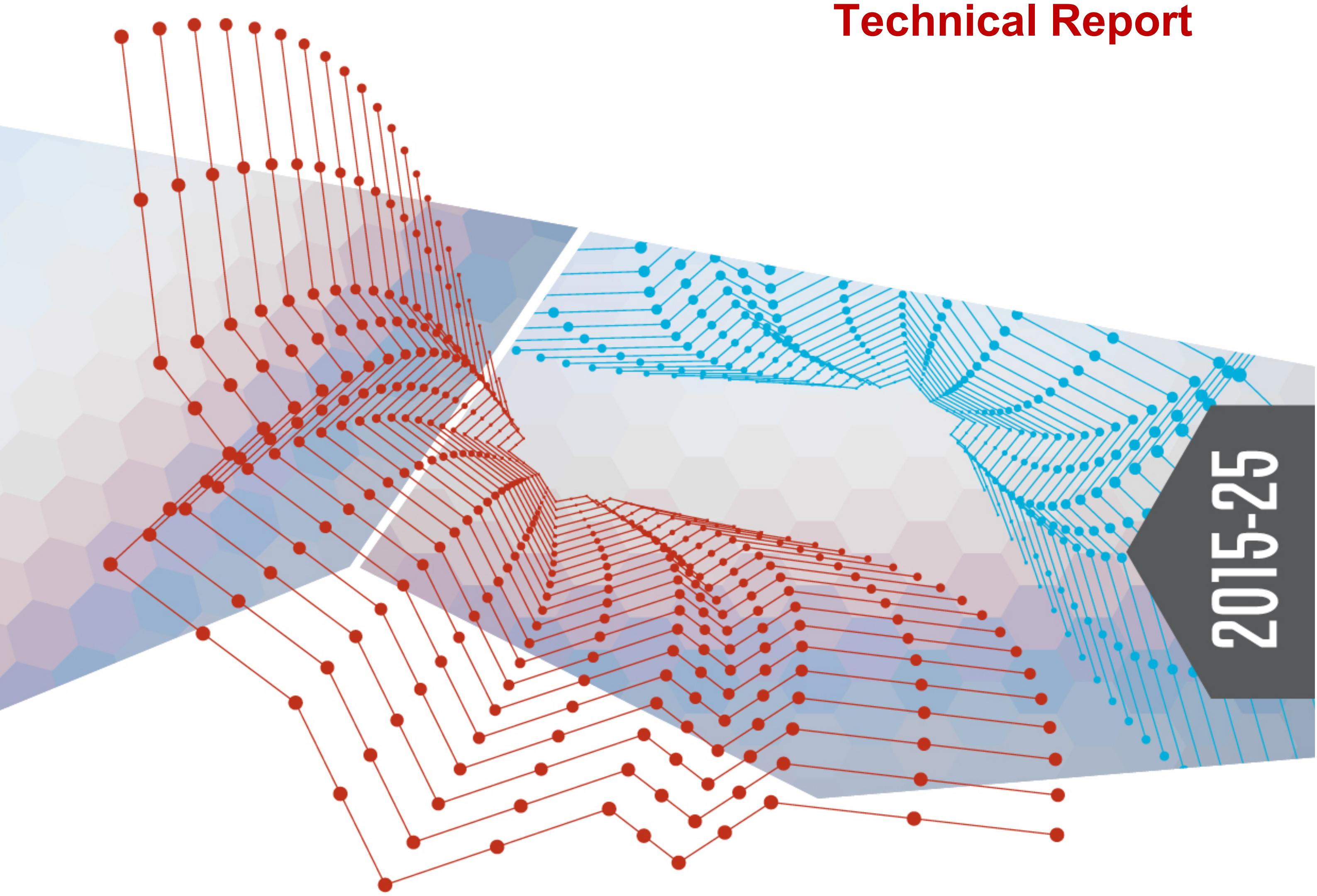
ELECTRICITY NETWORK TRANSFORMATION ROADMAP

Future Grid Forum – 2015 Refresh

Technical Report



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Important disclaimer

Executive summary

The Electricity Network Transformation Roadmap (the Roadmap) aims to set out pathways for the transition of Australia's electricity networks to 2025 toward a more efficient and customer-oriented future. The Roadmap program follows on naturally from the Future Grid Forum (the Forum) process convened in 2013 by CSIRO, Australia's national science agency.

Despite the relatively recent work of the Forum, given the pace of change impacting electricity systems globally, it was recognised that the Roadmap program would require an updated set of future scenarios as a baseline against which transformation alternatives could be assessed. Given the broad national acceptance of the 2050 scenarios developed by the diverse range of Future Grid Forum participants, these scenarios were reviewed and refreshed by CSIRO in collaboration with a wide range of stakeholders during the second half of 2015.

This Technical Report sets out the updated assumptions, narratives and modelling results for the Future Grid Forum scenarios which take into account the best available information in 2015. A draft version of the assumptions was originally published as an Industry Working Paper and widely circulated for comment in September 2015. The content was further enhanced with feedback received at a workshop attended by sixty electricity sector stakeholders.

The key changes to the original 2013 scenario assumptions (in no particular order) are:

- A common point across all the assumptions is that in some cases they generalised across Australia and did not recognise state differences which can be substantial. While some of these differences are taken into account, some assumptions were nationwide. We have revised our approach to take account of state differences particularly in relation to ownership of advanced meters and current and future adoption of on-site generation, storage, other demand management and cost-reflective network and retail pricing which are all interdependent.
- There is mixed evidence both positive and negative for adjusting the expected future rate of adoption of cost reflective pricing at the retail level. There are significant differences in the starting points between states both in terms of current adoption of tariffs and the advanced meters they often require. Consequently different outcomes across scenarios remain plausible. The differences in technology adoption may be the best guide available to when consumers will select new tariffs.
- The adoption of onsite generation across the scenarios remains plausible but a stronger emphasis on solar, rather than small scale gas technologies, in the commercial sector is warranted.
- The cost of battery technology has improved faster than was anticipated in 2013. However the long term outlook for battery costs remains fairly unchanged. As a consequence we adjust adoption of stationary batteries in the period to 2025. We do not bring forward electric vehicle adoption as oil prices have dropped since late 2014. The rapidity with which battery storage appears to be arriving as a consumer offering is likely to crowd out other peak demand management opportunities which were less mature.

- The renewable energy target has been reduced in absolute terms, however the government’s emission reduction ambition remains similar to previous government policies on this topic. This means the strength of any policy mechanism to achieve it should be fairly similar to previously assumed. However, the implementation will be delayed to 2020 and the form of policy mechanism that will be used to reach any given emission abatement target remains as uncertain as it was in 2013 or perhaps more so with a wider variety of mechanisms being considered. The Climate Change Authority is conducting a review specifically on this topic. The inclusion of an extended renewable energy target in *Renewables thrive*, is perhaps more plausible in the current context than it was in 2013.
- Forecasts assume that coal, gas, oil and petroleum product fuel prices will be lower in the next decade compared to the outlook in 2013.
- AEMO’s 2015 consumption and peak demand projections are significantly lower than in 2013 and the distance between the low and high scenarios is more than twice as large by 2025.
- Analysis of the economy wide, rather than electricity sector only, greenhouse gas abatement options indicates that consumption of electricity could grow much faster than anticipated as zero emission intensive electricity is substituted for fuels such as gas and petroleum which remain emission intensive.

Overall, after updating for new knowledge, the energy transformation drivers identified in Future Grid Forum scenarios remain plausible and provide important context for the Roadmap. The key insights from the updated modelling results are:

- Australia faces a broad spectrum of potential energy futures which vary greatly in the adoption of new technology, mode of customer engagement and the role of the central electricity network.
- Customer bills outcomes are slightly lower than forecast in 2013, reflecting the role of storage in facilitating economic integration of solar PV and other distributed generation.
- Solar panel adoption is dominating embedded generation and tracking to the high end of the 2013 projected share, while battery storage cost trends have improved further.
- The updated scenarios continue to reflect electricity networks performing an evolving range of critical roles to 2050, supporting diverse energy use and services for customers.

Abbreviations

Abbreviation	Meaning
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BEV	Battery Electric Vehicle
DER	Distributed Energy Resource
ENA	Energy Networks Association
ESAA	Energy Supply Association of Australia
EV	Electric Vehicle
FGF	Future Grid Forum
FiT	Feed in Tariff
GDP	Gross Domestic Product
GWh	Gigawatt Hour
IEA	International Energy Agency
kW	Kilowatt
kWh	Kilowatt hour
LRET	Large-Scale Renewable Energy Target
MW	Megawatt
MWh	Megawatt hour
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NSP	Network Service Provider
OECD	Organisation for Economic Cooperation and Development

PHEV	Plug-in Hybrid Electric Vehicle
POE	Probability of Exceedance
PPP	Purchasing Power Parity
PV	Photovoltaic
RMI	Rocky Mountain Institute
SRES	Small-scale Renewable Energy Scheme
SWIS	South-West Interconnected System
TOU	Time of Use

Introduction

The *Future Grid Forum – 2015 Refresh: Technical Report* sets out the assumptions, narratives and final modelling results for the 2015 update of Australia's Future Grid Forum scenarios.

The original Forum was convened by CSIRO in August 2012, spanned fifteen months and brought together approximately 120 experts working across the national electricity value chain. Over eleven full day workshops, Forum participants systematically debated key issues and developed integrated scenarios of Australia's electricity future to 2050. In parallel, CSIRO's technical and economic modelling capability was used to quantitatively stress-test each of the scenarios as they were qualitatively debated and further refined.

Given the pace of change impacting electricity systems and technologies, it was recognised that the Electricity Network Transformation Roadmap program would require an updated set of future scenarios. As such, given the level of national acceptance of the original set of scenarios it was decided that CSIRO would review and update them with the collaborative input of diverse stakeholders, many of whom also participated in the 2013 process.

It is important to note that the four 2050 scenarios are explorative and not normative. That is, they explore four plausible future states but do not select any as a 'preferred' future state. Instead they provide a quantitative baseline for examining and comparing alternative transformation pathways against a balanced scorecard of customer and societal outcomes.

This Technical Report sets out the updated assumptions, narratives and modelling results for the Future Grid Forum scenarios taking into account the best available information in 2015. Informed by this updated view of plausible futures, the Roadmap program will identify a range of 'no regrets' priorities for the 2015-25 decade with the goal of maximising customer value, system resilience and efficiency regardless of which future(s) may actually evolve.

Transformation drivers and updated scenario narratives

Transformation drivers

A wide variety of change drivers in the electricity sector motivated the development of the Future Grid Forum's scenarios. Three of the major motivators were

- An unprecedented decline in electricity consumption and peak demand in most States,
- Growing adoption of roof-top solar panels, and
- A significant and sustained rise in retail residential electricity prices and the main source of electricity price rises coming from the distribution sector

Other countries around the world have experienced similar outcomes and have diagnosed that their electricity systems are undergoing a fundamental transformation. There are also a number of global megatrends such as digitalisation of business models which feed into this electricity sector transformation. Graham et al (2015) describe experiences in similar countries, global and electricity sector specific drivers and how industries which have faced similar changes have responded – either successfully or unsuccessfully.

That work is provided separately as a companion report to this and the other reports in the Electricity Network Transformation Roadmap. However, a major insight of examining disruptive change in other sectors, such as telecommunications, is that industries should expect several waves of disruptive change rather than a single transformative driver. If we think of rooftop solar panel adoption as the first major disruption, and battery storage as an anticipated second wave, then input from stakeholders strongly suggested that electric vehicles should be expected as a likely third wave.

Like rooftop solar panels, electric vehicle drivetrains are a technology that has been available in niche applications for a very long time. Solar panels reached a tipping point, supported by significant government policy incentives and the manufacturing scale efficiencies that the global accumulation of those policies enabled, such that solar panels became cost competitive in many countries, including Australia. Electric vehicles could follow a similar path to market with several countries offering incentives and global manufacturing appearing to scale up. The increased confidence in reductions in costs of battery storage also increase the likelihood of vehicle electrification.

Since the Future Grid Forum concluded at the end of 2013 the prospects for the key transformation drivers has only strengthened. Roof-top solar adoption has continued to increase such that Australia is the leading residential adopter of solar panels (APVI, 2015). Battery storage costs have decreased significantly and projections indicate that more costs reductions should be expected (Nykvist & Nilsson, 2015; Brinsmead et al 2015). Global electricity vehicle sales increased 50 percent in 2014 (IEA 2015). These developments are significant in considering what elements and how, if at all, the Future Grid Forum scenarios should be updated.

Future Grid Forum scenario design

There are many methods for constructing scenarios with various advantages and disadvantages and consequently the method is chosen to match the application it is best suited for. Graham et al (2015) compares and contrasts four of the most common approaches. The Future Grid Forum participants deliberately chose a narrative scenario approach because it is best suited to capturing several themes of industry structural change across a small number of scenarios.

To develop the scenarios they developed the framework shown in Figure 1. The framework was designed to acknowledge that while there are many impactful uncertainties, such as fuel prices, there are only a limited number of drivers that will change the structure and function of the electricity system. These were called megashifts and included: low cost storage, low demand for centrally supplied electricity (owing to primarily to onsite generation but also energy efficiency and changes in the importance of domestic manufacturing) and greenhouse gas reduction.

The key uncertainty driving the three megashifts and how they would play out was consumer choices which were considered to range along a spectrum from passive to active. *Set and forget* explored a passive customer who has a preference for the system (which could be represented by retailers, distributors or their agents) to take the lead in terms of adopting new technologies and assisting customers to get the most out of those technologies when combined with new tariff options. *Rise of the prosumer* is the polar opposite to *Set and forget* in that consumers take the lead in adopting new technologies and services. *Leaving the grid* is a variation on a more active consumer environment where a lack of trust, rising prices, enabling technology and other factors lead consumers to seek independence from the grid. *Renewables thrive* is less driven by a particular consumer lens, and rather is based around the interplay between strong improvements in renewables and battery storage technology underpinning a strong orientation towards decarbonising the electricity sector.

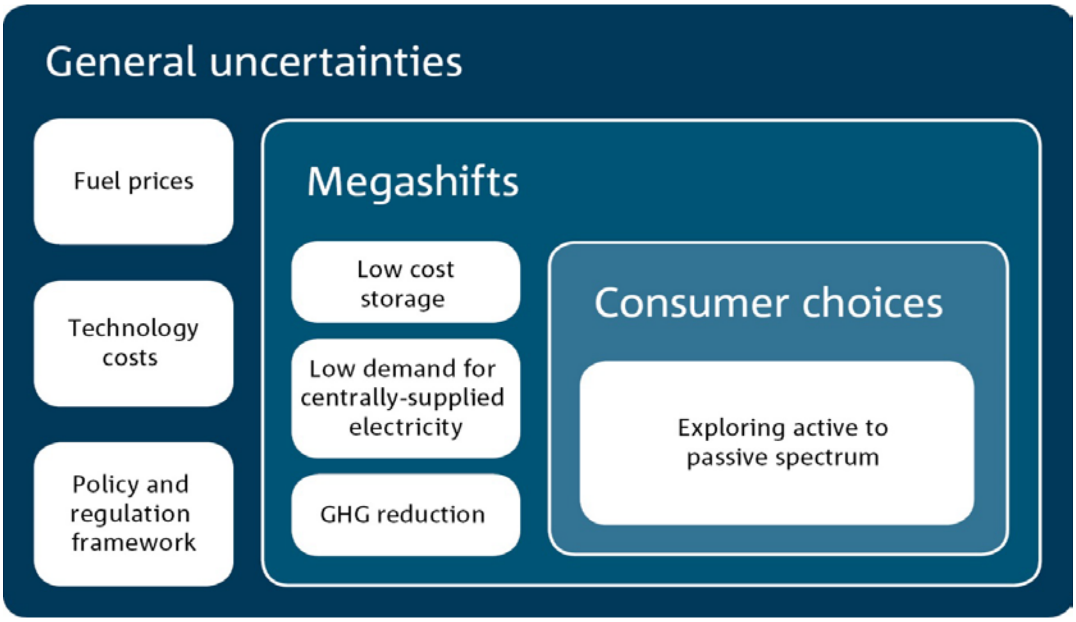


Figure 1: The framework developed by the Future Grid Forum for understanding future changes in the electricity sector

A consequence of this design approach is that it can give the impression that customers are all alike in the scenarios. However, the scenarios should be interpreted as having a social attitude bias, such that a significant number of customers behave in a certain way to tip the electricity sector in certain directions but a wide diversity of customer types and behaviours remain.

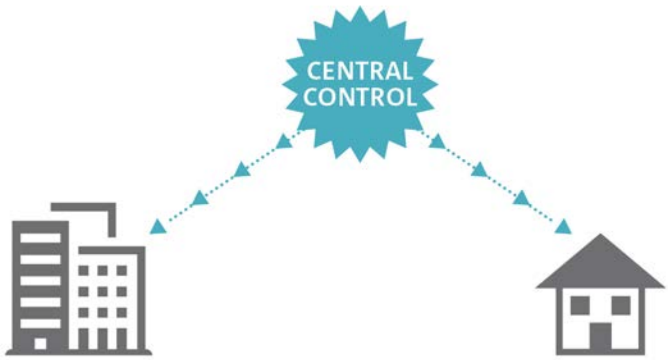
Updated scenario narratives

The following provides the updated Future Grid Forum scenario narratives. They have been updated with the following considerations:

- To address new information since they were constructed during 2012 and 2013 that would make them inconsistent with new assumptions
- To develop a clearer picture of the 2025 intermediate state and to reflect new information, are presented in the second to next section
- To make any other useful improvements

The scenario narratives are presented here in their updated form. However, Graham et al (2015) presents changes tracked against the previous narratives. In some cases, it will be necessary to read the following section, which provides a commentary on changes in scenario assumptions, in order to understand the thinking behind some elements.

Scenario 1: 'Set and forget'



Following the availability of cost effective battery storage towards 2020, residential and commercial customers become open to taking up demand management.

Retail tariff deregulation and competition reforms in metering services make offering consumers new electricity service options easier. The level of customer engagement is light, however, and customers prefer to rely on their utility company for the solutions for contracting, integrating and operating demand response.

Customers lead busy lives and want to 'set and forget' their demand management once they've worked out which level of demand control suits them. For example, community or on-site battery control systems automatically adjust their operation to minimise the customer's electricity bill according to their retail tariff which now includes more rewards for managing their load.

2025

The first decade to 2025 was a critical period of learning for customers, retailers and networks alike as it became evident that battery storage would be used in a variety of different ways, on-site with customers, with and without solar and embedded in distribution networks. Retail price signals to customers led to changes in demand that were not always to the advantage of the system as a whole. Consequently some battery owners were dismayed as subsequent tariff changes eroded the return they expected to receive. By the end of the decade it emerged that customers preferred the whole system to self-organise the most mutually advantageous business model for all, delivered by a partnership of consumers, networks and retailers. Some of these arrangements begin to take the form of bundled utility services and comfort level packages.

2050

By 2050 a centralised, set and forget, model of managing demand through retail and network control and reward systems has been established and other demand management technologies such as air-conditioning system control have also become important. Smart meters and alternative technologies are ubiquitous, providing the infrastructure for cost reflective network and retail pricing arrangements, inclusion of other large appliances in demand management schemes, and efficient operation of on-site storage to shift demand when it is not practical to ramp down appliances.

Specialised markets for industrial demand reduction are streamlined. Customers take up on-site generation and electric vehicles as well, but, overall, centralised generation and transmission remain dominant. Centrally coordinated peak demand management has been gradually successful in presenting a viable alternative approach to reducing power bills.

Scenario 2: 'Rise of the prosumer'

Customer-centric model
where customers consume, trade, generate and store electricity.

Over several decades, lowering costs of solar photovoltaic panels, and flexible new business models has meant that eventually nearly every residential consumer with a usable roof space takes up solar power. Not owning a home does not prevent uptake because retailers facilitate the sale of rooftop solar output between roof owners and non-roof owners making every roof space valuable. Through this approach renters and apartment dwellers are able to access roof-top solar power. Other approaches such as building integrated solar and increasing panel numbers in shaded aspects also extend the reach of this technology. Small customers maintain a preference as a group for volume based retail pricing which maximises the return from their solar systems and retail pricing rules do not force anyone to switch to alternative pricing structures (i.e. an opt-in system), although a minority who judge they can benefit do switch.

2025

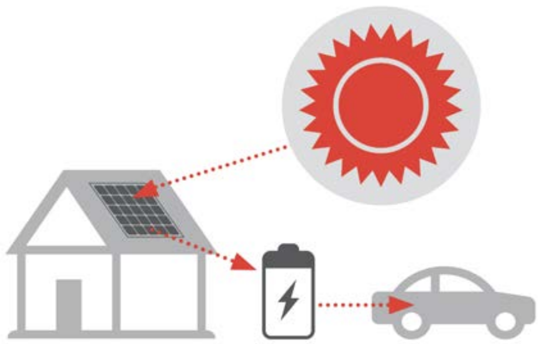
Retailers and energy service companies embrace prosumers' needs and compete to provide them with financing arrangements where needed and the best opportunities for trading power or using it on site through storage systems. With some exceptions, transmission and distribution networks only provide a peripheral role during this period to 2025 as they were unable to move fast enough to develop the infrastructure and business models to compete effectively with alternative service providers.

2050

To create further value for customers distribution networks work in partnership with retailers and consumers to establish a grid-edge market that provides clearer price signals and utilises the network as a platform for transactions, while a variety of companies compete to carry out the integration and facilitation roles.

Consumers choose the level of control they require from a wide variety of plans. A popular plan involves using batteries from electric vehicles as storage at the end of their vehicle life. Electric vehicles are popular in passenger and light commercial vehicle transport, reducing the demand for oil in Australia. Centralised generation and transmission are constrained in terms of growth but are still performing their important functions in the system.

Scenario 3: 'Leaving the grid'



Recognising the need for customers to receive a price signal that indicates both the costs of supplying network capacity, as well as the traditional volume charges, and that most small customers lack the metering required to measure capacity, in most states electricity pricing is transitioned towards a combination of fixed charge and volume pricing, also known as a declining block tariff. Low returns for use of on-site solar generation associated with this pricing structure slows, but does not halt, new adoption and builds customer distrust for utilities in those who already own solar systems. Large-scale uptake of electrification for light vehicles builds customers' comfort with operating storage systems but the pricing structure does not initially encourage their adoption in buildings.

2025

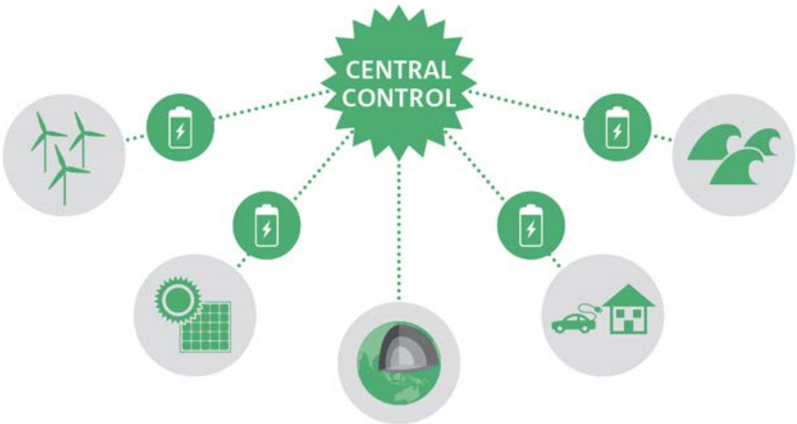
Discourse about customer's seeking to disconnect continues but the cost and reliability of a battery and storage based off-grid system remains very unattractive for the decade to 2025 for all but a small number of fast adopters. However, consumers of all levels remain equally unhappy with utilities as retail prices begin to rise in the late 2020s due to low utilisation of networks and increases in generation costs associated with tightening supply and greenhouse gas reduction policies.

2050

From 2035, new energy service companies seeing a market opportunity make available building control systems and interfaces that take care of most of the details of operating a completely off-grid system for the customer.

As battery costs decline, an increasing number of customers, particularly in states with already high solar uptake, begin to wonder whether there is sufficient benefit in staying connected (much like they did with landlines during the rapid uptake of mobile phones). A trickle of disconnections becomes an avalanche because, in a self-reinforcing cycle, off-grid system costs decline the more they are adopted. Customers remaining on the system are those who do not own an appropriate building and industrial customers whose loads can't be easily accommodated by on-site generation. Some new development and fringe of grid communities adopt disconnected mini-grid systems rather than individual systems.

Scenario 4: 'Renewables thrive'



At a political level, Australia debates a number of emission reduction policy mechanisms while individually significant numbers of residential and commercial customers make their own choices to move towards systems based around renewables and storage as their economic viability expands to an increasing number of applications, grid-side and on-site.

2025

By 2025, renewable electricity generating technologies are found to cost less than expected, largely as a result of deliberate programs and targets introduced in countries across the world to deploy them and bring down their costs. While a moderate carbon pricing scheme is maintained for the remainder of the economy, the success of these renewable target policies results in the introduction of a linearly phased 100 per cent renewable target by 2050 for the centralised electricity generation sector.

Besides emission reduction, the renewable target is also seen as an opportunity for Australia to build new technology supply industries and to develop regions expected to be the focus of renewable deployments. Technology cost reductions mean that it is economically feasible to deploy battery storage in place of natural gas as the primary back-up system for managing peak demand and renewable energy supply variability.

Transmission service providers face their greatest challenge in retiring transmission assets near end-of-life associated with closing fossil plants while building new assets to connect renewable resources to the grid. This is partially managed by encouraging renewables to locate with potential-to-be-under-utilised transmission lines.

2050

Storage is deployed and controlled both at transmission and generation utility-scale and distribution network locations as well as on-site with customers, shifting demand and storage charging loads to the middle of the day to take advantage of high large-scale solar and decentralised rooftop solar output. The distribution network is tasked with integrating these processes. Some customers maintain on-site back-up power (for example, diesel) for remote and uninterruptible power applications, offsetting these emissions by purchasing credits from other sectors, such as carbon forestry. Residential, commercial and industrial customers are rewarded for participating in peak demand management.

Overall, the renewable share, taken as a share of both centralised and on-site generation, is 96 per cent by 2050.

Updated Future Grid Forum scenario assumptions

Framework for the update

In this section we consider each of the assumption domains such as technology, policy and regulation and, given we are updating from a previous set of assumptions in 2013 we provide both a statement of what the existing scenario assumption was before turning to what the updated scenario assumption has been changed to. We then provide a rationale for the proposed changes, highlighting new information that has become available since the assumptions were developed in 2013.

Many of the assumptions are interdependent (e.g. electricity pricing and technology uptake) and so it is necessary to read this section as a whole although we have cross-referenced where possible.

Given the focus of the Electricity Network Transformation Roadmap is on the decade to 2025 we highlight assumptions in that year but also include assumptions to 2050 to indicate the pathway that lies beyond the roadmap.

State regional differences

A common point across all the 2013 assumptions is that in some important cases they generalised across Australia and did not recognise state differences which can be substantial. We have revised our approach to take account of state differences particularly in relation to adoption of advanced meters, on-site generation, storage, other demand management and cost-reflective network and retail pricing which are all interdependent. Background growth in consumption in peak demand are also state differentiated.

Whilst we can take differences into account as scenario modelling assumptions the high level message from this observation is that we need to recognise that the state electricity systems will not all move in a consistent direction and it is plausible that different regions will be in very different situations by 2050. This is evident form the very different starting points as shown in Table 1.

The different customer value propositions in each state will flow on to different service levels, reliability standards, complexities in benchmarking and differences in customers understanding of the value of the grid. This could have implications for how we approach national regulation in circumstances where states are in very different positions over time.

