entities which provide data of existing plants together with their technical characteristics, costs and other important data such as demand. Collection of all this data.
- Collection of information about expected decommissioning of old installations and about developments of new generators together with their costs are also relevant. Two scenarios are considered: high and very high renewables penetration, whereas the model is allowed to invest on some generation technologies.
- Creation and justification of a scenario of commodities prices. This is relevant because these prices have a direct impact on the final prices of electricity and on the incomes received by generators.
- Analysis of the results and of the profitability of new renewable energy plants under those two scenarios.

When collecting necessary data provided by the System Operator or other institutions and companies, a literature survey, comparisons and analysis are required in order to find out errors or avoid misunderstandings of this data to include realistic estimations in the model. There are cases in which there is lack of accurate information or there is disorganised data. Hence, there some barriers for accurate data collection have been encountered.

## 1.4 Structure of this Thesis

In **Chapter 2** of this Thesis, the reader can find an introduction about Australia's specificities and electricity system.

**Chapter 3** presents data and characteristics of the National Electricity Market which are relevant. Most of this data is used as inputs for the model.

In **Chapter 4** the actual model is explained. Also, the methodology followed to do simulations, presentation of the scenarios and how data presented in the previous chapter is selected to be introduced into the model.

Results of the modelling under the two scenarios can be found in **Chapter 5**. Once presented, they are discussed in order to identify important differences and find some conclusions.

In **Chapter 6** a set of conclusions is provided to make a brief summary of all the important learnings from all the work done. Moreover, some recommendations for future works are suggested.

## **Chapter 2. Australia: Overview**

As stated in Chapter 1, Australia started to liberalise its electricity sector in the 90's, following the international trend. The first country to do it was Chile, which in 1982 began to apply reforms that are generally considered to have been successful [10].

In order to understand Australia's electricity sector, which is mostly but not fully liberalised, a general assessment must be done. Therefore, in this Chapter, general topics such as politics and economy will be briefly addressed, together with electric power system information.

### **2.1 Political division and inhabitants**

Australia is divided into eight different states. Total population was around 24.7 million in 2017, historically with an increasing tendency and distributed along the states as follows (values in million) [11]: Queensland had 5.0 million inhabitants, New South Wales 7.9, Australian Capital Territory accounted 0.4, Victoria 6.4 million people, South Australia 1.7 million inhabitants, Tasmania had 0.5 million, Northern Territory 0.2 million and Western Australia accounted 2.6 million. The capital city is Canberra.

Therefore, the largest state by population is NSW, whereas the one accounting the lowest number of people is Northern Territory.

### **2.2 Australia's electricity system**

The electric power system of Australia is different than the found, for instance, in member countries of the European Union.

Because of the heterogeneous dispersion of population and of industrial regions which have a high consumption of electricity in such a large country (its total area is around 7.7 km<sup>2</sup> [12]), the whole Australian electricity system is not fully interconnected (see Figure 2).

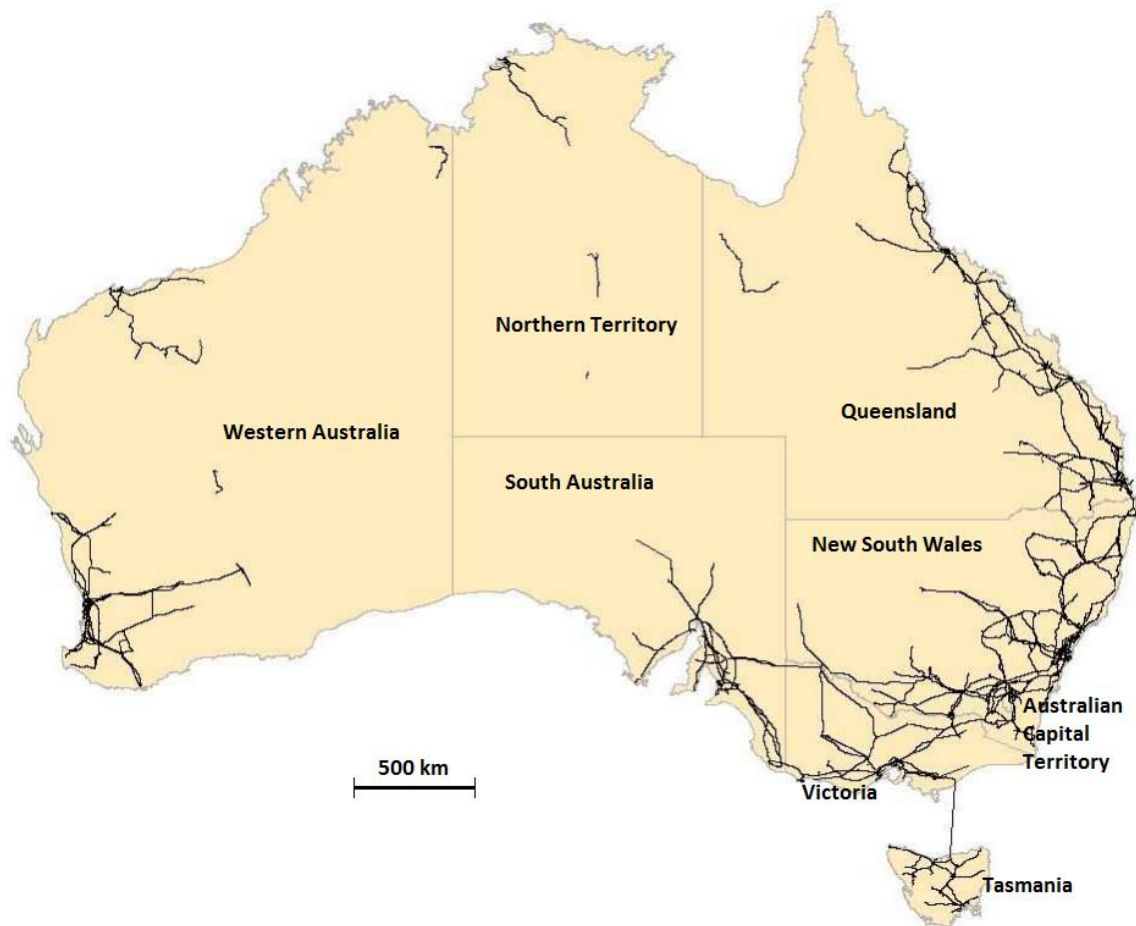


Figure 2 – Map of Australia’s electricity transmission lines and states. Source: [13]

Figure 2 shows there is a clearly interconnected grid in all the eastern and south-eastern parts of the country. In these areas we can identify as well that transmission networks are more meshed within a state, except the case of ACT, which is strongly connected to NSW, and thus theoretically considered inside this last state by the Australian Energy Market Operator (AEMO).

This is because historically electricity networks used to be developed by the vertically-integrated utilities (which generally own electricity transmission, distribution, generation and supply) controlled by the governments of each state separately until they started to link them for economic efficiency and reliability purposes. Actually, there is still one different owner of the electricity transmission grid per state. These companies are the following in each state [14]:

- **QLD:** Powerlink is the transmission owner, which belongs to the Government of the state.
- **NSW** has TransGrid in charge of this business. It is also owned by the state Government.
- **VIC:** SP AusNet, with different shareholders, is the electricity transmission company of this state.



- In **SA** the owner of the transmission grid is ElectraNet. Its shareholders are diverse, being Powerlink among them.
- In **WA** we can find Western Power and Horizon Power. The first one is in charge of all the network in the south-west whereas the second one has is a vertically-integrated utility and its business in the north. Both are publicly-owned by the state Government.
- **NT**: Power and Water Corporation is the vertically-integrated utility and publicly-owned company in charge of transmission. It develops its business in this state, where the market has still not been fully liberalised.

Despite of the dispersion of consumption and generation areas, we can identify three main electricity systems in the country (which can be or not formed by interconnected networks), explained in the next three subchapters.

### 2.2.1 Northern Territory

As it is poorly populated compared to the other states, there are a few transmission lines, so local generators supply small consumption areas. In the Northern Territory the sector is still not liberalised. For example, the transmission owner is as publicly-owned company. There have been discussions about a market implementation since 2015 [15].

### 2.2.2 Western Australia

This state is more populated than the previous one. There is a main transmission grid in the south west of the state around its capital city, Perth. Then it has other consumption zones of less importance around small cities or mining areas which are isolated from the system of Perth.

In the south west a wholesale market was developed in 2006 [16], employing a net pool-based approach in which agents are only obligated to inform AEMO about the bilateral contracts signed. Energy and capacity that are not covered by bilateral contracts are settled in the market [17].

### 2.2.3 National Electricity Market

It began as a wholesale spot market for electricity in 1998 [18]. It involves wholesale generation that is transported through transmission lines from generators to large consumers and to electricity distributors in each region, which deliver it to smaller consumers. It is a gross pool system with a centrally coordinated dispatch process. In other words, generators are obligated to sell their output to the pool at the pool's price [17].

The NEM is not nation-wide, but it comprises by far the largest interconnected grid in Australia. It includes the interconnected grids in Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania. Hence, there are some isolated areas in those states which are not-NEM connected.

In this thesis Northern Territory and Western Australia are not considered because they are not part of the NEM, thus if evaluated, it should be done in a separate study. Moreover, they only have a share of around 10% over the total electricity consumption in the country [19], therefore being negligible.

The characteristics of the National Electricity Market are presented in detail in Chapter 3.

#### 2.2.4 Regulatory and relevant organisations

In order to collect data for the purpose of developing this Thesis and to understand the functioning of the Australian electricity sector, having a broad knowledge of those relevant organisations in the topic is essential. Moreover, knowing those institutions in the energy sector is important for a company willing to start its business in Australia.

One of the most relevant organisations is the **Australian Energy Market Operator**, which is Australia's independent energy markets and power systems operator since 2009. It provides planning, forecasting and power systems information, security advice, and services. It fully operates NEM and Western Australia's wholesale market and power system. It is also in charge of some wholesale gas markets and gas transmission systems [20].

The **Australian Energy Regulator** is in charge of regulating electricity and gas networks in all the country except in WA. Its objectives are, among others, driving effective competition and regulation and agents' protection [21].

Established in 2005, the **Australian Energy Market Commission** is the energy policy institution in charge of advising the Australian government. It makes and revises energy rules. It is responsible for developing energy markets in the country following national electricity and gas laws [21].

The **Council of Australian Governments Energy Council** is a forum to pursue national energy reforms. It began in 2013 and its objectives are, among others, allowing industry participation in policy development and promoting the development of competitive energy markets [22].

The **Clean Energy Regulator** is in charge of the administration of emissions reduction and information legislations, and of renewable energy targets. It has operated since 2012 [23].

An organisation whose role is supporting projects in the field of energy is the **Australian Renewable Energy Agency**. It was established in 2012 for funding businesses and knowledge sharing [24].

### 2.2.5 Current and possible future policies

Australia's current polluting electricity sector is expected to become cleaner in the coming decades. There are attempts at both the national and state levels. For example, Queensland's government is making efforts to set a target to have 50% of the energy generation from renewables in 2030 [25].

The problem with these policies is that they are in some cases biased by political decisions which might change for example after elections or when a high uptake of renewables is found to be too expensive. Therefore, these publications can set an intention, which in reality will probably not happen because of uncertainty and political decisions of the moment.

Prospects studies which are more reliable are those published by neutral (meaning that they are not or should not be biased) entities such as system operators. For example, AEMO published in 2016 a forecasting report in which they consider the following scenarios [26],[27]:

- **Neutral:** electricity generation of 215 TWh in 2036. According to Australia's international commitment to reduce emissions around 27% over 2005 levels in 2030.
- **Emissions reduction:** the same consumption as before in 2036 plus a more aggressive emissions reduction, 45% reduction, which means coal-fired power plants would be faster decommissioned.
- **Distributed generation:** generation of electricity in 2036 of 158 TWh.



## Chapter 3. Australia's National Electricity Market

The purpose of this Chapter is giving a detailed view of NEM to explain how it works and to present important data used for modelling together with their resources.

### 3.1 An interconnected electricity transmission system

The NEM is an interconnected system. Figure 3 shows the distribution of transmission lines and cables within it. We can see that, as stated before, they are mainly in those most populated areas with higher consumption and generation, not far from the coast.

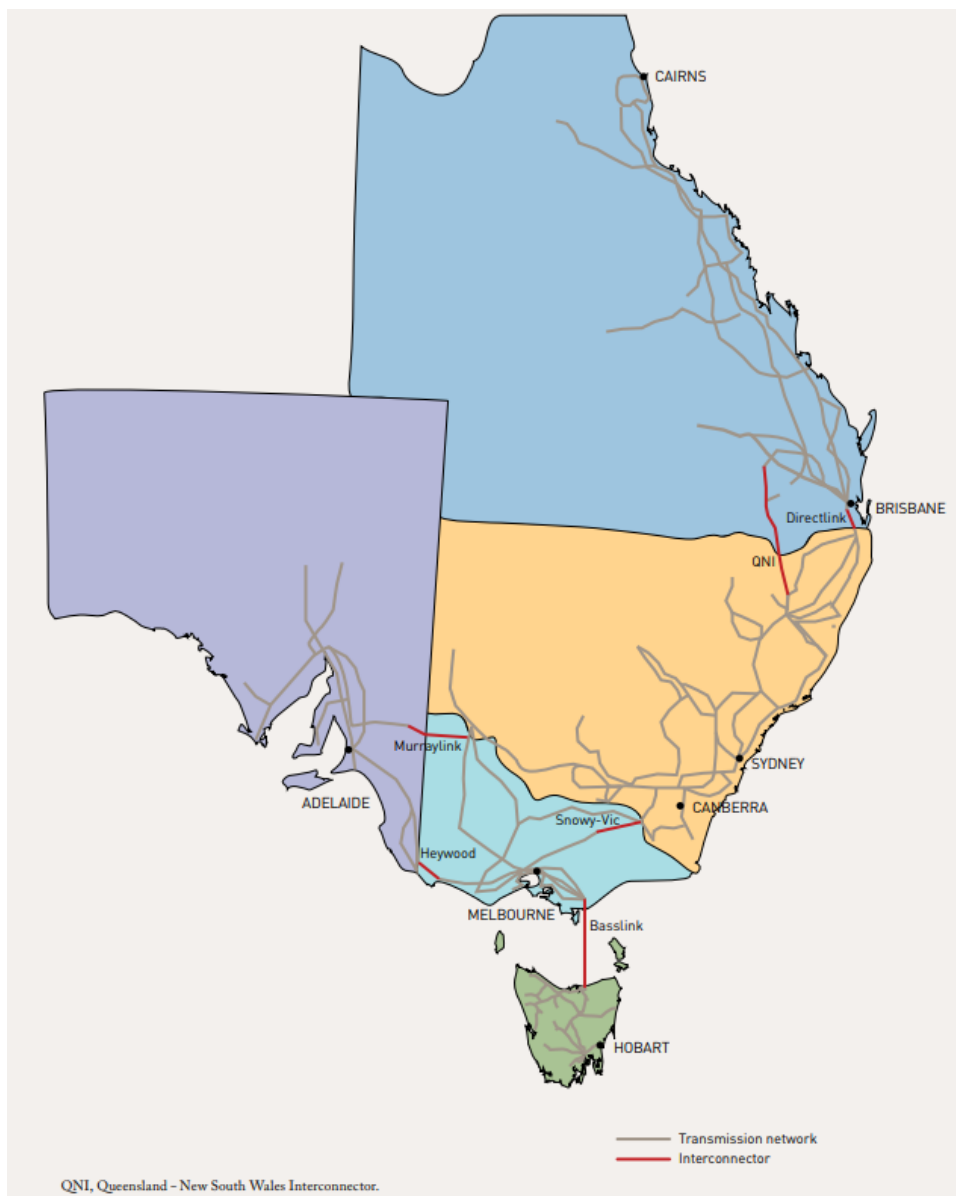


Figure 3 – Transmission network map of NEM. Source: [14]

The existing interconnectors spotted in the previous map are presented below, whereas their characteristics for long-term modelling are shown in Table 1 [28], [29]:

- **QNI**: it is an alternating current (AC) link that also connects QLD with NSW.
- **Terranora** (formerly Directlink as seen in Figure 3): it is a high voltage direct current (HVDC) interconnector between QLD and NSW.
- **VIC-NSW** (or Snowy-VIC in Figure 3): AC interconnector between VIC and NSW.
- **Heywood** connects VIC with SA. It is an AC line.
- **Murraylink**: it is an HVDC interconnector between VIC and SA.
- **Basslink**: it is an HVDC link. It is the only one which connects the island of Tasmania with the mainland, through Victoria.

**Table 1 – Interconnector transfer capability. Source: [28]**

Interconnector	Forward Direction	Forward capability (MW)	Reverse capability (MW)
<b>QNI</b>	NSW to QLD	300	1078
<b>Terranora</b>	NSW to QLD	107	210
<b>VIC-NSW</b>	VIC to NSW	700	400
<b>Heywood</b>	VIC to SA	650	650
<b>Murraylink</b>	VIC to SA	220	200
<b>Basslink</b>	TAS to VIC	594	478

These values of Table 1 are, according to [29], appropriate for long-term modelling. Hence, in reality some of them can be allowed to be higher, but under certain circumstances of the network and working generators, the values presented in the table are the considered as firm, which is important to be taken into account.

There are some studies and discussions about building new interconnections, but no information is clear yet, so in this Thesis the only interconnections considered are these ones.

### 3.2 Locations of current generation and outlook

Australia has a lot of natural resources to generate electricity, but not in every state they have the same kind of fuels. It is important to take it into account for modelling the system. Regarding the main existing generators connected to the NEM and their fuels, their location can be found out in the following map in Figure 4 (the Australian Capital Territory is included within New South Wales).

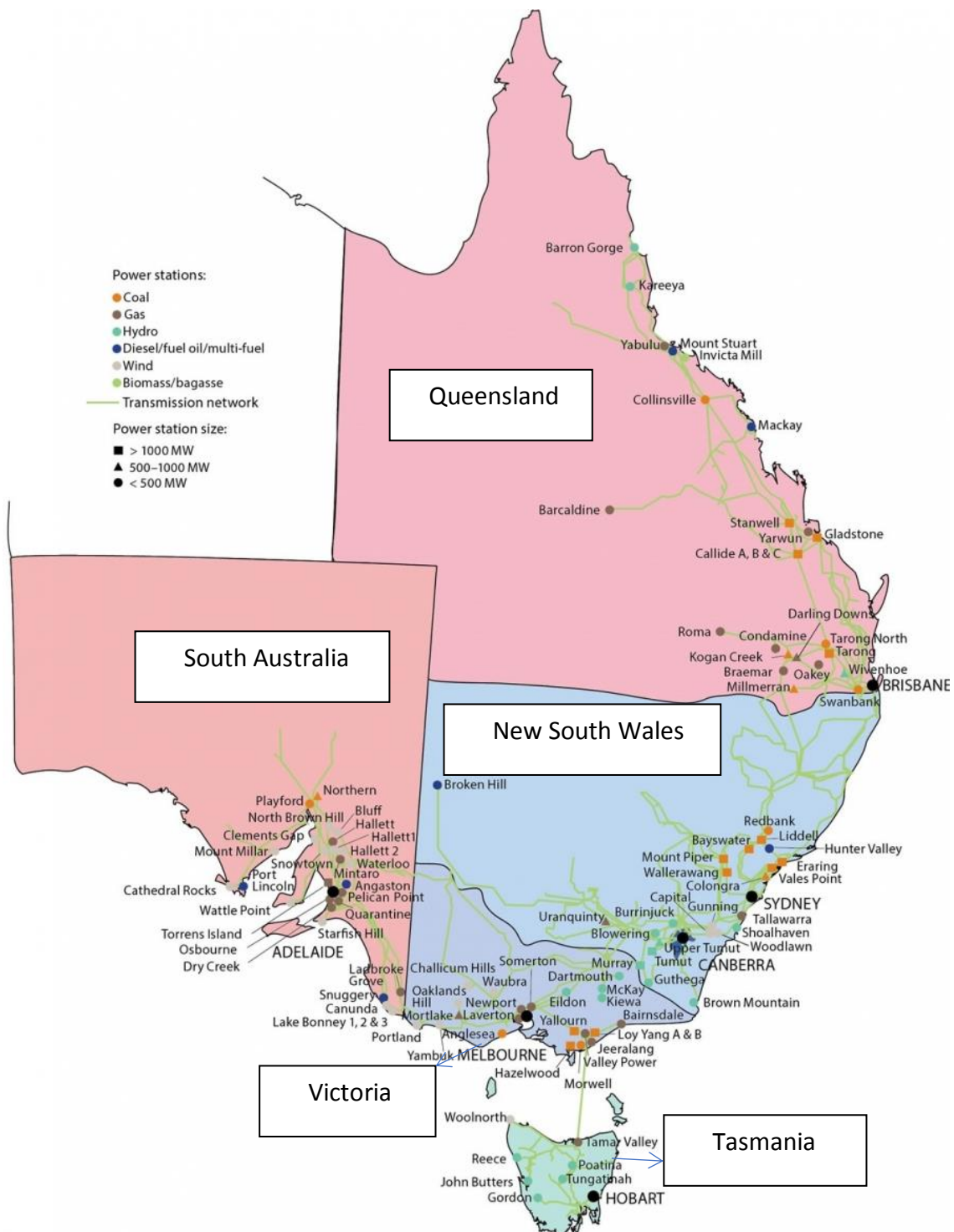


Figure 4 – Map of power stations and transmission lines in the NEM. Source: [30]

In the previous Figure, the reader may observe that power plants are mostly located near the coast. Those locations are in general selected because of the proximity to natural resources and/or to demand centres, such as big cities.

We can see that coal-fired power plants are mainly in QLD, NSW and VIC. Gas plants are spread all over the states, whereas hydro is located mostly in NSW, VIC and TAS, and some in QLD. There are a few plants fuelled with biomass or with liquid fuels.

In the next subsection a discussion on thermal generation technologies available at each of the states is carried out.

### 3.2.1 Thermal generation technologies

First of all, we need to note that a lot of different technologies, fuels, small generators, etc. can be found in the NEM. For the sake of simplicity, only the most relevant ones are presented here.

There are steam generators whose fuel is black coal (QLD and NSW) and brown coal (VIC). Then, in the NEM there are Open Cycle Gas Turbines (OCGT) and Combined Cycle Gas Turbines (CCGT), normally sourced with gas, but in some cases with liquid fuels, such as diesel.

And finally, other kind of technologies listed as *other gas* in Appendix A, which includes piston engines, steam generators and others. They are only found in SA and they have higher O&M costs than other technologies. They may use liquid or gaseous fuels.

In Tasmania there is not much thermal generation installed (nowadays only one gas-fired power station is commissioned) because of their high hydroelectric resources.

The list of generators of the NEM in Appendix A include all their characteristics (name of the power plant, abbreviation used by AEMO, installed capacity, fuel, technology, efficiency, commissioning date, proposed closure date, operation and maintenance costs). These characteristics are mostly sourced from the Planning study of 2016 done by AEMO [28]. There, they are separated by generation unit, but in this Appendix, they are clustered by generation plant.