Table 1: Comparison of state differences in residential tariffs and residential and commercial solar output 2014-15

	Vic.	Qld	NSW	SA	WA	Tas.
Residential Time of use tariffs (%)	1	0.01	23	0	2	3
Residential two part tariff (peak and off-peak) (%)	99	99.99	77	100	98	97
Residential controllable loads (%)	16	37	NA	41	NA	NA
AEMO residential solar output (GWh)	876	1779	1012	753	NA	99
AEMO commercial solar output (GWh)	94	115	204	109	NA	12

NA: not available

Small customer electricity pricing and advanced metering

Previous and updated electricity pricing and advanced metering scenario assumptions

Previous and updated FGF scenario assumptions are shown in Table 2 and Table 3 respectively. Crucially, in the previous FGF assumptions we made no distinction between network and retail tariffs and were not specific about the differences between states. We discuss this further in the notes to Table 3.

Table 2: Previous FGF tariff and metering assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Cost reflective supporting engagement	Cost reflective supporting engagement	Non-cost reflective encouraging disconnection	Cost reflective supporting engagement
Share of small customers on cost-reflective *retail* tariffs and with advanced meters (%)	2015	5	5	0	5
	2025	100	100	0	15
	2050	100	100	0	36
Cost of advanced meter ($2013)	2015	185	185	185	185
	2025	185	185	185	185
	2050	185	185	185	185

Table 3: Updated FGF scenario assumptions

	Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description	Fast transition to cost reflective network and retail pricing enabled by solar uptake and supply-chain deployment of demand management technology. Smart meter (SM) adopted with any technology adoption, new building or meter retirement at existing building and strong (75%) correlation between SM installation and retail tariff reflecting network costs.	Slow transition to cost reflective retail pricing Smart meter adopted with any technology adoption, new building or meter retirement at existing building – however weak (33%) correlation between SM installation and retail tariff reflecting network costs.	A fixed network charge or declining block tariff structure is dominant at network and retail level limiting incentives for user-side technology adoption in the next two decades but leading to full disconnection from the 2030s. Some capacity based network pricing is also available where SMs deployed but poorly correlated (10%) with retail prices	Fast growth in network and retail cost-reflective pricing enabled by both supply-chain and consumer adoption of storage in particular. Smart meter adopted with any technology adoption, new building or meter retirement at existing building and strong (75%) correlation between SM installation and retail tariff reflecting network costs.
Share of small customers where more cost-reflective *network* tariffs apply	Implemented wherever an advanced meter is available (i.e. 100% in Victoria from 2017 and progressively in other states)	Implemented wherever an advanced meter is available (i.e. 100% in Victoria from 2017 and progressively in other states)	Capacity tariffs implemented in Victoria. Fixed network charges dominant in other states	Implemented wherever an advanced meter is available (i.e. 100% in Victoria from 2017 and progressively in other states)

Share of small customers that have adopted more cost-reflective *retail* tariffs and owning smart meters	See Table 4				
Cost of advanced meter ($2015)	2015	300	300	300	300
	2025	212	212	260	237
	2050	150	150	225	188

Important Table 3 and 4 notes

In the context of a *retail* tariff, a "more cost-reflective tariff" is defined as either a Seasonal time-of-use tariff, Critical peak tariff, Combined capacity and volume tariff or Fixed network charge and volume tariff (some advantages and disadvantages of these alternative formulations are discussed in Table 1 of *Change and choice*). Less cost-reflective tariffs are regular Volume only or Two part volume tariffs with rates for peak and off-peak (including a controllable load such as hot water – this can be as high as 40 percent of customers in, for example, Queensland and South Australia).

In the context of a *network* tariff charged to retailers (but not necessarily passed through to customers) "more cost reflective tariffs" are generally Capacity based where meters are available to measure capacity used by the customer. Alternatively, where no meter is available, either existing arrangements or fixed charges will apply.

The distinction between the tariffs that networks charge retailers and those that the customer is ultimately charged by retailer is important and we refer to the former as "network tariffs" and the latter as "retail tariffs".

Rationale for assumption changes

New information that has influenced the update of assumptions are as follows:

- The AEMC (2014) reached a final determination on a new rule to require network business to set cost-reflective prices for use of their network services. The rule requires distribution businesses to consult with consumers and retailers to develop a tariff structure statement that outlines the price structures that they will apply for a regulatory period. This statement will be approved by the AER as part of the five-year regulatory reset process. The businesses will also publish annually an indicative pricing schedule to provide consumers and retailers with the most up to date information on expected price levels throughout the regulatory period. Network prices based on the new pricing objective and pricing principles will be introduced no later than 2017. Under the final rule, network businesses will need to submit their initial tariff structure statement to the AER by late 2015. The new rule was based on AEMC (2014) analysis that found:

- "81% of consumers would face lower network charges in the medium term under a cost-reflective capacity price and up to 69% would see lower charges under a critical peak price."
- "A consumer using an average-size north-facing solar PV system will save themselves about $200 a year in network charges compared with a similar consumer without solar. Because most of the solar energy is generated at non-peak periods during the day, it reduces the network's costs by $80, leaving other consumers to make up the $120 shortfall through higher charges."
- "A consumer using a large 5kW air-conditioner in peak times will cause about $1,000 a year in additional network costs compared with a similar consumer without an air-conditioner, but the consumer with the air-conditioner pays about an extra $300 under the most common network prices. The remaining $700 is recovered from all other consumers through higher network charges."

The scenarios make different assumptions about the rates at which cost-reflective network pricing is adopted in each state. Victoria has a full fleet of advanced meters capable of measuring the peak demand of small customers, and networks are proposing to gradually phase in a monthly maximum demand (Capacity) charge, from 2017. Under all scenarios networks will charge retailers a Capacity tariff that covers 100 per cent of small customers in Victoria by 2025. In other states the majority of small customers have accumulation meters and the options for cost-reflective network pricing structures are limited to rebalancing tariffs to more fixed cost recovery. For example, in NSW the networks are proposing declining block tariffs. In these jurisdictions the rate of take up of capacity based network tariffs is assumed to vary with the rate at which enabling meters are adopted.

The extent to which retailers will choose to pass on network pricing structures directly to customers in retail tariffs is uncertain. Under capacity-based network pricing retailers will be charged the cost of the customer's use of the network. The retailer can choose to pass on the cost directly to the customer, or may offer the customer a choice of tariff structures. Retailers have opportunities to manage the risk, where they do not have a matching tariff structure[1].

- Given around 70 percent of customers only have accumulation meters, the future processes and drivers for the adoption of advanced meters will be important in determining how quickly (capacity based) cost-reflective prices can be adopted. The AEMC (2015) confirmed in their draft rule determination on expanding competition in metering and related services that there will be market-led (unlike the historical Victorian complete mandatory roll out approach). The only mandatory element is that replacement of old meters must be with a minimum standard meter. This places a lower bound on advanced meters such that there will be a limited amount of growth in advanced meter installations equal to the number of occasions where an old meter is replaced for the

[1] The AEMC has indicated that it sees managing this type of risk as a core part of a retailers' role in the market in rejecting the COAG Energy Council's rule change request for networks to supply tariffs that match standing offers imposed by State or Territory governments. In the AEMC's response it stated that "In a competitive market, the overall prices of these various retail offers should reflect the retailer's costs, including any risks that the retailer manages on behalf of the consumer. However, this does not require that the structure of retail prices must match the structure of network prices. Retailers have a number of tools to help them manage the risk of differences in network and retail price structures and efficiently price that risk." http://www.aemc.gov.au/Rule-Changes/Aligning-network-and-retail-tariff-structures-(1)/Draft/AEMC-Documents/Draft-rule-determination.aspx

purposes of adopting new technology (e.g. solar panels or battery storage), where a meter is replaced at the end of its life or due to failure, or in new building construction. In addition, the competitive metering regime is only due to commence at end of 2017 at the earliest, with little clarity at present on potential for early adoptions before that time.

- The ENA (2014) put forward their position on the ideal process for tariff reform toward cost-reflective pricing. The position paper reaffirms that cost-reflective network and retail pricing is in the long term interests of customers with modelling by Energeia (2014) indicating that:
    - up to $655 per year ($2014) in unfair cross subsidies in 2034 could be avoided for residential customers which cannot or do not invest in distributed energy resources;
    - network tariff reform could achieve average residential electricity bills up to $250 (in $2014) per year lower in 2034, when compared to the base case scenario;
    - network tariff reform could make the difference between network prices increasing by only 7% by 2034, compared to a cumulative increase under the base case scenario of over 30%; and
    - network tariff reform could be technology neutral and result in rooftop solar photovoltaic (PV) and storage capacity increasing more than 1000% to 35 gigawatts (GW) by 2034.

  However the ENA believes the AEMC (2014) rule change alone will not be strong enough to achieve these benefits in a timely manner. It proposes five key steps:
    - A balanced framework for smart meters that achieves the fastest, economic rollout to benefit all consumers.
    - National agreement to introduce flexible pricing and smart meters for key consumers (outside of Victoria), based on triggers (such as the connection of solar panels, battery storage, electric vehicles and connections to new premises) and consumption thresholds.
    - Better Information and decision tools for consumers through a joint initiative between electricity networks, retailers and governments.
    - Review of customer hardship programs to support vulnerable consumers during change to pricing structures.
    - Deregulation of retail prices, delivering long-standing Council of Australian Governments (COAG) commitments to deregulate where markets are sufficiently competitive

  A major concern is that advanced meters could remain a major barrier to cost-reflective price adoption for a significant time to come. To address this ENA proposes a slightly more directive approach to encourage faster adoption of advanced meters, in jurisdictions outside of Victoria. It proposes:
    - a new and replacement meter policy which provides for ‘smart ready’ meters to facilitate future tariff reforms outside Victoria;
    - the ability for network businesses to assign new or upgrading customers to cost-reflective network tariffs, without scope to opt-out to an unfair tariff; and

    - the ability for network businesses to assign existing customers to a cost-reflective network tariff above a consumption threshold of 40 MWh, or based on a capacity requirement.

- Deloitte Access Economics (2014) provides an updated view of the current rate of adoption of cost-reflective retail prices across Australian states. Based on this report the updated assumed shares of costs reflective retail prices for 2015 are shown in Table 3. The dominant form of cost reflective pricing at present is a time of use tariff. The highest adoption is in NSW[2], despite Victoria having the highest availability of smart meters. The study also indicates that between 16 and 41 percent of households have an existing controllable load (typically a hot water system). Given the greater depth of base year data on tariff type adoption, the updated FGF scenario assumptions are on a state basis whereas previously each state was assumed to have the same adoption.

  In their review of tariffs Deloitte Access Economics (2014) conclude that Capacity tariffs are the most optimal in terms of cost-reflectivity, revenue stability for network businesses and equity (although perceptions of equity may differ). This is more so if the capacity charge is aligned to coincident peak rather than a household's own peak.

- AECOM (2014) provided a survey that provided insights into how countries with similar electricity system attributes to Australia are managing their tariff structures. A key insight from this research is that there is no perfect pricing structure. Each of the pricing structures that have emerged or are under consideration represent the outcome of historical, cultural, technical and social considerations. No single approach to cost-reflective pricing is emerging.

- Stenner et al (2015) conducted an experimental survey of Australian households' responses to more cost-reflective retail tariffs (the final sample size was 1181 respondents) and characterised the responses through established human behavioural types such as neglect of opportunity cost, public good motives, trust as a decision heuristic, norms and conformity, temporal discounting and risk aversion. Customers were not informed of the potential impact of the different tariffs on their bill outcomes. Based on descriptions of the tariffs alone the survey found that:

    - Consumers generally prefer flat rate tariffs to all forms of cost-reflective pricing.
    - Simpler, more familiar and seemingly lower-risk tariff types were more appealing.
    - The greatest barrier of all may actually be consumers' aversion to making any kind of choice, i.e., status quo bias
    - If the survey response is used as a guide voluntary uptake of cost reflective pricing might be limited to an additional 5-10 percent of households
    - Cost-reflective pricing will be more successful the less it relies on consumers themselves responding to changing price signals

[2] Anecdotally, a lot of NSW customers were switched to time of use tariffs as part of the process of installing solar panels.

- Automated demand management solutions (e.g. enabling devices) are likely to prove particularly consequential for effective usage
- It is important to distinguish between what might be required to promote adoption and optimal response to cost-reflective pricing. Inducing the former without facilitating the latter could have longer term consequence for how cost-reflective pricing is perceived.

- As discussed elsewhere in this document solar panels and battery storage are expected to increase their adoption and are influenced by the type of electricity service pricing. Storage gives customers increased capacity to manage their load and indicates that while the work by Stenner et al (2015) suggests small customers will not ordinarily seek out a change in their tariff, they may do so as part of optimising the reduction in electricity cost from their solar / battery storage systems which can also include upgrading to an advanced meter.
- The relationship between technology adoption and retail tariffs is a complex one. For a customer adopting solar panels, a tariff where a volume based price collects the most share of the bill is generally better since solar panels primarily reduce volume. For a customer adopting storage their electricity bill might be minimised via a Time of use or capacity based pricing component. For a solar-storage bundle the difference between customer outcomes for different pricing structures may be less consequential as they have the ability to adjust both the volume, timing and capacity of their consumption and load depending on the size of the systems they've deployed (so long as there is a high enough reward for managing their device towards at least one price component). In addition to these technology-tariff interactions analysis of electricity bill outcomes is further complicated by the fact that networks and retailers have the ability to change prices, generally on a yearly basis. To collect the appropriate revenue to cover system costs price structures and price levels will need to adjust as customer behaviour adjusts. This make projecting future technology adoption and associated future tariff levels, of all types, very difficult.
- Improved data on the costs of advanced meters is available from the Australian Energy Regulator website which publishes data from its Advanced Metering Infrastructure Budget and Charges Determinations 2012-2015 for Citipower, Jemena, Powercor, Ausnet Services and United Energy This data indicates advanced meter costs in 2015 are higher than those used in the Future Grid Forum. However, it also indicates that costs, for both the technology and installation, are falling over time.

Summary

To utilise the updated data on advanced metering costs, that indicates that costs are to decline with further roll out, we have matched cost reduction assumptions to the expected adoption of advanced metering across the scenarios. Overall we assume a 25 to 50 percent cost reduction (including installation) by 2050.

Taking into account the new information on electricity pricing reform, we conclude there is significant uncertainty about the future rate of adoption of network and retail cost-reflective pricing in Australia. A transition to capacity based network pricing structures will critically depend on the roll out of enabling meters in jurisdictions other than Victoria and it appears more cost reflective retail tariff adoption will depend on the deployment of other technologies such as storage and on customer acceptance of different pricing structures.

Supporting the up side case for change to pricing structures, AEMC rules require networks to shift to more cost reflective pricing, tariff reform benefits some 80 percent of customer immediately (and all customers in the long run) and adoption of solar panels and battery storage technologies gives consumers the ability to better manage their load and could encourage consumers to seek out new tariffs and adopt advanced metering which matches their capability. Further the AEMC has proposed to implement a national new and replacement meter policy from December 2017 that could set a floor under the take up of enabling meters.

On the down side, retailers may not directly pass through network tariff structures into retail tariff structures, surveys indicate customers do not prefer cost reflective retail pricing, the majority of small customers have accumulation meters not capable of supporting most cost-reflective pricing structures and government and regulators have indicated a preference for market-led, rather than mandatory approaches to adoption of advanced meters.

Given this uncertainty our assessment is that the diversity in the Future Grid Forum scenarios, from significant adoption over time of cost-reflective retail pricing to almost no change in adoption remains plausible but could be modified to take into account a more nuanced environment. For all scenarios, more cost reflective network tariffs based on capacity based pricing will be rolled out in Victoria from 2017 and in other states as enabling metering technology is installed. For retail tariffs, the starting point has been updated to reflect state differences and we assume a 75% adoption of cost reflective retail tariffs in *Set and forget* and *Renewables thrive* for every advanced meter deployed either due to new building or replacement meter deployments or solar and storage technology adoption. However, in *Rise of the prosumer* we assume that due to one or more factors, retail tariffs only correlate with network costs in 33% of small customers. This could be for instance, because networks have not implemented, or not been permitted to implement, cost reflective pricing reform or because retail tariffs do not pass through the network tariff cost structures. In such circumstances, the various cross subsidies inherent in existing volume based two part network tariffs remain in place. This is consistent with the high on-site generation uptake in this scenario. In *Leaving the grid*, we assume a high adoption of cost-reflective retail tariffs but the tariff is a fixed network charge (in states other than Victoria). This type of tariff is in the family of more cost-reflective tariffs since it recognised the fixed costs of network assets, independent of the volume of consumption, and a key advantage is that it can be implemented for customer who do not have smart meters. However, unlike capacity based tariffs it provides much less incentive for peak demand management.

Noting the complex relationship between technology uptake, retail tariffs and system revenue we had to go through the loop of modelling all these factors more than once to determine if the scenario assumptions were truly consistent. We also deliberately chose to link the types of tariffs that were being adopted at a retail level to the social attitude in each scenario as a starting point in order to resolve the inherent dependency between tariff and technology adoption.

We do not specify in each scenario exactly what form the more cost reflective pricing takes. We assume that networks have a general preference for their part of the retail pricing structure to be represented by demand/capacity (kW) based charges. However over time it may be beneficial to go significantly beyond that and introduce other aspects of cost reflective pricing such as locational and temporal pricing signals to recognise differences in network congestion across these parameters.

The exception is *Leaving the grid* where we do assume a particular type of pricing which is a declining block tariff which in effect means that network charges are a fixed dollar amount because almost all customers meet the criteria for being charged in the first tariff block. This pricing structure is particularly suited to this scenario because it makes the decision to disconnect from the grid more plausible. That is, a fixed network charge means that customers wishing to decrease their electricity bill through deploying more solar and storage would eventually need to disconnect to do so given they get no more rewards from the pricing structure for reducing consumption below a certain level.

Social attitude implied by scenario	Determines retail CRP, advanced meter and solar adoption	Determines DSM & storage adoption to minimise bill
Set and forget: passive; open to others selecting best tariff and technology for them	High retail CRP; low solar adoption	High storage & DSM
Rise of prosumer: engaged; markets waits for their lead; opt-in pricing to suit them	Medium-low retail CRP; very high solar adoption	Medium-low storage & DSM
Leaving the grid: lack of trust in grid; responding to unintended incentives (e.g. fixed charges, volume tariffs)	Medium retail CRP and high disconnected solar adoption	Connected: Low DSM; Disconnected: high storage
Renewables thrive: trust, warmth and familiarity for renewables, storage and centralised power supply	High retail CRP and medium-low solar	High storage & DSM

*CRP = cost reflective pricing
*DSM = demand side management

Figure 2: Methodology for resolving the relationship between electricity pricing and technology adoption in each scenario

We next use the choice of pricing structure across the scenarios to set the level of technology adoption. The less cost reflective the pricing structure, the larger the adoption of solar whose value to the customer is maximised under the nationally dominant volume based tariff (since the major effect of solar is to reduce a customer net volume consumed). Conversely, high levels of cost reflective pricing leads to lower solar adoption but only in a relative sense – we still see growth under all scenarios relative to 2015.

We assume that the use of storage and other demand side management across the residential and commercial sectors is determined by the availability of willing customers with smart meters and so is generally associated with high cost reflective pricing scenarios, but not exclusively so - the key issue is whether there is a pricing incentive to participate in peak demand management. The integrated set of assumptions for tariffs with peak incentives, smart meters and adoption of different types of demand management are shown in Table 4. The rationale behind the adoption of different types of demand management is discussed further under the headings of storage and other demand management below.

Table 4: Integrated assumptions for residential electricity pricing, demand management and residential and commercial storage

			2015							2025							2050						
Set and forget			**NSW**	**Vic**	**Qld**	**SA**	**Tas**	**WA**	**NT**	**NSW**	**Vic**	**Qld**	**SA**	**Tas**	**WA**	**NT**	**NSW**	**Vic**	**Qld**	**SA**	**Tas**	**WA**	**NT**
Residential	**Peak incentive tariffs***	%	23	0	0	0	3	2	0	24	75	14	11	10	11	9	45	75	40	32	31	37	36
	Advanced meters	%	23	100	0	0	3	2	0	32	100	19	15	13	14	12	59	100	53	43	41	50	48
	Battery storage	%	0	0	0	0	0	0	0	12	5	7	6	5	5	5	22	18	20	16	16	19	18
	HVAC control	%	0	0	2	0	0	0	0	5	3	3	2	2	2	2	9	7	8	6	6	7	7
	Pool control	%	0	0	4	0	0	0	0	7	5	4	3	3	3	3	13	11	12	10	9	11	11
Commercial	**Battery storage**	%	0	0	0	0	0	0	0	1	0	14	1	4	4	4	12	7	35	12	22	18	18
Rise of the prosumer																							
Residential	**Peak incentive tariffs***	%	23	0	0	0	3	2	0	15	33	6	5	9	12	11	30	33	17	14	25	33	32
	Advanced meters	%	23	100	0	0	3	2	0	46	100	19	15	28	36	34	91	100	53	43	76	100	98
	Battery storage	%	0	0	0	0	0	0	0	8	5	3	3	5	6	6	15	13	9	7	13	16	16
	HVAC control	%	0	0	2	0	0	0	0	3	1	1	1	2	2	2	6	5	3	3	5	7	6
	Pool control	%	0	0	4	0	0	0	0	5	2	2	2	3	4	3	9	8	5	4	8	10	10
Commercial	**Battery storage**	%	0	0	0	0	0	0	0	0	0	6	0	2	2	2	5	3	15	5	10	8	8
Leaving the grid**																							
Residential	**Peak incentive tariffs***	%	23	0	0	0	3	2	0	4	10	2	2	2	3	3	8	4	5	4	6	8	8
	Advanced meters	%	23	100	0	0	3	2	0	41	100	19	15	22	27	25	78	36	53	43	62	80	78
	Battery storage	%	0	0	0	0	0	0	0	2	5	1	1	1	1	1	4	3	3	2	3	4	4
	HVAC control	%	0	0	2	0	0	0	0	1	0	0	0	0	1	1	2	1	1	1	1	2	2
	Pool control	%	0	0	4	0	0	0	0	1	1	1	0	1	1	1	2	2	2	1	2	2	2
Commercial	**Battery storage**	%	0	0	0	0	0	0	0	0	0	2	0	1	1	1	2	1	5	2	3	2	2
Renewables thrive																							
Residential	**Peak incentive tariffs***	%	23	0	0	0	3	2	0	26	75	14	11	12	14	12	49	75	40	32	36	45	43
	Advanced meters	%	23	100	0	0	3	2	0	35	100	19	15	16	18	16	66	100	53	43	48	60	58
	Battery storage	%	0	0	0	0	0	0	0	21	5	11	9	10	11	10	34	29	28	23	25	31	30
	HVAC control	%	0	0	2	0	0	0	0	1	1	1	1	1	1	1	5	4	4	3	4	4	4
	Pool control	%	0	0	4	0	0	0	0	4	2	2	2	2	2	2	10	8	8	6	7	9	9
Commercial	**Battery storage**	%	0	0	0	0	0	0	0	1	0	14	1	4	4	4	12	7	35	12	22	18	18

* Tariffs that provide an incentive for peak demand management. **Technology adoption relates to customer remaining on-grid. Off-grid customer have 100% storage adoption.

Technology

Roof-top solar panels

The previous and updated FGF scenario assumptions are shown in Table 5 and Table 6 respectively.

Table 5: Previous rooftop solar PV capital cost assumptions (2013 $/kW) applied in *Set and forget, Rise of the prosumer* and *Leaving the grid*

	Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Residential				
2013	3163	3163	3163	3142
2025	1727	1727	1727	1585
2050	1063	1063	1063	818
Commercial				
2013	2531	2531	2531	2513
2025	1382	1382	1382	1268
2050	850	850	850	654

Table 6: Updated rooftop solar PV capital cost assumptions (2015 $/kW) applied in *Set and forget, Rise of the prosumer* and *Leaving the grid*

	Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Residential				
2013	2100	2100	2100	2100
2025	1344	1344	1344	1233
2050	852	852	852	655
Commercial				
2013	1680	1680	1680	1680
2025	1075	1075	1075	987
2050	681	681	681	524

These assumptions include balance of system (inverter) and installation. To relate these costs to common market quotes, be aware that market quotes include a credit from the Renewable energy scheme (small scale technology certificates) -typically around $700 per watt depending on the location.

The updated projections are based on recent re-run of CSIRO’s Global and Local Learning Model (GALLM). The major difference in the projections is recognition of the cost reductions that have occurred between 2013 and 2015.

At the time of the FGF modelling, feed-in tariffs (FiTs) were in flux with a number of gross FiTs transitioning to a net FiT scheme. Since that time, net FiT rates have been declining. For the revised modelling, the FiTs that are assumed to apply in 2015 are shown in Table 7. We assume that the FiT is linked to the general level of the wholesale electricity price in the long term. One could argue its value could fall below that level to reflecting the potential for lower wholesale prices during peak solar output periods. However, the significant adoption of storage in most scenarios indicates this potential outcome is likely to be ameliorated over time.

Table 7: Net feed-in tariffs in 2015

State/Territory	FiT (c/kWh)
NSW	6
Vic.	8
Qld	6.53
SA	6
Tas.	5.6
WA	8.9
NT	27.13

Source: Solar Choice, "Available feed-in tariff schemes," [Online]. Available at: http://www.solarchoice.net.au/solar-rebates/solar-feed-in-rewards [accessed 13 August 2015]

The change in assumed solar PV capital costs are likely to lead to greater uptake in the revised results. As a comparison, Figure 3 shows the percentage of consumption served by rooftop solar PV in the NEM in the previous FGF modelling compared to the current projection from AEMO's latest National Electricity Forecasting Report.

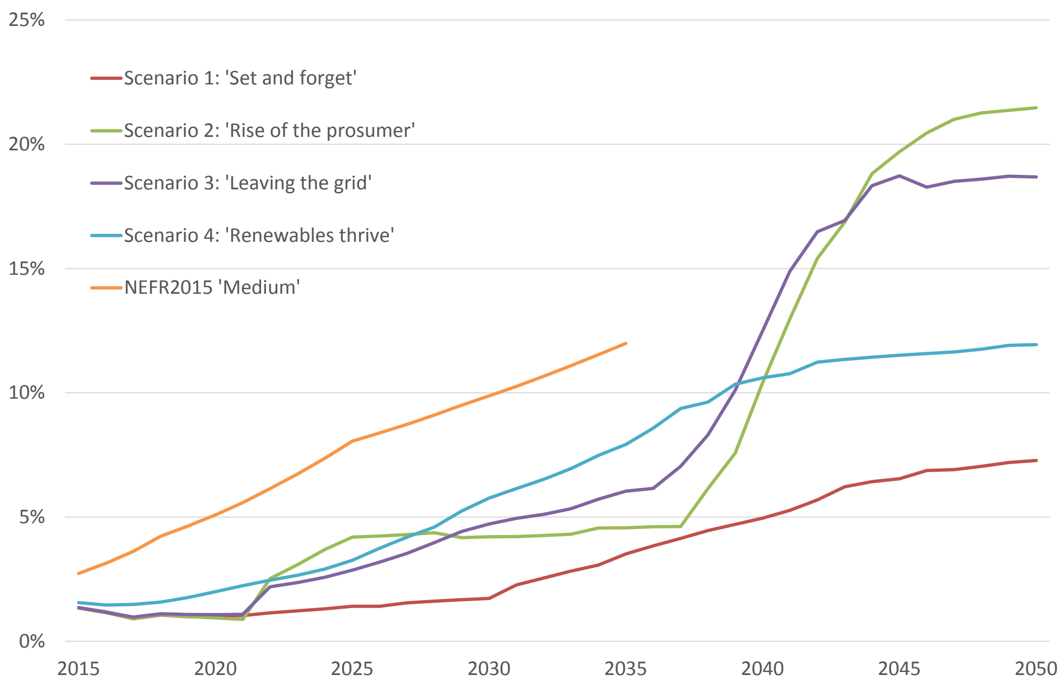


Figure 3: Rooftop solar PV percentage of load served, NEM

The 2013 FGF modelling under-estimated the uptake of rooftop solar panels in the next few decades mainly because it considered solar as just one of several on-site generation technologies. Growth in on-site generation was fairly evenly share between solar and gas based technologies. However, it is now clear that solar will be the dominant on-site generation technology. In its analysis, AEMO expects rooftop solar panel uptake in the residential segment to continue over the short- to medium-term, but then slow as it begins to reach saturation levels. Commercial PV continues to increase for the entire projection period, with small commercial installations expected to display the strongest increase (Table 8).

Table 8: AEMO cumulative rooftop PV installed (MW) and forecast generation (GWh)

	Commercial PV		Residential PV		Total	
	MW	**GWh**	**MW**	**GWh**	**MW**	**GWh**
2014-15	497	535	3700	4518	4196	5052
2017-18	1149	1363	5550	6949	6698	8311
2024-25	2942	3690	9919	12736	12861	16427
2034-35	5808	7398	15083	19504	20890	26902

Source: AEMO, *Detailed summary of 2015 forecasts*, p.17.

There are a number of factors that influence the saturation level of rooftop solar PV in the residential sector, but there are differing views on how binding these factors are (see Table 9).

Table 9: Considerations in determining an upper bound on residential solar panel adoption

Consideration or argument	Contrary view
Split incentives mean that only building owners will have the motivation to install solar panels because only they can reap the electricity bill savings **The home ownership rate is 70%[3]**	A landlord will be able to sell solar output from their leased building to a retailer instead of the tenant
Apartment owners do not have access to a private roof **The separate or semi-detached category represents 76% of dwellings[4]**	Business models already exist elsewhere in the world[5] that allow apartment dwellers to buy excess solar output from people who do have a private roof.
A percentage of roofs will be shaded and therefore not be suitable for installation or will have lower output	The declining cost of solar panels means it may be viable to over-install panels (relative to the inverter size) to boost output during indirect sunlight events

[3] http://www.abs.gov.au/ausstats/abs@.nsf/Lookup/by%20Subject/1370.0~2010~Chapter~Levels%20of%20home%20ownership%20(5.4.3)

[4] http://stat.abs.gov.au/Index.aspx?DataSetCode=RES_DWEL_ST

[5] http://www.yeloha.com/

A percentage of roofs will have poor orientation and therefore not be suitable for installation or will have lower output	Research indicates that "over a reasonable range of photovoltaic array orientations and inclinations, annual energy generation is not significantly impacted" (Ward et al 2010).
Aversion to high upfront costs will impact adoption in low income groups	No money down business models are already available. Also, over time, it appears that the cost of solar systems is approaching the cost of other household appliances.
The size of solar systems installed is increasing	The incentives for exporting excess solar generation are decreasing due to deregulation of feed-in tariffs in some states although they remain comparable to other states at present
The quantity of roof space is a hard limit	Households are projected to increase by 50% by 2035[6]. So solar panel generation in watthours increases by at least that amount even if adoption per household saturates. Building integrated solar systems are looking at replacing glass and walls with solar photovoltaic materials

For the residential sector, Wilson et al. (2014) estimate the potential for conventional rooftop solar PV for Australia and the NEM to be around 74 TWh (49 GW) and 64 TWh (43 GW) respectively. For the commercial sector, Weiss (2014) estimates the potential for the NEM to be around 10 GW by 2030.

Our preferred approach for modelling roof-top solar panel adoption is that it should be an output of a least cost modelling process. However, we have chosen to impose some assumptions to reflect the social attitude in the model (see Figure 2) and in recognition that since solar panels are already cost effective and likely to be more so over time, non-cost related factors may be increasingly stronger drivers of uptake. Based on the factors discussed in Table 9 and the scenario social attitude and electricity pricing structure we assign the following upper bound on residential rooftop uptake (by volume of electricity supplied to customer) by 2050:

Set and forget – 55 percent

Rise of the prosumer – 90 percent

Leaving the grid – 75 percent

Renewables thrive – 65 percent

6 http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/3236.0Main%20Features42011%20to%202036?opendocument&tabname=Summary&prodno=3236.0&issue=2011%20to%202036&num=&view=

Other on-site generation

The previous other (non-solar) on-site electricity generation capital cost assumptions are set out in Table 10 and Table 11. In 2013 modelling, *Rise of the prosumer*, *Leaving the grid* and *Renewables thrive* assumed capital costs that were consistent with an accelerated technological change case reflecting drivers in these scenarios that imply increased development of on-site generation technologies (Table 11).

Table 10: Previous other on-site electricity generation capital cost assumptions ($/kW) applied in *Set and forget*

Technology	2013	2020	2030	2040	2050
Reciprocating engine based systems:					
Gas cogeneration - Industrial (30 MWe)	1886	1821	1732	1647	1567
Gas cogeneration - Industrial (1 MWe)	1775	1714	1630	1550	1475
Gas cogeneration - Commercial (500 kWe)	1997	1928	1834	1744	1659
Gas trigeneration - Commercial (500 kWe)	2496	2410	2292	2180	2074
Gas trigeneration - Residential (500 kWe)	4438	4285	4075	3876	3687
Landfill or biogas cogeneration (200 kWe)	2068	2068	2068	2068	2068
Gas engines - Industrial (1 MWe)	1263	1263	1262	1261	1261
Diesel engines - remote (1 MWe)	552	552	552	552	552
Fuel cell based systems:					
Gas cogeneration - Residential (2 kWe)	7456	7456	7456	2801	2801
Micro turbine based systems:					
Gas turbine - Commercial (65 kWe)	1603	1545	1528	1528	1528
Gas cogeneration - Commercial (65 kWe)	3883	3749	3566	3392	3226
Gas trigeneration - Commercial (65 kWe)	4438	4285	4075	3876	3687

Table 11: Previous other on-site electricity generation capital cost assumptions ($/kW) applied in *Rise of the prosumer, Leaving the grid, and Renewables thrive*

Technology	2013	2020	2030	2040	2050
Reciprocating engine based systems:					
Gas cogeneration - Industrial (30 MWe)	1413	1317	1191	1077	974
Gas cogeneration - Industrial (1 MWe)	1766	1646	1489	1346	1218
Gas cogeneration - Commercial	1775	1714	1630	1550	1475
Gas trigeneration - Commercial	2496	2410	2292	2180	2074
Gas trigeneration - Residential	2496	2410	2292	2180	2074
Landfill or biogas cogeneration (200 kWe)	2068	2068	2068	2068	2068
Gas engines - Industrial (1 MWe)	883	823	744	673	609
Diesel engines - remote (1 MWe)	552	552	552	552	552

Fuel cell based systems:					
Gas cogeneration - Residential (2 kWe)	7456	7456	7456	2801	2801
Micro turbine based systems:					
Gas turbine - Commercial (65 kWe)	1603	1545	1528	1528	1528
Gas cogeneration - Commercial (65 kWe)	3883	3749	3566	3392	3226
Gas trigeneration - Commercial (65 kWe)	4438	4285	4075	3876	3687

The capital cost assumptions in Table 10 and Table 11 have not been revised for the 2015 modelling given that there is limited new information about non-solar distributed generation technologies. This might reflect their relative maturity or simply an absence of recent studies. This is a potential area for further knowledge development should resource allow in stage 2 of the Roadmap process.

Battery storage

The previous and updated FGF battery storage cost, size and adoption assumptions are set out in Table 12 and Table 13 respectively. We do not address other types of storage although we include solar thermal with 6 hours storage and pumped hydro as generation sector technologies.

Table 12: Previous FGF battery storage cost, size and adoption assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Cost ($/kWh)	2015	520	520	520	520
	2025	260	260	260	260
	2050	130	130	130	130
Size (kWh-kW)	2015	5-1	5-1	16-5	5-1
	2025	5-1	5-1	16-5	5-1
	2050	5-1	5-1	16-5	5-1
Adoption (% at households)	2015	0	0	0	0
	2025	3.5	3.5	3.5[1]	3.5
	2050	20	20	20[1]	20

1. The percentage is given for residences remaining on the grid. All residences off grid are assumed to adopt batteries and are a negligible group before 2035 but grow to around 30 percent of all generation by 2050

Table 13: Updated FGF battery storage cost, size and adoption assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Cost ($/kWh)	2015	443	443	443	443
	2025	183	183	183	165
	2050	115	115	115	104
Size (kWh-kW)	2015	NA	NA	NA	NA
	2025	5-2	5-2	5-2[1]	5-2
	2050	5-2	5-2	5-2[1]	5-2
Adoption (% at households)	See Table 4				

1. This size and percentage is given for residences remaining on the grid. All residences off grid are assumed to adopt batteries and are a negligible group before 2035 but grow to around 30 percent of all generation by 2050. The battery size for off-grid customer has reduced to 10kWh-5kW reflecting that the previous round trip efficiency assumption was 70 percent but has increased to 90 percent (see Appendix A for full off-grid system requirements).

Rationale for updated assumptions

In both the current and previous assumptions we locate batteries at the end-user and also in the generation sector but we do not necessarily assume the location must control the battery. In *Set and forget*, in particular, we assume that batteries located at households are controlled by utilities rather than the householder.

The previous FGF modelling assumed deployment of zinc-bromine battery systems. The initial cost estimate was sourced from James and Hayward (2012) and reflected a 30% mark-up on a utility scale battery for application at the residential-scale.

The updated FGF assumptions focus on lithium-ion (Li-ion) batteries for three main reasons. First, Li-ion batteries are the preferred chemistry for portable and vehicle applications. Second, the two largest retailers (AGL and Origin) are offering battery products based on Li-ion technology. Third, while other chemistries are being explored for stationary applications, there is less data available about them.

The revised costs in Table 13 are sourced from Brinsmead et al. (2015) and are costs for the battery system excluding the inverter to be comparable to the previous FGF assumptions. As discussed in Brinsmead et al (2015), the CSIRO cost projection methodology has improved with the inclusion of battery storage as a technology option in GALLM. Accordingly, an accelerated technological change case (lower projected costs) has been modelled and will form the assumed cost trajectory for all scenarios plus a further 10 percent reduction in costs in *Renewables thrive* to represent the much deeper deployment of storage in that scenario.

The indicative system sizes presented in Table 11 are a compromise between what is being offered on the market and what was found to be the economically optimal storage size in Brinsmead et al (2015). Brinsmead et al (2015) found that battery sizes in the range 1-3 kWh were appropriate for the medium sized residential customer (10.5-13.4kWh/day consumption) determined on the basis of benefit to cost ratio, and depending significantly on the tariff incentives driving customer behaviour. The smaller sizes are sufficient for reducing a household’s maximum daily demand, or for ensuring that most of the output of its solar photovoltaic system can be either used immediately or stored for later use. Smaller system sizes are also preferable for an up-front finance constrained household, which is assumed to be the case for many of those household's remaining on the grid in the "Leaving the Grid" scenario. The larger battery systems, (4-7kWh) are preferred in order to take advantage of differences between peak and off-peak pricing times, and are more likely in scenarios in which battery costs are lower.

Assumed adoption rates across the scenarios (Table 4), although based on a different methodology, are consistent with those in Brinsmead et al (2015) which are based on projected payback period. That work finds that uptake is either motivated by seeking to reduce electricity bills through use of storage alone or through bundling storage with solar panels. These motivations occur under quite different pricing arrangements. As such we cannot say that storage adoption will necessarily be coincident with solar uptake alone or uptake of different retail tariffs alone but could be motivated by both. Brinsmead et al (2015) projects battery storage uptake of 5 to 25 percent by 2035 amongst residential customers depending on the State, solar ownership and type of electricity pricing.

The methodology applied assumes for residential customers that where there is a smart meter and cost reflective retail pricing providing an incentive to manage demand, a demand management technology will be taken up. Of these customers 50 percent choose to adopt batteries (with the remainder selecting other demand management options). For commercial customers we more directly apply the Brinsmead et al (2015) which found battery storage uptake of 0 to 22 percent by 2035 depending on the State, solar ownership and type of electricity pricing. However, we make two changes. We harmonise the state differences, which are substantial, to acknowledge that it is unlikely those differences would remain so large indefinitely. We also introduce differences in assumptions between the scenarios to reflect the different social attitudes.

Off-grid systems

The previous and updated off-grid assumptions are shown in Table 14.

Table 14: Previous and updated off-grid system assumptions

		Leaving the grid (previous)	Leaving the grid (updated)
Qualitative description		From 2035 all on-site generation owners disconnect	From 2035 all on-site generation owners disconnect
Levelised cost of solar-battery-back-up-generator system (c/kWh)	2013	104	NA
	2015	NA	75
	2030	46	39
	2050	21	22

The *Leaving the grid* scenario was the only scenario that included full disconnection by on-site generation owners. In all other scenarios on-site generation owners remain connected to the grid although they may only be drawing a small amount of electricity from the grid in either absolute or net terms depending on how their system is set up.

Given the uncertainty and relative novelty of off-grid systems for non-remote power areas, CSIRO produced a spreadsheet model for the Future Grid Forum participants to review that calculated a levelised cost of electricity for a system that relied mostly on solar panels and batteries but also included a small generator for the limited number of days per year when the battery and solar system could not provide electricity. The line by line assumptions in this spreadsheet were also published in Graham et al (2013).

The 2013 estimates for levelised costs for such a system, for a medium size household (6000kWh p.a.) are shown in Table 14. It is evident that before 2030 the system costs are not competitive with retail electricity but are approaching competitiveness (particularly with FGF residential retail prices that were forecast to increase above 30c/kWh from the 2030s). However, by 2050, at 21 c/kWh the system was easily competitive with the retail price. It is on this basis we arrived at the date of 2035 as the time when disconnection would start to occur in this scenario.

For this update we have used the exact same spreadsheet tool and only changed three cost assumptions for – the smart meter component of the control system, the solar panels and the batteries. For solar panels and batteries, costs are lower throughout. For advanced metering the costs are higher (see each of the relevant sections on these topics in this report for more detail). Also the round trip efficiency of the battery was updated from 0.7 to 0.9 to match the capability of the Li-ion battery chemistry assumed. As a result of these changes the cost of an off-grid system is significantly lower in 2015 than estimated in 2013 and 2030 but fairly similar in 2050.

Since 2013 there have been some additional studies that assess off-grid systems. Energy for the people and Alternative Technology Association (2013) explored off-grid solutions for single and community (mini-grid) scenarios in Victoria based around solar and storage as well as other supporting generation. Where gas was unavailable in the case study areas explored, wood heating was assumed as an alternative approach to space heating. The economic analysis of the case studies found that all of the cases were viable now or by 2020. It should be noted that adoption of significant energy efficiency was assumed together with minor house size reduction compared to the norm.

Similar to the grid disconnection model applied in the Future Grid Forum, Energy for the people and Alternative Technology Association (2013) assumed a solar - battery storage - generator combination as the technology deployed for individual disconnections and community mini-grids. A petrol generator was assumed for a household and a large diesel generator for a community (of 500 homes).

Key assumptions that perhaps contributed to the conclusion that the case studies were economically viable are the inclusion of payments made to the individual or community associated with the value of centralised infrastructure that is offset ($2500 per customer for electricity plus $2000 for gas) and the assumption of 30 to 45 percent discounts on some of the equipment that is delivered by professional energy service companies (rather than off the shelf prices from retailers). The battery price by 2020 is assumed to be $175/kWh (which is significantly lower than previous or updated FGF battery costs) but the solar panel price was held constant at its level in 2013.

Wood et al (2014) also explore the cost of off-grid systems and present three cases. One is a system 7 kW solar panel system with 35kWh storage, providing power for 95 percent of the year for $34000. Another is a 10 kW solar panel system, with 60 kWh of storage providing power for 99 percent of the year for $52,000. A third is a 15kW solar panel system, with 85kWh of storage providing power for 99.9 percent of the year for $72,000. These are compared to retail power for 10 years costing $13,000. These assumed combined battery and inverter costs of $600/kWh. Wood et al (2014) also considers using a generator rather than adding more solar and batteries to achieve the 99.9 percent reliability and this comes in at $44000.

This is surprisingly consistent with the FGF cost estimates given there are many differences in assumptions. Both sources estimate that an off-grid system would be around 3 times the cost of grid power at present. Given all of the above we expect the choice of 2035 as the beginning of disconnection of on-site generation system date remains a reasonable assumption for *Leaving the grid*.

Electric vehicles

The previous and updated electric vehicle assumptions are set out in Table 15 and Table 16 respectively.

Table 15: Previous electric vehicle assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Modest, managed charge profile	Medium-high, managed charge profile	Medium-high, unmanaged charge profile	High, managed charge profile
Road vehicle fleet share (%)	2015	0	0	0	0
	2025	7	13	13	15
	2050	19	28	27	36
Electricity consumption (TWh)	2015	0	0	0	0
	2025	6	10	10	13
	2050	24	32	32	43

Table 16: Updated electric vehicle assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Medium, 66% of EVs with managed charging by 2025, 100% by 2050	Medium, 66% of EVs with managed charging by 2025, 100% by 2050	Medium, 66% of EVs with managed charging by 2025, 100% by 2050	High, 66% of EVs with managed charging by 2025, 100% by 2050
Road vehicle fleet share (%)	2015	0	0	0	0
	2025	4	4	4	5
	2050	27	27	27	36
Electricity consumption (TWh)	2015	0	0	0	0
	2025	3	3	3	4
	2050	32	32	32	43

Rationale for updated assumptions

The rationale for the minor changes to the electric vehicle assumptions is that they remain within a plausible range and that new information has not changed the fundamental economic standing of the alternative electric drive train relative to the internal combustion vehicle.

An updated summary of electric vehicle adoption projections is shown in Figure 4. The first half of the projections (down to and including Higgins et al 2012) are all based on CSIRO's Energy Sector Model which includes a model of the Australian road fleet and assumes investment choices are based primarily on economic merit but also includes some additional constraints such as limits on the share of short range vehicles. ESM includes the use of electric trucks in the rigid truck fleet while the remaining references generally deal with the passenger vehicle market only.

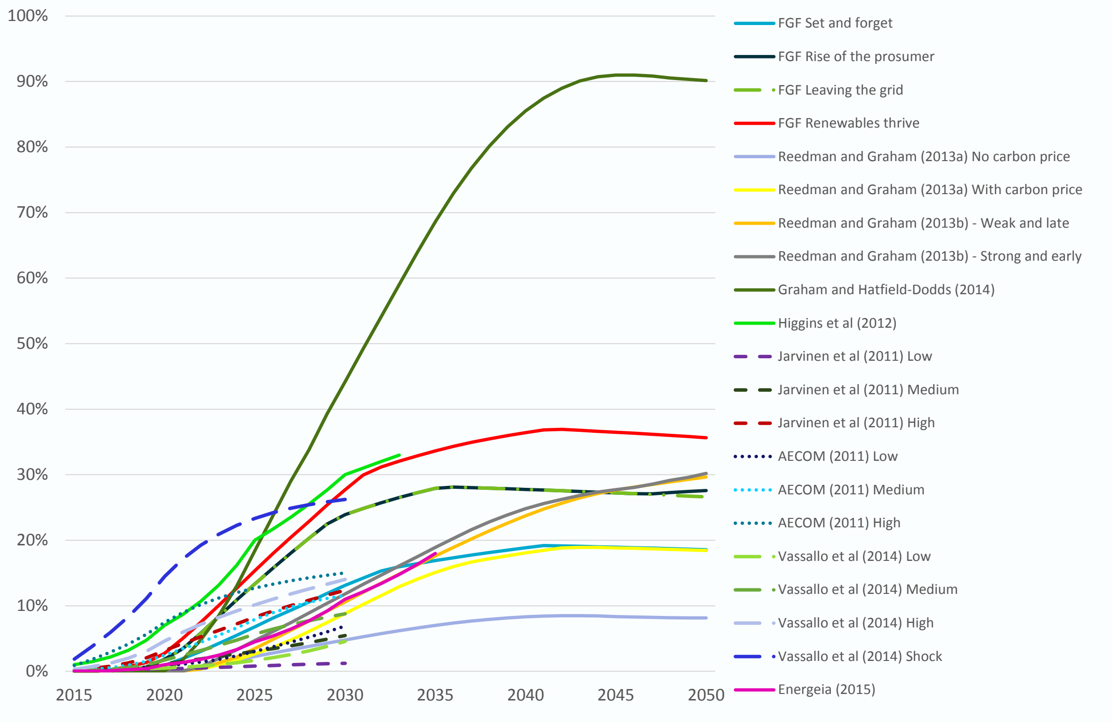


Figure 4: Projections of electric vehicle fleet shares

CSIRO recently implemented an alternative projection methodology whereby the payback period was calculated and a relationship was proposed between payback and a logistic adoption curve (Brinsmead et al 2015). That is, the rate of adoption of pure electric and plug-in hybrid electric vehicles increases according to a specified logistic curve as the payback period declines. This methodology resulted in uptake that was similar to 2013 projections for scenarios *Rise of the prosumer* and *Leaving the grid*.

If electric vehicles become economically viable there is no real upper limit on their adoption except the rate of turnover of the vehicle stock. Plug-in hybrid vehicles offer the same range as internal combustion vehicles but allow you to do most of your trips using only the battery. Electric vehicle models range from luxury cars, through to SUVs, down to small size hatches. Graham and Hatfield-Dodds (2014) represents a close to maximum adoption rate as it was designed as part of a scenario for deep decarbonisation of the Australian economy.

Economic viability remains the most serious barrier and source of uncertainty in projections. The difficulty for forecasting uptake lies in the chicken and egg paradox: Electric vehicles will be cost competitive when they are manufactured at efficient scale. However, consumers will only take up electric vehicle at large scale when they are cost competitive.

To overcome this chicken and egg problem some countries, particularly the United States, are offering subsidies. This strategy appears to be working. Global electric vehicle production increased 50 percent to 300,000 per annum in 2014 (IEA, 2015) (Figure 5).

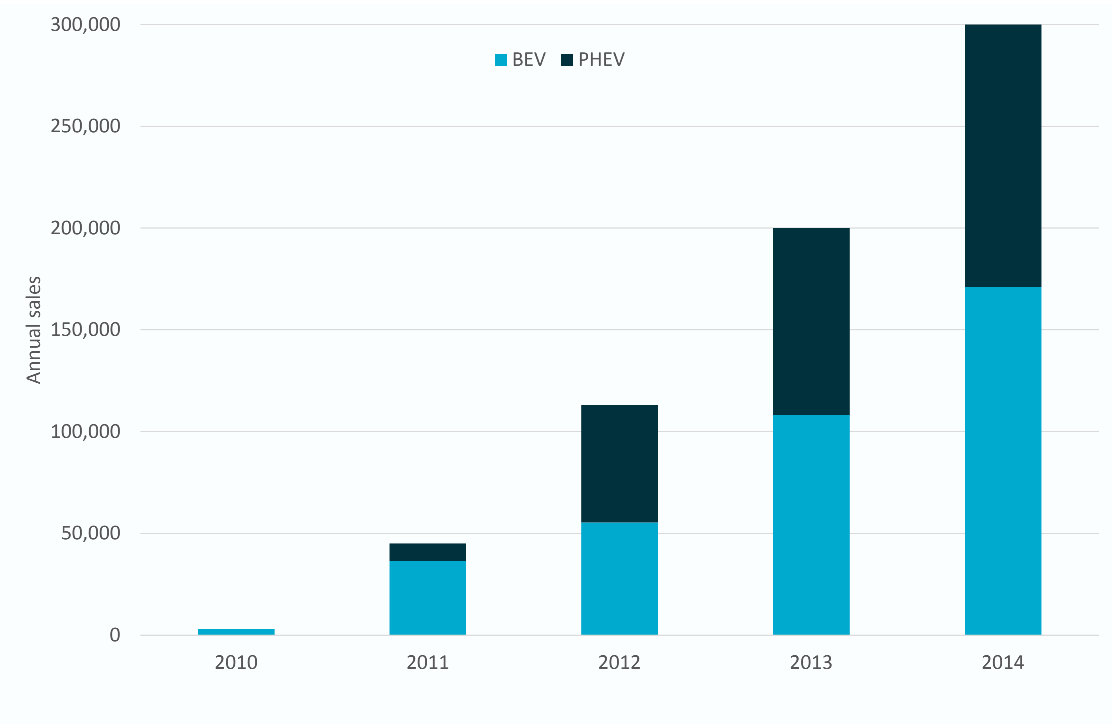


Figure 5: Global electric vehicle sales, IEA (2015)

The reason for some confidence in the idea that electric vehicles will inevitably be cost competitive is the increasing confidence around the future cost of batteries. As presented in Brinsmead et al (2015), the cost of an electric vehicle battery pack should be less around $5000 in the long run for a 125km range vehicle[7]. An amount of this magnitude can be fairly comfortably paid back with fuel cost savings in around five years depending on the distance travelled.

The recent reduction in the price of oil (discussed further under the section on fossil fuel prices) has been a negative in terms of the economic viability of electric since 2013. However, on the positive side, the cost of batteries has improved faster than expected in 2013.

A concern that is sometimes raised is whether electric vehicles will face some type of new Commonwealth tax to make up for the loss of fuel excise revenue. Graham and Reedman (2015) examined this topic. This research indicates that the policy decision to revert to fuel indexation in 2014 has softened the blow to future revenue streams. Considering also that the uptake of electric vehicles is gradual enough such that there is not a significant collapse in

[7] For example, for a cost of $200/kWh per battery and a storage requirement of 25kWh, the battery pack cost is $5000.

road transport revenue that would be strong enough to trigger a new tax being introduced. However, it remains a risk.

Given all of these considerations, whilst acknowledging the uncertainties that the range of uptake across the scenarios address, we have assumed a minimal change of a delay of around 5 years in the electric vehicle adoption assumptions to reflect the reduced oil price environment but faster adoption thereafter so that the previous 2050 adoption levels are still reached. We also eliminate the application of a low uptake scenario to *Set and forget*. Given this scenario includes significant storage it was considered inconsistent for it to have low electric vehicle uptake.

We have also changed the electric vehicle charging arrangements slightly to be uniform across the scenarios and recognise that, given the lack of smart meters in all Australian states outside of Victoria there will not initially be full adoption of managed electric vehicle charging.

Large scale generation

The previous and updated centralised electricity generation capital cost assumptions are set out in Table 17 and Table 18. The previous capital cost assumptions were consistent with the Australian Energy Technology Assessment conducted by BREE (2012). It was also assumed that capital costs for large scale solar phototovoltaics would decrease to $1286/kW in *Renewables thrive* to recognise the stronger deployment of that technology and co-learning with the decentralised generation sector deployment of rooftop solar. However, given the updated cost data (Table 18) recognises much stronger improvements in solar phototovoltaics we no longer apply this approach so that all scenarios use the same technology costs.