The Integrated system plan consultation [31], published in 2017, is a good resource together with webpages of the owning companies for useful life length of power plants. In this Thesis, it is assumed that coal-fired power plants can last for 50 years and gas-fired power plants for 40 in those cases in which no information has been found.

### 3.2.2 Hydroelectric generation

Below we can see installed capacity [32] and average annual hydroelectric generation [5] per state:

- In QLD there is an expected hydroelectric production per year of 0.6 TWh. There are 0.7 GW of installed capacity and 0.15 GW of run-off-the-river installed capacity.
- In NSW there are 3.0 TWh/year and 2.7 GW of installed capacity
- VIC has 3.1 TWh/year and 2.3 GW of capacity.
- TAS has 8.2 TWh/year and 2.4 GW of installed capacity.



There are some discussions about building new reservoirs. This is the case of Snowy 2.0 [33], which would bring benefits to the system, but it might be not economically viable.

No information has been found about monthly inflows of water to the reservoirs.

### 3.2.3 RES: costs and relevant information

In this Thesis an evaluation of the revenues of renewables (solar PV and wind) is done (see also Sections 4.2.1, 5.3, 5.2 and 5.5) to find out how profitable those investments could be during the next decade. In order to do it, the following data is needed:

- Costs, mainly CAPEX and O&M. CAPEX are different for every year as will be shown below.
- Load factors (LF).

On the one hand, for estimating the future CAPEX, in [28] AEMO provides expected data, shown in Table 2. But that data was published in 2016, when costs were higher, and according to the International Renewable Energy Agency (IRENA) in [34], the weighted average installation costs of utility-scale solar PV in 2017 was of around 1500 AUD/kW (assuming AUS/AUD=0.75), whereas AEMO's forecast is 1848 AUD/kW. In the case of wind, IRENA states that the weighted average CAPEX for wind was in 2017 around 1600 AUD/kW.

In order to provide more realistic estimations, other assumptions are presented in the table below, which is 80% of AEMO's data in the case of PV, and 65% in the case of wind, which result in values in accordance with IRENA's data for 2017 [34].

Table 2 – CAPEX of RES under AEMO's forecast (1) and under own assumptions in relation to IRENA's estimations (2):

	2017	2020	2025	2030
<b>PV<sub>1</sub> (AUD/kW)</b>	1848	1683	1467	1020
<b>PV<sub>2</sub> (AUD/kW)</b>	1478	1347	1174	816
<b>Wind<sub>1</sub> (AUD/kW)</b>	2689	2660	2167	2090
<b>Wind<sub>2</sub> (AUD/kW)</b>	1613	1596	1300	1254

Where:

- $PV_1$  are AEMO's assumptions for CAPEX of PV.
- $PV_2 = PV_1 * 0.8$
- $Wind_1$  represents AEMO's assumptions for CAPEX of wind.
- $Wind_2 = 0.6 * Wind_1$

For O&M costs, solar PV is assumed to have a fixed cost of 17 AUD/kW/year [35] and wind of 38 AUD/kW/year according to [36].

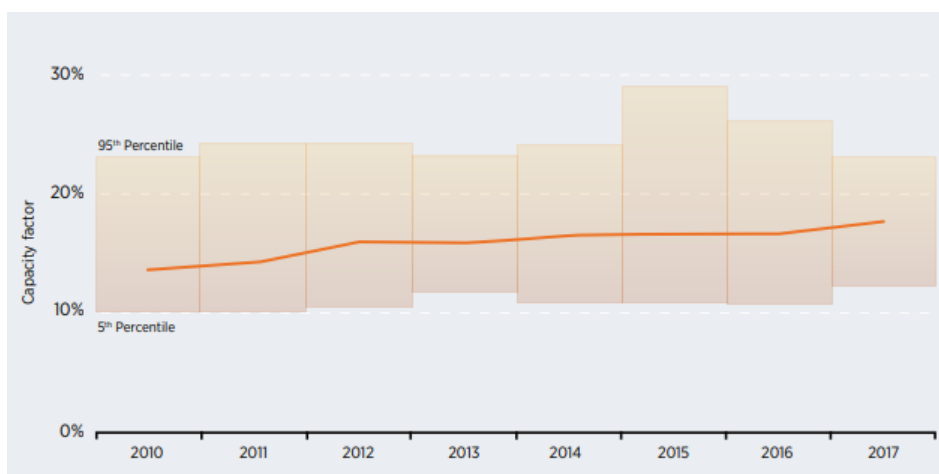
On the other hand, AEMO provides generation profiles (called *large-scale solar traces* and *wind traces*) of some existing renewable generation plants in most of the states that belong to the NEM in [37]. Therefore, by extracting and computing all those traces, average

profiles for all the states have been obtained, and from them the load factors presented below:

**Table 3 – Load factors of large-scale solar PV and wind per state. Source: [37]**

	QLD	NSW	VIC	SA	TAS
<b>LF of PV (pu)</b>	0.29	0.27	0.29	0.30	0.14
<b>LF of wind (pu)</b>	0.35	0.31	0.33	0.34	0.39

The LFs for wind may seem very high but considering the high wind resources of some parts of Australia, they make sense. The same happens with large-scale solar PV (except for Tasmania). For example, IRENA reported also some existing solar PV plants with a LF of around 30% as can be seen in Figure 5:



**Figure 5 – Global weighted average capacity factors for large-scale PV until the year 2017. Source: [34]**

Therefore, Australia is one of the locations with highest RES resources in the world.

It is worth mentioning that LFs calculated with wind and solar traces [37] are congruent with those sourced at AEMO’s Generation Outlook [5].

### 3.2.4 Future thermal generation technologies

We already know power plants’ characteristics of commissioned ones. But for the future, estimations must be done. In a report done by ACIL Allen for AEMO [38], they expect the following costs for new plants built nowadays presented in Table 4 as OCGT, CCGT<sub>16</sub> (built in year 2016), B. coal (black coal-fired power plant) and Lignite (lignite-fired power plant). The rest of CCGTs are improvements for new plants in 2026, 2031 and 2036, according to Iberdrola’s assumptions, over CCGT<sub>16</sub>.

Table 4 – Characteristics of future thermal power plants

	Power (MW)	Investment (AUD/kW)	Fixed O&M (AUD/kW/year)	Variable O&M (AUD/MWh)	Useful life (y)	Efficiency over HHV
<b>OCGT</b>	530	725	4	10	30	35%
<b>CCGT<sub>16</sub></b>	390	1092	10	7	40	51%
<b>CCGT<sub>26</sub></b>	390	1000	10	7	40	58%
<b>CCGT<sub>31</sub></b>	390	1000	10	7	40	60%
<b>CCGT<sub>36</sub></b>	390	1000	10	7	40	62%
<b>B. coal</b>	750	2880	50	4	50	42%
<b>Lignite</b>	750	4386	65	5	50	29%

In the upper table we can see that for a plant which is barely used, the most economic technology is OCGT. Then, if a plant needs to usually be committed, probably a CCGT would be the best choice because of its higher efficiency. And lastly, for plants working most of the time, maybe coal-fired power plants would be the cheapest ones. But this would depend on commodities prices (gas and coal), since the efficiency of the latter is lower than in the case of CCGTs.

### 3.3 Demand outlook

For modelling, in this Thesis the total demand is considered as the sum of demand (presented in the next Subsection and just referred as *demand* in this Thesis) plus demand for electric vehicles (analysed in section 3.3.2), because the latter has a different tendency.

#### 3.3.1 Demand

It takes into account demand recorded within NEM including residential and business consumptions plus self-generated energy from rooftop-PV to withdraw the net balance of energy. Therefore, the future increase on rooftop-PV in Australia does not affect the demand forecast presented here.

AEMO has provided hourly demand profiles for every state in the NEM per month in a half hourly settlement since the year 1999. Moreover, the Australian Energy Regulator has publications on the maximum yearly demand per state and per season (winter and summer) also since 1999.

From 2011 to 2017 the consumption and peak demand data available is the following for every state:

Table 5 – Yearly historical consumption (TWh) and peak demand (GWh/h). Sources: [39], [40]

Year	QLD		NSW		VIC		SA		TAS		NEM
	TWh	GW	TWh	GW	TWh	GW	TWh	GW	TWh	GW	TWh
<b>2011</b>	51.1	8.8	76.5	14.8	50.1	9.9	13.1	3.4	10.0	1.8	<b>200.8</b>
<b>2012</b>	51.0	8.7	72.3	12.0	49.6	9.1	12.9	3.0	9.6	1.7	<b>195.4</b>
<b>2013</b>	51.1	8.6	76.4	13.9	50.1	9.8	13.1	3.1	10.0	1.8	<b>200.7</b>
<b>2014</b>	50.3	8.4	69.4	12.0	46.6	10.3	12.3	3.3	9.7	1.7	<b>188.3</b>
<b>2015</b>	52.8	9.0	69.9	11.9	45.5	8.6	12.3	2.8	10.0	1.7	<b>190.5</b>
<b>2016</b>	54.9	9.3	69.9	13.6	44.1	9.5	11.8	3.0	9.3	1.7	<b>190</b>
<b>2017</b>	54.6	9.5	70.6	14.1	43.4	8.7	11.6	3.1	9.9	1.7	<b>190.1</b>

Analysing the 2017 profile demand we can see in which months that peak demand happened during that year. In Table 6 they are presented together with the values and the months in which they occurred:

Table 6 – Maximum (max), minimum (min) demands and months in which they happened in 2017. Source: [40]

	QLD		NSW		VIC		SA		TAS	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
<b>Value (GWh/h)</b>	4.7	9.3	5.3	14.0	3.0	8.6	0.6	3.0	0.7	1.7
<b>Month</b>	Aug	Jan	Dec	Feb	Jan	Dec	Dec	Feb	Apr	Jul

Minimum demands did not follow any common pattern as they happened at different months of the year and at different times of the day.

But maximum demand was during summer (note that in the south hemisphere summer is in between the months of December and March) in all the states except in Tasmania, where it happened during winter because it is the most southern state, temperatures are normally lower, and weather is quite rainy. In all cases it occurred in the afternoon (around 4-5 pm), whereas in Tasmania it happened a day during the morning (at 8 am).

This is in line with the forecasting report published by AEMO [26], in which they expect the same seasonal behaviour of peak demands in all states for 2017 than those reported in Table 6.

Demand is expected to grow in the total of the NEM to a value of 215 TWh in 2036, without considering rooftop-PV generation. This growth is expected to be twice faster in Queensland (around an annual growth of 0.9%) than in the other states separately (around 0.4% per year), which are expected to have a similar growth [41]. This difference might be due to LNG projects in QLD.

For the period 2036-2050 no sources are published. Thus, a constant growth of 0.5% at every state is chosen, which is estimated to be reasonable, in both the energy demand and the peak demand is considered.

### 3.3.2 Demand for electric vehicles

Electric vehicles (EV) future demand analysis is a trend nowadays due to the start of transport decarbonisation. Because of this, system operators all around the world have started to evaluate the possible impacts both on energy consumption and on peak demand of EV uptake.

AEMO does not lag behind and has published in 2017 a study done by Energeia in which this company assesses the expected impact of EVs [42]. This report is used to collect data for the model, taking the neutral scenario proposed by AEMO as a reference. As presented in Figure 6, EVs are expected to hugely grow in the states of the National Electricity Market, counting of around 60% of the total fleet of vehicles in 2050.

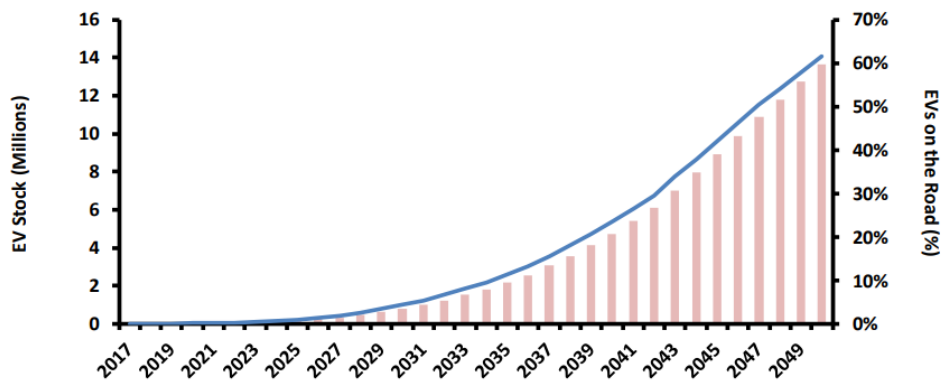


Figure 6 – EV uptake in NEM. Source: [42]

This increase on EVs in Australia will mean more electricity consumption, forecast by the report to also highly grow as can be seen in Figure 7:

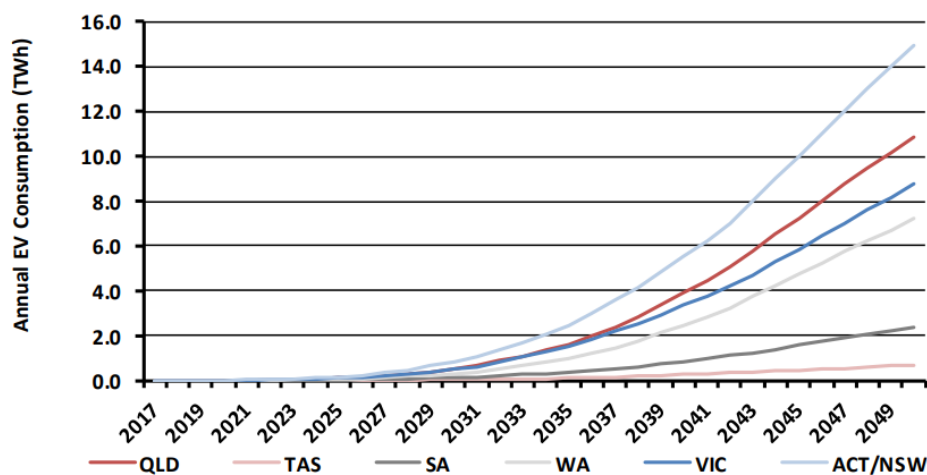


Figure 7 – EV electricity consumption by region. Source: [42]

In the previous Figure the reader can observe that the highest energy demand is expected to correspond to New South Wales, which is the most populated state in Australia. Consumption of Western Australia is obviously not taken into account for the inputs of the model used in this Thesis.

In the inputs for the model EVs are assumed to have a 50% of managed load to avoid consuming all the power during peak demand periods, when it is supposed that electricity prices are higher. This is introduced into the model in the following way: there is a minimum demand which happens along the day. The model can decide to allocate the rest of the daily demand to be charged during a block of 6 hours. Therefore, over that minimum, the rest of the demand is added in these 6 hours.

## 3.4 Commodities outlook

In Australia mainly gas and coal are the fuels consumed for electricity production. The country has plenty of energy resources in its territory. Commodities' prices are not uniform for all the country and, what is more, there are different types of coal which of course have also not the same prices.

### 3.4.1 Coal

There are two types of coal in the country:

- **Black coal** or bituminous coal. Because of price differences, in this Thesis it is divided into two types: national coal which and is sourced from the mine mouth to be used in the plants and in principle cannot be sold in international markets (CNAC), and coal whose price varies according to international markets (CIMP). Queensland and New South Wales have black coal mines. In principle Australia does not import coal, but a coal mine with access to other markets has to evaluate the opportunity cost, so the price of its coal will change with international coal markets.
- **Brown coal** or lignite (LIG). It has a lower calorific value than black coal. It is only produced in the state of Victoria and is not imported or exported, but sourced in the mine mouth.

AEMO, in [28], has published expected fuel costs of every coal-fired power plant in the NEM until 2040. In Figure 8 this data is presented in AUD/MWht over the low heating value (LHV) as given in the previous file, shown as the average of all plants per state and type of coal that is used.

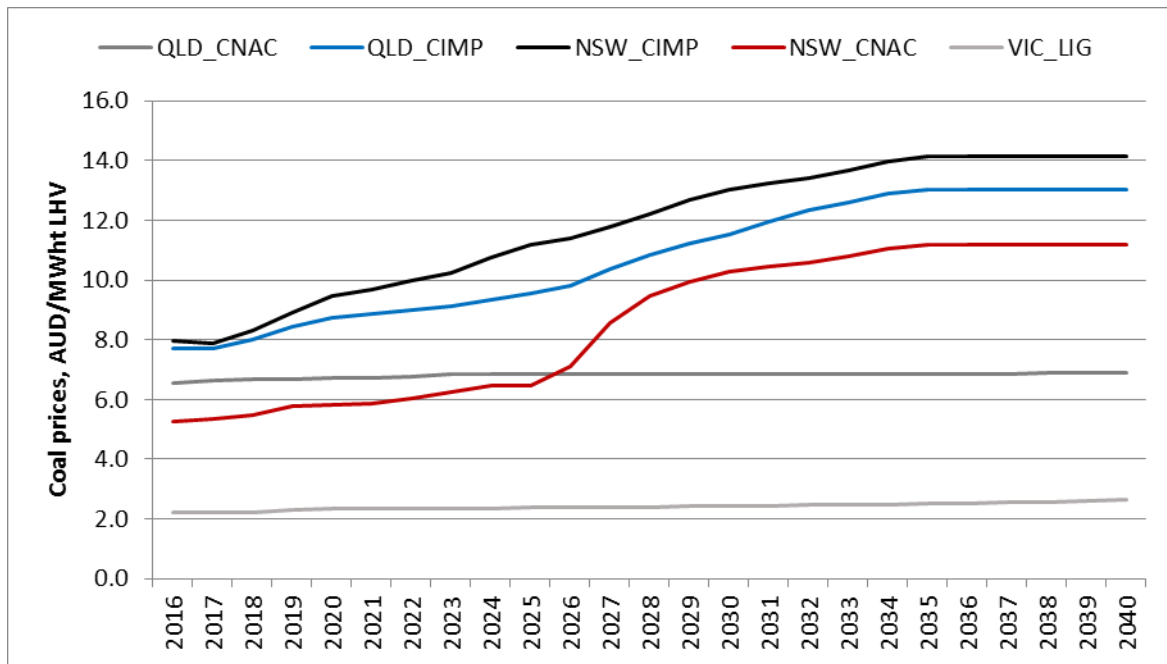


Figure 8 – Forecast of coal prices by AEMO. Source: [28]

We can see in the previous Figure that under these assumptions the cheapest coal, by far, is brown coal (in VIC), with a more or less stable price for all the years of around 2.4 AUD/MWht. A similar tendency is found at the national black coal in QLD, with a price of around 6.7 AUD/MWht.

In the other cases, the reader can see that prices are not stable, but with an increasing tendency. Coal indexed to international prices is expected to range between 7.7 in 2016 to 13.0 AUD/MWht in 2040 in QLD, with a parallel tendency than the one of NSW (black line), which is expected to range between 8.0 and 14.1 AUD/MWht.

The red line seen in the Figure represents the coal supplied to two power plants in New South Wales. Until approximately 2025 the line indicates a smooth growth, with prices from 1.4 to 1.8 AUD/MWht, but from this year till 2040, a high increase is expected, with prices ranging from 5.3 to 11.2 AUD/MWht. These coal prices, although linked to international prices, are considered as CNAC in NSW to make a differentiation from the other coal prices in NSW, represented by the black line in the graph.

But Iberdrola has also future estimations of coal prices from Australia, which are based on the hub of Newcastle, in New South Wales. They have a higher price (real) in 2018 than the one done in 2016 by AEMO, and they also have a decreasing tendency of prices, opposite to AEMO’s forecast.

Iberdrola’s data is used for coal subject to international prices because it is considered to be more accurate. In Figure 9 we can see the new QLD\_CIMP and NSW\_CIMP have now the same price. NSW\_CNAC is also linked to Iberdrola’s prices, but the difference between the latter and CIMP is the provided by AEMO’s data and shown in Figure 8, taken as the differences between the average of all CIMP and CNAC\_NSW.

This difference is due to logistics costs; in other words, NSW\_CNAC's cost is lower than CIMP's cost because the mines have a shorter distance to those coal power plants than to the coal hub.

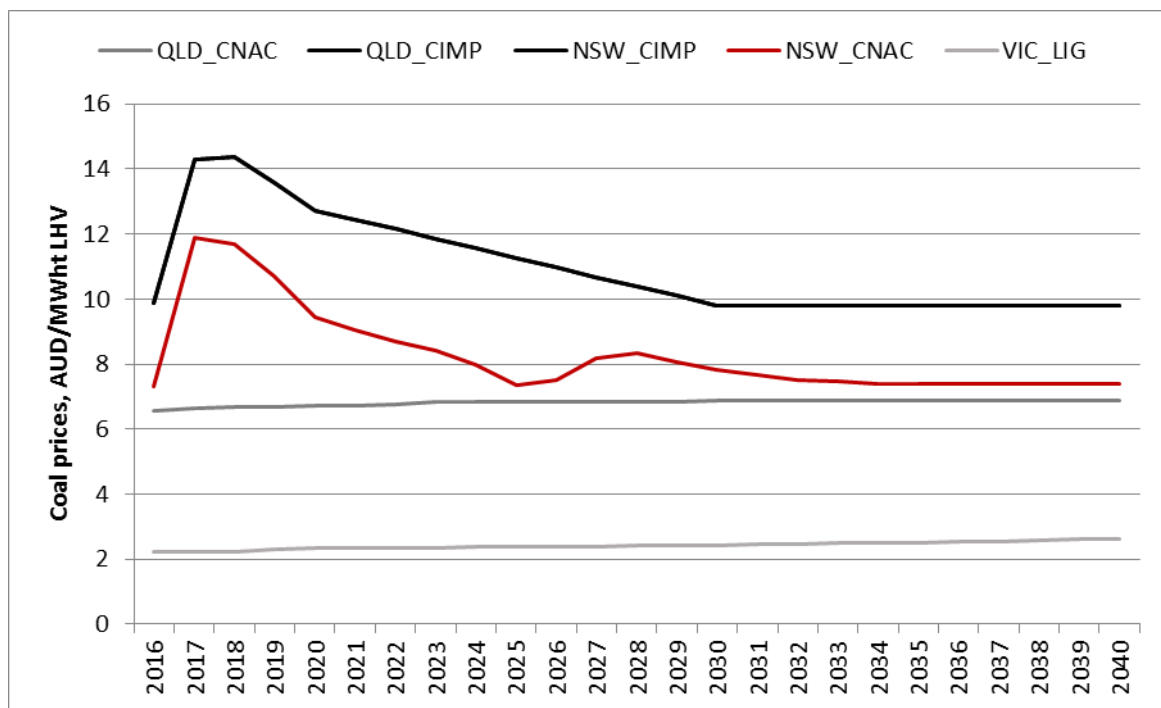


Figure 9 – Forecast of national coal prices by AEMO and of coal subject to international markets by Iberdrola, with some corrections according to AEMO's data

In the previous Figure, national coal in QLD and lignite in VIC are maintained with the same prices shown at Figure 8. These are the data of coal prices used in this Thesis for modelling. AEMO's estimation of coal prices subject to international markets is optimistic.

However, the two CIMP and NSW\_CNAC have a peak price in 2017 and 2018, with a forecasted decreasing tendency.

### 3.4.2 Gas

In the case of gas, AEMO indicates in the Gas Prices Consultancy Databook [43], published in 2016, a forecast of gas prices in which they take into account the fuel cost of gas-fired power stations at each of the states. It is shown in Figure 10.