Table 17: Previous centralised electricity generation capital cost assumptions applied in *Set and forget, Rise of the prosumer* and *Leaving the grid*

Technology, 2013 $/kW	2013	2020	2030	2040	2050
Brown coal	3787	3783	3768	3748	3763
Brown coal IGCC	6270	6014	6134	6263	6413
Brown coal CCS	7768	7785	6130	6036	5981
Brown coal DICE	2289	2320	2378	2408	2463
Black coal	3209	2954	2947	2938	2935
Black coal IGCC	5525	5412	5524	5644	5783
Black coal CCS	5643	5656	4453	4385	4345
Nuclear	3615	3682	3729	3839	3856
Gas CCGT	1090	1097	1113	1130	1160
Gas CCS	2864	2920	2232	2230	2234
Gas OCGT	735	742	751	766	782
Biomass thermal	5140	5258	5349	5279	5457
Hydro	3373	3257	3098	2946	2802
Wind - onshore	2478	1771	1799	1828	1848
Wind - offshore	4468	3978	3942	4026	4119
Enhanced geothermal	7222	7278	7279	7327	7453

Solar thermal	4935	3180	2770	2750	2786
Solar thermal (6 hours storage)	8495	5511	4801	4724	4740
Solar-gas hybrid	2148	1882	1826	1839	1876
PV - utility scale	3648	2434	2138	1585	1529
Wave	6128	6193	3807	3800	3651

Table 18: Updated centralised electricity generation capital cost assumptions

Technology, 2015 $/kW	2015	2020	2030	2040	2050
Brown coal	3850	3755	3571	3397	3230
Brown coal IGCC	6150	5674	5634	5634	5634
Brown coal CCS	8270	8128	7189	5866	5580
Brown coal DICE	2405	2437	2498	2530	2588
Black coal	3000	2926	2783	2647	2517
Black coal IGCC	5000	4881	4863	4863	4863
Black coal CCS	6770	6665	5891	4577	4328
Nuclear	9000	9000	8974	8859	8665
Gas CCGT	1450	1447	1406	1400	1400
Gas CCS	3891	3855	3149	2067	1967
Gas OCGT	1000	975	928	882	839
Biomass thermal	3943	3943	3943	3697	3596
Hydro	3875	3779	3594	3419	3251
Wind – onshore	2608	2348	2043	2012	1899
Wind – offshore	4702	5274	4477	4432	4233
Enhanced geothermal	10500	10482	10214	10191	10191
Solar thermal	4938	4117	2252	2231	2240
Solar thermal (6 hours storage)	8500	7136	3903	3833	3811
Solar-gas hybrid	2257	1977	1918	1932	1971
PV - utility scale	2300	1692	1177	633	606
Wave	5899	5899	2379	2379	2379

Up until recently there have been no new major electricity generation technology cost studies of similar breadth published since BREE (2012). BREE (2013) published a partial update in December 2013 a few weeks after the Future Grid Forum published its work and therefore it could not be incorporated at the time. The main changes in the 2013 update were to reduce the operating and maintenance costs of some renewable technologies and to increase the cost of nuclear power.

A new and reasonably comprehensive study by the CO2CRC, with input from a wide set o stakeholders has been completed in November 2015 and has been used as the primary source in this update of the Future Grid Forum electricity generation capital cost assumptions[8].

The CO2CRC study does not cover the full technology data set we require and so consequently some data remains linked to the BREE (2012) and BREE (2013) data (updated for inflation) or is an internal CSIRO estimate.

The previous technology performance and operating and maintenance costs, which were mostly drawn from BREE (2012) will also be updated from BREE (2013) and the CO2 CRC study. Their previous and updated values are shown in Table 19 and Table 20.

Table 19: Previous technology cost and performance data

	Capacity factor %	Fuel efficiency % HHV	CO_2e emissions kt/MWh	Capture Rate %	Year available	Fixed O&M $/MW	Variable O&M $/MWh
Brown coal	83	32	1024	0	2015	60500	8
Brown coal IGCC	83	33	1008	0	2015	99500	9
Brown coal CCS	83	201	156	90	2023	91500	15
Brown coal DICE	83	50	700	0	2020	150000	10
Black coal	83	42	773	0	2015	50500	7
Black coal IGCC	83	38	840	0	2015	79600	7
Black coal CCS	83	31	103	90	2023	73200	12
Nuclear	83	34	0	0	2012	34400	15
Gas CCGT	83	50	368	0	2012	10000	4
Gas CCS	83	43	60	85	2023	17000	9
Gas OCGT	10	35	515	0	2012	4000	10
Biomass thermal	80	27	0	0	2012	125000	8
Hydro	16	0	0	0	2012	35000	3
Wind - onshore	38	0	0	0	2012	40000	12
Wind - offshore	40	0	0	0	2012	80000	12
Advanced geothermal	83	0	0	0	2020	200000	0
Solar thermal	23	0	0	0	2012	60000	15
Solar thermal (6 hours storage)	42	0	0	0	2012	65000	20
Solar-gas hybrid	85	51	336	0	2012	15000	10
PV - utility scale	21	0	0	0	2012	25000	0
Wave	35	0	0	0	2020	190000	0
Current	40	0	0	0	2012	1000	10

Table 20: Updated technology cost and performance data

	Capacity factor	Fuel efficiency	CO_2e emissions	Capture Rate	Year available	Fixed O&M	Variable O&M

[8] Modelling for this study was completed before the publication of the CO2CRC study and so there may be some slight differences between values assumed here and published study data

	%	% HHV	kt/MWh	%		$/MW	$/MWh
Brown coal	85	36	953	0	2015	55000	3
Brown coal IGCC	80	34	1009	0	2020	55000	8
Brown coal CCS	85	25	137	90	2023	65000	12
Brown coal DICE	85	50	700	0	2020	150000	10
Black coal	85	40	792	0	2015	45000	3
Black coal IGCC	80	40	792	0	2015	50000	8
Black coal CCS	85	29	109	90	2023	55000	10
Nuclear	85	33	0	0	2030	100000	2
Gas CCGT	65	50	373	0	2012	20000	2
Gas CCS	65	42	89	80	2023	34000	3
Gas OCGT	8	34	548	0	2015	8000	12
Biomass thermal	80	27	0	0	2015	125000	8
Hydro	16	0	0	0	2015	35000	3
Wind - onshore	39	0	0	0	2015	55000	12
Wind - offshore	40	0	0	0	2015	80000	12
Advanced geothermal	80	0	0	0	2020	150000	10
Solar thermal	23	0	0	0	2015	60000	15
Solar thermal (6 hours storage)	45	0	0	0	2015	60000	15
Solar-gas hybrid	85	51	336	0	2015	15000	10
PV - utility scale	27	0	0	0	2015	35000	0
Wave	35	0	0	0	2020	190000	0
Current	40	0	0	0	2015	1000	10

Fossil fuel prices

The previous and updated FGF scenario assumptions are shown in Table 21 and Table 22 respectively. Note that the uranium price projection from the FGF is not included in the tables because we will not be updating the nuclear sensitivity case in this refresh.

Table 21: Previous FGF fuel price assumptions

	Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive

Qualitative description		AETA medium	AETA low supporting gas on-site generation	AETA low supporting gas on-site generation	AETA medium
East coast gas netback price (A$/GJ)	2015	7.7	6.9	6.9	7.7
	2025	10.7	8.6	8.6	10.7
	2050	11.9	9.5	9.5	11.9
East coast netback coal price ($A/GJ)	2015	2.0	1.8	1.8	2.0
	2025	1.6	1.6	1.6	1.6
	2050	1.6	1.5	1.5	1.6
Petrol price ($A/L)	2015	1.40	1.34	1.34	1.40
	2025	1.57	1.45	1.45	1.57
	2050	1.61	1.49	1.49	1.61

Table 22: Updated FGF fuel price assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Medium outlook	Low outlook supporting high on-site generation uptake and medium EV uptake	Low outlook supporting high on-site generation uptake and medium EV uptake	Medium outlook
East coast gas netback price (A$/GJ)	2015	6.6	6.6	6.6	6.6
	2025	8.8	4.9	4.9	8.8
	2050	11.2	6.6	6.6	11.2
East coast netback coal price ($A/GJ)	2015	1.5	1.5	1.5	1.5
	2025	2.2	1.5	1.5	2.2
	2050	2.7	1.8	1.8	2.7
Crude oil price ($A/bbl)	2015	74	74	74	74
	2025	116	84	84	116
	2050	180	116	116	180
Petrol price ($A/L)	2015	1.27	1.27	1.27	1.27
	2025	1.50	1.28	1.28	1.50
	2050	1.95	1.50	1.50	1.95

Rationale for updated assumptions

The FGF used fuel price assumptions from the 2012 Australian Energy Technology Assessment. However, those assumptions are no longer appropriate because the global oil market experienced a major downward adjustment in late 2014. There are many possible explanations for this adjustment and none can be proven definitively. They are based around different theories of why Saudi Arabia has chosen not to decrease supply[9] and include:

- A build-up of both domestic oil-fired electricity generation and value adding oil refining in Saudi Arabia which makes them less inclined to act as a swing producer
- Saudi-US collusion to put pressure on Russia and Iran for geopolitical gain
- An assessment that in a potentially carbon-constrained future world, fossil reserves in the ground will be less valuable
- Rational competitive behaviour by the world's lowest cost producer to cause higher cost producers to exit the market
- A pre-emptive move to discourage further development of non-conventional oil resources and other alternative fuels and technologies

Depending on which combination of drivers are real it could mean low oil prices are will be sustained for potentially decades or more temporary in duration. Whatever the case, this movement in the oil price has reduced the long term outlook for the world oil price and, by partial substitutability, the outlooks for gas and coal as well (e.g. export liquefied natural gas is often contracted on a formula which directly links oil and gas prices). Even if not for the partial substitutability driver, gas and coal markets have their own reasons for a deflated price environment. The slowing economic growth in China, greater commitment towards energy diversity and some new protections for the domestic coal industry have weakened global coal export prices. For natural gas there is a growing expectation that low cost US gas supplies will begin to influence gas prices in the long term as US LNG export facilities are developed.

The selection of future oil and gas prices is made more difficult by the fact that most projections available in the literature were made before the declining price event. EIA (2014) provided a summary of available projections and we have updated that list with those from EIA (2015) and IEA (2014) in Figure 6. The spread of oil price projections shows that the future oil price range is generally expected to be flat to rising.

[9] See, for example, the IAEE's 2nd Quarter 2015 Energy Forum for various discussion of this topic: http://www.iaee.org/documents/2015EnergyForum2qtr.pdf

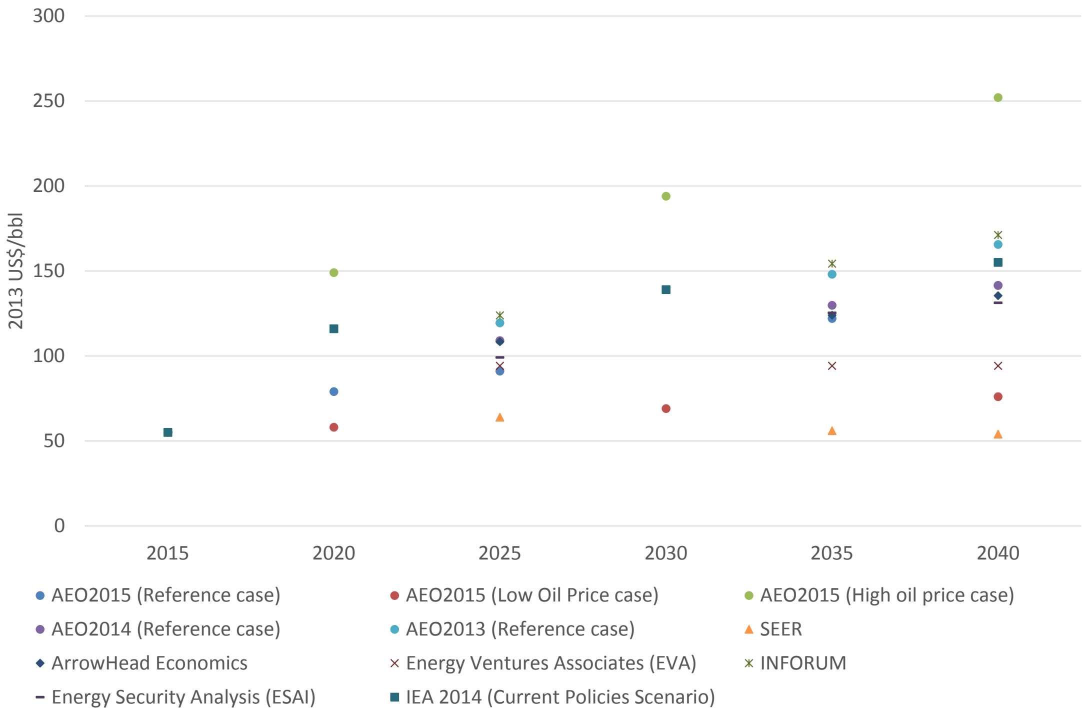


Figure 6: Summary of available (Brent) oil price projections

A concern with using projections from the upper end of the projection range is that they may be assuming a no-climate action world which is not consistent with the FGF scenarios. Were they available, projections from the International Energy Agency that take into account the recent substantial price reduction would be preferable since they are the only group who regularly and transparently take into account the impact of increasing action on climate change on the world oil price with explicit global carbon price and policy framework assumptions. However, given the IEA (2014) oil and gas projections are out of date we apply the Energy Information Administration (2015) projections but reduce them slightly to make them more consistent with the IEA's methodology.

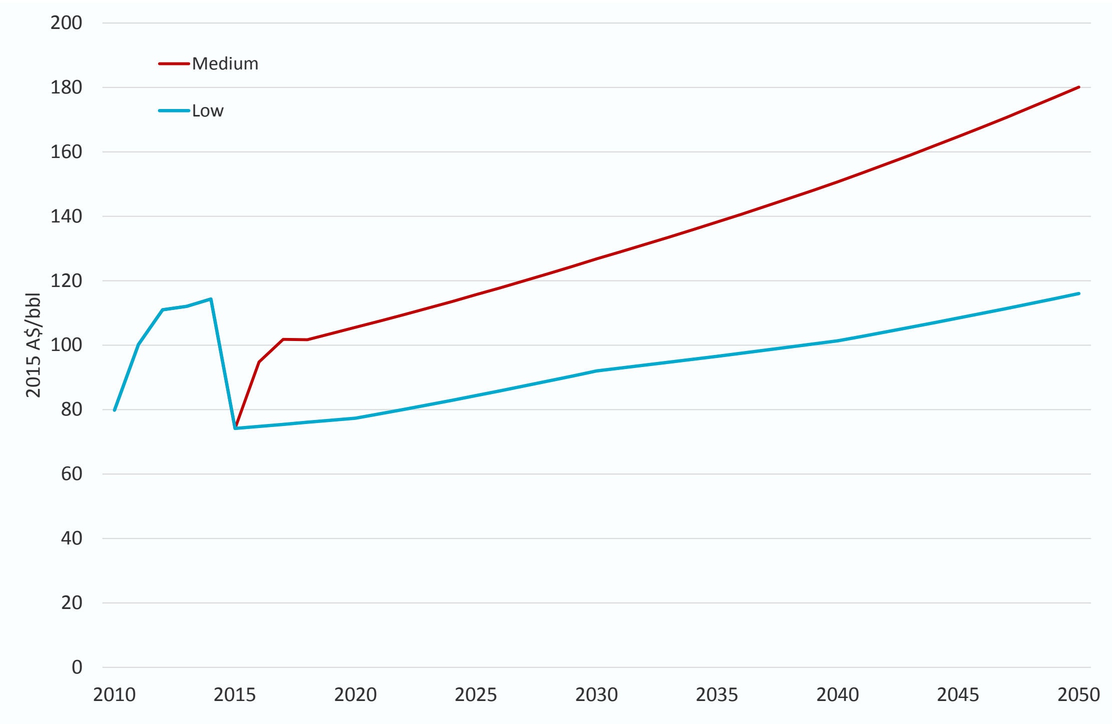


Figure 7: Projected global oil prices expressed in Australian dollars

The gas and coal price projections are built off the oil price projections on the assumption that gas and coal maintain their relative price differentials at a global level (due to their partial substitutability) and Australian domestic coal and gas (after an adjustment period as LNG export facilities gear up)) have a fixed netback value from the international (Asian regional) price.

An issue which is raised by this approach of building gas and coal prices via the oil price outlook is that compared to the previous FGF assumptions this leads to higher long term fuel prices. This is because the previous price projections were flat from 2030 whilst the updated price projections continue to rise.

In trying to resolve this issue we examined ACIL Allen Consulting (2014) projections for AEMO which provides revised forecasts to 2045 and in this case prices are increasing beyond 2030. However, as shown in Figure 9, the projections still have a tendency for a slower rate of growth in this period (we show the highest, lowest and average projections for prices that a combined cycle gas turbine would pay across the NEM states). This is despite assumed linearly increasing global oil price assumptions. ACIL Allen Consulting (2014) note that an open cycle turbine will pay a premium of around $2/GJ for intermittent use of gas supply.

For the purposes of constructing an Australia petrol price (to evaluate the economic value of electric vehicles) we use the methodology described in Gargett (2010) to convert the world oil price to an Australian dollar per litre price. The long term exchange rate used to make all US dollar conversions is A$0.75/US$.

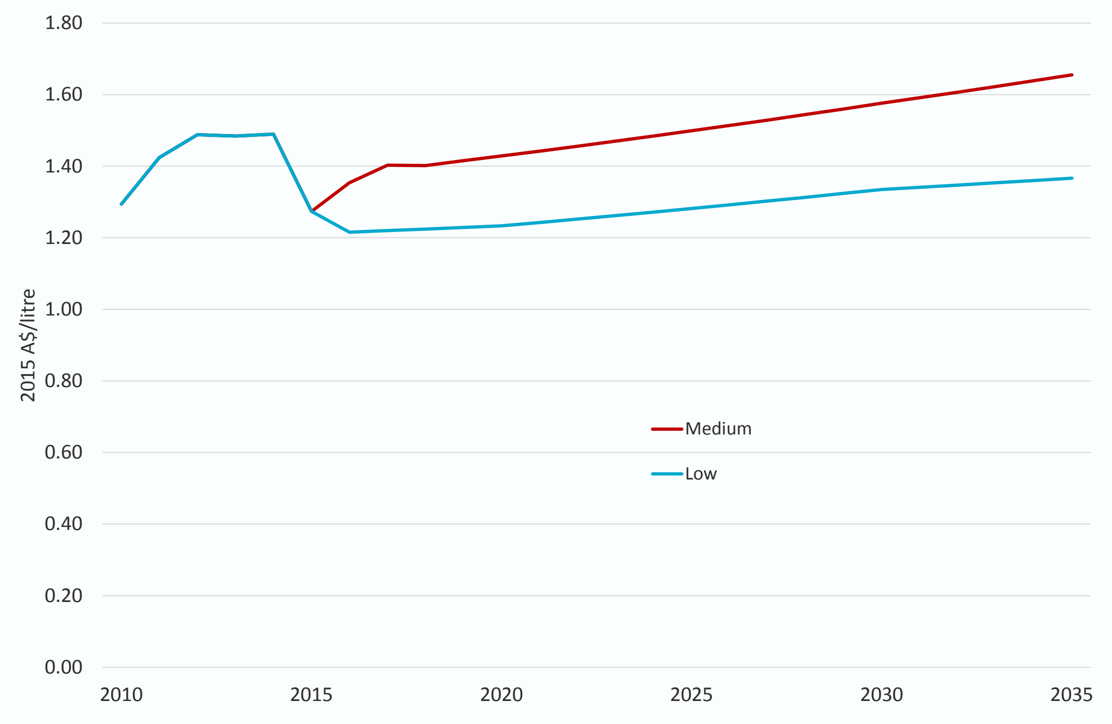


Figure 8: Projected Australian petrol prices

Summary

There is considerably more uncertainty in the future of fossil fuel prices now than in 2013 due to the 2014 recent reduction in oil prices which reduces the outlook for all fossil fuels in the near term. The previous scenario assumptions adopted a medium outlook for fossil fuels in *Set and forget* and *Renewables thrive* and a low fuel price outlook in *Rise of the prosumer* and *Leaving the grid.* The reason for choosing a low price scenario for the latter two scenarios was for the purposes of making the high adoption of on-site generation in those scenarios more plausible, particularly in relation to gas cogeneration. However, given most new on-site generation is now expected to be solar, the assumption of different fuel prices across the scenarios is no longer appropriate. It would have some value in representing the fuel price uncertainty but we judge that benefit is outweighed by the inconvenience of having an arbitrary difference in the scenarios which could confuse the interpretation of their outcomes.

Consequently we assume only one gas and coal price across all scenarios and these are shown in Figure 9 and Figure 10. In both cases they are lower than the medium price used in the 2013 modelling assumptions.

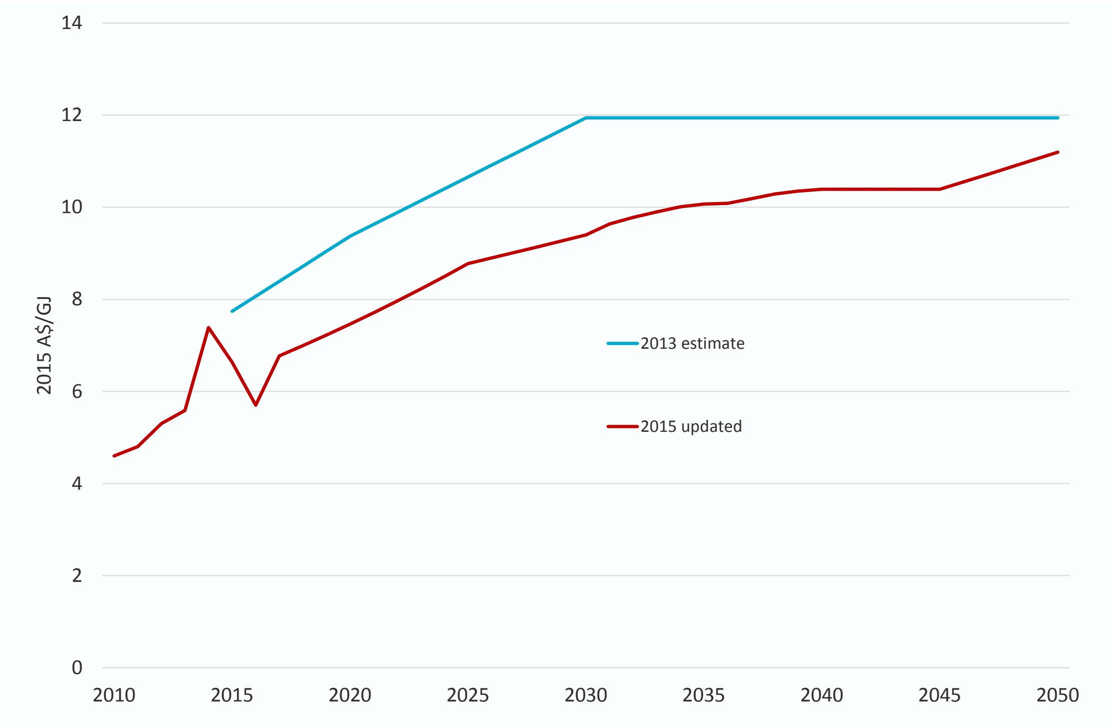


Figure 9: Projected Australian east coast netback gas prices

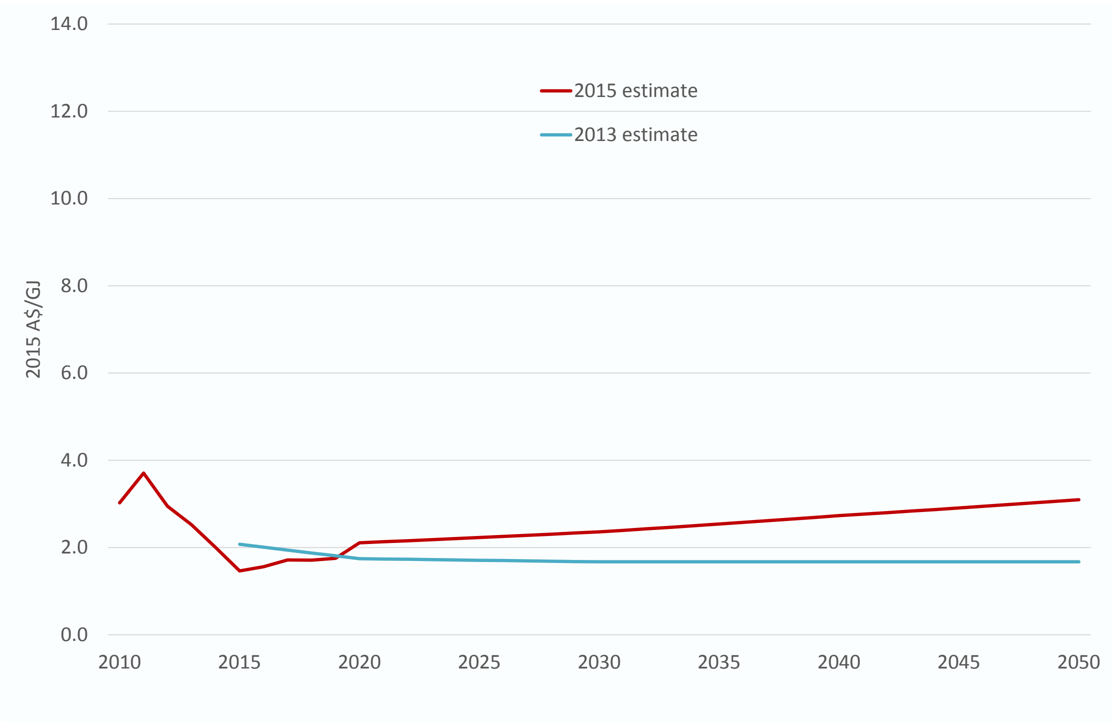


Figure 10: Projected Australian east coast netback coal prices

Government energy and climate policy

The previous and updated FGF scenario assumptions for government energy and climate policy are shown in Table 23 and Table 24 respectively.