But Iberdrola has data of prices based on the fact that gas is exported from the United States to Japan, taking the Japan Korea Marker (JKM) as a reference. Therefore, to estimate the price found at the gas hub in Queensland, a discount is applied by Iberdrola to this reference price.



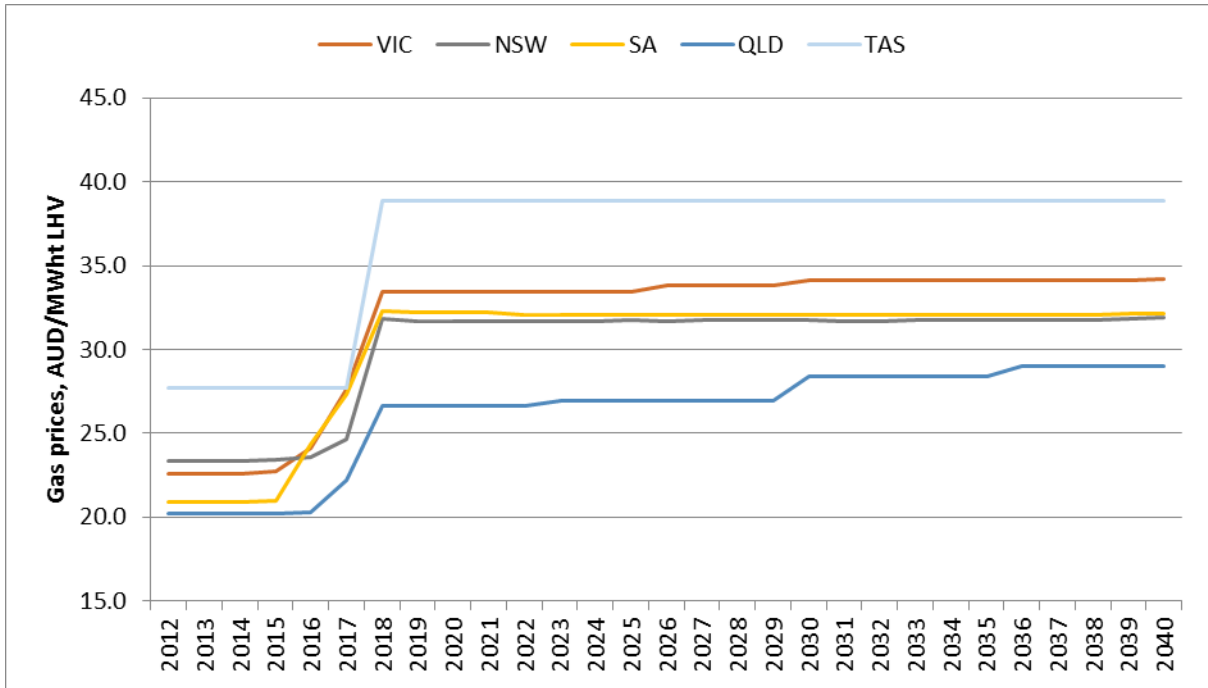


Figure 10 – AEMO’s forecast per state of gas prices for 2012-2040. Source: [43]

In Figure 10 we can see that according to AEMO’s data, the most expensive gas is in Tasmania, with around 39 AUD/MWh from 2018 onwards. This is reasonable because gas needs to be transported through pipelines from the mainland, where it is produced. The cheapest is found in Queensland, where the hub is located, having an expected price between 20 and 29 AUD/MWh from 2018 to 2040.

Something worth mentioning is the huge increase in prices after 2016. This is due to the fact that LNG liquefaction projects have been commissioned in Queensland since 2014, which has meant that prices of gas consumed in the NEM are nowadays subject to international markets, since now gas producing companies have the following opportunity cost: they need to estimate if exporting (mainly to Asia and especially Japan) or selling the product in the National Electricity Market is more profitable [44].

Iberdrola’s forecast and AEMO’s forecast for QLD are quite alike. Similarly, as done in the case of coal, in this Thesis prices of Iberdrola are selected for QLD because they are more recent. For the other states, the differences for each year between the prices of QLD and the other states are kept as given by AEMO with the average of past data: the differences from 2012 to 2015. The final result is shown in the Figure below:

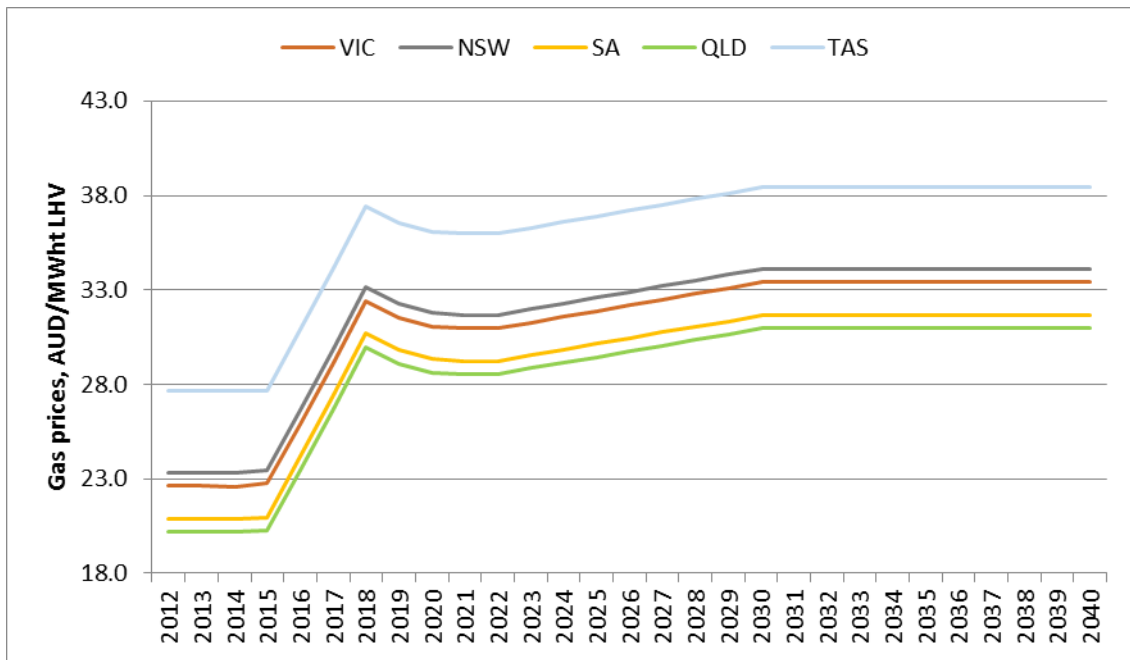


Figure 11 - Iberdrola's forecast of gas prices per state with corrections from AEMO's forecast for 2012-2040

In this Figure 11 we can see these differences in prices among states. The states in the mainland are expected to have prices between 29 and 34 AUD/MWh from 2018 to 2040, whereas Tasmania is expected to have a price between 36 and 38 AUD/MWh.

As the prices outlook is until the year 2040. After that, the model assumes that the prices are kept constant.

There are a few power stations which use liquid fuels (normally fuel oil or diesel) and not enough information about their prices. For the sake of simplicity, liquid fuels prices are not considered as an independent input in the model, as no proper data has been found. Actually, the implications of this price, unless it was very low, which is not reasonable, are negligible because those plants using liquid fuels are barely used as it is presented in Chapter 5.

Moreover, there are some plants burning coal bed methane, but to simplify costs, only natural gas costs are considered as there is as well not proper data about these costs for each plant.

## Chapter 4. Methodology

This Chapter is focused on the methods followed to do the actual modelling of NEM, based on data previously presented and on procedures and resources used at Iberdrola.

### 4.1 Modelling

For accomplishing the objectives of this Thesis, a model is not developed, but one that Iberdrola utilises is used. It is necessary to define justified inputs and obtaining outputs that are analysed. From a broad point of view, the modelling process followed is presented in Figure 12.

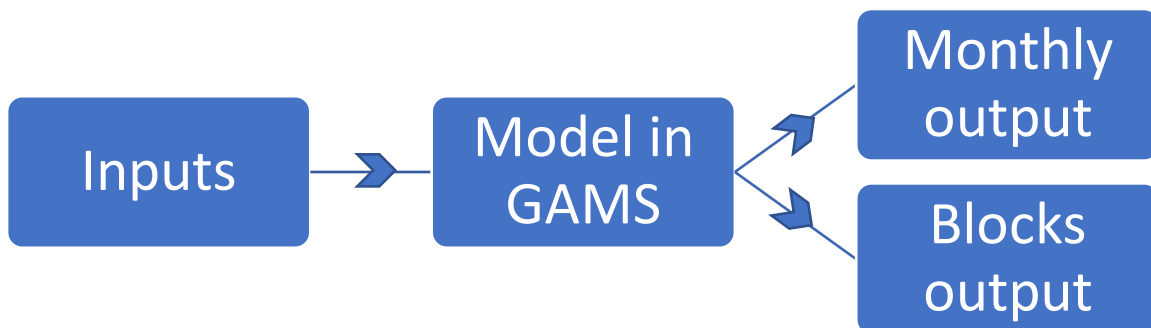


Figure 12 – Modelling process

First of all, the input file is adapted with NEM's data already presented. A file in .txt format is generated so that it can be read by the model. Then, the model creates two output files: monthly output and blocks output. They include the results that are analysed. The reader can find more detail about each step in the next Subsections.

#### 4.1.1 Inputs

A file in Excel format is used so as to have a friendly interface to include data. This file is sorted by type of input. For example, there is a sheet about renewables, another one about existing thermal technologies, another one about demand, etc. All relevant data for the model are taken from them to a relevant sheet which generates the input file for the model in .txt format.

Some of the data such as demand profiles or solar and wind generation profiles are included with a block resolution. A block is defined as two hours and one week per month is taken as representative. Therefore, there are 84 blocks per month.

Solar and wind generation are technologies fixed, which means that the model is not allowed to invest in them. The same case is applied for hydroelectric generation. However, thermal technologies are included with cost data so that the model is able to invest.

### 4.1.2 Description of the model

This model used by Iberdrola for long-term optimisation is called *Modelo de Análisis de Inversión Óptima* (MAIO). The objective of the model used is obtaining **optimal investments** in new and existing generators, forecast of their **energy production** and, as a consequence of this, a forecast of **electricity prices**. This model is able to represent how the electric system is exploited and to explore different possible investments both in new and existing generators.

The optimal exploitation and planning of investments are obtained by minimising total costs through **linear programming in GAMS** (General Algebraic Modelling System) **language**. Dual variables of the optimisation allow for the reduction of energy and capacity prices.

The model **minimises total exploitation and investment costs** considering these variables of the power stations:

- Fixed and variable O&M costs.
- Fuel and emissions variables (although in this modelling no price of emissions are considered, emission factors of plants are introduced for future modelling).
- Investment variables in new or existing generators.
- Variables of plants decommissioning.

Some of the characteristics of the model are the following:

- Demand coverage is represented in several **demand blocks** for each month: the monthly detail is necessary to collect parameters such as hydroelectric production or seasonality of some fuels prices.
- The model ensures reliability of the system through **deterministic** indexes such as the reserve margin.
- Hydroelectric generation is added as a single generator and an equivalent reservoir. Hydro production is characterized by a minimum power and energy (run-of-the-river hydro) and a maximum monthly output.
- Constraints used in **short-term** production models are **NOT** considered, such as: unit commitment, minimum stable load, performance curves, ramp-ups and rump-downs, etc.
- The model is prepared to have a chronological hourly detail that reflects the variability of intermittent renewables. However, the number of demand blocks is limited by the computing capacity.
- MAIO can only be used in “single node” systems without zonal constraints.
- The model **removes** installed capacity when the end of their **useful life** is reached, but it can also decide to withdraw this power before the end of its useful life due to **economic reasons**.

- To avoid that the period that is modelled (2011-2050 in the case of this Thesis) is affected by the boundary conditions of the end of the period, more periods need to be analysed (in this case, until 2070).
- In order to simulate the operation of an electric system, the conditions of energy balance and reliability are defined:
  - **Energy balance:** generation balance is done in each demand block of each scenario, taking into account the production of technologies, hydroelectric production, exchanges between areas, energy not supplied (ENS) and energy spillages (EES).
  - **Reliability:** a reliability constraint is defined through setting a reserve margin (in the case of this thesis, this is 1.1 times the maximum demand of the thermal gap) which needs to be overcome. This calculation is previously done and is introduced into the model as a constraint, meaning that every year there must be a minimum of available thermal power. Therefore, the system can cope with extreme situations during which there are high demand and low renewable generation. This constraint implies the need for the existence of generators which are off during demand blocks but necessary for the system.
- Optimisation is considered as a linear programming problem. The objective function is defined as a global cost minimisation, a series of constraints that describe investment conditions, a set of constraints that contain exploitation scenarios and optional operation constraints that include possible economic or environmental conditions.
- The output of the model is the optimal capacity mix, in GW, and its associated production, in TWh, as well as the dual variables of the energy balance and reliability constraints that provide the energy prices (AUD/MWh) and the capacity respectively (AUD/MW).

As a summary of the description of MAIO, Figure 13 is included:

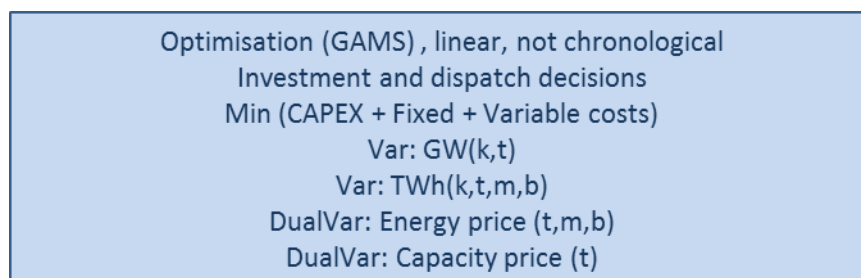


Figure 13 – Summary of the model's description

Where the sets are:

- $k$  represents thermal generation technologies.
- $t$  is the year.
- $m$  is the month.
- $b$  represents the block.

### 4.1.3 Simulation procedure

For the first simulations, the trial and error method is used.

In order to get acquainted to the input file and the model, once some of the necessary data to run was collected (technologies and their characteristics, demand...) and the new electric systems (the states) were introduced for every variable, the model was run even with commodity prices taken from other input files used at Iberdrola.

The work was done using Microsoft Excel to introduce input data and from it generate a .txt file that was used by the .gms file in which the code of the model is. GAMS made the simulations and created output files in .txt format which were exported to Microsoft Excel files to make proper analysis.

At the beginning, errors related to the input file appeared, normally created by wrong data which triggered failures in the simulation, which could not be performed. For example, there was once the case of including a too high value of run-of-the-river capacity hydro with a low amount of energy available in a period of time, which was not enough to provide that capacity along the time.

Once those kind of errors were solved, the important goal was starting fast to get familiar with the procedure, solving errors and then looking at the output files to have a broad view of everything. Then more accurate data of commodity prices, RES or demand were introduced to run the model again to obtain more proper results. The output files were prepared to allow the analysis of the results. If something was found to be wrong or not reasonable, input data was checked again.

This procedure was followed. Moreover, once data of the first scenario of high renewables were established, that procedure was repeated to create a reasonable second scenario of very high renewables taking into account the premises explained in the previous Section 4.2. In total around 40 simulations were carried out.

### 4.1.4 Monthly output: prices and technology mix

When finishing the simulation, the model finds the objective function. Among others, it creates as a result two data files that are analysed in detail in Chapter 5.

The first file, which is called Monthly output, presents, among others, generation, different costs (O&M, fuel...), decommissioning because of economic and useful-life reasons, load factors, incomes, capacity payments, installed capacities, available capacities, and invested capacities because of new plants. All of them for each of the technologies.

Then there are also data about demand and demand for EVs, in which energy consumption and peak demand are shown; as well as installed power and energy use of

import and exports with each of the states. And finally, average prices of energy, energy not served and energy spillages.

The model includes all this in Monthly output as data with a monthly resolution at every state and for every year from 2011 to 2050.

It is managed by using the program Microsoft Excel and because of the big amount of data (it has more than 50,000 rows), a clustering per year is done with dynamic tables to perform the analysis of the results. Important data to be discussed here are:

- **Energy:** of every technology, of demand and EV demand, exported and imported, as well as energy prices for each state and every year. Then this is summed, except for prices and interconnections, to evaluate the total of NEM.
- **Capacity:** of every technology for each state and every year. An overview of NEM is done as well. Then, capacity payments in a decade basis are shown for every state.

#### 4.1.5 Blocks output: prices and technology mix

Nevertheless, the second file, Blocks output, presents the energy output of every technology and interconnection with each state, together with demand and EV demand. Moreover, prices, thermal load factor and marginal technology are shown.

This file shows data with a block resolution. The result variables are multiplied by 4 or a number slightly higher, depending on the number of weeks in the month, which changes if it has 28, 30 or 31 days. The results are for every state and every year since 2011 until 2050, although in Chapter 5 the presented period is 2020-2050.

Revenues of every technology with this block resolution can be extracted for example by using dynamic tables. This is important to analyse the profitability of renewable generators, explained below.

## 4.2 Generation

The chosen coal prices for modelling are those of the graph in Figure 9. In the case of gas, those presented in Figure 11.

The model is only allowed to invest in new technologies from 2016 because this is the year when the file with the list of generators in the NEM [28] of AEMO was published.

In the case of renewables, as said before, they are added, and the model cannot invest in them. Two scenarios are built: high renewables scenario and very high renewables scenario. The process followed to build the second one, from data of the first one, is summarised below in Figure 14.

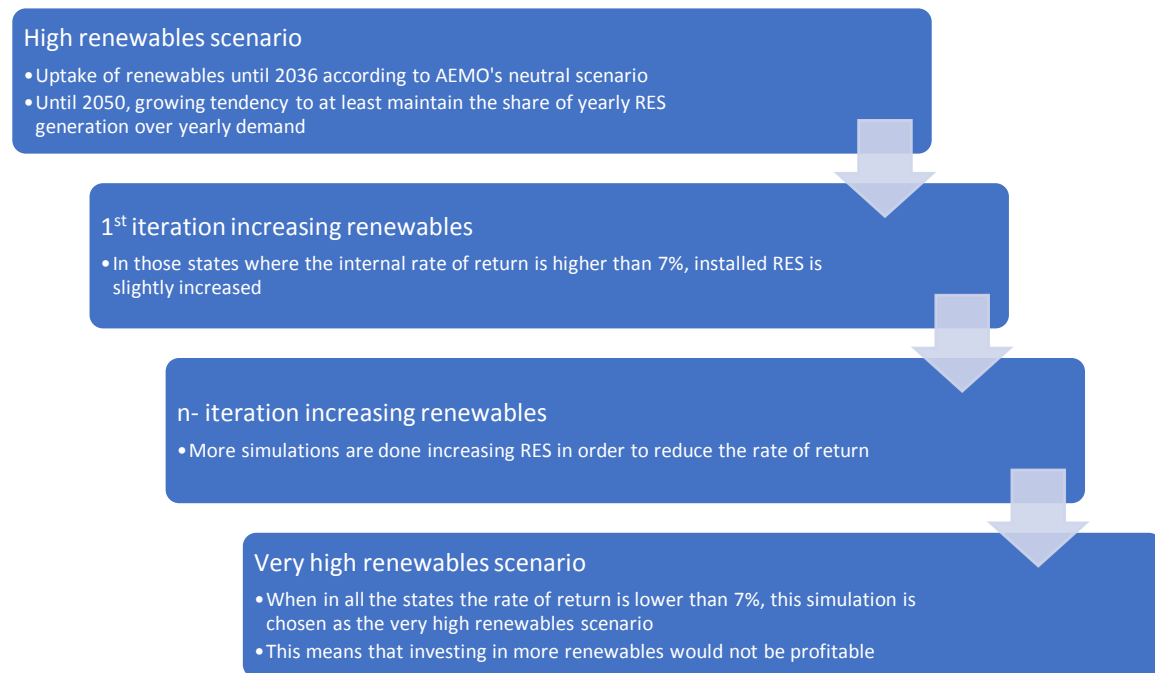


Figure 14 – Methodology followed to build the very high renewables scenario

The next Subsection explains in detail the methodology followed to build the scenario of high renewables and how much renewable generation it includes. The details of the very high renewables scenario can be found in Chapter 5, because is built from the results of modelling the high renewables scenario.

#### 4.2.1 Scenario of high renewables

Renewables outlook is taken from the neutral scenario (base case) of AEMO [5], which provides values of expected generation by technology until the year 2036. As seen before, there are a lot of renewable energy resources in the country. Therefore, there is no resource availability constraint for wind and solar PV, so it has been decided to maintain the share of renewables (including also hydro) over the total demand (including EV demand) in VIC, SA and TAS. But in the case of QLD and NSW, the decision is to increase the share of renewables because it was too low.

This is done in the following way:

- **QLD:** for this state, AEMO's neutral scenario (base case) [5] indicates that whereas solar PV (rooftop plus large-scale) would increase until 2036, wind capacity would be stable at a value of 354 MW from 2025 until 2036. This seems not reasonable counting on the high wind resources in some areas of Queensland, with reported load factors of around 35% (see Subsection 3.2.3); so an increase to an installed capacity of 2200 MW is used. Under these assumptions, in 2036 the share is expected to be of 34%. It is increased to 50% in the year 2050.
- **NSW:** the share of renewables is increased from a value of 45% in 2036 to 54% in 2050.



- **VIC:** in this case the share is maintained at around 57-58%.
- **SA:** the share is kept at 96-97%.
- **TAS:** the share of renewable energy over total demand is maintained at around 112-116%.

The share of renewables in a certain year and in a specific state is calculated in the following way:

$$\text{Share (\%)} = \frac{\text{PV} + \text{wind} + \text{hydro (TWh)}}{\text{Total demand (TWh)}} * 100$$

The calculated average share of renewables during 5 years for the period 2016-2050 and the average installed capacities of PV and wind are shown in Table 7. Note that '16 corresponds to year 2016, '20 to year 2020, etc.