Table 23: Previous government energy and climate policy assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Moderate carbon price (proxy policy) and existing RET policy to 2030	Moderate carbon price (proxy policy) and existing RET policy to 2030	Moderate carbon price (proxy policy) and existing RET policy to 2030	Moderate carbon price (proxy policy) plus extended RET to 100% of grid by 2050
Carbon price proxy (A$/t)	2015	23.8	23.8	23.8	23.8
	2025	42.4	42.4	42.4	42.4
	2050	141.0	141.0	141.0	141.0
Large-scale renewable energy target (TWh)	2015	18	18	18	18
	2025	41	41	41	41
	2050	0	0	0	156 (i.e. 100%)

Table 24: Updated government energy and climate policy assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Moderate carbon price (proxy policy) and amended RET policy to 2030	Moderate carbon price (proxy policy) and amended RET policy to 2030	Moderate carbon price (proxy policy) and amended RET policy to 2030	Moderate carbon price (proxy policy) plus extended RET to 100% of grid by 2050
Carbon price proxy (A$/t)	2015	0.	0	0	0
	2025	42.3	42.3	42.3	42.3
	2050	189.0	189.0	189.0	189.0
Large-scale renewable energy target (TWh)	2015	18	18	18	18
	2025	33	33	33	33
	2050	0	0	0	~156 (i.e. 100%)

Rationale for updated assumptions

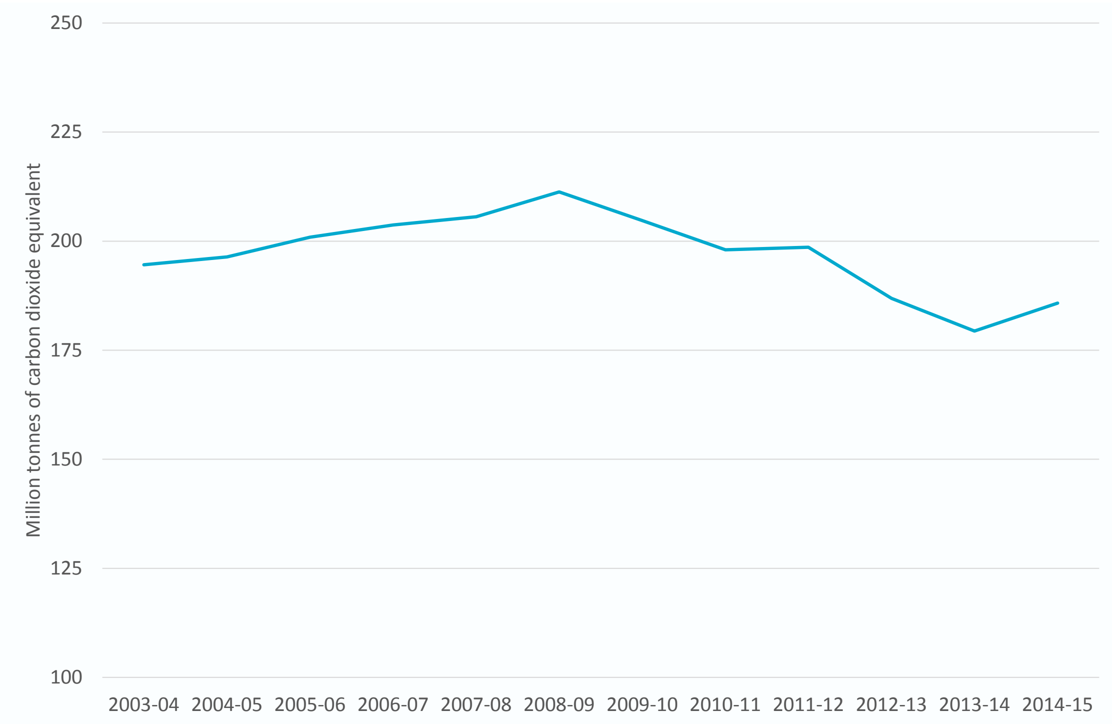
The assessment of the Future Grid Forum in 2013 was that there was bipartisan political consensus on the need to address climate change but disagreement about the ideal form of policy response. It was also recognized that the incoming government intended to remove the existing carbon price legislation. Given these observations a carbon price was used as a proxy for whatever form of policy was chosen to send a signal to markets to reduce greenhouse gas emissions in the electricity sector. This recognised that although the form of policy does matter, there was no way to predict what might be implemented.

There is little that has changed this historical assessment. However there are three important points to note.

No legislative constraint on electricity emissions in short to medium term

The first is that the carbon price legislation was repealed coming in to effect on July 2014. In its place the government introduced the Direct Action plan which provides funding for a reverse auction of greenhouse gas abatement activities. The activities that have so far been most successful in the auctions are based around energy efficiency which reflect the low abatement cost of energy efficiency as the abatement it delivers the co-benefit of savings in energy expenses. It does not appear that Direct Action will fund any major supply-side greenhouse gas abatement in the electricity sector. The lack of legislative constraint on electricity sector emissions since July 2014 has coincided with an increase in electricity sector greenhouse gas emissions (Figure 11). However, as the Future Grid Forum emphasised in regard to the reduction in greenhouse gas emissions when the carbon price policy was in place, the impact of the policy alone the change in emission cannot be solely attributed to the policy and it is difficult to separate its impact from all the other drivers (e.g. changes in demand, hydroelectric plant water constraints, fossil plant outages and recoveries).

Nevertheless, unless the ‘Safeguards’ feature of the Direct Action policy which sets emission standards for companies is strengthened or a new policy mechanism is introduced, electricity sector emissions would be expected to biased towards an increase in the short term, depending on the residual growth in electricity demand after new renewable supply from the Renewable Energy Target has been adopted into supply.



Source: Department of Environment (2015) and Pitt and Sherry (2015)

Figure 11: Electricity sector greenhouse gas emissions

Renewable targets and investment confidence has declined

The Future Grid Forum did not foresee that bipartisan support for the Renewable Energy Target would be lost in 2014. It was recognised by all parties that the Renewable Energy Target, which was nominally designed to enable a 20 percent share of renewables by 2020, would likely exceed its target to achieve approximately 27 percent by 2020. This is because the nominal target is set by requiring a fixed 41 TWh (in the large scale scheme) to be delivered by 2030. However given demand for centralised electricity generation is growing slower than was expected when the fixed TWh amount was set, the nominal target will likely be exceeded unless the fixed target is changed.

After a year or so including a review and political negotiations it was agreed and legislated that the fixed target is reduced to 33 TWh by 2020[10]. This political process highlighted some important points about the renewable energy policy:

- It was generally agreed that whenever bipartisan support for the policy is withdrawn investment in renewable energy projects cannot proceed due to the increased financial risk to the project.
- While there is bipartisan support for the Renewable Energy Target policy at a high level the underlying reasons for the existence of the policy are not well agreed. There is no clear agreed articulation of whether the policy is primarily designed to reduce emissions,

[10] The legislation also allows for biomass-fired electricity from native plantation forestry to participate in the scheme and for energy intensive export exposed industries to be exempt from the scheme

reduce the cost of renewable power, promote deployment of new technologies, build industry experience in renewables or some combination of goals.

Two other policy changes impacting the renewables sector are the direction from the government to the Clean Energy Finance Corporation not to invest any further in wind and small scale solar panel technologies and the creation of a commissioner to review the deployment of wind farms, specifically to manage concerns about their sonic impact on nearby residents. The latter represents the government playing a stronger role in determining the outcome of social license issues around the impact of wind farms. The former indicates a preference by the present government for the Renewable Energy Target to deliver deployment of new technologies rather than deployment of the established and lowest cost technologies (this relates to the second dot point above).

Further policy clarity expected over next 9 months from a variety of information sources

The climate negotiations to be concluded in Paris at the end of 2015 are regarded as an important opportunity to provide the foundation for an agreed global climate policy for the period 2020 to 2030. A feature of the lead up to that meeting is that each country is required to announce their own national emission reduction target with the expectation that countries will seek to match the efforts of other similar countries. It is generally expected that, based on previous commitments and announcements to date, the combined targets of all countries will not be sufficient to achieve the agreed long term target of avoiding a 2^0C increase on 19^{th} century temperature levels but will likely be more consistent with avoiding a 3^0C increase.

The announcement of Australia's target in August 2015, which is to reduce emission by 26 to 28 percent by 2030 relative to 2005 levels, indicates that Australia will not be more ambitious than the rest of the world on average and therefore the strength of the policies needed to implement the target will likely be consistent with the total global abatement ambition. Following the August announcement there is an expectation that this the government will move to outline in greater detail the policy mechanisms by which it intends to achieve the target.

To some extent this discussion has already started with many options being discussed amongst both government and other stakeholders. A potentially valuable piece of information for the electricity sector is the Climate Change Authority's review of electricity sector emission reduction policies as part of its *Special Review: Australia's Future Emission Reduction Targets*. In the review the CCA will qualitatively and quantitatively the equity, effectiveness and efficiency of a range of electricity sector emission reduction policies. The illustrative policies to be reviewed include (Jacobs 2015):

- **RET only**: RET expanded to achieve the emissions constraint.
- **Low emissions target**: operates in a similar manner to the 'RET only' policy scenario but with an expanded set of eligible technologies including more efficient gas generation and carbon capture and storage (CCS).
- **Explicit carbon price** via a 'cap and trade emissions trading scheme' (version A) or a 'carbon tax' (version B).
- **Absolute baselines**: a scenario with some features in common with the safeguard mechanism for the electricity sector under the ERF.
- **Intensity target**: sector is subject to a declining sector-wide emission intensity baseline. All generators receive an allocation of permits at the baseline level of intensity; at the end

of the compliance period all generators surrender permits for each tonne of carbon dioxide equivalent emitted (tCO2-e).

- **Regulatory approach** of standards for existing and new generators. Maximum allowable emissions intensity standards for new generators introduced. Existing generators are closed in order of age (version A) or emissions intensity (version B).
- **Feed-in tariffs with contracts for difference**: incentives are provided for specific forms of low emissions generation through feed-in tariffs with contracts for difference (broadly based on policy design in the United Kingdom).

A temporary way forward

Given Australia's climate policy remains in a state of flux the Future Grid Forum's previous approach of using a carbon price proxy for future policy mechanism would appear to be the best way forward until a stronger consensus around the policy mechanism emerges. The approach we take is to update the Renewable Energy Target to the new value of 33 TWh and assume that there will be no other constraint on electricity sector greenhouse gas emissions until 2020. From 2020 we use a carbon price to proxy future policy mechanisms that would be expected to be introduced to ensure Australia meets its target announced as part of global negotiations.

As the original source of carbon prices in the previous Future Grid Forum modelling is now 4 years old (Treasury, 2011), we have updated the carbon price proxy using the midpoint of global carbon price needed to achieve a 530-580ppm CO_2e world by 2100 estimated by multiple model runs that were reported in IPCC (2014). The achievement of this global carbon dioxide equivalent concentration level by 2100 provides an estimated 54 to 94 percent probability of exceeding a 2^0C increase on 19th century temperature levels and 8-19 percent probability of exceeding a 3^0C increase. The previous and updated carbon prices are shown in Figure 12. Despite the sources of the carbon prices being quite different, the updated carbon price only significantly diverges from the previous carbon price in the first five years and last 20 years.

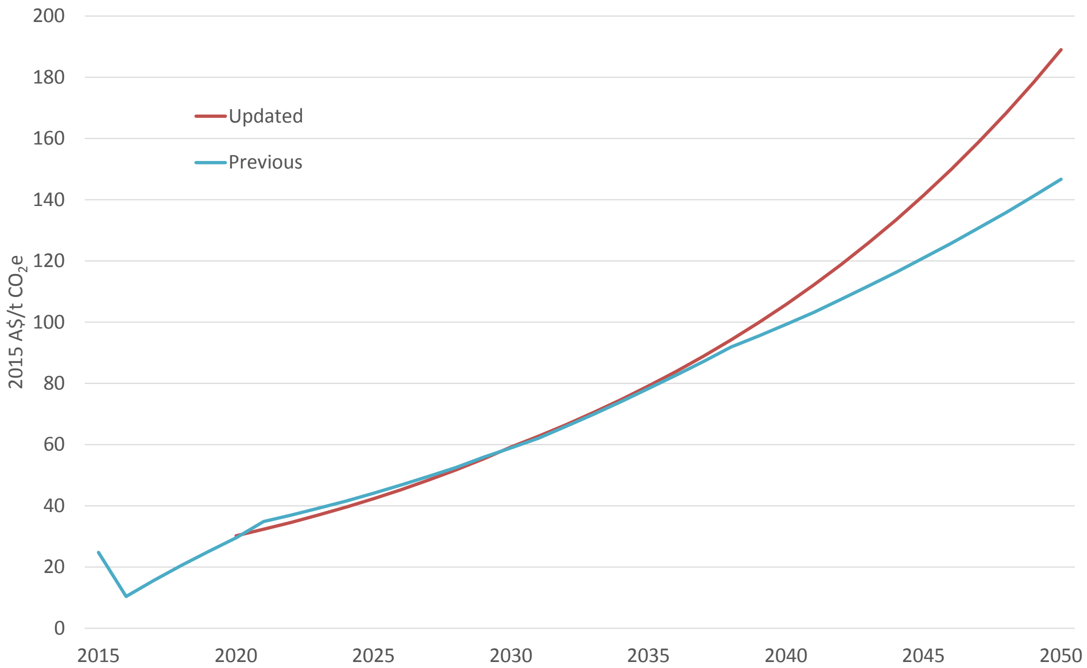


Figure 12: Previous and updated carbon price (proxy policy) assumptions

Regulation

The Future Grid Forum did not include any significant changes to the existing electricity sector regulations other than a migration, in some scenarios, to more cost-reflective pricing which will require further price deregulation in some States. *Rise of the Prosumer* and *Renewables thrive* suggest the role of networks has changed to something of a transactions hub but does not fill in the regulatory detail needed to facilitate that change

However, in the past two years there are some changes in the application of regulation and some rule changes under consideration that could provide further detail of the possible future regulatory environment in the Future Grid Forum scenarios. They are discussed under the following sub-headings.

Network costs and approaches to benchmarking

The previous and updated FGF scenario assumptions for distribution network average capital costs are shown in Table 25 and Table 26 respectively.

Table 25: Previous distribution network average operating capital cost assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Constant but differentiated by distribution zone	Constant but differentiated by distribution zone	Constant but differentiated by distribution zone	Constant but differentiated by distribution zone
Operating expenditure	2015-2050	As per previous regulatory period	As per previous regulatory period	As per previous regulatory period	As per previous regulatory period
Amortised capital cost ($/kW p.a.)	2015	141-449	141-449	141-449	141-449
	2025	141-449	141-449	141-449	141-449
	2050	141-449	141-449	141-449	141-449

Table 26: Updated distribution network average capital cost assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Middle to top end of range declining due to benchmarking and differentiated by distribution zone. Increasing relevance of non-network solutions.	Middle to top end of range declining due to benchmarking and differentiated by distribution zone. Increasing relevance of non-network solutions.	Middle to top end of range declining due to benchmarking and differentiated by distribution zone	Middle to top end of range declining due to benchmarking and differentiated by distribution zone. Increasing relevance of non-network solutions.
Operating cost (% change relative to pre-2015)	2015	-5 to-30	-5 to-30	-5 to-30	-5 to-30
	2025	-5 to-35	-5 to-35	-5 to-40	-5 to-35
	2050	-10 to -40	-10 to -40	-5 to-45	-10 to -40
Amortised capital cost ($/kW p.a.)	2015	141-314	141-314	141-314	141-314
	2025	141-300	141-300	141-282	141-300
	2050	127-285	127-285	127-254	127-285

Rationale for update assumptions

The previous FGF assumptions on distribution network capital costs assumed that they would be able to maintain those capital costs at a constant level in real terms to 2050. This seemed a reasonably challenging target given the industry had just experienced significant real increases in material costs in the previous decade due to demand for some raw materials (particularly refined metals) being high in the Asian region.

Since 2013 there has been further deepening of the downward phase of the global commodity price cycle, reducing pressure on some raw material costs. On the other hand, further upwards phases cannot be ruled out in decades to come. There has also been a significant reduction in the cost of financing since the previous regulatory period.

In the current regulatory period a more aggressive approach to benchmarking of allowable operating and capital costs has been taken by the Australian Energy Regulator (AER). Benchmarking of distribution network costs structures is used as a means of pushing less efficient networks towards the theoretical most efficient production frontier. Comparing the costs all of the different networks to work out where the efficient frontier lies provides some guidance but is imperfect because of the differences between the networks – customer density and load behaviour, terrain, legacy systems, local infrastructure. The benchmark process collects cost data from each of the distribution networks and aims to correct for these differences.

Although at present the NSW and ACT AER decision remains contested, to update our assumptions, we assume a large one-off reduction in allowable operating and capital costs in the current regulatory period and some additional minor adjustments over the longer term which could be driven by further modest benchmarking targets or other factors discussed.

Contestability of network services

The Future Grid Forum suggested that in some scenarios networks would operate out of their traditional business areas, would partner with others in the supply chain and would also face competition from new entrants in traditional network roles. However, it wasn't specific about how those changes would come about.

One proposed rule change has provided some clarity around metering services[11]. The AEMC's draft determination on expanding competition in metering and related services proposes that:

- Any party can set up a business to provide metering services if they meet registration requirements
- New and replacement meters will be required to meet a minimum service specification for advanced metering, including operational remote communications
- The change would come into effect on 1 December 2017

These changes make it easier for customers to choose to keep their existing working meter or change their meter as part of taking up new services, although all new and replacement

[11] http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Metering-and-related-services-Draft-determination

meters (for meter faults and failures) are to meet the minimum standard. The final determination is due to be made in November 2015[12].

This model for market-led deployment of advanced meters means that the proliferation of advanced meters (outside Victoria) will be driven by the minimum service specification for new and replacement meters and competition amongst retailers and their metering partners to provide innovative products to consumers.

An existing area where networks also face competition is in new connections in regional areas. Where customer density is very low and distance to the grid of a customer seeking connection exceeds a given distance that customer can consider an off-grid system. Remote Area Power systems are not new. However, reductions in the cost of solar and batteries have perhaps extended the economically viable range of RAPS system. We discuss this further in the technology system under 'off grid'.

A potential pathway to network competition in currently connected fringe of grid locations is likely to emerge, and will be driven jointly by network businesses seeking to transfer high cost-to-serve network connections to lower cost stand-alone solutions (both individual customers and small communities). Ultimate delivery of these lower cost solutions is likely to transfer customers from a natural monopoly situation to a marketplace that is congenial to competition. The policy, regulatory and operational framework to support this transition will require significant attention

We have just provided two examples here that relate to situations where existing roles of networks would be delivered by other parties. However, the potential for new products and services associated with new technologies also opens up the potential for competition between networks and others in non-network business areas. This raises a number of issues such as ring fencing, multiple trading relationships, competitive advantage and competitive neutrality that are being discussed in different forums but are yet to be resolved. While nothing concrete can be taken from these discussions to inform the scenarios, they fill in some details as to the issues that have to be resolved in arriving at some of the futures envisaged by the FGF scenarios.

Likelihood of asset stranding or RAB write down

The current electricity rules provide the AER power to direct a reduction in the value of the RAB where the utilisation of assets meets some limited circumstances. However, those circumstances were generally referring to where a major customer closed or relocated rather than a general reduction in utilisation Since the publication of the Future Grid Forum some literature has suggested that a large scale, across the board write off of the Regulated Asset Base (RAB) of distribution and transmission networks would be preferable to the network price rises that are envisaged due to declining utilisation and that is generally referred to as the 'death spiral' or 'vicious cycle' (Simshauser and Nelson, 2012; King, 2013). For example, Wood and Carter (2013) propose this approach and suggest that were retail prices to spiral upwards the cost of a RAB write down could be borne by consumers, private network owners or governments. There would be many practical and political problems with this approach (particularly the increased cost of financing any new assets after such an event) but aside

[12] http://www.aemc.gov.au/News-Center/What-s-New/Announcements/Extension-of-time-for-final-determination-on-meter

from those considerations, ultimately the Future Grid Forum scenarios did not find sufficient cause to justify such a drastic step.

Contrary to expectations and perceptions the FGF found that the distribution and transmission system remained significant under all scenarios. Under *Leaving the grid*, a large segment of customers disconnecting from the grid was not the worst outcome (from a retail and network unit cost perspective) since customers who were no longer connected did not need to be supported with new or replacement infrastructure costs. Rather, *Rise of the Prosumer* led to the largest network price increases because there were a large number of very low utilisation customers still connected to the grid, largely for back-up and export (which subsequently led to the highest increase in unit costs).

Where there were high unit price increases associated with declining network utilisation, for small customers these were largely offset by energy efficiency improvements and savings from onsite generation such that their overall electricity bill remained largely unchanged. For large customers changes in the generation price drowned out any network impacts due to their tariff structure. That is, for large customers the effect of changes in network costs is not significant because they represent a small proportion of the electricity bill.

In the transmission sector we would also find a RAB write down associated with declining utilisation equally implausible. However, one aspect that did not receive significant attention during the FGF process was the impact of closures of existing generation assets, mainly coal-fired power, on the transmission network. In the FGF modelling we were mainly concerned with identifying any new transmission connections that needed to be built to accommodate new electricity generation sites, particularly in *Renewables Thrive* where all centralised generation had to be supplied by renewables by 2050. However, potential redundancy of existing transmission lines and connections is yet to be examined in any detail.

Depreciation allowances

The possibility of shorter than planned asset lives raises the broader issues of cost recovery and depreciation allowances. To the extent that there may be plausible scenarios where the required capacity of the grid may decline, this suggests existing rules about the timeframe over which the costs of those assets may be recovered could be reconsidered. This topic is unresolved at this stage and so is not included in the scenarios but could be considered as an ‘action’ in later stages of the roadmap project.

Baseline electricity consumption, peak demand and energy efficiency improvement

The modelling methodology applied for the FGF was to use the AEMO (2013) demand projections as a starting point to understand what the future of demand is expected to be under a fairly unchanged electricity system. Using this as a starting point we replace AEMO’s projection of on-site generation with the projected uptake under each FGF scenario and we then add in a number of items which are generally not dealt with in significant detail by AEMO[13] such as:

[13] However, AEMO are building the capability to examine these issues in more detail in the future as indicated by their *Emerging Technologies Information Paper* that was released as a supplementary report to the *National Electricity*

- Electric vehicle uptake
- Battery storage adoption
- Building air conditioning and pool pump control
- Industrial load management

In 2013 we assumed that in *Renewables thrive* and *Leaving the grid* we would apply AEMOs low demand scenario reflecting expected higher retail costs in each scenario and in *Leaving the grid* additional motivation comes from a stronger desire to be independent of the grid which is partly enabled by having lower electricity needs. However, on reflection the retail price differences in the final 2013 modelling results were not large enough to justify a significant difference in demand and it is not clear how owners of on-site generation change their electricity consumption. Therefore in the updated assumptions we apply the AEMO medium projections all scenarios and use the AEMO low projections for sensitivity testing of the impact of lower demand.

AEMO's medium and low 2013 and 2015 projections are shown in Figure 13. A clear trend in the updated AEMO (2015) projection is that consumption is expected to be lower than was projected in AEMO (2013). The updated medium scenario now projected to be below or level with the 2013 low scenario. The 2015 low scenario is almost 50,000 GWhs lower than the 2015 medium case by 2024-25.

This indicates that not only is the consumption projection lower than 2013 but it is also significantly more uncertain. In 2013 the difference between the high (not shown) and low scenario was 26,000 GWh by 2024-25. In 2015 the difference is 62,000 GWh, mostly to due to down-side risk on the medium scenario.

Forecasting Report 2015, http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

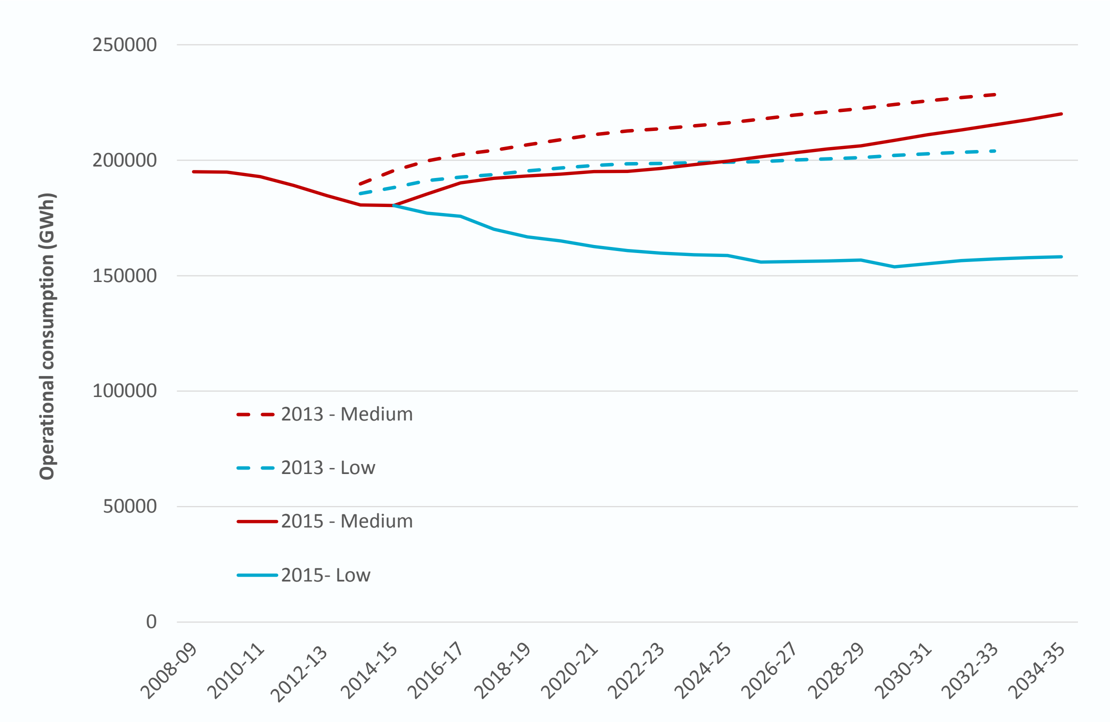


Figure 13: AEMO's 2013 and 2015 medium and low electricity consumption projections

This change in AEMO's projections does not necessarily mean that the updated consumption projections for the Future Grid Forum are radically lower. It reflects that AEMO's projections have caught up to the FGF modelling in that they are incorporating more on-site generation in their consumption forecast. In our modelling process we replace AEMO' onsite generation projection with our own projection and after this step demand may not change as much as it previously did in 2013.

ClimateWorks Deep Decarbonisation sensitivity case on Renewables Thrive

ClimateWorks, together with other collaborators, published its report on *Pathways to Deep Decarbonisation in 2050* for Australia in September 2014 and presented an alternative view of what may happen to demand in a high greenhouse gas abatement scenario (ClimateWorks Australia, ANU, CSIRO and CoPS 2014). While in greenhouse abatement scenarios we tend to focus on the negative impacts of higher electricity prices on electricity demand, this new report has highlighted that substitution away from more emission intensive fuels such as gas in direct combustion and petroleum based fuels in transport and towards low or zero emission electricity to enable deeper greenhouse gas abatement could be a source of strong electricity demand growth.

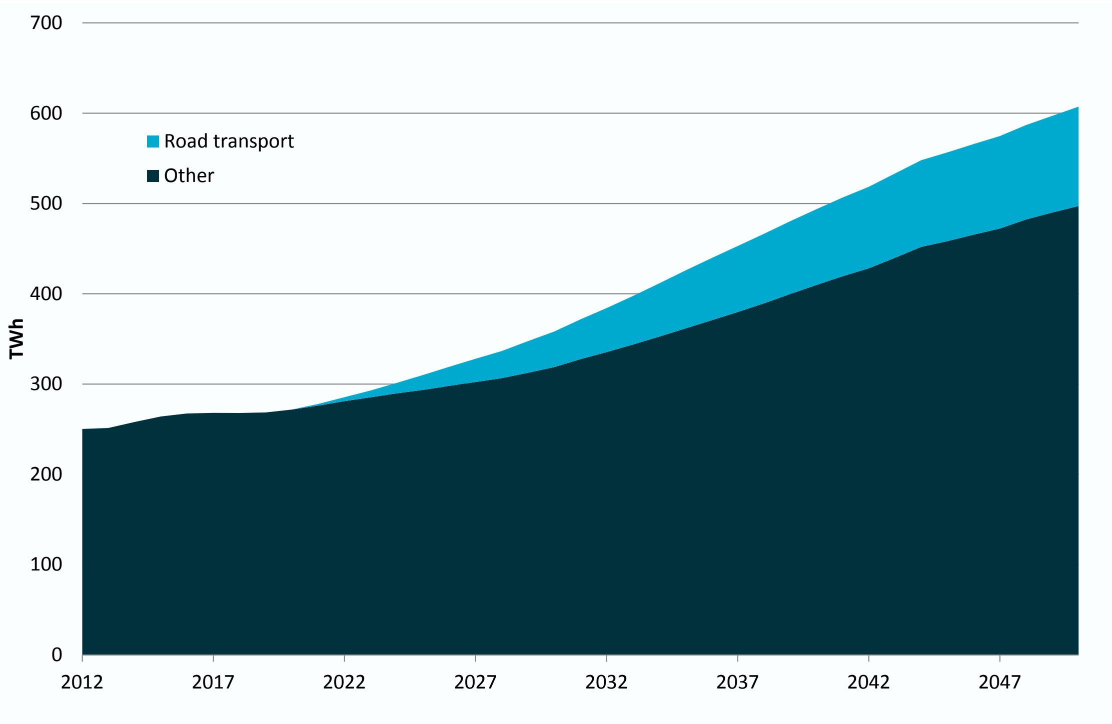


Figure 14: Electricity demand by road transport and other under the *Australian Deep Decarbonisation Pathway*

The average electricity demand growth rate under the *Australian Deep Decarbonisation Pathway* is 2.4 percent per annum to 2050. The key drivers are electrification of buildings, transport and industrial processes and the redistribution of economic activity from fossil fuel production and export to non-fossil fuel-related minerals which remain electricity intensive activities.