**Table 7 – Forecast of installed PV and wind capacity in GW, and share of total RES including hydro in % over total demand in the state under the high renewables scenario**

	'16-'20	'21-'25	'26-'30	'31-'35	'36-'40	'41-'45	'46-'50
<b>PV<sub>QLD</sub> (GW)</b>	2.2	3.6	5.5	7.9	9.7	10.3	10.9
<b>Wind<sub>QLD</sub> (GW)</b>	0.1	0.3	0.7	1.6	2.9	4.5	6.1
<b>Share<sub>QLD</sub></b>	7%	12%	19%	28%	37%	43%	48%
<b>PV<sub>NSW</sub> (GW)</b>	1.9	3.0	4.8	8.3	12.5	14.0	15.5
<b>Wind<sub>NSW</sub> (GW)</b>	1.1	1.9	3.0	3.3	4.3	5.4	6.4
<b>Share<sub>NSW</sub></b>	12%	18%	26%	35%	47%	50%	53%
<b>PV<sub>VIC</sub> (GW)</b>	1.7	3.5	5.1	6.7	8.1	8.9	9.6
<b>Wind<sub>VIC</sub> (GW)</b>	2.0	3.7	4.8	5.6	5.9	6.1	6.4
<b>Share<sub>VIC</sub></b>	25%	42%	51%	57%	58%	58%	58%
<b>PV<sub>SA</sub> (GW)</b>	0.9	1.3	1.7	2.3	3.2	3.5	3.7
<b>Wind<sub>SA</sub> (GW)</b>	2.3	3.0	3.0	3.0	3.1	3.3	3.5
<b>Share<sub>SA</sub></b>	73%	91%	89%	90%	97%	97%	97%
<b>PV<sub>TAS</sub> (GW)</b>	0.1	0.3	0.4	0.6	0.9	0.9	1.0
<b>Wind<sub>TAS</sub> (GW)</b>	0.5	0.6	1.0	1.0	1.1	1.1	1.3
<b>Share<sub>TAS</sub></b>	104%	105%	115%	115%	114%	112%	112%

It is worth mentioning that according to AEMO's neutral scenario for renewables, in 2036 they already expect that in SA 97% of the annual energy demand will correspond to RES production, and what is more, in TAS this annual energy generated from renewable sources will be higher than the annual consumption.

In the other states, which have a lot of generation from coal-fired power stations, AEMO does not forecast much renewable generation in 2036. Then, RES are increased to have around 50-60% of share in the other states, which is much lower than in SA and TAS.

The data chosen both for capacity installed and energy generated of these renewables as an aggregation for all the NEM are shown in the graphs of Subsection 5.1.6.

Once the model is run, an evaluation of the profitability of renewables is done with data taken from the resulting prices. These correspond to the revenues, which are impacted by load factors, whereas the costs would be CAPEX and O&M, presented in Subsection 3.2.3.

Having said this, three future possible projects are assessed per each state both for PV and wind: one constructed in 2020, another one in 2025 and the last one in 2030. Load factors and O&M costs are kept constant, not mattering when they were constructed, through the expected life-time of the projects, which is 25 years.

The years in which the projects are built affect only to the CAPEX, which decreases through the years, and to the revenues, which are obviously different every year. Taking all this data, the internal rates of return of the projects are calculated to evaluate if they might be profitable investments or they may need other supports. The profitability analyses are performed in Sections 5.2 and 5.5.

## Chapter 5. Results

This Chapter shows the output data provided by the model after the simulations done. An analysis and evaluation of it is performed according to every scenario and output file. At the end, in Subsection 5.6, a comparison of the NEM under the two scenarios is carried out.

### 5.1 Scenario of high renewables: prices and technology mix

From the Monthly output file data, two graphs per state have been done. The first one represents the installed capacity of every technology plus capacity payments needed (shown as the average for every decade) to cover peak demand of the thermal gap for the period 2020-2050. The second one shows the amount of energy produced with each of the technologies, demand, EV demand, exchanges with other states and annual average price during the same period. They are separated per state, and finally an aggregation of NEM is done and analysed.

#### 5.1.1 Queensland

The results of installed capacity and capacity payments are shown in Figure 15.

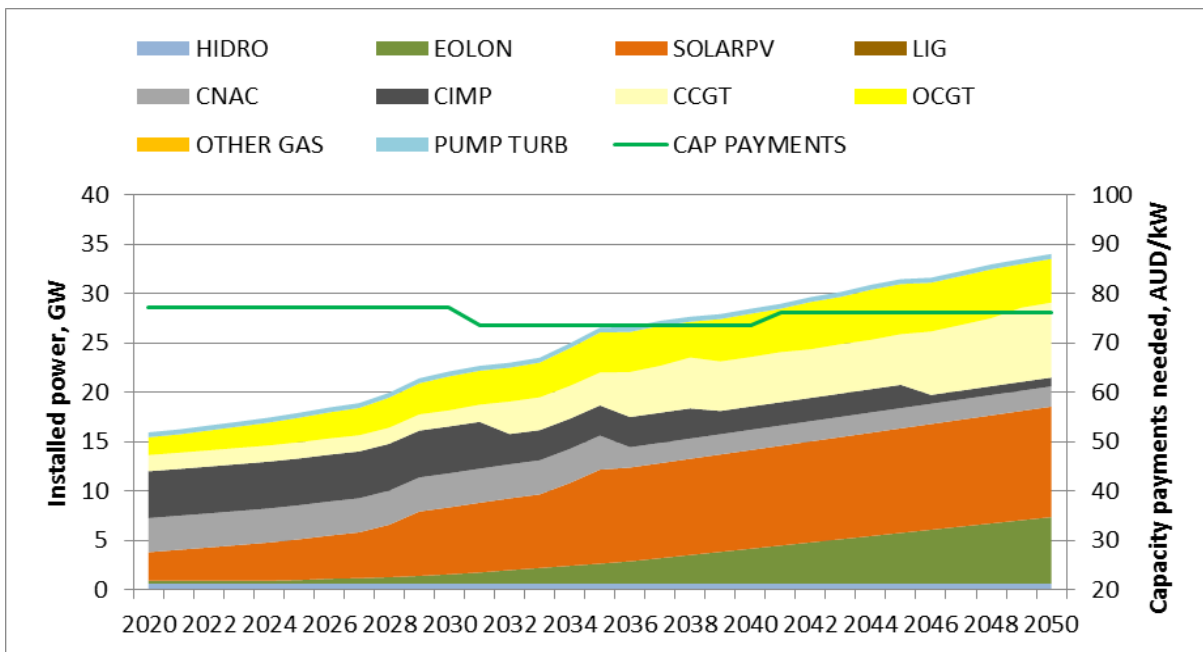


Figure 15 – Installed capacity and payments in Queensland under the high renewables scenario for 2020-2050

Capacity payments are of around 75 AUD/kW. We can see that there are closures of coal power plants after 2030. The model invests both in CCGTs and in OCGTs to maintain the reserve margin after these closures.

Figure 16 presents consumption, generation and prices of energy in QLD.

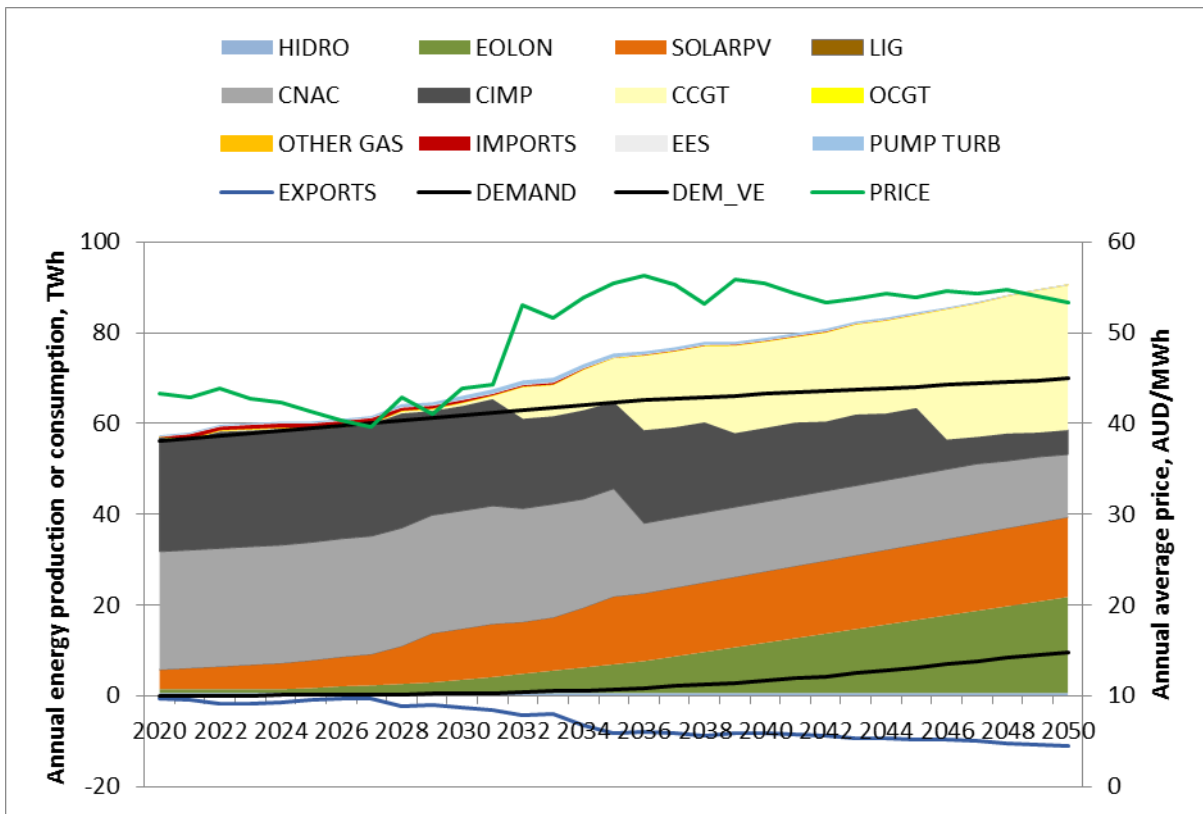


Figure 16 – Annual energy and average prices in Queensland under the high renewables scenario for 2020-2050

In the Figure, we can see that prices are stable at around 43 AUD/MWh in the first decade until a coal plant is decommissioned in 2032. More closures drive the increase in prices until around 55 AUD/MWh, as gas is now the marginal technology.

Until 2032, exports to NSW are minor, whereas from it onwards, they grow year by year. It is worth noting that the higher the generation with gas is, the higher the exports. This is due to the fact that QLD's gas prices are the lowest in the NEM (see Figure 11). Imports from NSW are low.

Hydroelectric generation (the blue area in the bottom of the graph) is almost negligible, the same as peaking power plants (OCGTs), which almost do not work. Pumping turbine is not used much, mostly between 2025 and 2040.

### 5.1.2 New South Wales

Figure 17 and Figure 18 are the graphs which represent installed capacity and its payments, and energy and prices, respectively, for NSW.

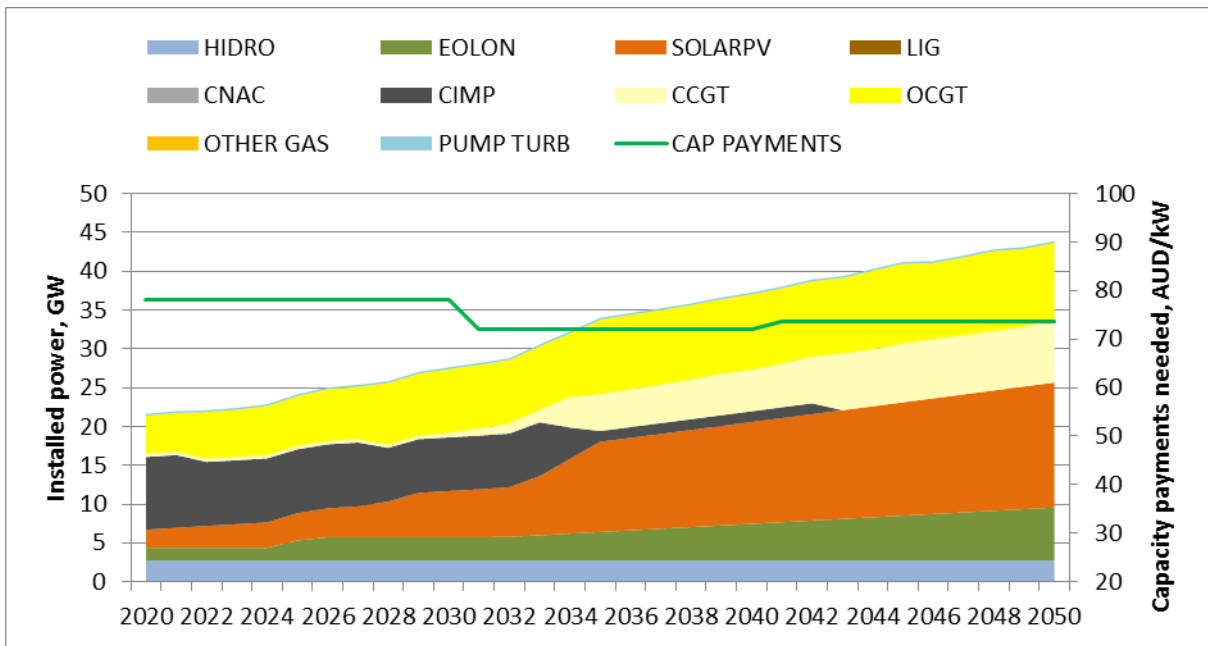


Figure 17 – Installed capacity and payments in New South Wales under the high renewables scenario for 2020-2050

We can see how the model invests in OCGTs and CCGTs especially around 2033, when some coal plants are closed. This is to maintain the reserve margin and to generate in the case of the latter, as seen in Figure 18. Capacity payments have an average of 75 AUD/kW.

The high uptake of PV forecast by AEMO between 2032 and 2035 is probably to partially cover this closure of two coal-fired power plants for a total of 5520 MW.

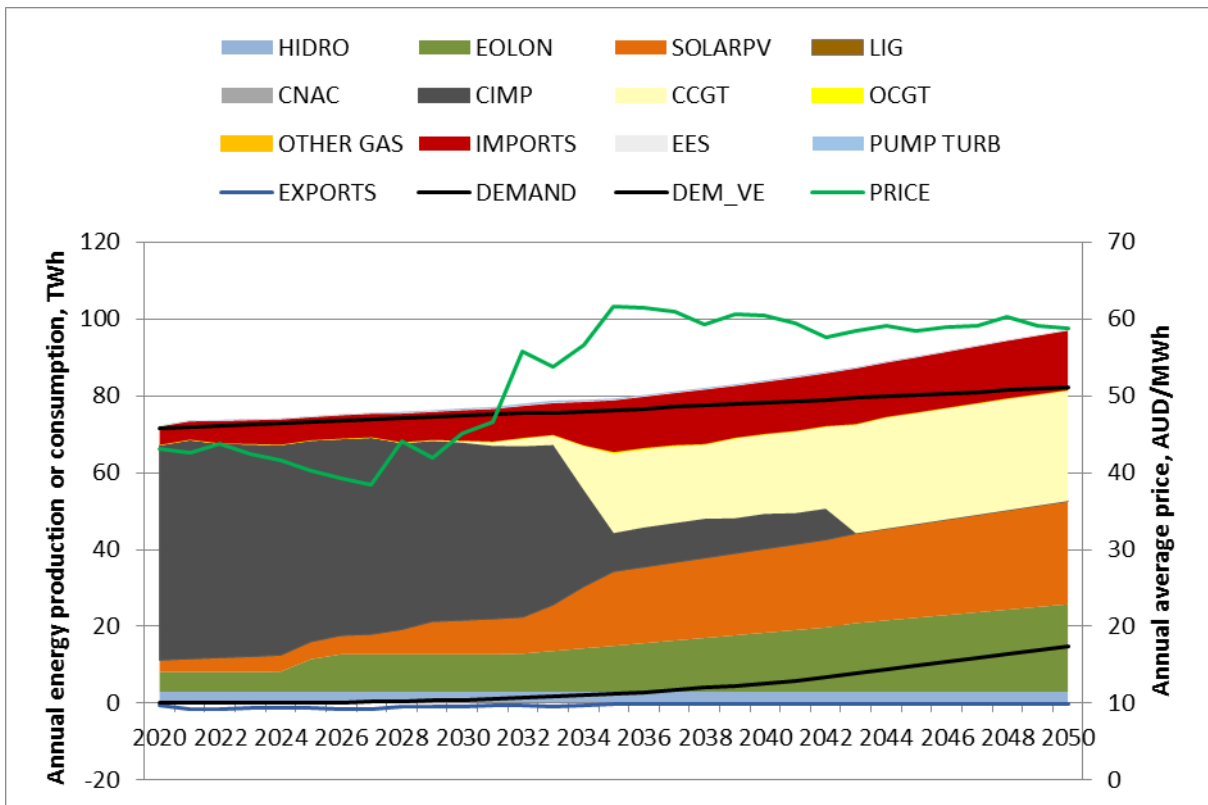


Figure 18 – Annual energy and average prices in New South Wales under the high renewables scenario for 2020-2050

From 2020 onwards, coal, renewable generation and cheap imports from Victoria drive decreasing prices until 38 AUD/MWh in 2027. In 2028 a coal plant is decommissioned, and prices achieve higher levels (until 60) when coal CIMP is closed in NSW. After these closures, CCGT is the marginal technology during most of the time, stabilising prices at around 60 AUD/MWh from the year 2034. Hydro generation is more relevant than in QLD, and pumping turbines are also used.

We can also see that NSW has some exports to QLD and especially to VIC until around 2030, but it is generally an importing state, mainly after 2035, then receiving more energy from QLD and less from VIC because of lower gas prices in the former.

### 5.1.3 Victoria

Figure 19 and Figure 20 represent, respectively, installed capacity and capacity payments; and expected energy generated and prices in Victoria.

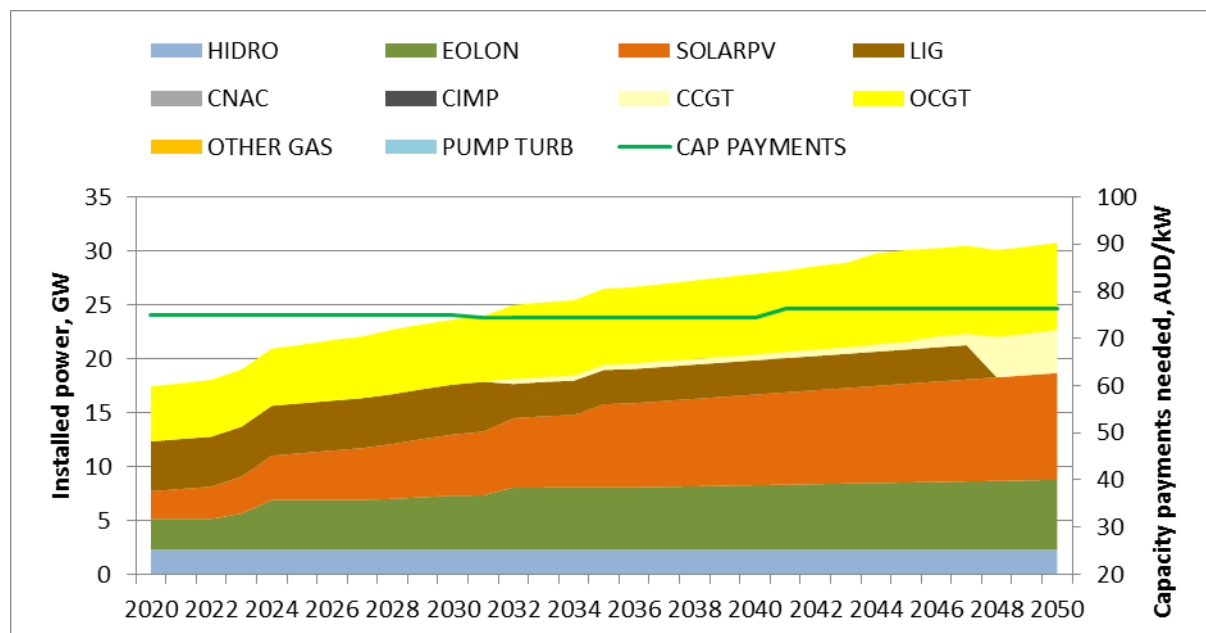


Figure 19 – Installed capacity and payments in Victoria under the high renewables scenario for 2020-2050

In Figure 19 the reader can see the closure of a lignite power plant in 2032, year in which the model starts investing in CCGTs. The largest lignite plant, which has 3180 MW, is closed in 2048. More CCGT capacity is then installed

Along the studied period, there are mainly investments in OCGTs to accomplish the reserve margin requirement. Capacity payments are again of around 75 AUD/kW since 2016.

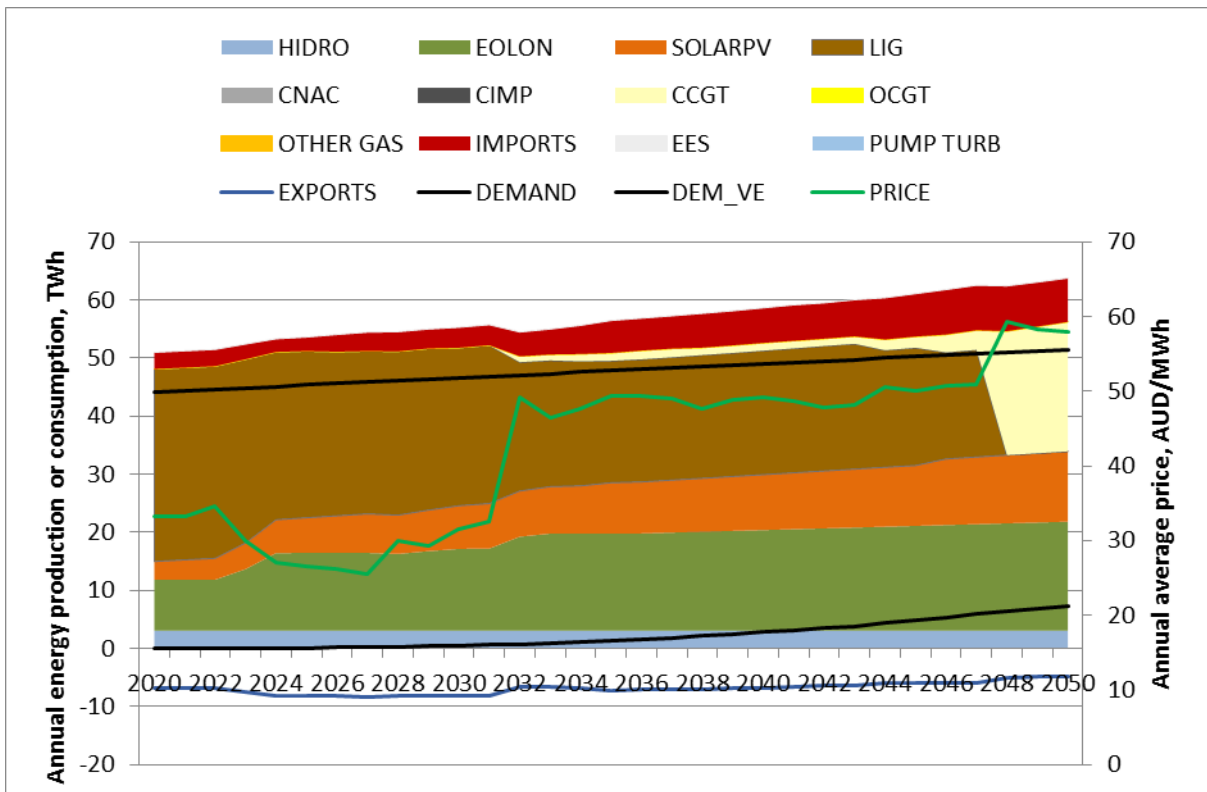


Figure 20 – Annual energy and average prices in Victoria under the high renewables scenario for 2020-2050

During the period 2020-2031 there is a depression of prices, reaching a minimum of only 26 AUD/MWh, due to the uptake of renewables plus cheap production with lignite. From 2032 onwards, the use of CCGTs and more expensive imports surrounding states drive an increase in prices to values of 50-60 AUD/MWh. Finally, a high peak of prices can be seen in 2048 because of the previously mentioned closure of a power plant in VIC.

Until around 2022, Victoria imports its energy mainly from NSW. But then imports mostly come from SA and TAS. Both states have a lot of renewables (also hydro in the case of TAS) as will be presented below. VIC is a big exporter to SA until around 2037, it does not export much to TAS and it is a big exporter of energy to NSW. This all is due to the fact that Victoria is the state which is connected to the highest number of states.

We can say that in Victoria, hydroelectric generation is quite relevant.

### 5.1.4 South Australia

South Australia's results are shown in Figure 21 and Figure 22.

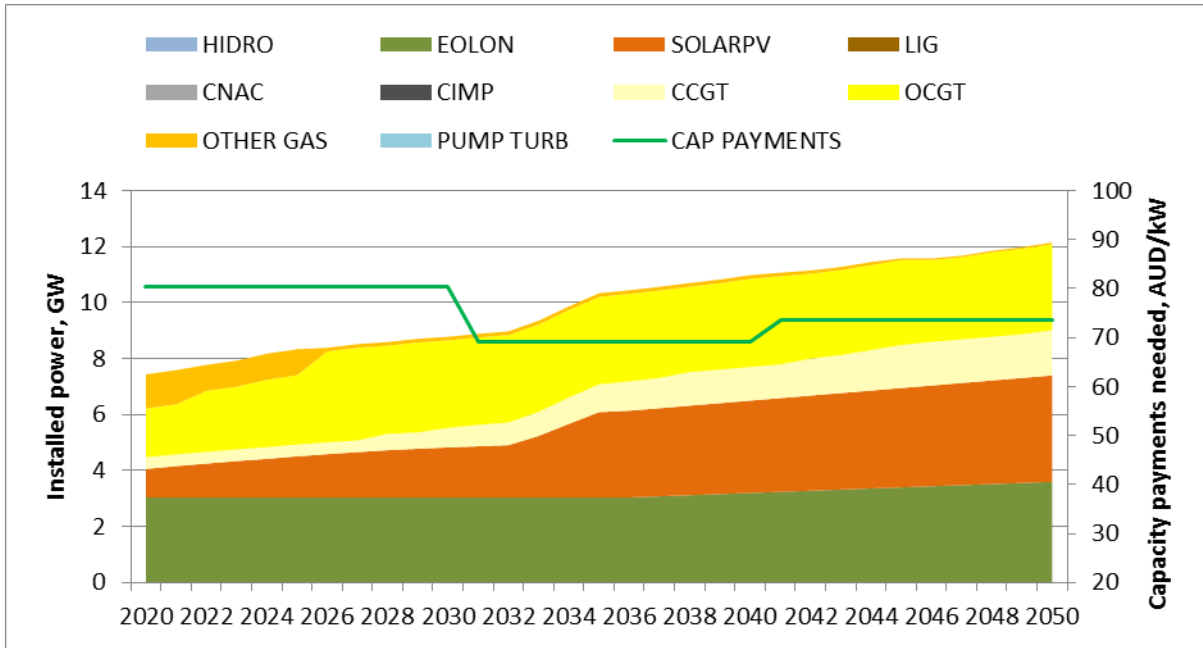


Figure 21 – Installed capacity and payments in South Australia under the high renewables scenario for 2020-2050

The reader can see how in 2026 most of other gas' capacity is decommissioned, being substituted by fast-ramping OCGTs to cover the reserve margin and generate some energy, as seen below. Some CCGTs are installed in order to generate energy. Capacity payments are around 75-80 AUD/kW.

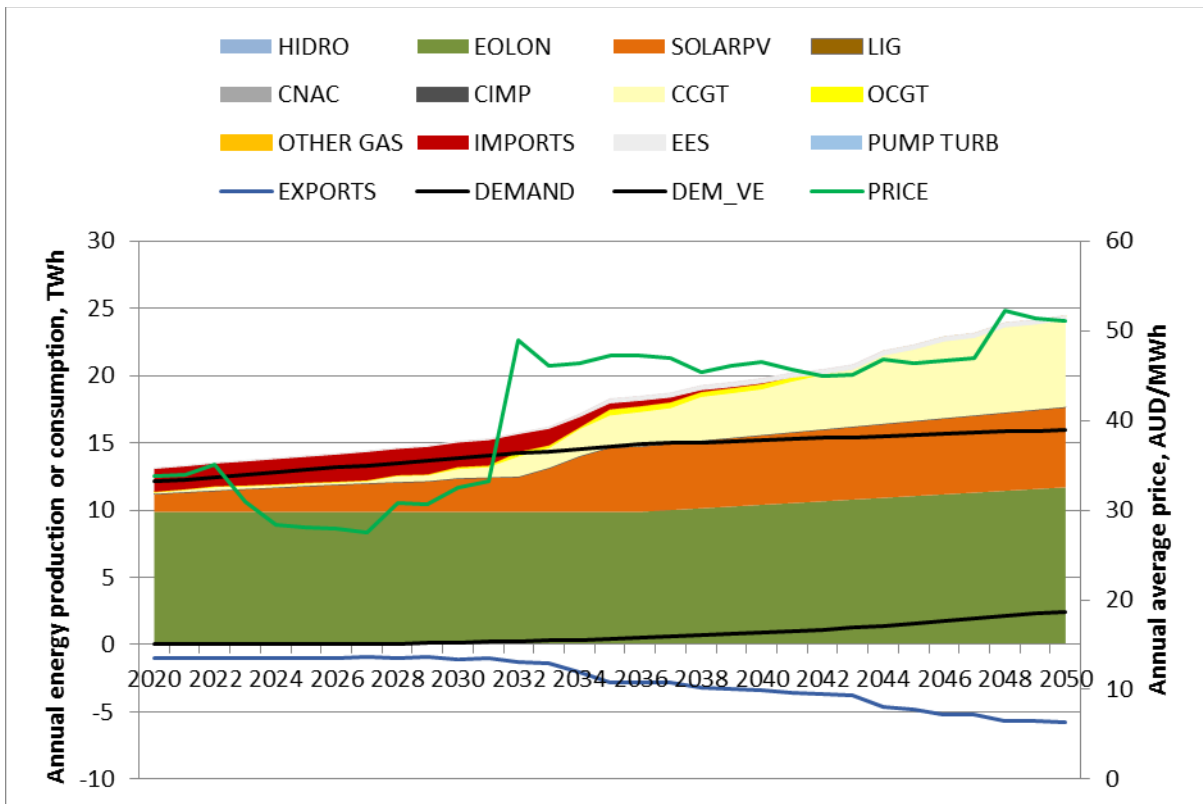


Figure 22 – Annual energy and average prices in South Australia under the high renewables scenario for 2020-2050



Like the case of Victoria, Figure 22 shows a depression of prices from 2020 to 2032, having a minimum of 28 AUD/MWh in 2027 because of the high uptake of renewables and cheaper imports from VIC.

After 2032 prices are around 50 AUD/MWh because of the use of more CCGTs. And finally, in 2048 we can see a peak caused by the previously mentioned lignite-fired power plant decommissioning.

Imports from VIC are very important in SA until the deployment of renewables together with CCGTs starting to be marginal. Exports to VIC are not very high until around 2034, when a big investment in solar PV is done. After it, the large share of renewables of the state contributes to the increase on exports to VIC. According to Figure 11, SA is the second state with the lowest gas prices. This also drives exports to Victoria.

There are some energy spillages, which might give a signal for the increase on interconnections. This is commented in more detail in Subsection 5.1.6.

### 5.1.5 Tasmania

Finally, in Figure 23 we can find installed capacity and payments in Tasmania, whereas in Figure 24, annual energy production and average prices.

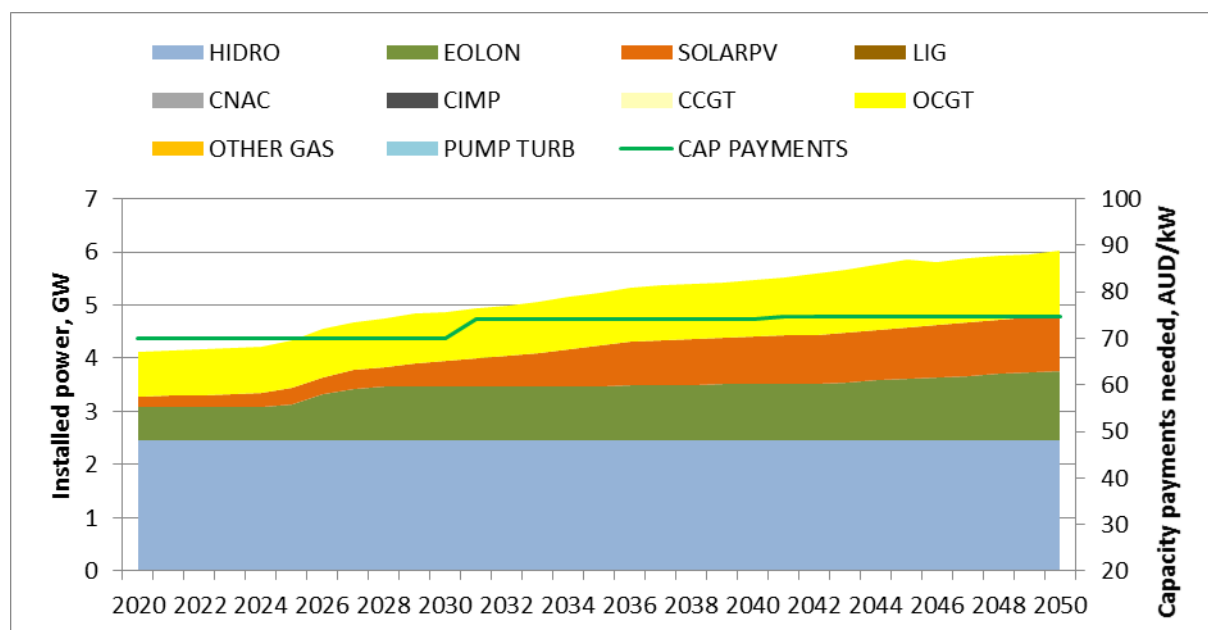


Figure 23 – Installed capacity and payments in Tasmania under the high renewables scenario for 2020-2050

In the previous Figure we can see how TAS is mostly based on hydro generation. Capacity payments are of around 75 AUD/kW. It is worth mentioning that in this state, only investments of OCGTs are carried out. This is because of the share high of renewables (overcoming 100%) which is presented in Table 7 and of the manageability of hydro, which mean no production with CCGTs is needed.

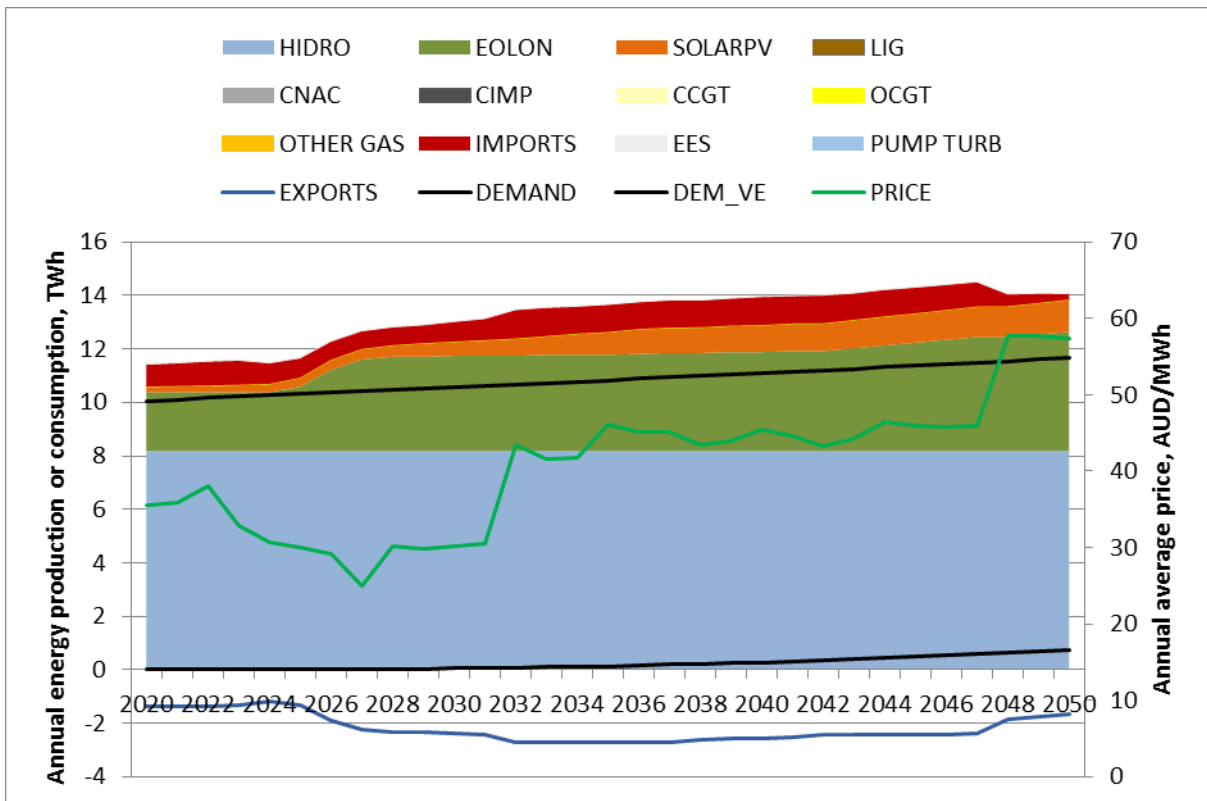


Figure 24 – Annual energy and average prices in Tasmania under the high renewables scenario for 2020-2050

In Figure 24 we can see, similarly to VIC and SA, a decrease on prices, with a minimum of 25 AUD/MWh because of renewables and cheap imports until 2032, when coal power plants start to be closed. But in the rest of the years prices are of around a value of 45 AUD/MWh, until Victoria's decommissioning of the last lignite power plant, when prices reach almost 60 AUD/MWh.

There are a lot of exchanges between Tasmania and Victoria, especially from TAS to VIC because of the large share of renewables that there are in the present state which can provide very low prices.

### 5.1.6 National Electricity Market

The aggregation for all the states of technology mix data (generation and installed capacity) together with the prices at every state presented before is shown below.

In Figure 25 and Figure 26 we can see this aggregation for the installed capacity and share of energy production, together with total energy generation, per technology in 2020, 2030, 2040 and 2050.

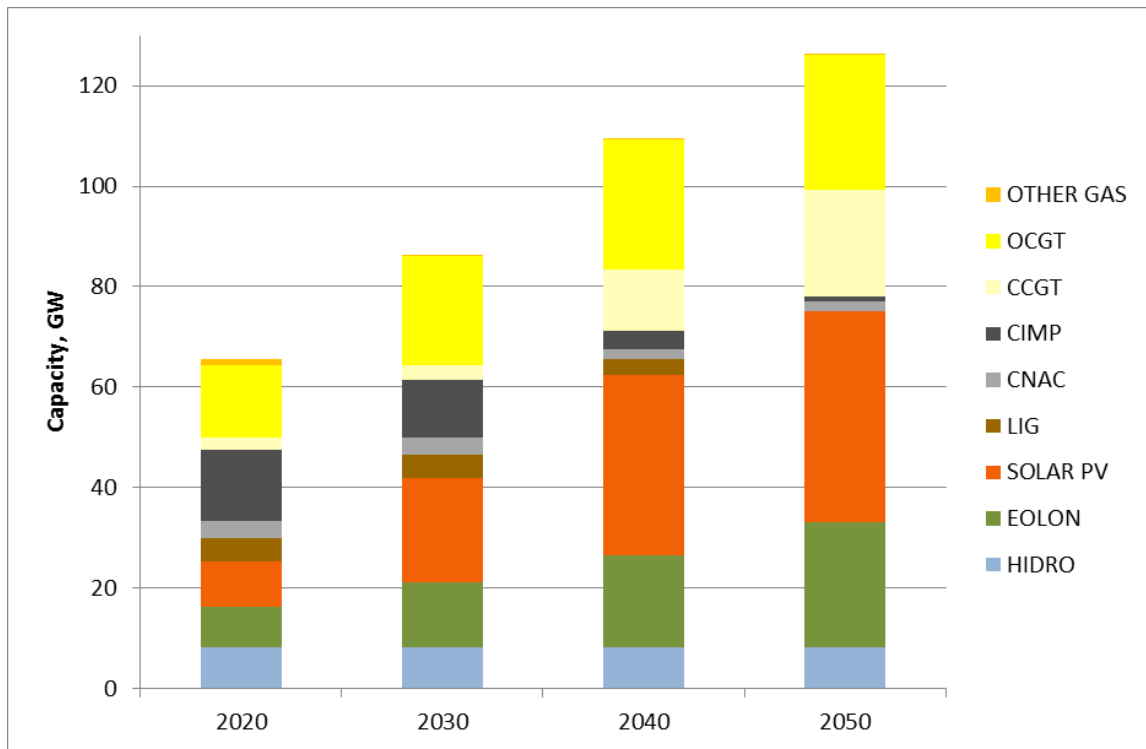


Figure 25 – Installed capacity in GW per technology in the NEM under the high renewables scenario in 2020, 2030, 2040 and 2050

In the previous graphs we can see how coal-fired power plants are subsequently substituted by technologies with lower emissions. They go from a total of around 22 GW installed in 2020 to only 3 GW in total in 2050. Nevertheless, CCGTs and OCGTs increase their capacities a lot, from 2.5 GW and 14 GW in 2020 to 21 GW and 27 GW in 2050, respectively.

Something worth mentioning is the huge amount of total installed capacity in 2050 (126 GW), which is around twice the total capacity expected for 2020 (66 GW) because of the high uptake of renewables and of the reserve margin constraint. This is an indicator of the need of storage such as more water pumping stations or even batteries, provided that they are cost-effective, which might be reasonable, to be used as fast-ramping technologies to substitute OCGTs.

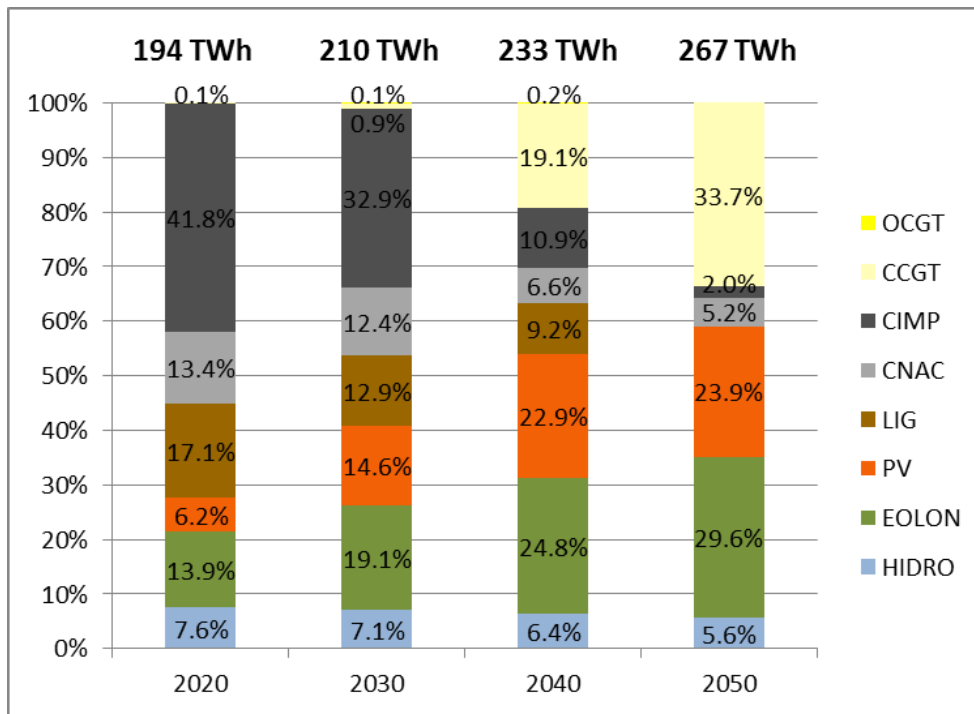


Figure 26 – Share of energy produced per technology in the NEM under the high renewables scenario in 2020, 2030, 2040 and 2050

In the last Figure, the values in TWh indicate the total energy production during that year. The production of “other gas” and “pumping turbine” are 0.0%, so they are not shown in the previous graphs.

We can see how base load production of energy changes from coal-fired power stations in 2020, which accounts more than 72% of the generation, to CCGTs, which represent 34% of the energy generated in 2050 due to the fact that investing in CCGTs is cheaper than investing in coal.

It is worth mentioning that in 2050 almost 60% of the energy would be generated by RES. There are energy spillages only in South Australia, accounting for 0.30 TWh in 2050.

Once analysed the technology mix, we can find in the next Figure 27 all the annual prices per state for the period 2020-2050.

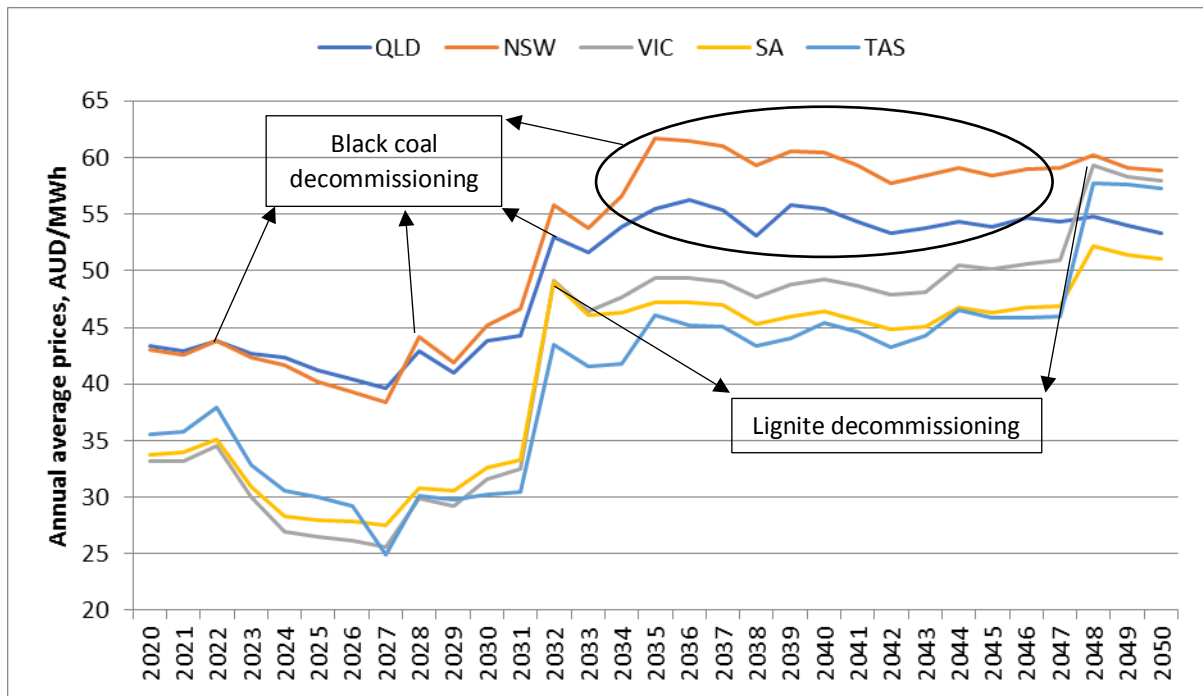


Figure 27 – Annual average prices per state in the NEM under the high renewables scenario for the period 2020-2050

This clearly shows how prices change during this period. On the one hand, the reader may observe that prices in QLD and NSW are correlated, probably because of the fact that they have coal-fired power plants with similar fuel prices. Any closure of those plants directly affects prices such as around 2034. The effect on the other three states is not so noticeable.