The electrification of road transport and shift in economic activity were estimated as outputs of ESM and MMRF respectively, while the electrification of buildings and industrial processes is based on detailed bottom-up analysis by ClimateWorks. The amount of electricity which ESM projects to be consumed by the road transport sector is shown in amounts to around 110 TWh or 28 percent of electricity consumption by 2050 but is fairly negligible up until around 2025. This is based on Graham and Hatfield-Dodds (2014) in the summary of electric vehicle adoption projections presented in Figure 4.

With the exception of this high demand projection, the *Australian Deep Decarbonisation Pathway* and *Renewables thrive* are very similar in other scenario assumptions. They both assume:

- A 100% renewable grid by 2050 via extension of the Renewable Energy Target[14], and
- Accelerated technology change for electricity generation technologies consistent with a world that has a strong commitment to greenhouse gas abatement (e.g. limiting global average temperature change to less than 2°C)

[14] The Australian Deep Decarbonisation Pathway also explored sensitivity cases where the demand was met by renewables plus either fossil fuels with carbon capture and storage or nuclear.

The main difference is that the *Australian Deep Decarbonisation Pathway* was broader in nature in that it considered how sectors other than the electricity sector might deal with achieving deep emission cuts and hence it was able to identify additional potential sources of electricity demand that were not incorporated in the FGF scenarios.

Given the similarity of scenarios and the potentially important role of consumption growth in assisting distribution and transmission networks in managing the impacts of increased on-site generation, the FGF refresh will include a sensitivity case on *Renewables thrive* which will adopt the demand projection of the *Australian Deep Decarbonisation Pathway*.

Peak demand management assumptions

Table 27 and Table 28 (and Table 4 where some residential and commercial elements were previously discussed) set out the previous and updated peak demand management assumptions for the FGF scenarios across a number of categories. Battery storage is another category of peak demand management which is not included here but it is dealt separately under its own section given the substantial new information on this topic since 2013.

Table 27: Previous peak demand management assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Managed across residential, commercial and industrial	Managed across residential, commercial and industrial	Unmanaged, remaining customers can't afford actions	Managed across residential, commercial and industrial
Residential HVAC control (% adoption)	2015	5	5	0	5
	2025	9	9	0	9
	2050	20	20	0	20
Commercial HVAC control (% adoption)	2015	5	0	5	0
	2025	8	8	0	8
	2050	15	15	0	15
Managed electric vehicle charging (% adoption)	2015	0	0	0	0
	2025	100	100	0	100
	2050	100	100	0	100
Industrial load shifting (% adoption)	2015	5	5	0	5
	2025	6	6	0	6
	2050	10	10	0	10

Table 28: Updated peak demand management assumptions

		Set and forget	Rise of the prosumer	Leaving the grid	Renewables thrive
Qualitative description		Managed across residential, commercial and industrial	Managed across residential, commercial and industrial	Unmanaged, remaining customers can't afford actions	Managed across residential, commercial and industrial
Residential HVAC and pool pump control (% adoption)		See Table 4			
Commercial HVAC control (% adoption)	2015	3	3	3	3
	2025	5	5	5	5
	2050	10	10	10	10
Managed electric vehicle charging (% adoption)	2015	0	0	0	0
	2025	66	66	66	66
	2050	100	100	100	100
Industrial load shifting (% adoption)	2015	2	2	2	2
	2025	4	4	4	4
	2050	6	6	6	6

The previous peak demand management assumptions were designed in collaboration between CSIRO and the Future Grid Forum participants who combined their expertise on various approaches to demand management. The purpose was mainly to ensure that no major opportunities were excluded and that the potential scale of each demand management activity was plausible.

In revising these assumptions we have considered the following observations about peak demand management:

- The major focus of public and private discussion of peak demand management technologies has been in relation to battery storage. This has been characterised by major manufacturers and retailers forming alliances to provide the technology to consumers as an installed package. Key advantages of battery storage are that it enables demand management without requiring a change in behaviour by electricity end-users and allows solar users who are coming off high feed-in tariffs or new solar adopters who will also only receive low feed-in tariffs to minimise how much they export to the grid relative to own use.
- There have been no new major public studies on non-battery related peak demand management technologies. The most mature technologies would appear to be commercial building HVAC control where there are established solutions that can be retrofitted and the existing arrangements that allow large industrial loads to bid into the NEM directly or into direct calls for load reduction (e.g. Transgrid have held such auctions in New South

Wales). In contrast, residential HVAC control appears to be limited by lack of appropriate control systems in the existing air conditioner fleet and delays in introducing standards that would eventually controllable systems adopted into the appliance stock. Also, the lack of adoption in electric vehicles has meant this market is too small to develop specific responses for load management.

- Queensland's deployment of a rewards system for demand management of air conditioners and pool pumps appears to be the strongest example of new residential demand management adoption. It is interesting to note in that region control of pool pumps, not included in 2013 modelling, have greater adoption than HVAC control. This could reflect the relative less time dependent activity of pool cleaning.
- Regulatory incentives for networks to implement demand management initiatives as an alternate to network augmentation are to be strengthened in late 2015. The AEMCs draft rule change on the Demand Management (DM) incentive scheme, released in May 2015, seeks to overcome inherent regulatory barriers to DM which in practice hinders networks from retaining avoided or deferred capital expenditure savings from DM activities, leading to a preference for network investment. These reforms will include an ability for network businesses to access enhanced revenue structures for DM projects, namely:
    - Net Market Benefit - a proportion of the market benefits and avoided or deferred network costs produced by a DM project. This is likely to be between 30 and 50% of avoided or deferred costs.
    - Foregone Revenue - a payment as compensation due to a reduction in throughput volumes resulting from the implementation of DM projects.
- Feedback from workshops suggested that there was no particular reason why electric vehicle charging, commercial HVAC control and industrial load control should differ across the scenarios

Taking into account these developments we make the following changes to the assumptions in this update:

- Assume that battery storage is the dominant form of demand management across the scenarios, and particularly *Renewables thrive*. Slightly reduce other demand management options relative to 2013 assumptions to represent the crowding-out impact of battery storage
- Reduce emphasis on residential HVAC control and explicitly include pool pump control.
- Harmonise electric vehicle charging, commercial HVAC control and industrial load control across the scenarios
- Slightly reduce management of electric vehicle charging until it achieves greater market critical mass

The combined effect of these changes a fairly similar level of demand management overall, but delivered by different technologies, differing by state (Table 4) and greater conformity in large customer technology adoption but greater diversity in small customer technology adoption across the scenarios.

Gas and electricity substitution

The Future Grid Forum scenarios did not previously have any specific assumptions about changes in preferences for electricity or gas use in buildings and industrial processes. As we built our demand projections on top of the AEMO (2013) projections we implicitly assumed no major substitution. AEMO (2015b) reaffirm that the gas price is not considered in its residential and commercial demand forecasting equation as it is not statistically significant. However, in their Emerging Technologies Information Paper (AEMO, 2015c) they have examined this issue further and conclude:

“The proportion of households which can switch varies across NEM regions, and also involves a behavioural element that AEMO has not considered. Based on initial assumptions, AEMO expects the impact of fuel switching in the residential sector to be low across the NEM during the outlook period.

Using an assessment of the economic viability of switching from gas to electricity appliances, AEMO estimates that, in 2024–25, fuel switching may contribute an additional 815 GWh (0.4%) to forecast operational consumption, increasing to 2,552 GWh (1.2%) in 2034–35.

As the gas market is small relative to the NEM, the impact of fuel switching may be more apparent in this sector. AEMO will continue assessing the impact of fuel switching in the 2015 National Gas Forecasting Report.”

There are also other views, notably Forcey (2015), that argue a stronger potential for gas to electricity fuel switching given due interplay between existing appliance ownership.

For the purposes of the FGF scenarios we expect both electricity and gas prices to increase in all scenarios but not necessarily in the same time periods (the electricity price is a model outcome and the gas price an assumption). Consequently, there is no clear case for dominance of one fuel type and we do not make any further specific assumptions about this issue but it could be an avenue for future research.

Summary of major updated assumptions relative to 2013

From the discussion above we summarise the major changes to the scenario assumptions relative to 2013 as follows:

- A common point across all the assumptions is that in some cases they generalised across Australia and did not recognise state differences which can be substantial. While some of these differences are taken into account, some assumptions were nationwide. We have revised our approach to take account of state differences particularly in relation to ownership of advanced meters and current and future adoption of on-site generation, storage, other demand management and cost-reflective network and retail pricing which are all interdependent.
- There is mixed evidence both positive and negative for adjusting the expected future rate of adoption of cost reflective pricing at the retail level. There are significant differences in the starting points between states both in terms of current adoption of tariffs and the advanced meters they often require. Consequently different outcomes across scenarios remain plausible. The differences in technology adoption may be the best guide available to when consumers will select new tariffs.

- The adoption of onsite generation across the scenarios remains plausible but a stronger emphasis on solar, rather than small scale gas technologies, in the commercial sector is warranted.
- The cost of battery technology has improved faster than was anticipated in 2013. However the long term outlook for battery costs remains fairly unchanged. As a consequence we adjust adoption of stationary batteries in the period to 2025. We do not bring forward electric vehicle adoption as oil prices have dropped since late 2014. The rapidity with which battery storage appears to be arriving as a consumer offering is likely to crowd out other peak demand management opportunities which were less mature.
- The renewable energy target has been reduced in absolute terms, however the government's emission reduction ambition remains similar to previous government policies on this topic. This means the strength of any policy mechanism to achieve it should be fairly similar to previously assumed. However, the implementation will be delayed to 2020 and the form of policy mechanism that will be used to reach any given emission abatement target remains as uncertain as it was in 2013 or perhaps more so with a wider variety of mechanisms being considered. The Climate Change Authority is conducting a review specifically on this topic. The inclusion of an extended renewable energy target in *Renewables thrive*, is perhaps more plausible in the current context than it was in 2013.
- Forecasts assume that coal, gas, oil and petroleum product fuel prices will be lower in the next decade compared to the outlook in 2013.
- AEMO's 2015 consumption and peak demand projections are significantly lower than in 2013 and the distance between the low and high scenarios is more than twice as large by 2025.
- Analysis of the economy wide, rather than electricity sector only, greenhouse gas abatement options indicates that consumption of electricity could grow much faster than anticipated as zero emission intensive electricity is substituted for fuels such as gas and petroleum which remain emission intensive.

Which pathway are we currently tracking?

Australian solar panel adoption since 2013, and extending its path forward, is tracking at the high end of the range of on-site generation shares projected under the 2013 Future Grid Forum scenarios and modelling. In that respect the electricity system is tracking further away from *Set and forget* than the other scenarios on this point alone. On the other hand, the early improvement in the costs of battery storage, regulations which encourage more cost reflective network pricing and competition around deployment of metering services provide a number of enabling pieces of the puzzle that would be required to create a system that provides benefits to consumers without the need for solar panels to play the central role in addressing bill shock or for consumers to have to play an integral role in its day to day operation.

A number of other important scenario features such as electric vehicle uptake, climate policy and grid-disconnection may take a decade to play out and as such provide no early guide for tracking scenario progress. On cost reflective pricing, as we discuss in the section on tariffs and metering there has been both positive and negative developments in this space.

Overall, all the scenarios remain of generally similar plausibility.

Modelling methodology

The update of the Future Grid Forum scenarios was designed to take place in a compressed timeframe of July to October 2015 as a foundational activity for the Network Transformation Roadmap. Although there are many improvements that could be made to the modelling methodology, using the same modelling framework is part of the strategy to complete the work with the resources available and also maintains some consistency between the previous and updated modelling results.

A further concession to resources is that some parts of the previous modelling framework have not been included in the update. We have chosen not to model the augmentation of the transmission sector in detail (this was previously carried out by TNEP and 2-4-C), nor the half hourly dispatch in the generation sector (2-4-C). These two models, both being highly temporally and spatially detailed would not have been able to deliver results within our timeline (requiring multi-day solve times whereas the remaining models have within-day solve times).

Excluding these models obviously has some impact on the quality of the updated modelling results. However, the reason we have some comfort in excluding these results is:

- We previously found that the coarser electricity modelling in ESM projected the similar electricity prices to 2-4-C
- The technology mix projected by ESM was generally found to meet NEM reliability standards, only requiring small adjustments to peaking plant capacity
- With the exception of *Renewables thrive*, most scenarios did not result in any significant new transmission connections between NTNDP zones (augmentation within zones may also be relevant but we do not model at that level)

In the absence of new transmission augmentation modelling we apply the 2013 results in all cases where we require a transmission cost projection, but used the updated modelling of network utilisation to inform the overall trend in transmission costs.

The difference between the frameworks is illustrated in Figure 15. We do not repeat the descriptions of these models here in this document as that detail remains publicly available in Graham et al (2013).

In Stage 2 of the Roadmap we anticipate that we will be in a position to introduce some new capabilities into the modelling framework.

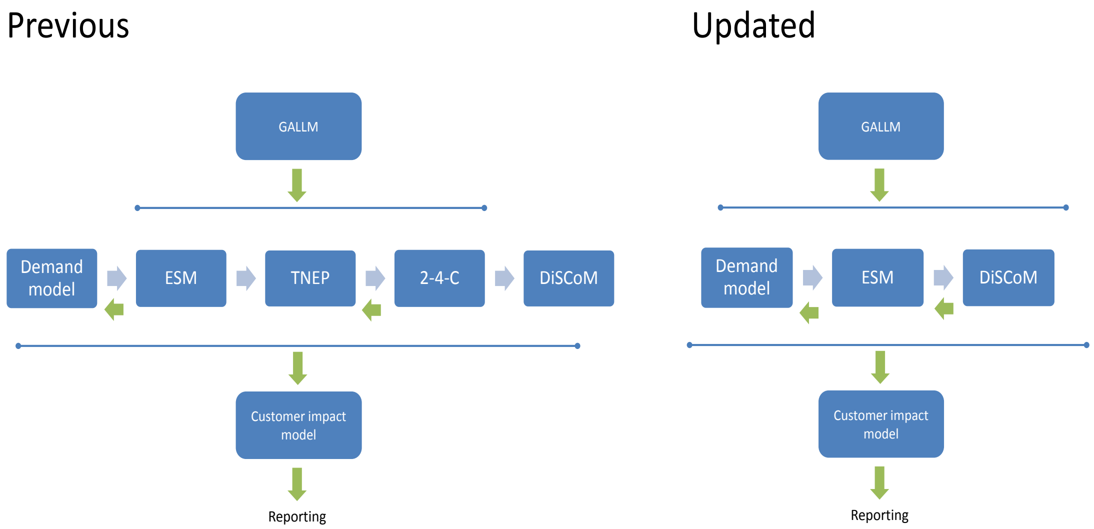


Figure 15: Modelling framework applied in the previous and updated scenario modelling

Scenario modelling results

To describe and discuss the modelling results we address each scenario in turn and then provide some cross scenario comparisons to illustrate the range of outcomes.

The results cover the whole value chain from generation down to the customer and are of course interdependent, particularly given the scenarios all include generation on-site with the customer. However, we generally commence each discussion of the scenario modelling results with the generation sector and work our way down the supply chain to conclude with customer bills.

Results for Scenario 1: Set and forget

Demand

Applying the assumptions outlined in this report, on the left axis, Figure 16 shows the projected level of NEM peak demand after the demand management measures have been applied. On the right axis Figure 16 shows the projected level of NEM electricity consumption after on-site generation has been subtracted from consumption, representing the amount that must be supplied by the grid.

It shows consumption and peak demand recovering from recent declines and growing throughout the period to 2050. While growth in grid-supplied consumption has been moderated by adoption of on-site generation (which we provide further detail about shortly), the demand management adoption has restrained growth in peak demand such that they are growing roughly in balance with each other. Peak demand growth is just slightly stronger in percentage terms except for in the 2030s where consumption growth is stronger due to a slowing of on-site generation adoption and growth in electric vehicle adoption.

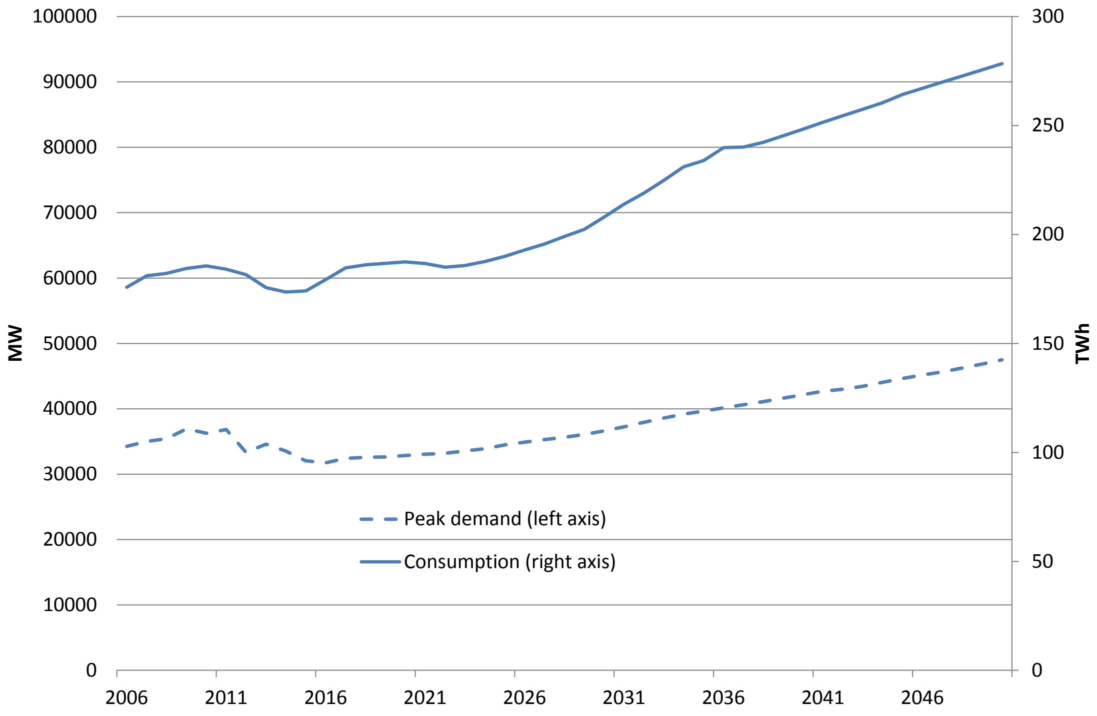


Figure 16: Projected NEM peak demand after demand management and consumption after on-site generation in Scenario 1

Generation

Figure 17 shows the projected centralised and on-site electricity generation technology mix to 2050. It shows that in the last five years to 2015, as electricity demand has declined and more renewables have been deployed, coal fired electricity generation has reduced its share. Although there is a slight recovery associated with the removal of the carbon price in 2014, further reduction in the coal share is expected as the Renewable Energy Target reaches its peak in 2020. Thereafter coal-fired power stabilises. The assumed introduction of a carbon constraint from 2020 has resulted in all new electricity generation capacity being derived from renewables or gas-based technologies, while coal plant is slowly retired by 2050 either economically, via the carbon price, or due to reaching the end of its asset life.

The dominant renewable technologies are wind and both roof-top and large scale solar panels. Biomass maintains its present size. In the gas technologies, gas peaking, gas combined cycle and gas with carbon capture and storage all play a role. As the carbon price continues to rise gas combined cycle with and without carbon capture and storage becomes the preferred gas baseload technology. Gas peak plant expands and plays an important role in supporting intermittent renewables. Note that we do not allow battery storage as an alternative, although recent studies suggest this may be competitive with peaking gas in the second half of the projection period (Brinsmead et al, 2015). ESM is not yet capable of endogenously selecting between these two options.

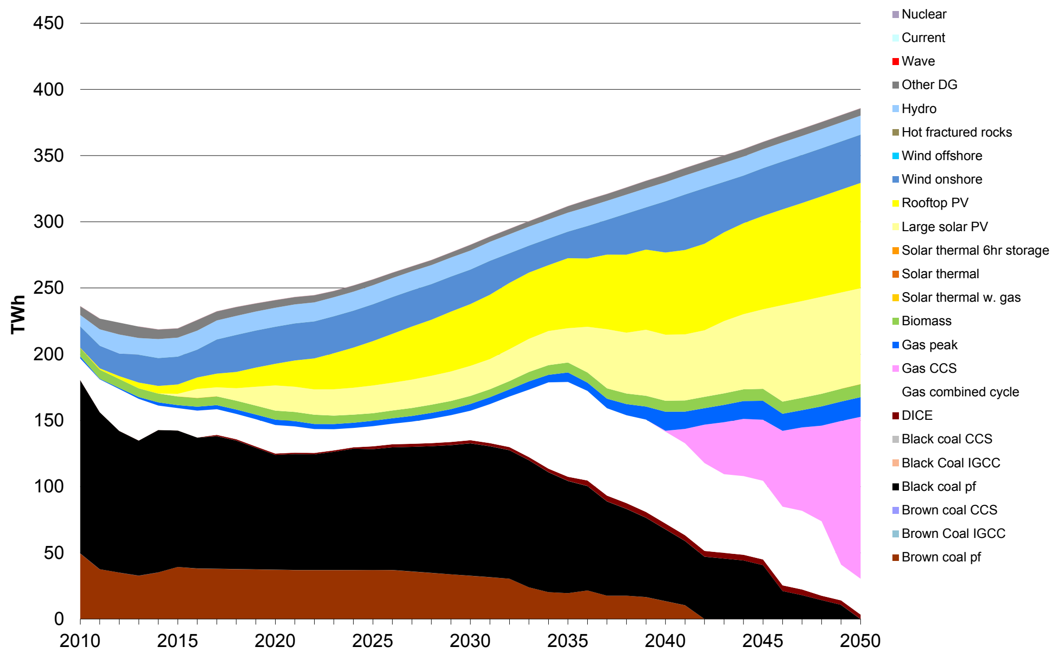


Figure 17: Projected centralised and on-site electricity generation technology mix in Scenario 1

Figure 18 provides more detail on the profile and technology mix of the on-site generation contribution to electricity supply. The projections show that while existing uses of land fill gas and biomass remain, most of the growth in on-site generation is in roof-top solar technology with gas co-tri generation the only other new technology which experiences slight growth. For solar panels, the greatest share is from the residential sector with smaller contributions from rural and commercial customers.

The slight slowdown in the deployment of on-site generation in the 2030s is driven by an adjustment in the centralised generation market. As a major proportion of existing coal fired generation is retired, it is replaced with gas combined cycle plant. While this replacement is occurring this limits the ability of on-site generation to grow at the rate it was prior to the 2030s. Of course this result assumes the retail and wholesale market price signals are well connected, which may not necessarily be the case in all scenarios but is consistent with this scenario.

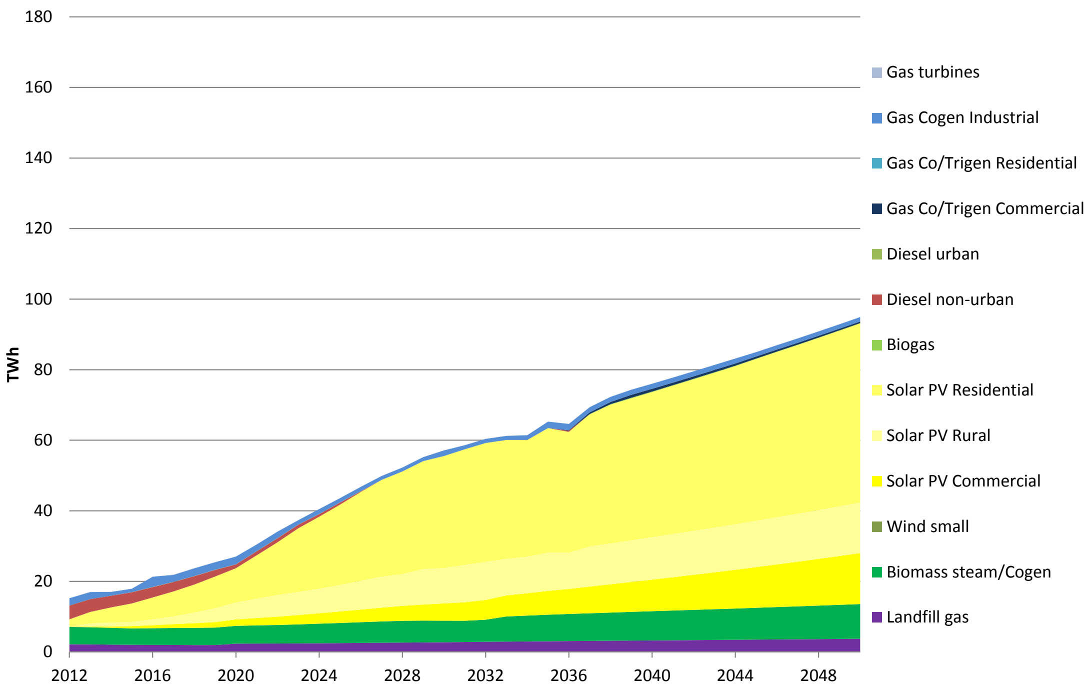


Figure 18: Projected on-site electricity generation technology mix in Scenario 1

The projected average wholesale electricity unit-costs are shown in Figure 19. This represents the long run marginal cost of supplying generation using the selected least cost electricity generation mix. As such it largely reflects the cost assumptions of the technologies plus the costs of the carbon constraint, for those technologies with emissions. Average national wholesale unit electricity costs increase to 2020 reflecting the introduction of the carbon constraint. National generation costs then move steadily higher as the carbon constraint tightens. There is an acceleration in the cost trajectory in the early 2030s and late 2040s reflecting that these are periods of significant investment in technologies to replace retiring coal capacity with new baseload technologies. By 2050 national average costs have reached around $148/MWh.

While wholesale unit electricity costs increase in Scenario 1 as a result of the carbon constraint, the constraint does deliver substantially reduced greenhouse gas emissions (Figure 20). By 2050, greenhouse gas emissions have reduced to 28 $MtCO_2e$ or 14 percent of their 2010 levels, an 86 percent reduction.