On the other hand, VIC, SA and TAS are correlated among them, meaning that every lignite power plant decommissioning in Victoria directly affects the prices in the three of them, such as in 2032 and 2048. In any case, the closure of 2032 also supposes an increase in prices in QLD and NSW.

From 2032 onwards gas power plants (CCGTs, OCGTs) are more needed in all the states because of coal-fired power plants closures plus renewable generation uptake. The highest prices are found in QLD and NSW, whereas high renewable generation in the other states keep prices relatively low and lignite.

### 5.1.7 General comments

Prices of capacity payments are shown as the average of every decade to smooth the curve and avoid too high peaks in some years and too low valleys in the next ones. As seen in Chapter 4, the model is allowed to invest after the year 2016, so everything presented before is subject to investments according to the model's decisions.

There is not energy not served, so the existing generation is more than enough to cover the demand until 2016 and after this year the model makes proper investments. But there have been some energy spillages in SA.

It was properly checked that the model correctly introduces existing installed capacities of every technology. Load factors of thermal plants are higher in those cheaper ones such as lignite or black coal than in gas-fired power plants.

## 5.2 Scenario of high renewables: profitability

In the following Subsections the results of the analysis of profitability of future projects of renewable energy (solar PV and wind) are presented and discussed. These data are result of the blocks output file.

### 5.2.1 Profitability of solar PV

The Blocks output file provides the revenues for each of the states and technologies (wind and solar PV). These ones for PV, as annual average per unit of energy, are shown in the following Figure 28:

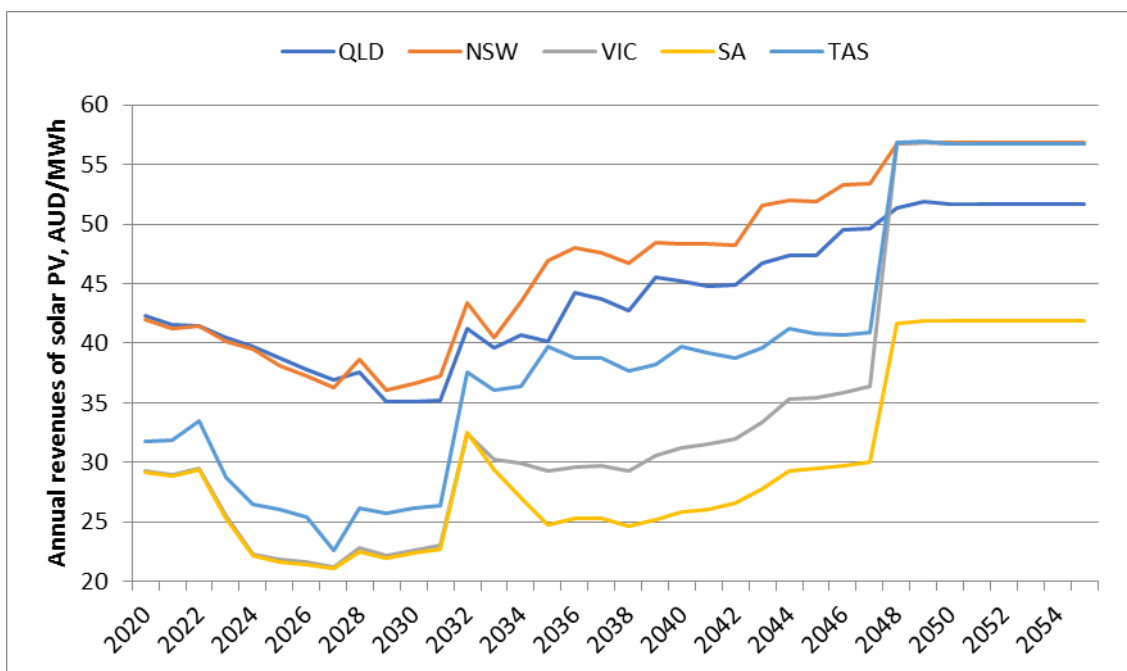


Figure 28 – Revenues of solar PV under the high renewables scenario from 2020 to 2055

The previous Figure shows a general increasing trend of prices after 2032 with the closure of coal-fired plants. The exception is SA, which has a high uptake of PV around 2034 and reduces prices after 2032. This determines that those plants commissioned after 2032 will receive higher prices than the ones built before. The reader may note that after 2050 those revenues (in AUD/MWh) are manually kept at the value of 2050 since this year until 2055.

Once taken the previous revenues for solar PV, the internal rate of return is calculated and shown in Table 8.

**Table 8 – Internal rate of return (%) of renewable investments in solar PV under the high renewables scenario for 2020, 2025 and 2030**

	2020	2025	2030
<b>QLD</b>	3.8%	5.3%	9.9%
<b>NSW</b>	3.7%	5.4%	10.3%
<b>VIC</b>	-0.1%	1.9%	6.7%
<b>SA</b>	-0.5%	1.0%	5.3%
<b>TAS</b>	-5.6%	-3.9%	-0.2%

In the previous Table, we can find in green colour those rates of return higher than 7% which are important to highlight to make the very high renewables scenario.

We can deduct from the values that the prices that solar PV sees, or in other words, the prices of the hours in which it produces electricity, are not enough even to cover the estimated investment costs for those plants built in 2020 in VIC, SA and TAS. And even in Tasmania, according to the assumptions commented in Chapter 4, projects built in 2025 and 2030 would not cover their costs as well, especially because of the low load factor that PV plants have there. This means that other supports, for example coming from governmental policies, would be needed to recover investments done there.

In the rest of the cases, we can see positive but quite low IRRs which might also require supports. Except for power plants built in 2030 in QLD, NSW and VIC, which would obtain reasonable IRRs of around 7% or higher.

In QLD and NSW the expected internal rates of return are so high that it is supposed that more agents would be willing to invest more after 2030. Therefore, the very high renewables scenario considers an increase in the installed capacity of solar PV in these two states.

## 5.2.2 Profitability of wind energy

In the next Figure 29 we can see the revenues for wind generation, shown as the annual average.

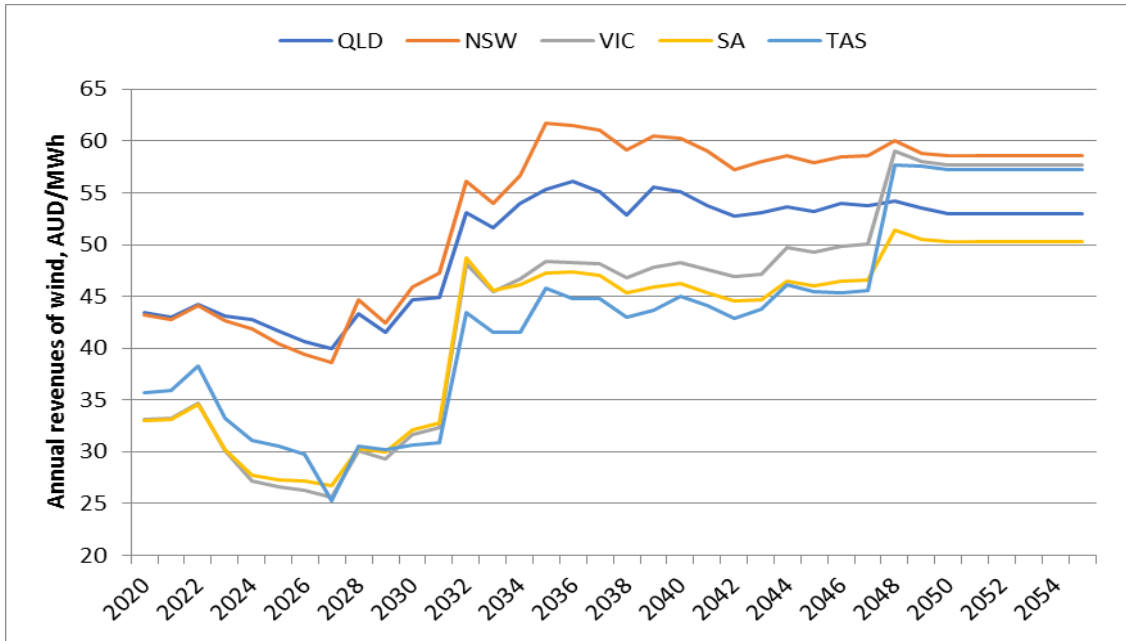


Figure 29 – Revenues of wind under the high renewables scenario from 2020 to 2055

In the case of wind, prices received are more similar among the different states than solar PV, especially after 2032, where we can see again a peak of prices both in 2032 and 2048. These average revenues are more stable and higher than in the case of solar since wind production is more spread along the day.

Moreover, this behaviour is also very similar to the annual average prices previously presented in Figure 27, where for example after 2030 average prices are higher in NSW than in the other states. This is due to the load factor of wind, which does not vary in a specific daily basis like PV.

Table 9 shows the internal rate of return calculated for future investments in wind farms.

Table 9 – Internal rate of return (%) of renewable investments in wind energy under the high renewables scenario for 2020, 2025 and 2030

	2020	2025	2030
<b>QLD</b>	4.3%	6.9%	8.4%
<b>NSW</b>	3.5%	6.2%	8.0%
<b>VIC</b>	1.1%	3.8%	6.1%
<b>SA</b>	1.2%	3.7%	5.6%
<b>TAS</b>	2.7%	5.2%	7.3%

Investments in wind yield in all the states positive rates of return. Anyway, companies considering building wind farm might need some extra support for investments done in 2020 in all states; and probably in VIC, SA and TAS in 2025. But in the case of investments done in 2030, revenues from the market are supposed to be enough to have a reasonable profit, especially in QLD, NSW and TAS (In green colour), where it is higher than 7%. Therefore, the very high renewables scenario, presented in the next Section, considers an increase in the installed capacity of wind generation in these three states.



### 5.3 Scenario of very high renewables

With the internal rates of return resulting from the high renewables scenario, the very high renewables scenario is made. This is done through the following criterion: when in a state, for a certain construction year (2020, 2025 or 2030), and for PV and wind the IRR of the project is lower than 7%, the installed RES is kept as in the high renewables scenario, which is considered as the minimum possible installed capacity of renewables.

But when IRR is higher than 7%, it is assumed that companies will be willing to invest in more projects in those states, increasing the renewables share and therefore reducing the revenues. More and more installed capacity is added until the IRR is lower than 7% for all the states, technologies and construction years.

According to the profitability analysis presented in Section 5.5, under the current scenario renewables are set in the following way, increasing their capacity only after 2030:

- **QLD:** the share of renewables is 25% in 2030 and grows up to 69% in 2050.
- **NSW:** the share of renewables is increased from a value of 30% in 2030 to 67% in 2050.
- **TAS:** the share of renewable energy from 2030 to 2050 is at around 115-119%.
- **VIC and SA:** the share is kept as in the high renewables scenario.

The calculated average share and average installed capacity for 5 years (6 in the case of 2030-2035) for the period 2030-2050 and the installed capacities of PV and wind are shown in Table 10.

**Table 10 – Forecast of installed PV and wind capacity in GW, and share of total RES including hydro in % over total demand in the state under the very high renewables scenario for 2030 to 2050 in comparison with the other scenario**

	2030-2035	2036-2040	2041-2045	2046-2050
<b>PV<sub>QLD</sub> (GW)</b>	8.5	11.2	13.7	16.2
<b>Wind<sub>QLD</sub> (GW)</b>	2.3	4.7	6.3	7.8
<b>Share<sub>QLD</sub></b>	33%	49%	58%	66%
<b>PV<sub>NSW</sub> (GW)</b>	8.5	14.4	17.5	20.0
<b>Wind<sub>NSW</sub> (GW)</b>	3.6	5.0	6.3	7.5
<b>Share<sub>NSW</sub></b>	38%	54%	61%	65%
<b>PV<sub>VIC</sub> (GW)</b>	6.7	8.1	8.9	9.6
<b>Wind<sub>VIC</sub> (GW)</b>	5.6	5.9	6.1	6.4
<b>Share<sub>VIC</sub></b>	57%	58%	58%	58%
<b>PV<sub>SA</sub> (GW)</b>	2.3	3.2	3.5	3.7
<b>Wind<sub>SA</sub> (GW)</b>	3.0	3.1	3.3	3.5
<b>Share<sub>SA</sub></b>	90%	97%	97%	97%
<b>PV<sub>TAS</sub> (GW)</b>	0.6	0.9	0.9	1.0
<b>Wind<sub>TAS</sub> (GW)</b>	1.0	1.2	1.3	1.4
<b>Share<sub>TAS</sub></b>	116%	119%	119%	119%

We can see that now shares are minimum 58% for 2050. This high renewable share will mean a reduction on profitability as is presented in Section 5.5.

Having profitability assumptions is relevant for companies willing to invest in renewables because, as stated in the motivation of this Thesis in Chapter 1, they need to have estimations of revenues that they will obtain, which must be enough to earn some benefits through the life-time of the project from the market and/or receiving extra supports.

## 5.4 Scenario of very high renewables: prices and technology mix

In this Section, in order to not repeat the analysis carried out before, the results obtained for every state are either not shown or analysed here. However, the graphs can be found at Appendix B, and an aggregated data of the NEM of prices and technology mix is presented and discussed in the next Subsection.

### 5.4.1 National Electricity Market

NEM's installed capacity under the very high renewables scenario is shown in Figure 30.

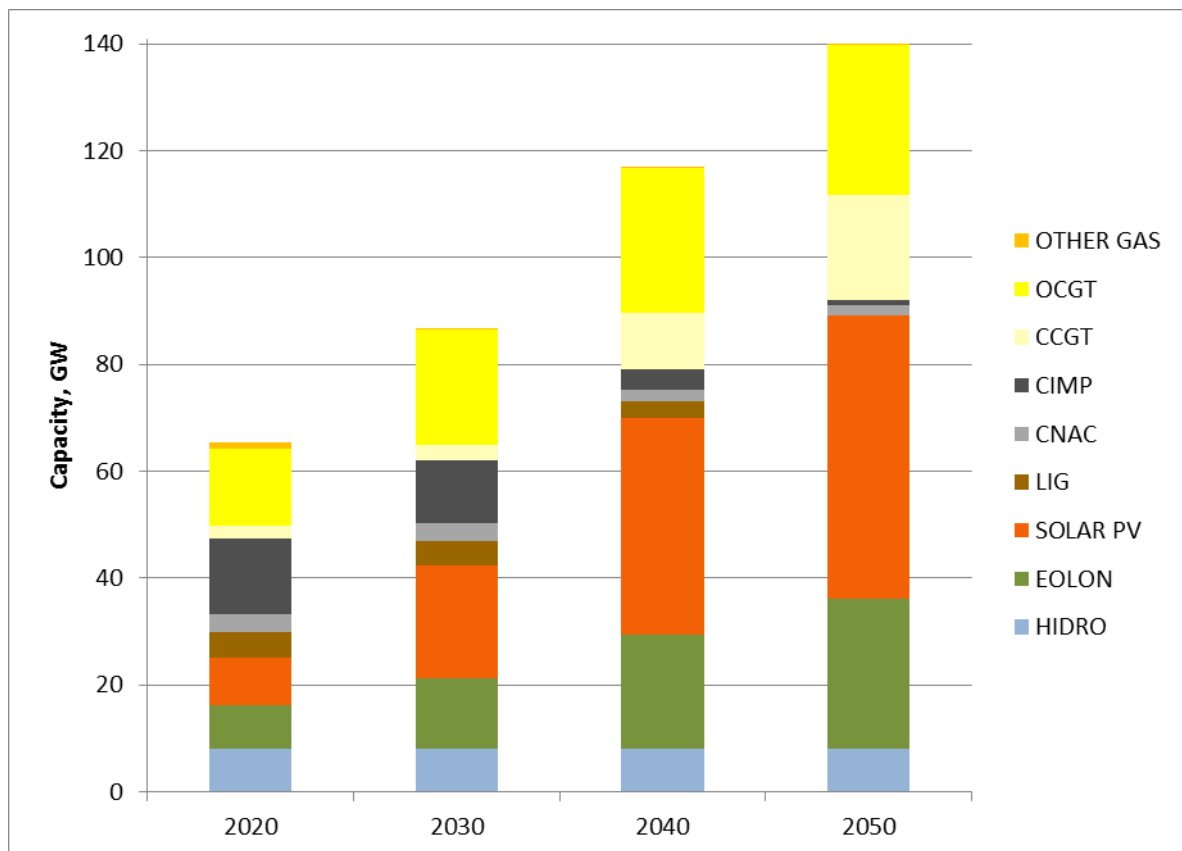


Figure 30 – Installed capacity in GW per technology in the NEM under the very high renewables scenario in 2020, 2030, 2040 and 2050

We can see that coal-fired power plants are again subsequently substituted by technologies with lower emissions. In this scenario, CCGTs' installed capacity increase from 2.5 GW in 2020 to 19.6 GW in 2050. In the case of OCGTs, they go from a value of 14.4 GW in 2020 to 28 GW in 2050.

The total installed capacity is huge in 2050 (140 GW), more than twice the capacity in 2020 (66 GW). This is because of high installed renewables, which are intermittent, and their load factors are at levels far from 100%.

In the next Figure 31 we can see from which sources are used to produce electricity in the NEM in 2020, 2030, 2040 and 2050.

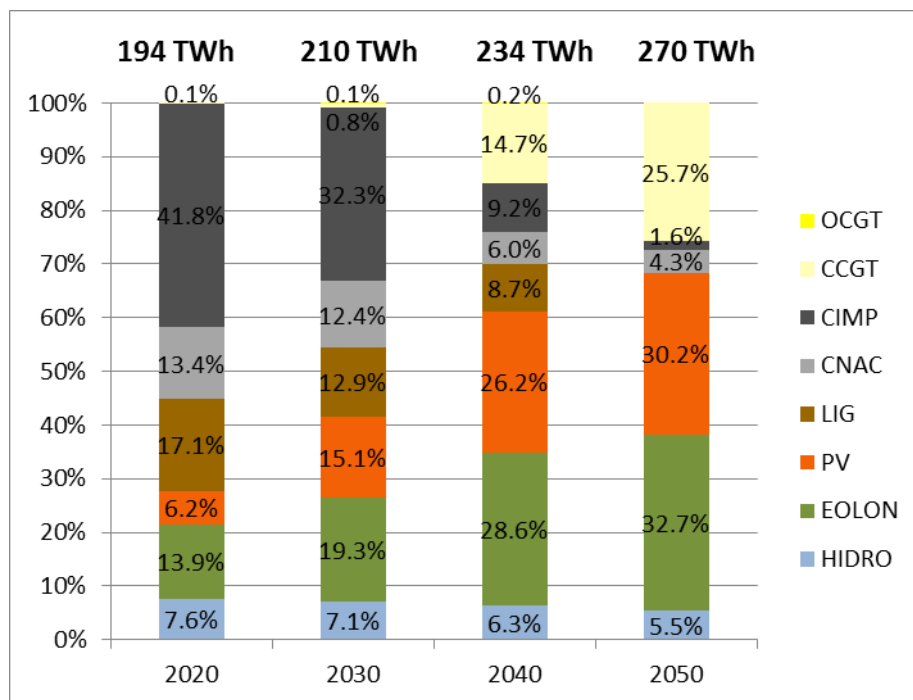


Figure 31 – Share of energy produced per technology in the NEM under the very high renewables scenario in 2020, 2030, 2040 and 2050

In the previous Figure the reader may observe that renewables are the big players, accounting for almost 70% of the energy in 2050. The second generation technology by share of production is CCGT, which accounts for almost 26%.

Energy spillages are quite important, which would happen in all the states except in VIC and TAS. In QLD, it is expected to be 1.67 TWh, in NSW 1.11 TWh, and in SA 0.34 TWh, all in 2050.

In Figure 32 we can find the comparison of prices per states under the very high renewables scenario.

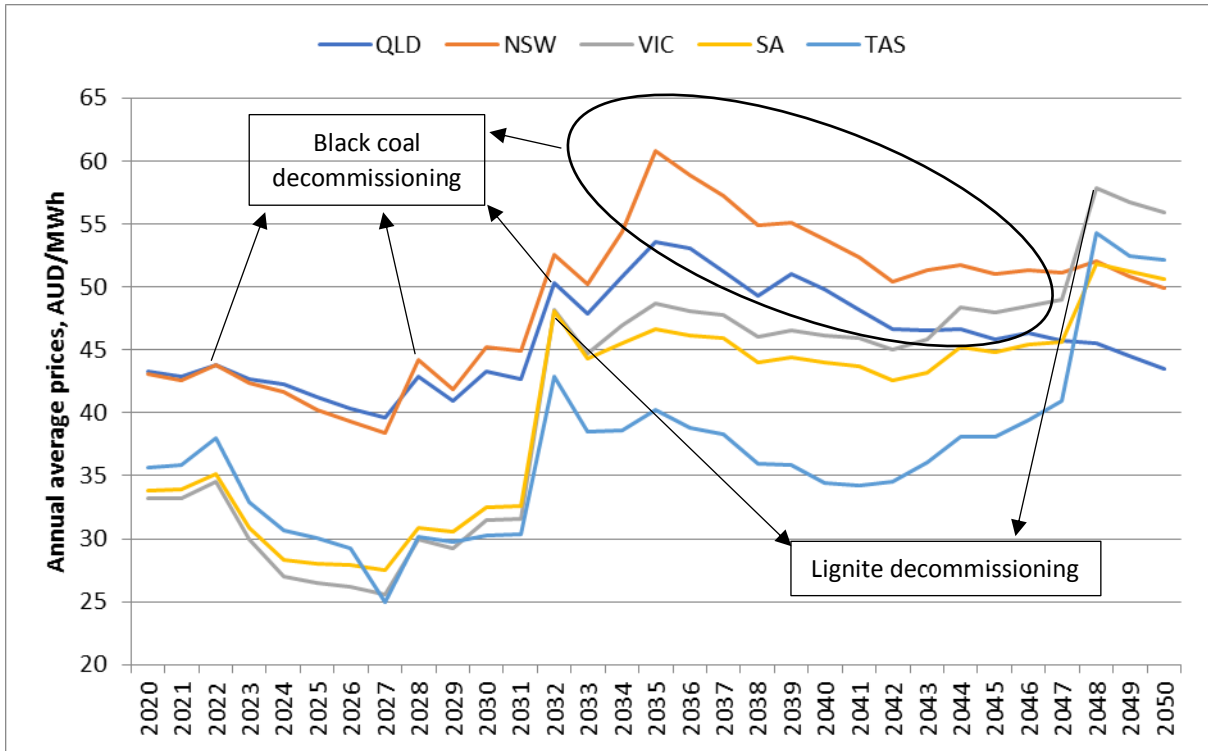


Figure 32 - Annual average prices per state in the NEM under the very high renewables scenario for 2020-2050

Coal-fired plants closures are easily spotted in the graph. For example, the small peaks of prices around 2035 or in 2048 happens because of this reason. Prices in all states tend to converge in 2050 at prices between 43 AUD/MWh and 56 AUD/MWh.