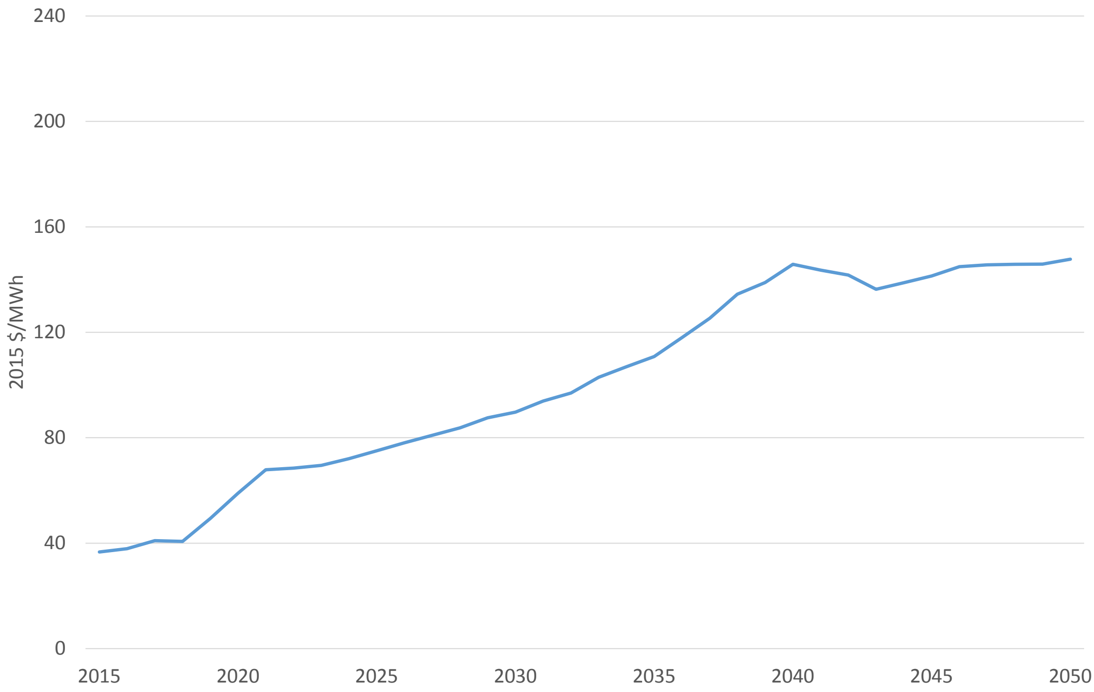


Figure 19: Projected wholesale electricity unit costs, in Scenario 1

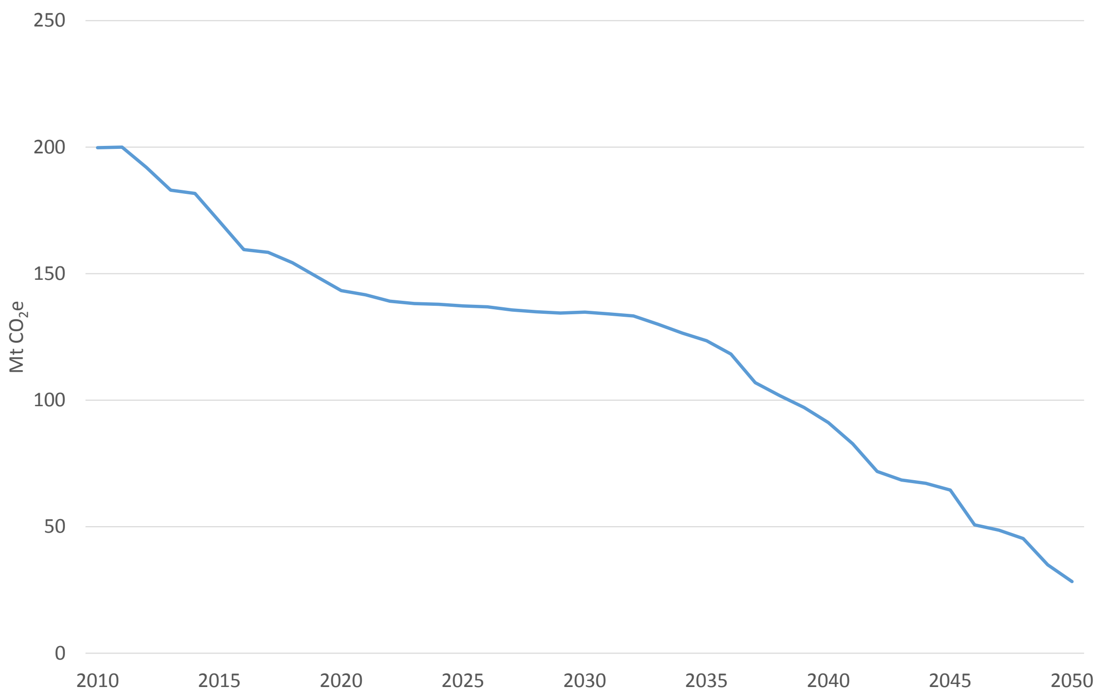


Figure 20: Projected electricity sector greenhouse gas emissions in Scenario 1

Distribution and transmission

Ideally we would apply a detailed geographical approach to determine how the utilisation of each part of the grid is impacted by changes in electricity loads. However, for simplicity, and consistent with the 2013 Future Grid Forum analysis, we have calculated an aggregate measure to indicate how the combination of electricity pricing structure and technologies is likely to impact the utilisation of the grid. By calculating the ratio of the projected volume to be carried through the grid, with its carrying capacity that will be built to meet projected peak demand, we project the implied aggregate utilisation of the grid, shown in Figure 21. It indicates that the more limited growth in on-site generation and strong demand management in Scenario 1 could result in an improvement in utilisation in the short term and some decline afterwards such that the net results by 2050 is maintaining the grid at slightly below its current utilisation.

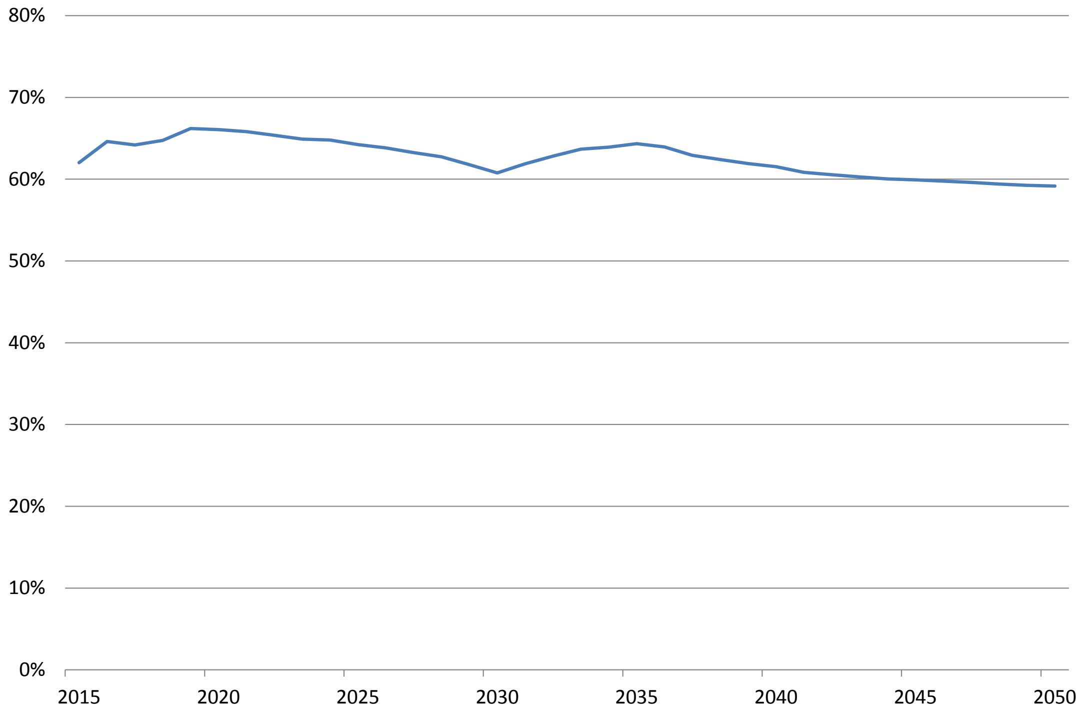


Figure 21: Implied aggregate utilisation of the grid in Scenario 1

To show how this outcome for network utilisation impacts customers we have calculated the projected average residential network costs in Figure 22. The projected outcome is largely the inverse of the grid utilisation projection, although we make some adjustments for the incomplete correlation between distribution level and state level demand conditions and assumed transmission network augmentation from 2013 modelling results. The projected network unit costs indicate that under Scenario 1, the contribution of distribution to residential retail electricity prices will experience some very moderately decreasing and increasing periods and be roughly constant relative to 2015 by 2050. Transmission costs will be flatter still.

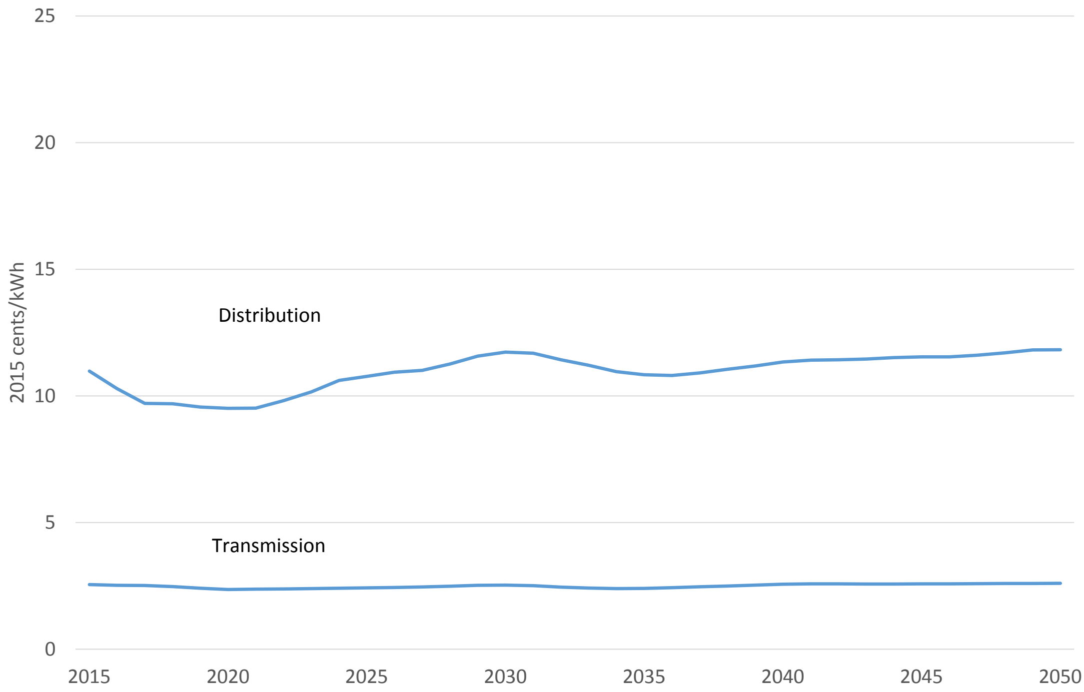


Figure 22: Projected average residential network costs in Scenario 1

Retail

It is our view that volume retail prices are not a good indicator of customer outcomes because customer bills are impacted by the choice of tariff types, technologies installed and many other household specific factors. However, for the purposes of summing up the impacts of the generation, distribution and transmission price impacts discussed so far we present the projected average and state volume based retail price in Figure 23.

As well as adding together the generation, distribution and transmission costs discussed it also includes assumed values for the retail margin, but this component is relatively constant and does not significantly impact the trend.

Reflecting the changes in distribution and generation costs, apart from the next five years, there is a projected increase in average residential retail prices. In this scenario, given distribution costs are fairly stable, the increase in retail prices almost entirely reflects the increase in generation costs, that is, the cost of reducing greenhouse gas emissions.

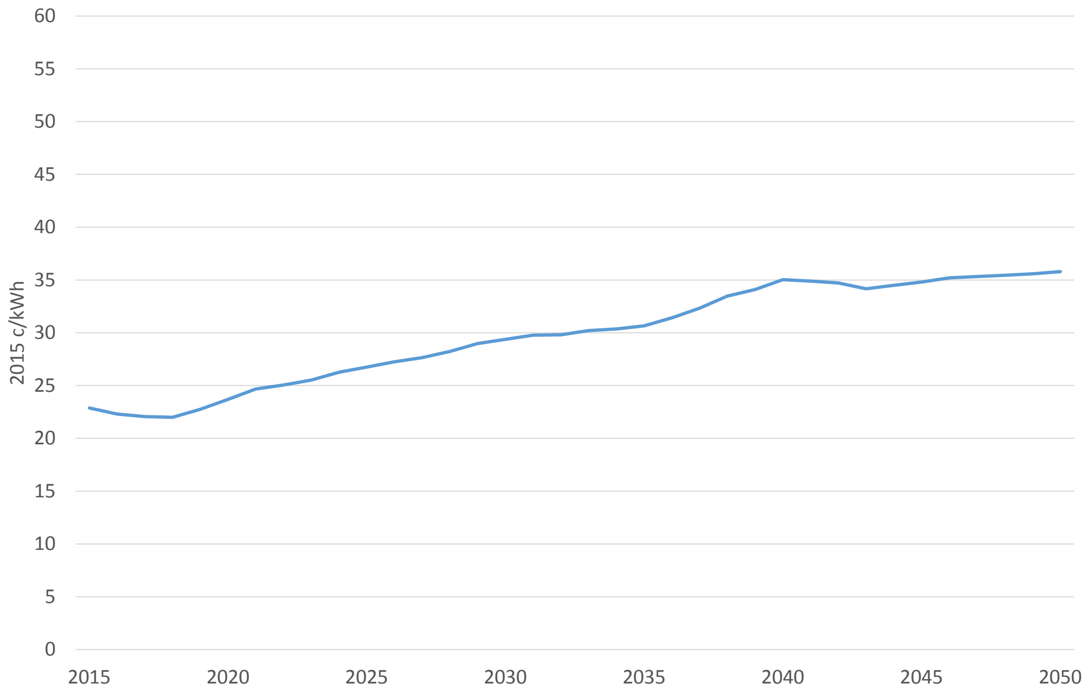


Figure 23: Projected average volume based residential retail price in Scenario 1

Results for Scenario 2: Rise of the prosumer

Demand

The *Rise of the prosumer* scenario has the highest uptake of on-site generation reflecting a largely volume based pricing structure for small customers, which is ideal for receiving value from rooftop solar, and the social attitude bias of the scenario which is towards a more engaged, interested and active customer that wants to take up new opportunities. They do not take up on-site generation exclusively but also adopt demand management technologies, but not to the same extent as other scenarios.

Figure 24 shows the outcome for NEM peak demand after demand management, and consumption after on-site generation. While total consumption is rising, the growth in consumption supplied by the grid is declining due to on-site generation meeting a major part of underlying consumption growth over time, particularly before 2030. As on-site generation saturates, underlying demand growth leads to a recovery in grid consumption during the 2030s and 2040s. On the other hand, peak demand growth has been slowed by modest demand management but remains in a steady upward trend. As a consequence, the ratio of peak demand growth to consumption growth is projected to be increasing throughout most of the early and middle part of the projection period in Scenario 2.

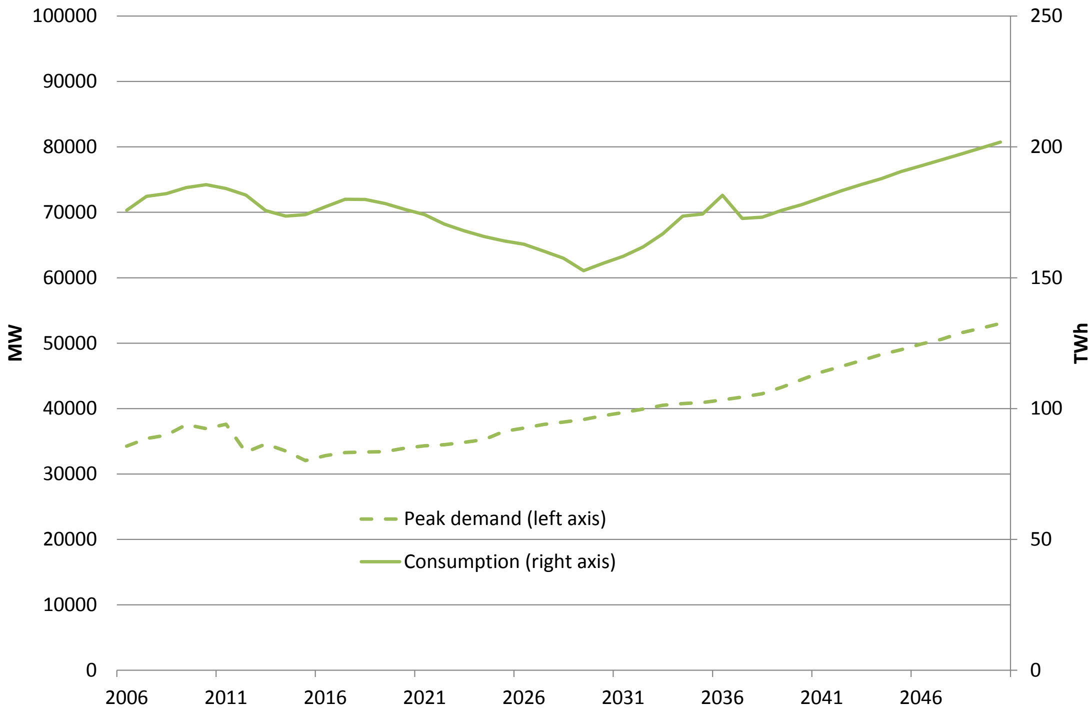


Figure 24: Projected NEM peak demand after demand management and consumption after on-site generation in Scenario 2

Generation

Figure 25 shows the projected technology mix of centralised and on-site generation for Scenario 2 and further detail on the breakdown of on-site generation is shown in Figure 26. The first decade shows much the same outcome as Scenario 1 with coal generation losing market share to renewables and gas due to the influence of the renewable energy target and the carbon price that was in place 2012 to 2014. However, unlike Scenario 1 where coal-fired generation stabilised after the Renewable Energy Target peaked in 2020, in Scenario 2 conventional coal-fired power generation continues its decline throughout the projection period. This is because on-site generation in the form of roof-top solar is much higher in Scenario 2 reducing the volume of grid supplied electricity required. Weak demand for grid-supplied electricity plus the assumed carbon constraint mean that existing fossil generation is economically retired faster than under Scenario 1.

The greater share of renewables has meant that the use of gas combined cycle with and without carbon capture and storage in Scenario 2 is significantly reduced in volume and slightly delayed in timing relative to Scenario 1.

In regards to on-site generation (Figure 26), while the level of roof-top solar adoption is high in Scenario 2, it also includes significant uptake of commercial gas co/tri-generation, particularly from the late 2020s. Compared to Scenario 1, the commercial share of roof-top solar is higher indicating that this market is activated to a greater extent. This is not surprising since the residential opportunities are fairly saturated already in Scenario 2 so this becomes the next viable opportunity for rooftop solar.

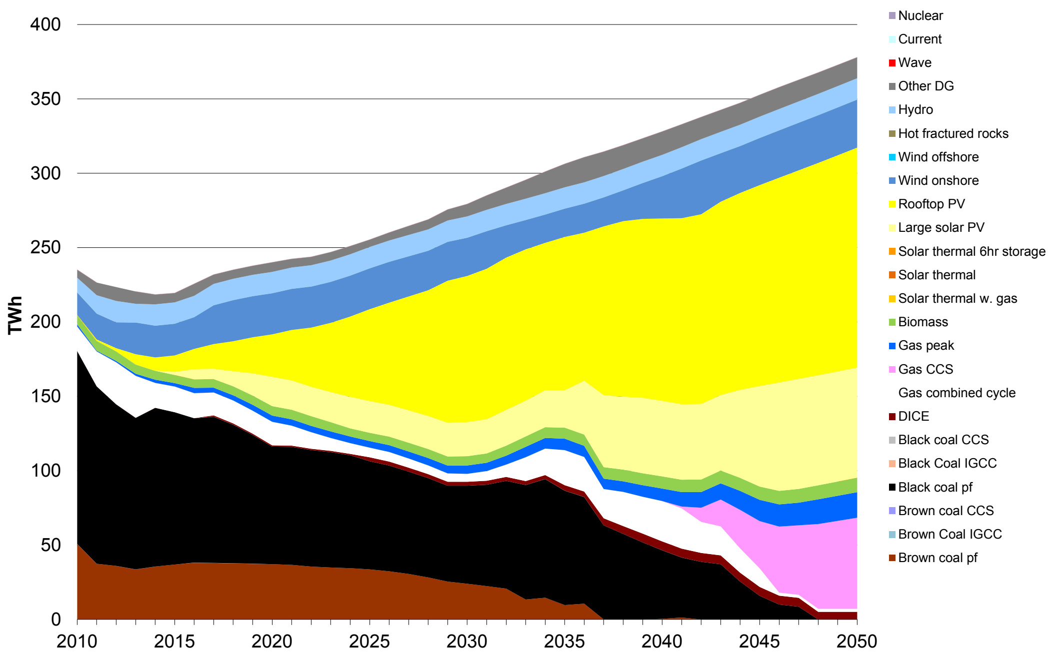


Figure 25: Projected centralised and on-site electricity generation technology mix in Scenario 2

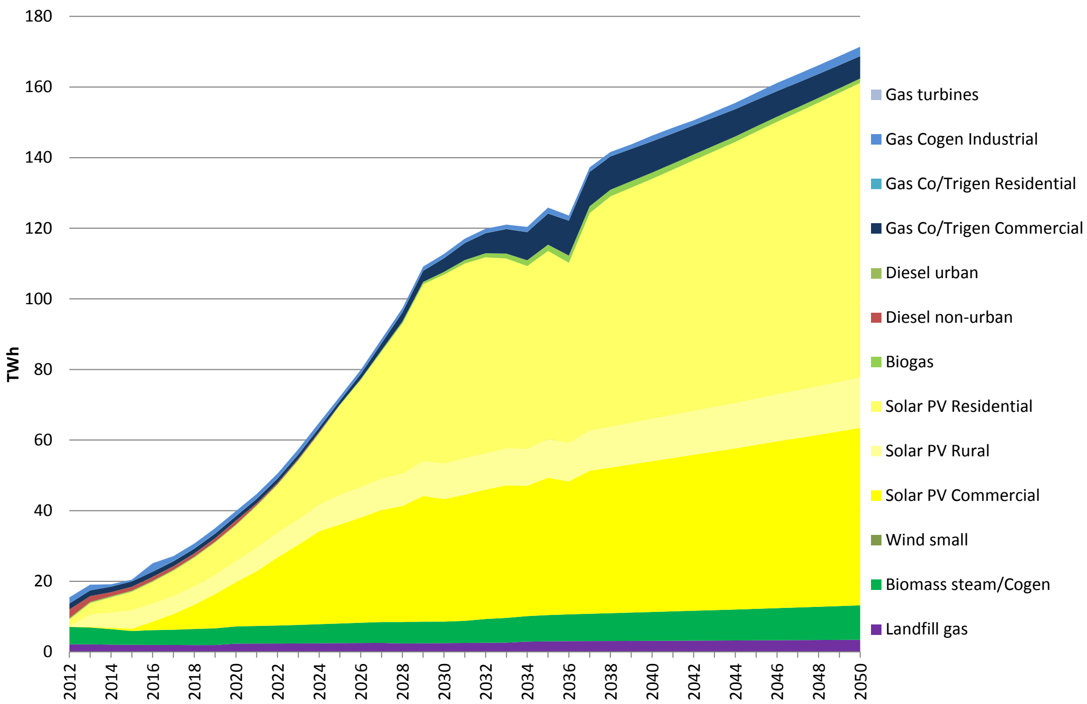


Figure 26: Projected on-site electricity generation technology mix in Scenario 2

The assumed carbon constraint (implemented in the form of a carbon price as a proxy for a wide range of policies), from 2020, leads to generation cost increases as existing fossil fuel technologies are imposed with additional costs which assist in allowing low emission technologies to compete with the existing stock of generating capacity. The rate of increase in costs at a national average and state level is shown in Figure 27 and is fairly steady through the period 2020 to 2030. There is an acceleration of cost increases in the 2030s as conventional coal plant retires and there is a greater rate of investment in low emission technologies. By 2050 the cost is $146/MWh, the same as Scenario 1, recognising they face the same carbon price with a similar technology mix. Gas with carbon capture and storage appears to be the marginal technology as its costs increase with the carbon price (while not so for renewables) and this is reflected in the projected electricity price.

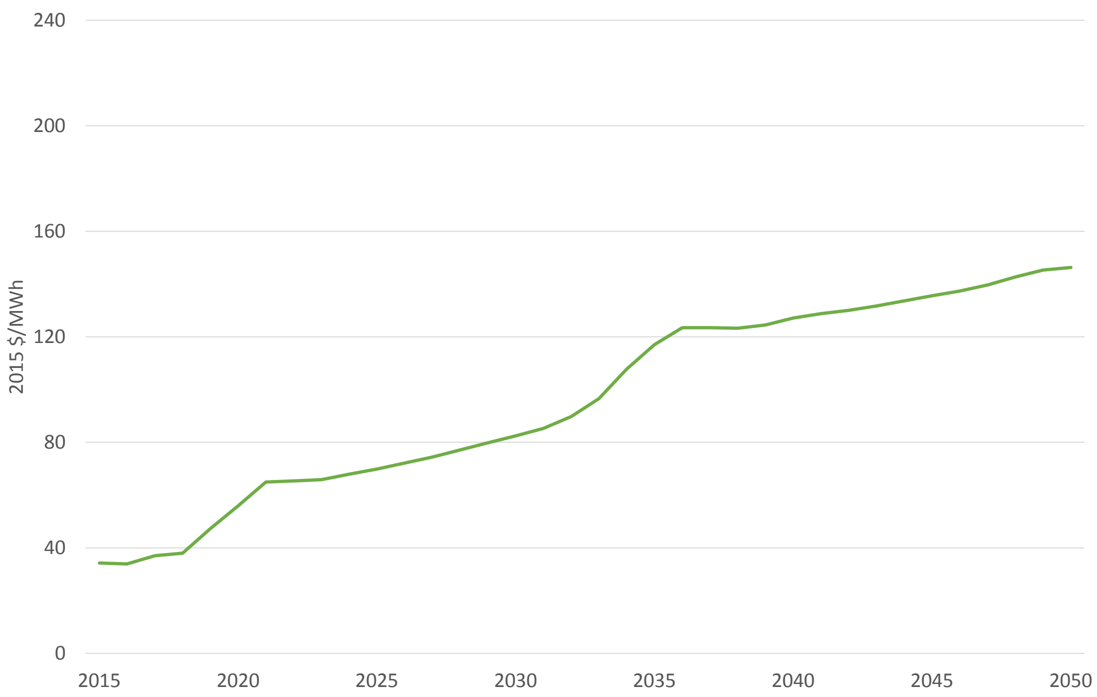


Figure 27: Projected wholesale electricity unit costs in Scenario 2

While the carbon constraint causes generation costs to increase, greenhouse gas emissions are projected to steadily decline to 2050 as a result. Figure 28 shows that greenhouse gas emissions decrease to 18 $MtCO_2e$, representing an almost 91 percent decline relative to 2010. Compared to Scenario 1 it appears that the higher share of roof-top solar panels has led to lower emissions for the electricity sector, by crowding out gas technologies.