Prices are again driven by fuel costs (coal at the beginning, gas at the end of the period) and renewables uptake, which creates this decreasing tendency of prices in QLD and NSW after 2035.

There is not energy not served, thus the model has appropriately taken into account the reserve margin constraint. But there are energy spillages, which should be avoided.

## 5.5 Scenario of very high renewables: profitability

In this Section we can see how all the states are affected by the increase in renewables performed in only some of them.

### 5.5.1 Profitability of solar PV

The price *seen* by PV generation under this scenario is presented in the following Figure 33:

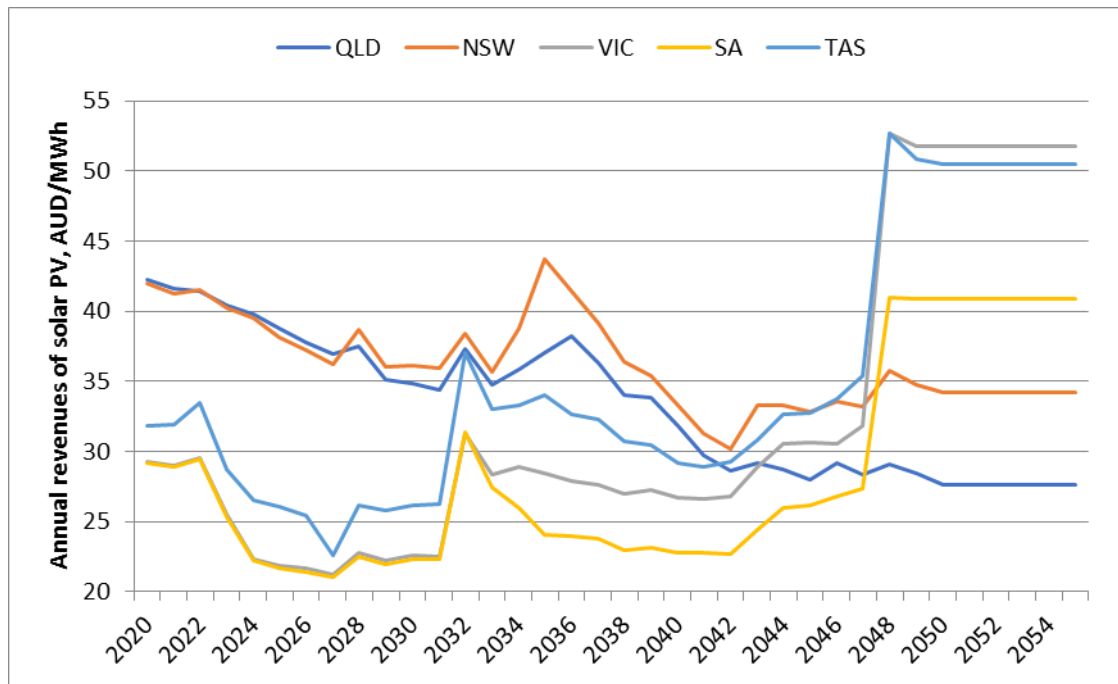


Figure 33 - Revenues of solar PV under the very high renewables scenario from 2020 to 2055

The reader may observe how there is a convergence trend of prices from 2035 to 2047 driven by higher PV especially in QLD and NSW, but then the closure of power plants breaks it, as no more PV was decided to be installed in Victoria after 2048 over the high renewables scenario.

In Table 11 we can see the resulting profitability taking these prices, load factors, etc.:

Table 11 – Internal rate of return (%) of renewable investments in solar PV under the high renewables scenario for 2020, 2025 and 2030

	2020	2025	2030
<b>QLD</b>	2,6%	3,1%	6,2%
<b>NSW</b>	2,4%	3,3%	6,8%
<b>VIC</b>	-0,7%	1,1%	5,7%
<b>SA</b>	-1,0%	0,4%	4,6%
<b>TAS</b>	-7,2%	-5,4%	-1,7%

As in the previous scenario, profitability is low except for QLD and NSW for projects built in 2030. The cannibalization process is evidenced by the lower prices and profits earned by solar PV when there are more and more installations.

It is worth mentioning that TAS has the third highest revenues, but load factors of PV are low there, so profitability is the lowest among all the states, not even covering costs. Once again, the need of supports is clear in these states where profitability from market revenues is low.

## 5.5.2 Profitability of wind energy

Figure 34 shows the prices seen by wind generators at every state.

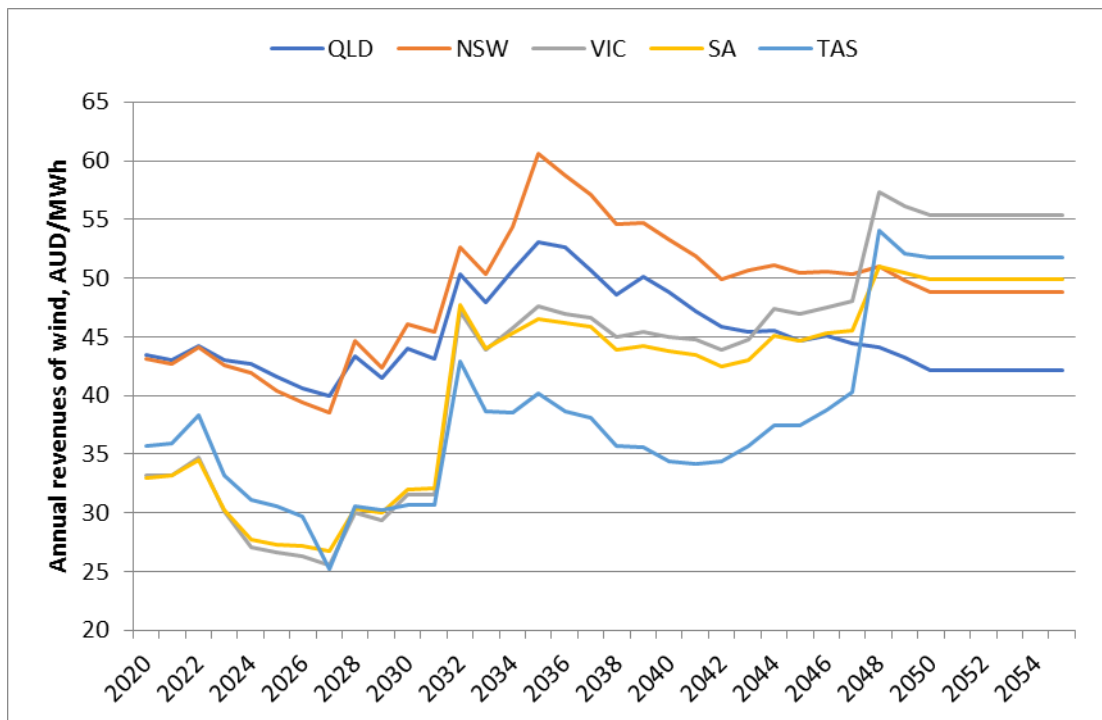


Figure 34 - Revenues of wind energy under the very high renewables scenario from 2020 to 2055

These revenues are much higher than the received by PV. QLD and NSW have a decreasing tendency from 2035 onwards, whereas the rest of the states have more or less stable prices from 2032 to 2047, and then a high increase.

These curves are very similar to the annual average prices presented in Figure 32 due to the fact that load factors of wind are quite stable along the day.

In Table 12 we can see the results of the profitability analysis:

Table 12 – Internal rate of return (%) of renewable investments in wind energy under the high renewables scenario for 2020, 2025 and 2030

	2020	2025	2030
<b>QLD</b>	3,8%	5,9%	6,8%
<b>NSW</b>	3,1%	5,4%	6,7%
<b>VIC</b>	0,9%	3,4%	5,6%
<b>SA</b>	1,0%	3,4%	5,3%
<b>TAS</b>	1,8%	4,0%	5,7%

Now all of them are lower than 7%. They all are still higher than 0%, which means that wind energy is more profitable than solar in reference to the uptake of renewables chosen.

## 5.6 Comparison between scenarios: discussion

In this Subsection, a comparison between the two scenarios is carried out to see the impact they might have in the National Electricity Market.

### 5.6.1 Technology mix for the National Electricity Market

There is more installed capacity in the very high renewables scenario, especially in 2050, as can be seen by comparing Figure 25 and Figure 30, than in the other scenario. This is due to the intermittency of renewables, whose installed capacity is much higher under the former scenario. This is also stated in Table 13 below:

**Table 13 – Increment in the very high renewables scenario in GW of PV and wind capacities over the high renewables scenario, shown per state from 2030 to 2050**

<b>Increments (GW)</b>	<b>2030-2035</b>	<b>2036-2040</b>	<b>2041-2045</b>	<b>2046-2050</b>
<b>PV<sub>QLD</sub> (GW)</b>	0.6	1.5	3.4	5.3
<b>Wind<sub>QLD</sub> (GW)</b>	0.7	1.8	1.8	1.7
<b>PV<sub>NSW</sub> (GW)</b>	0.2	1.9	3.5	4.5
<b>Wind<sub>NSW</sub> (GW)</b>	0.3	0.7	0.9	1.1
<b>PV<sub>VIC</sub> (GW)</b>	0	0	0	0
<b>Wind<sub>VIC</sub> (GW)</b>	0	0	0	0
<b>PV<sub>SA</sub> (GW)</b>	0	0	0	0
<b>Wind<sub>SA</sub> (GW)</b>	0	0	0	0
<b>PV<sub>TAS</sub> (GW)</b>	0	0	0	0
<b>Wind<sub>TAS</sub> (GW)</b>	0	0.1	0.2	0.1

In the previous Table the 5 years average of installed capacities of both scenarios (shown in Table 7 and Table 10) are deducted so as to see the increment in GW of solar PV and wind energy applied in the very high renewables scenario over the other scenario's data.

If we compare Figure 26 with Figure 31, total annual energy production is different under both scenarios for the years 2030, 2040 and 2050, being higher for the very high renewables scenario. This is due to more energy spillages in the latter scenario because of more renewables and not enough consumption during those moments of so much production. Two solutions may solve this problem: more interconnections, especially with Victoria, which has no spillages and is already interconnected with three states; or introducing storage such as more hydro pumping stations or low-cost batteries.

More OCGT and less CCGT installed capacities in 2050 are found under the very high renewables scenario than under the high renewables scenario. This is again because of the intermittency of renewables, which need to be backed-up by OCGTs, whereas the energy produced substitutes energy needs from CCGTs.

## 5.6.2 Prices for the National Electricity Market

Cannibalisation of renewables increases in the very high renewables scenarios. This difference is appreciated if we compare Figure 28 and Figure 29 with Figure 33 and Figure 34, where revenues of renewables are shown. It is clear that the more renewables, the lower prices these generators see. Moreover, profitability is obviously lower in this scenario.

Profitability is lower also in those states where renewables uptakes are kept constant between both scenarios because of cannibalisation such as in Victoria. We can see that the internal rates of return in the very high renewables scenario (Table 8 and Table 9) are lower in all of the states than in the high renewables scenario (Table 11 and Table 12).

There are attempts at having around 90% of generation from renewables by 2050 [45]. This seems to be unrealistic if renewable generators only receive revenues from the market. For allowing this to happen, other mechanisms should be introduced; or storage should go on stage.



## Chapter 6. Conclusions

The most relevant conclusions that can be drawn from the Thesis are the following ones:

- If coal plants are not closed earlier, renewables are not profitable under the neutral scenario proposed by AEMO. They are only in some states after the year 2030 because of the subsequent decrease on CAPEX.
- More renewables over AEMO's neutral scenario is only possible after 2030 and mostly in two states: Queensland and New South Wales. Moreover, projects built earlier might not recover costs only with the energy market. Therefore, to be accomplished this scenario or another one with higher renewables, companies interested in making new projects need to receive proper signals that allow them to recover their investments with a reasonable profitability. So they will need supports apart from the revenues obtained from the energy market.
- When talking about prices and renewables, cannibalisation is the most important concept. Basically, when adding more renewables into the system, prices *seen* by wind and PV are lower.
- With more renewables, the system might need more hydro storage and/or more interconnections, especially if batteries' costs are not low enough in the next decades.

### 6.1 Future works

The time devoted to this Thesis was limited. Therefore, if in the future more studies are carried out, I would suggest trying part or all of the following recommendations to improve the analysis:

- More scenarios of commodities prices and of demand outlook.
- Adding a forecast of prices of batteries to see if the model *chooses* to rely on them instead of on OCGTs.
- Maybe it would be interesting to try modelling the other two renewables pathways which AEMO proposes to see if they might make sense from the profitability point of view.
- Other pathways of decrease of costs of renewables.
- Introducing CO<sub>2</sub> prices (emissions data of every thermal power plant is already included in the inputs file).
- Adding new hydroelectric generation which might be commissioned in the future to see the impact it would have if finally built. This is the case of the project Snowy 2.0.
- Considering more interconnection capacity where new projects are proposed.

Moreover, more studies could be carried out. For example, a more detailed analysis may be performed from the data provided in the Blocks output file, from which comparisons of

weekly, seasonal or yearly generation could be done. A study of the length of time in which interconnections are fully utilised together with seasonal generation studies is also a suggestion to properly see if higher interconnections would benefit the system.

As the reader can see, the number of scenarios and their specificities can be as many as a human mind can think of. Therefore, this is my personal suggestion; but any person that might be in charge of this in the future will have to decide how to define every new scenario according to the objectives that they want to achieve.

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## APPENDIX A

List of NEM's power plants' characteristics.

State	Name of power plant	Abbreviation	Installed (MW)	Fuel	Tech	$\eta$ (%)	Commissioning date	Proposed closure date	Fixed O&M costs (\$/kW/year)	Variable O&M costs (\$/MWh)
QLD	Callide B	CALLB	700	CIMP		36,1%	1988	2039	54,96	1,00
QLD	Callide C	CPP	900	CIMP		36,5%	2001		54,97	1,00
QLD	Gladstone	GSTONE	1680	CIMP		35,2%	1976	2032	57,73	1,00
QLD	Kogan Creek	KPP_1	744	CNAC		38,4%	2007		55,48	0,49
QLD	Milmerran	MPP	852	CNAC		36,9%	2002		53,24	3,10
QLD	Stanwell	STAN	1460	CIMP		36,4%	1996	2046	54,37	3,10
QLD	Tarong	TARONG	1400	CNAC		36,2%	1985	2036	54,98	3,10
QLD	Tarong North	TNPS1	450	CNAC		39,2%	2003		53,23	1,00
QLD	Barcaldine	BARCALDN	37	Gas	CCGT	28,0%	1996		14,45	10,40
QLD	Braemar	BRAEMAR	1023	Gas	OCGT	30,0%	2009		14,48	10,40
QLD	Condamine	CPSA	144	Gas	CCGT	48,0%	2010		10,18	7,00
QLD	Darling Downs	DDPS1	644,5	Gas	CCGT	46,0%	2010		10,18	7,00
QLD	Oakey	OAKEY	281,8	Gas	OCGT	32,6%	1999		14,46	10,40
QLD	Roma	ROMA	80	Gas	OCGT	30,0%	1999		14,46	10,40
QLD	Swanbank E	SWAN_E	385	Gas	CCGT	47,0%	2002		10,18	7,00
QLD	Townville	YABUL	244	Gas	CCGT	46,0%	1999		10,18	7,00
QLD	Yarwun	YARWUN_1	180	Gas	CCGT	34,0%	2010		10,18	7,00
QLD	Mackay	MACKAYGT	34	Liquid fuel	OCGT	28,0%	1975		14,45	10,40
QLD	Mount Stuart	MSTUART	423,5	Liquid fuel	OCGT	30,0%	1998		14,46	10,40
NSW	Bayswater	BW	2640	CNAC		35,9%	1985	2035	54,37	1,00
NSW	Eraring	ER	2880	CIMP		35,4%	1982	2034	54,37	1,00

State	Name of power plant	Abbreviation	Installed (MW)	Fuel	Tech	$\eta$ (%)	Commissioning date	Proposed closure date	Fixed O&M costs (\$/kW/year)	Variable O&M costs (\$/MWh)
NSW	Liddell	LD	2000	CNAC		33,8%	1971	2022	57,72	1,00
NSW	Mount Piper	MP	1400	CIMP		37,0%	1993	2043	54,36	1,00
NSW	Redbank	REDBANK1	148	CNAC		29,3%	2001	2015	54,96	1,00
NSW	Vales Point	VP	1320	CIMP		35,4%	1978	2028	54,36	1,00
NSW	Wallewarang	WW	1000	CNAC		33,1%	1976	2015	57,71	1,00
NSW	Colongra	CG	724	Gas	OCGT	32,0%	2009		14,47	8,30
NSW	Smithfield	SITHE	170,9	Gas	CCGT	41,0%	1997	2018	10,20	7,00
NSW	Tallawarra	TALWA1	420	Gas	CCGT	50,0%	2009		10,18	7,00
NSW	Uranquity	URANQ	664	Gas	OCGT	32,0%	2009		14,47	10,40
NSW	Hunter Valley	HVGTS	50	Liquid fuel	OCGT	28,0%	1990		14,45	10,40
VIC	Hazelwood	HWPS	1600	LIG		22,0%	1964	2017	155,34	1,06
VIC	Loy Yang	LY	3180	LIG		27,2%	1985	2048	144,23	1,02
VIC	Yallourn	YWPS	1450	LIG		23,5%	1970	2032	149,83	1,02
VIC	Somerton	AGLSOM	160	Gas	OCGT	24,0%	2003		14,47	10,40
VIC	Bairnsdale	BDL	94	Gas	OCGT	34,0%	2001		14,46	10,40
VIC	Jeeralang	JL	440	Gas	OCGT	22,9%	1980		14,46	10,40
VIC	Laverton	Laverton_North	312	Gas	OCGT	30,4%	2006		14,46	10,40
VIC	Mortlake	MORTLK	566	Gas	OCGT	32,0%	2012		14,46	10,40
VIC	Newport D	VNPS	510	Gas	OCGT	33,3%	1980		44,37	12,50
VIC	Valley Power	VPGS	300	Gas	OCGT	24,0%	2002		14,47	10,40
SA	Northern	SANPS	546	LIG		34,9%	1985	2015	61,07	1,00
SA	Playford	PLAYB-AG	240	LIG		21,9%	1963	2015	63,32	1,30
SA	Hallett	AGLHAL	228,3	Gas	OCGT	24,0%	2002		14,50	10,40
SA	Dry Creek	DRYCGT	156	Gas	OCGT	26,0%	1978		14,46	10,40
SA	Ladbroke	LADBROK	80	Gas	OCGT	30,0%	2000		14,46	10,40

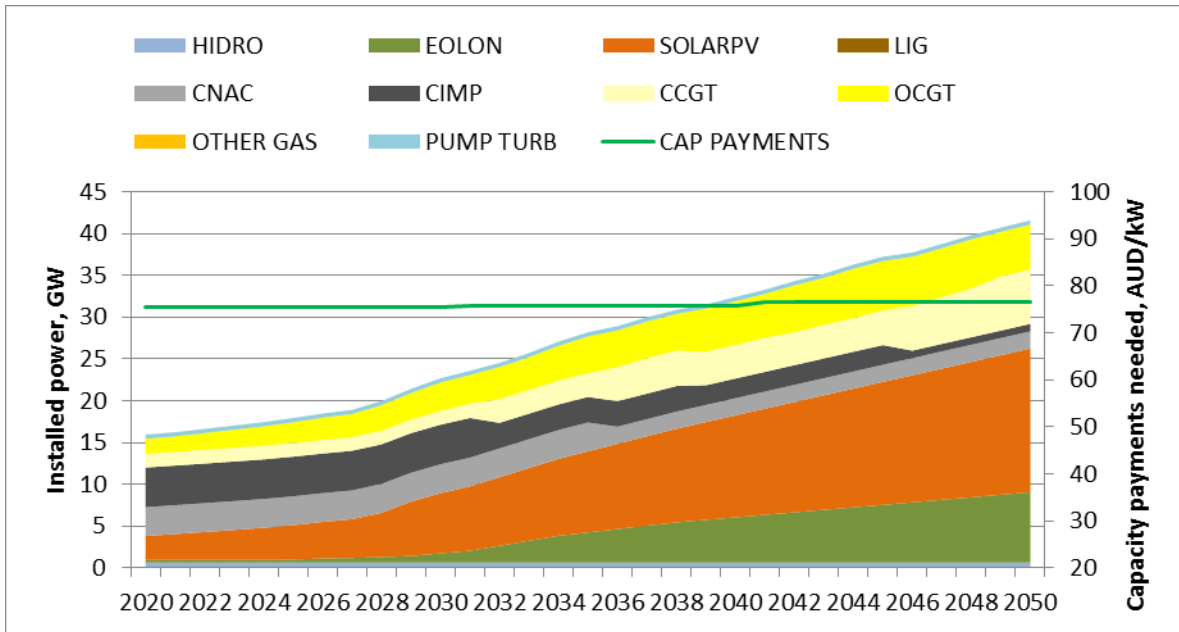


State	Name of power plant	Abbreviation	Installed (MW)	Fuel	Tech	$\eta$ (%)	Commissioning date	Proposed closure date	Fixed O&M costs (\$/kW/year)	Variable O&M costs (\$/MWh)
SA	Mintaro	MINTARO	90	Gas	OCGT	28,0%	1990		14,45	10,40
SA	Osborne	Osborne	180	Gas	CCGT	42,0%	1998		10,18	7,00
SA	Pelican Point	PPCCGT	239	Gas	CCGT	48,0%	2001		10,18	7,00
SA	Quarantine	QPS	224	Gas	OCGT	32,0%	2002		14,47	10,40
SA	Torrens Island A	TORRA	480	Gas	OTHER GAS	30,0%	1967		43,27	2,10
SA	Torrens Island B	TORRB	800	Gas	OTHER GAS	32,0%	1976		43,27	2,10
SA	Angaston	ANGAS	50	Liquid fuel	OTHER GAS	26,0%	2005		14,98	10,88
SA	Lonsdale	Lonsdale	21	Liquid fuel	OTHER GAS	26,0%	2002		14,98	10,88
SA	Port Lincoln	POR01	73,5	Liquid fuel	OCGT	26,0%	1998		14,46	10,40
SA	Port Stanvac	PSTAN1	58	Liquid fuel	OTHER GAS	26,0%	2011		14,98	10,88
SA	Snuggery	SNUG	63	Liquid fuel	OCGT	26,0%	1978		14,46	10,40
TAS	Bell Bay	BBTHREE	120	Gas	OCGT	29,0%	2006	2017	14,46	10,40
TAS	Tamar Valley 1	TVCC201	208	Gas	CCGT	48,0%	2009	2015	10,18	7,00
TAS	Tamar Valley 2	TVPP104	58	Gas	OCGT	28,0%	2009		14,45	10,40

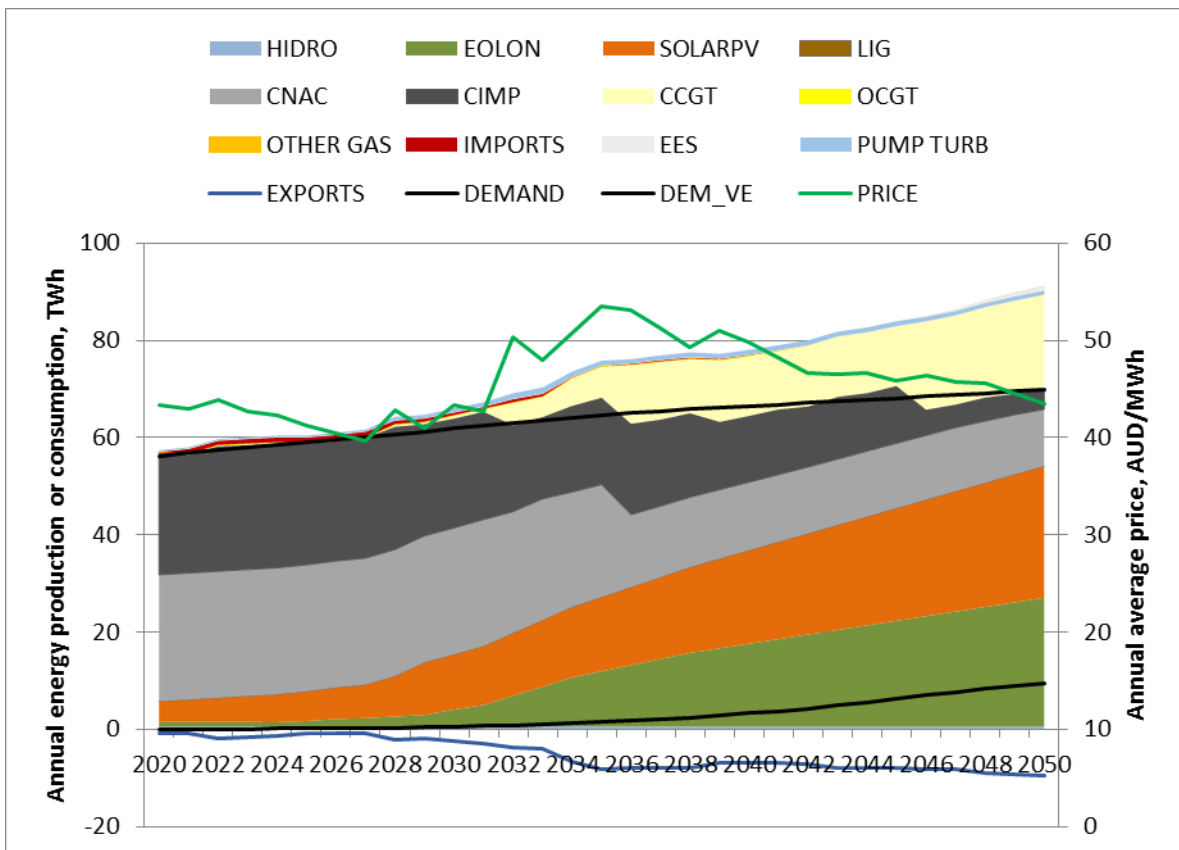


## APPENDIX B

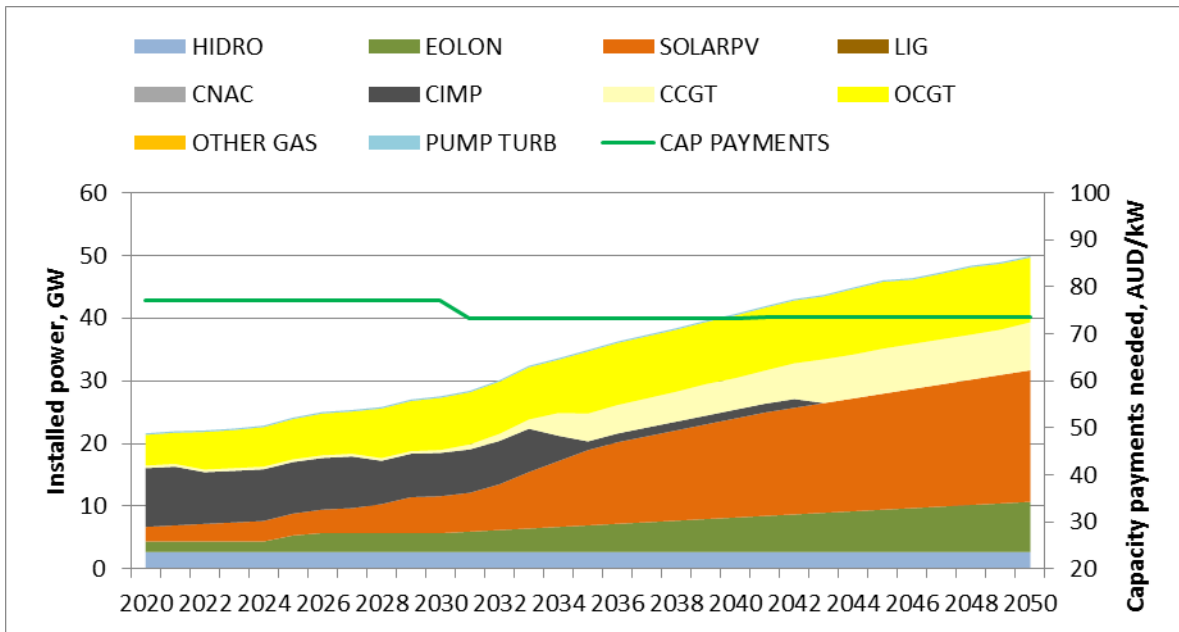
### QUEENSLAND: INSTALLED CAPACITY AND PAYMENTS UNDER THE VERY HIGH RENEWABLES SCENARIO



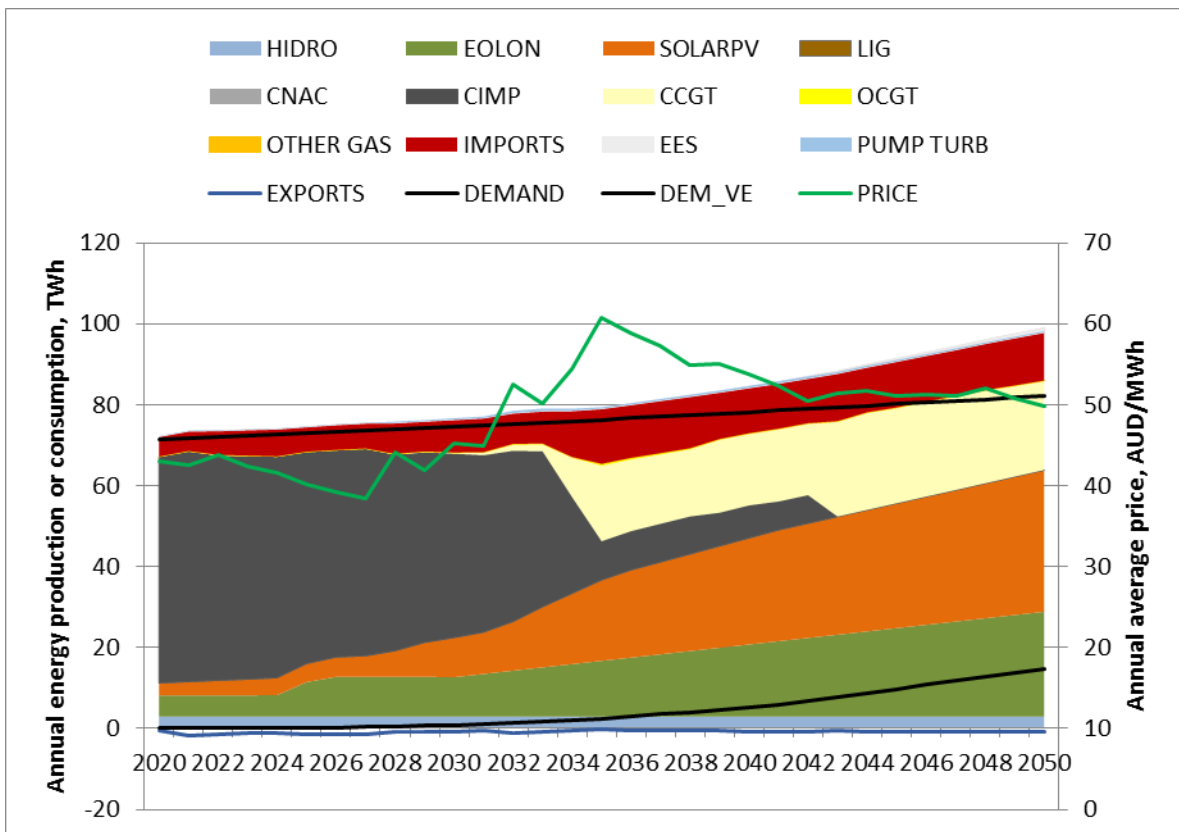
### QUEENSLAND: ANNUAL ENERGY AND AVERAGE PRICES UNDER THE VERY HIGH RENEWABLES SCENARIO



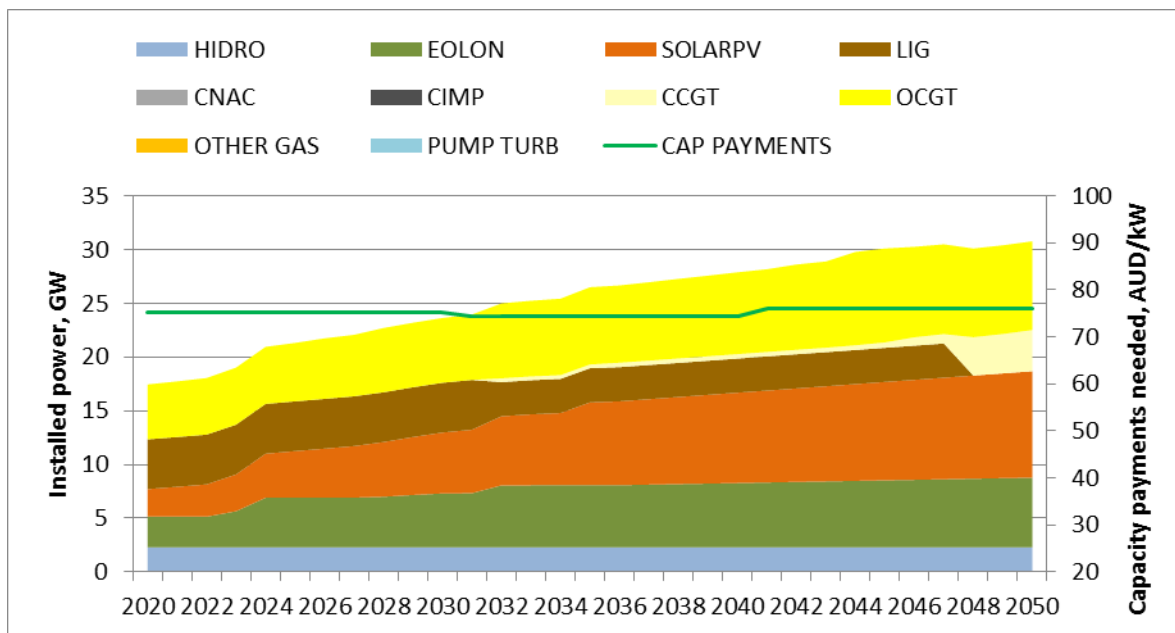
**NEW SOUTH WALES: INSTALLED CAPACITY AND PAYMENTS UNDER THE VERY HIGH RENEWABLES SCENARIO**



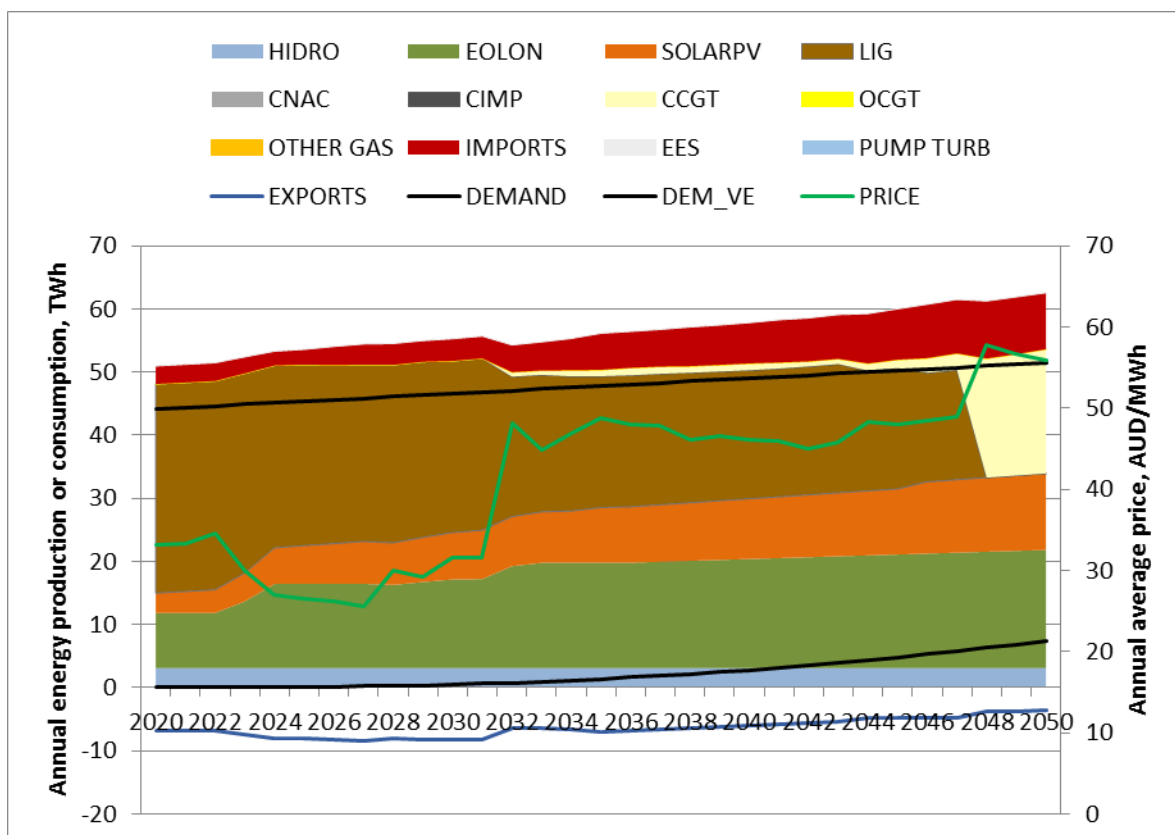
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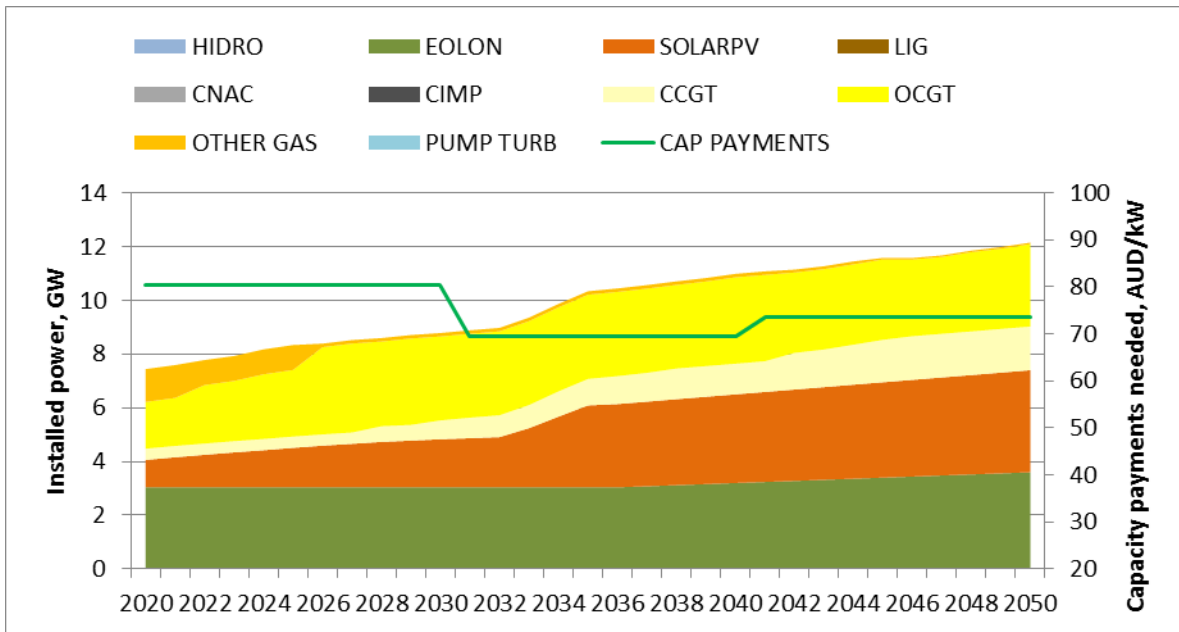
**VICTORIA: INSTALLED CAPACITY AND PAYMENTS UNDER THE VERY HIGH RENEWABLES SCENARIO**



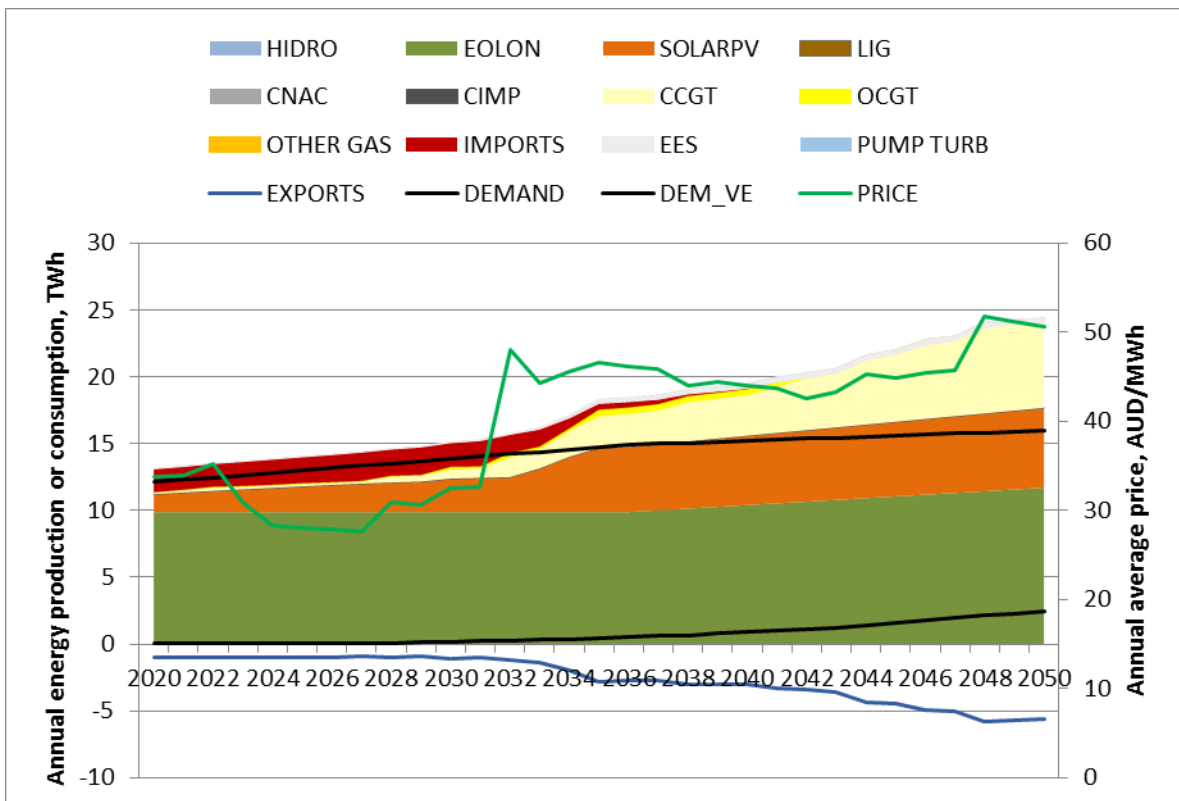
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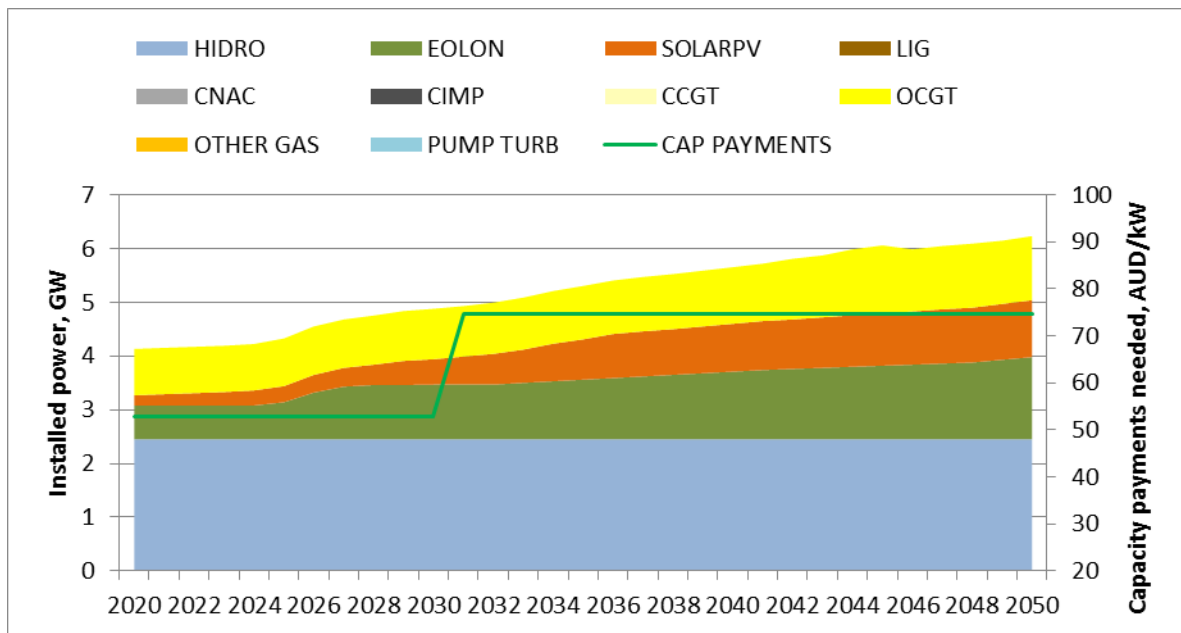
**SOUTH AUSTRALIA: INSTALLED CAPACITY AND PAYMENTS UNDER THE VERY HIGH RENEWABLES SCENARIO**



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**TASMANIA: INSTALLED CAPACITY AND PAYMENTS UNDER THE VERY HIGH RENEWABLES SCENARIO**



**TASMANIA: ANNUAL ENERGY AND AVERAGE PRICES UNDER THE VERY HIGH RENEWABLES SCENARIO**