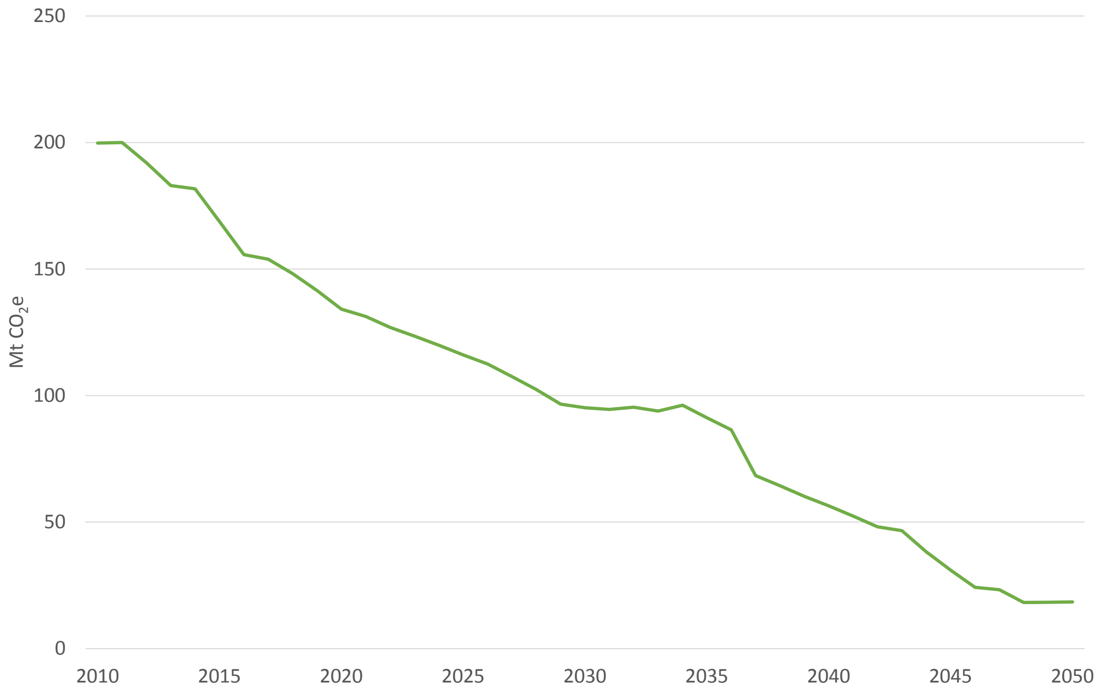


Figure 28: Projected electricity sector greenhouse gas emissions in Scenario 2

Distribution and transmission

We observed in our discussion of demand for Scenario 2 that peak demand was projected to grow faster than consumption owing to the greater adoption of on-site generation outstripping the adoption of demand management opportunities. The logical consequence of this outcome is that the implied aggregate utilisation of the grid will be declining. This is shown in Figure 29. In the case of Scenario 2 the change in utilisation is significant, starting at 62 percent at present, improving modestly in the next five years as volume growth is assumed to resume, declining steadily to 2030 and then improving again as on-site generation increases to 2035, but declining thereafter to approximately 40 percent by the mid- 2040s.

Taking into account that the state grid and distribution level utilisation rate will differ we use the information on utilisation to project changes in distribution costs for residential customers per kWh. Figure 30 shows the projected pathway for national average residential network volumetric prices under Scenario 2. The trajectory is largely the inverse of the utilisation projection. The most significant increases in network prices are in the early 2020s and again in the late 2030s. The trend flattens in the 2040s as utilisation stabilises. The transmission costs follow the same trend as the distribution sector but the changes are of a lower absolute level owing to the smaller scale of transmission costs.

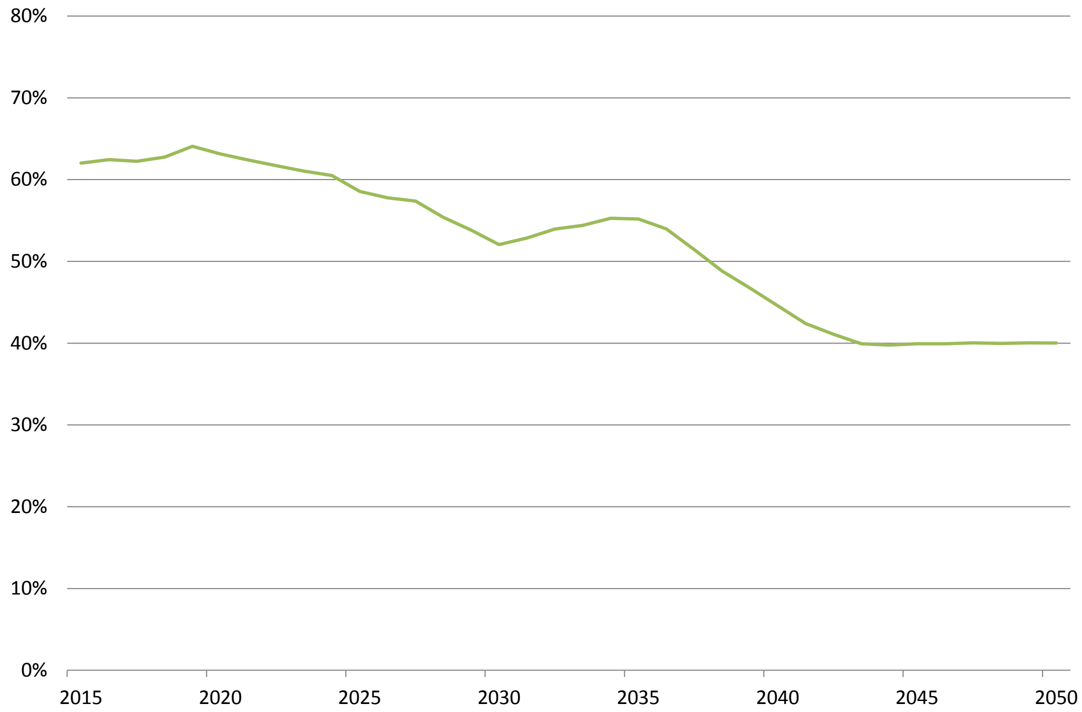


Figure 29: Implied aggregate utilisation of the grid in Scenario 2

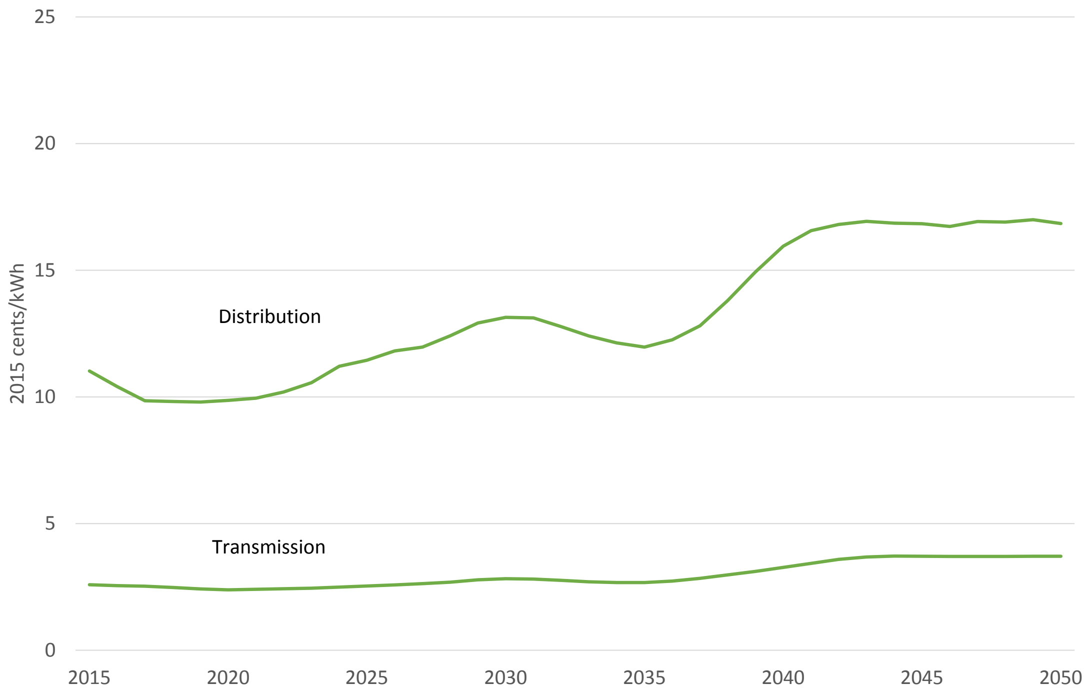


Figure 30: Projected average residential network costs in Scenario 2

Retail

Although the national average volume based retail price is a poor indictor of customer impact because changes in demand, technology ownership and tariff type also impact a customer's bill, we present the projection in Figure 31 in order to sum up the changes in generation, transmission and distribution costs discussed above. A retail margin has been assumed. The projection indicates a fairly smooth profile of increase in average residential volume based retail prices. The smoothness of the profile reflects that the generation and network cost profiles tend to fill in the gaps of the other. That is, when demand is growing weakly, the rate of growth in distribution and transmission costs tend to be higher (because of lower utilisation) while the rate of growth in generation costs tend to be lower (due to excess supply capacity) and vice versa. Reflecting the increase in generation costs due to greenhouse gas abatement action and the increase in distribution costs due to declining network utilisation, average volume based residential retail electricity prices increase 84 percent between 2015 and 2050.

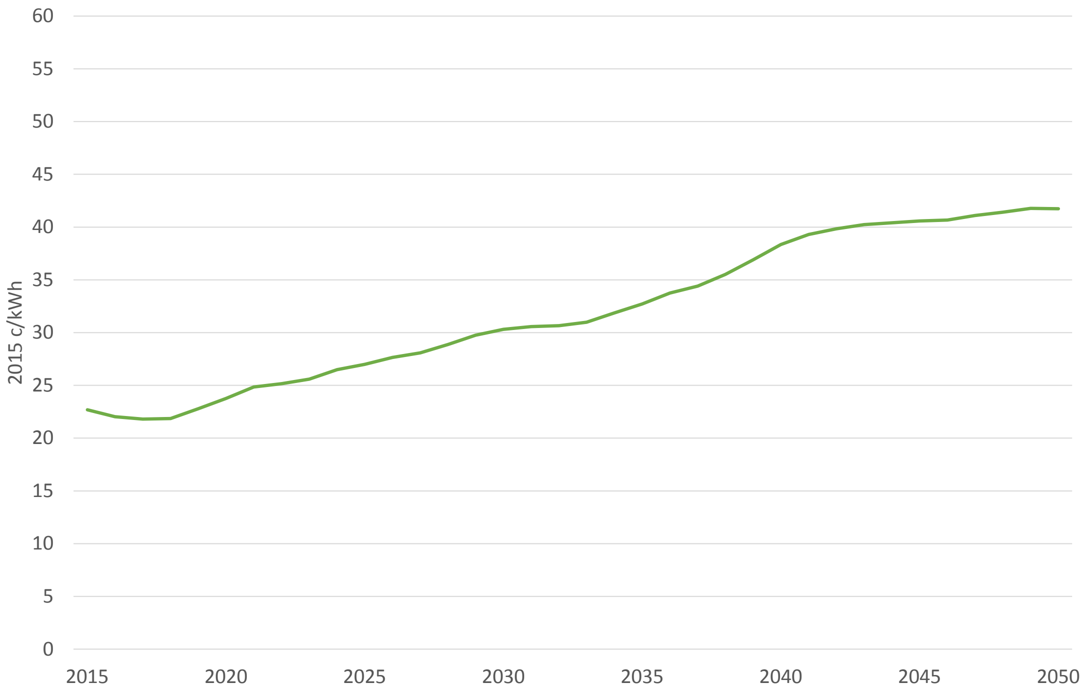


Figure 31: Projected average residential retail costs in Scenario 2

Results for Scenario 3: Leaving the grid

Demand

The *Leaving the grid* scenario assumes minor customer disconnection (meaning completely cutting physical connection to the grid) prior to 2035 and accelerated disconnection after 2035 consistent with economic analysis which finds it may be economic to do so beyond that point (see Appendix A).

When customers leave they take their full load from the grid reducing both consumption and peak demand. While somewhat counterintuitive this can, at an aggregate level, result in a better ratio of consumption to peak demand than if the customers had stayed connected, assuming if they remain connected many customers would still adopt on-site generation. Figure 32 shows that peak demand is rising faster than consumption through the middle part of the projection period but as customers disconnect, peak demand growth halts while consumption continues to grow.

At a disaggregate level this improvement in the ratio of consumption to peak demand may not hold true as how the load changes in each part of the network depends on the spatial distribution of customers. We might expect disconnection, if it were to occur, to be most attractive first for new connections, followed by rural customers who may be located on a higher cost network and work its way in from the fringe toward strong (dense), lower cost suburban and urban grids where incentives to disconnect would be weaker. However, there are no guarantees that disconnection would proceed in a way that reflects the relative strength and cost of the grid alternative given the price of grid supplied electricity services is just one input to customer decision making. Consequently, if disconnection occurs in a less ideal, spatially random fashion, then this scenario's assumptions will understate the extent of capacity that the grid will need to maintain to meet peak demand.

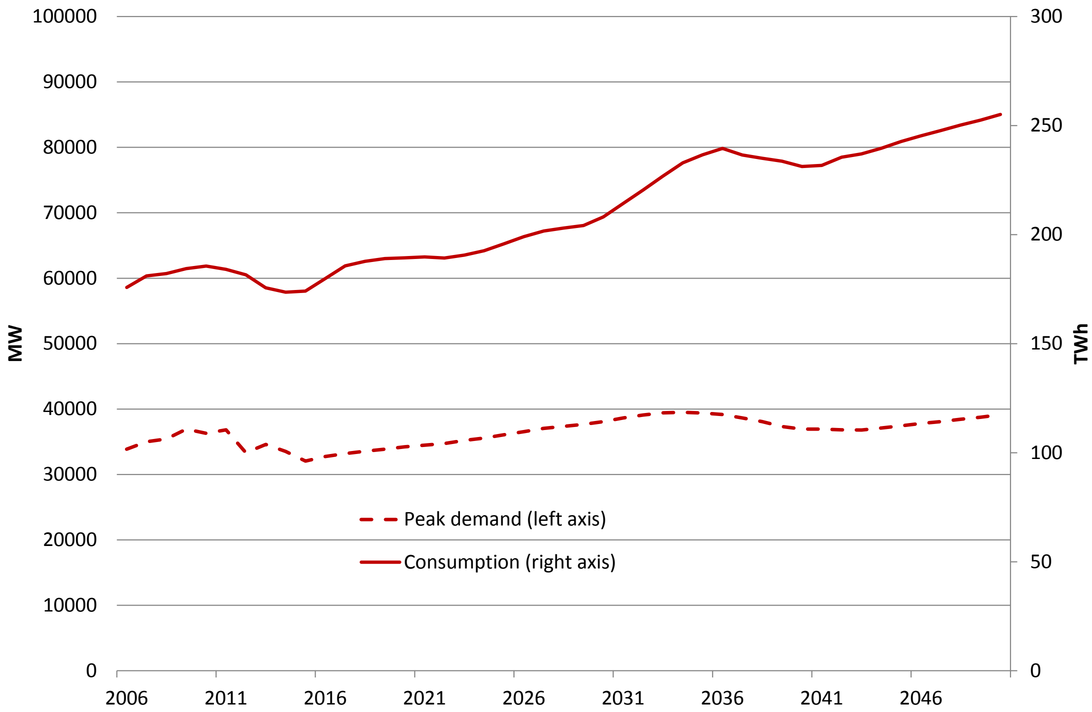


Figure 32: Projected NEM peak demand after demand management and consumption after on-site generation in Scenario 3

Generation

The projected electricity generation mix for Scenario 3 is shown in Figure 33 with further detail on the on-site generation mix shown in Figure 34. The trend in the electricity generation mix is most similar to Scenario 1 up to 2030 with declining and then stabilising coal fired generation and most growth being met by renewables. However, from the 2030s we begin to see some disconnection from the grid and and acceleration of this behaviour from 2035 consistent with the scenario assumptions. This significantly reduces the amount of generation which must be supplied by the grid at a time when much coal-fired egernation is due for retirement anyway. As a consqeuence, as the coal fired generation is retired, new generation is largely met by wind, solar photovotlaic panels and gas combined cycle with and without carbon capture and storage.

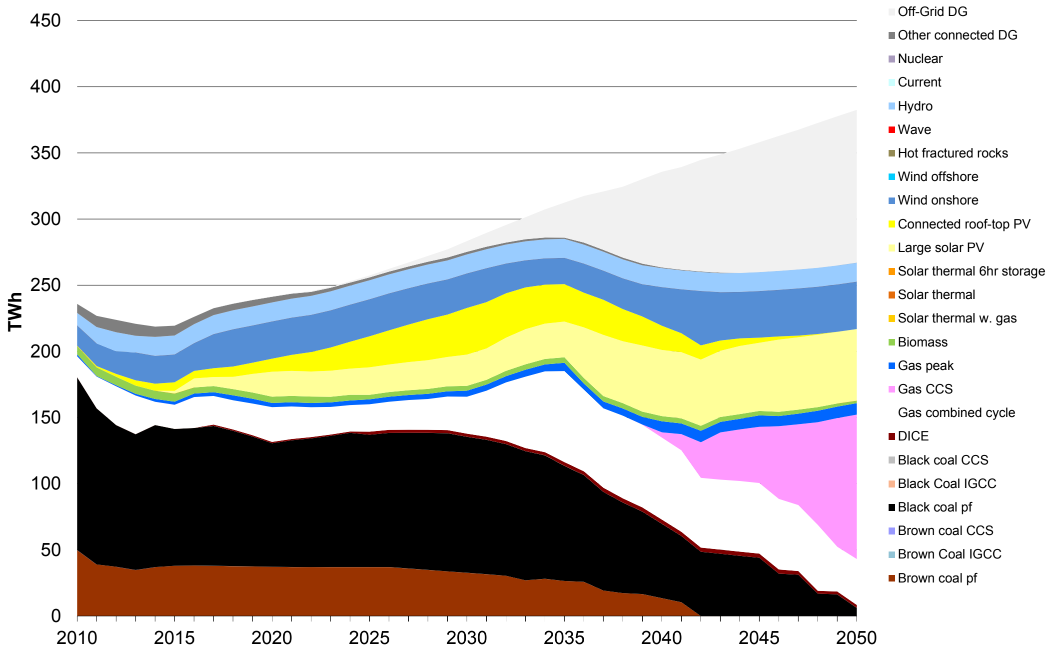


Figure 33: Projected centralised and on-site electricity generation technology mix in Scenario 3

The dominant form of on-site generation chosen by customers is solar panels. In this case, although not shown, for disconnected customers the panels are augmented with battery storage and some form of small generator for further back-up. We provide details of this assumed system in Appendix A. It is by no means the only system that could be used to disconnect for an individual and while not specifically modelled at this stage we acknowledge that individuals may group together in communities also to achieve disconnection with some economies of scale and community support.

Figure 34 shows that, up to the 2030s there is modest growth in connected on-site generation. However, this declines steadily down to a negligible amount as disconnection becomes economically viable and these systems are taken off the grid. This is a scenario assumption rather than modelled outcome. However it is consistent with the economic analysis in Appendix A. In reality non-economic factors and the responses of various players in the electricity system would also play a role in determining this outcome.

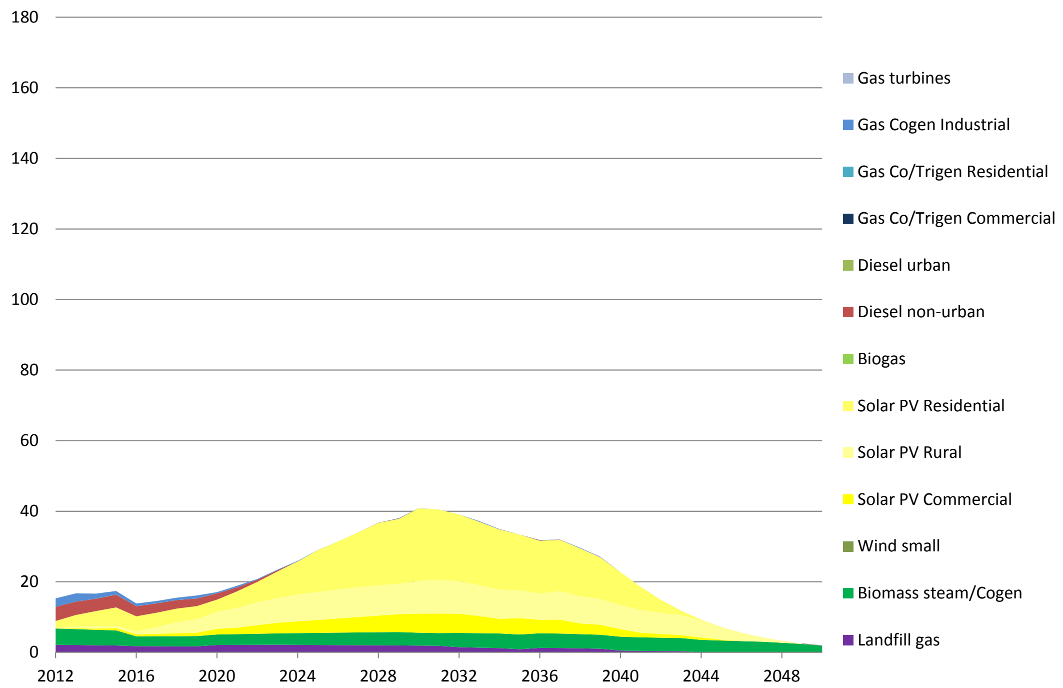


Figure 34: Projected connected on-site electricity generation technology mix in Scenario 3

The cost of generation increases largely as a result of the assumed carbon constraint, implemented as a carbon price to proxy possible future policies, which is imposed from 2020. Costs increase steadily throughout the projection period with the exception of some volatility in the 2030s during the period when coal fired plant are retiring and significant new plant are being deployed to replace them (Figure 35). By 2050 the national average cost of electricity is $146/MWh.

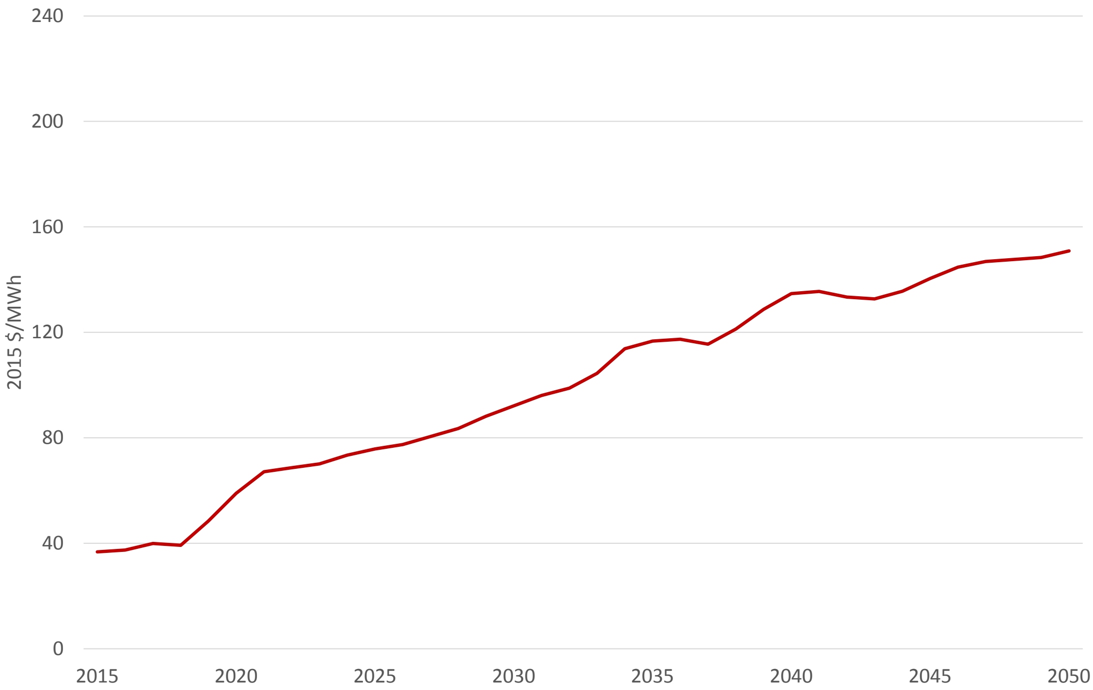


Figure 35: Projected wholesale electricity unit costs in Scenario 3

While responsible for increasing generation costs, the carbon constraint is successful in reducing greenhouse gas emissions. As shown in Figure 36, greenhouse gas emissions decline to 34 $MtCO_2e$ by 2050, with the decline accelerating in the period after 2035 reflecting declining grid connected demand and both the economic and natural life retirement of existing coal-fired generation stock during this period. Scenario 3 has achieved a slightly higher greenhouse gas emissions level compared to Scenario 1 or 2. This appears to be because it has a higher level of gas based generation.

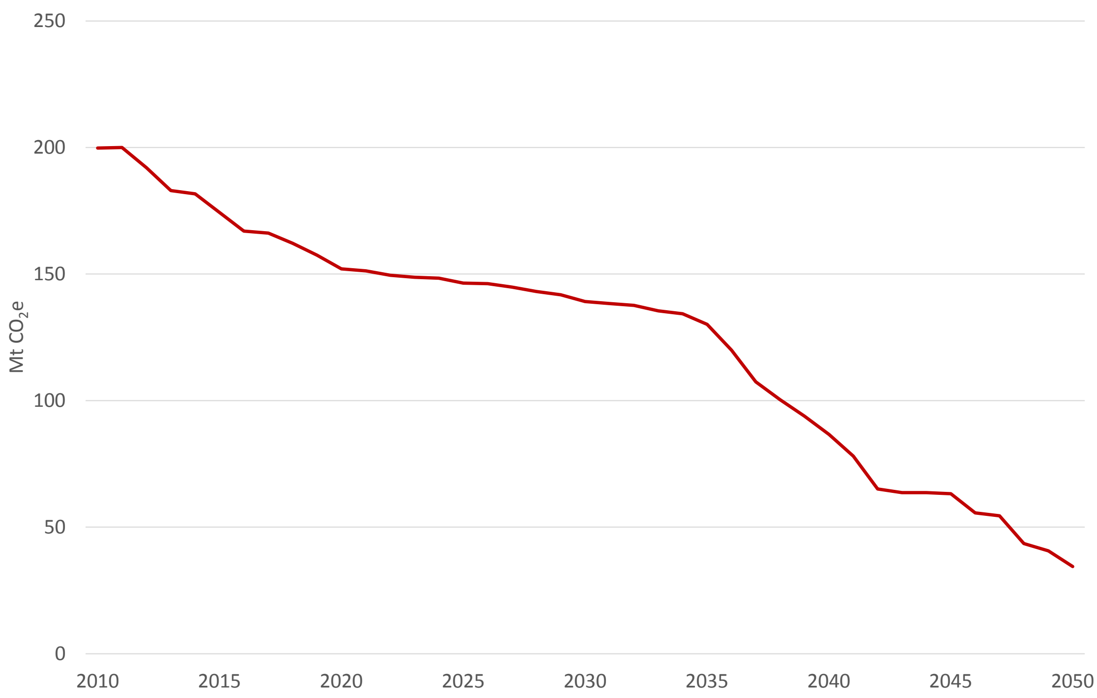


Figure 36: Projected electricity sector greenhouse gas emissions in Scenario 3

Distribution and transmission

The projections for peak demand and consumption under Scenario 3 showed that the consumption to peak demand ratio was declining in the first half of the projection period and then stabilising and improving in the last decade and a half. This relationship between peak demand and consumption can also be expressed as an implied aggregate grid utilisation factor which we show in Figure 37. It shows utilisation falling from just above 60 percent at present to around 50 percent by 2050.

A declining utilisation factor means that distribution and transmission network costs, per volume of consumption, increase. We demonstrate this in Figure 38 where the network component of the residential retail price is projected to 2050. It shows that under the projected decline in network utilisation, distribution prices to residential customers would be expected to increase to just over 14c/kWh and transmission to 3c/kWh.

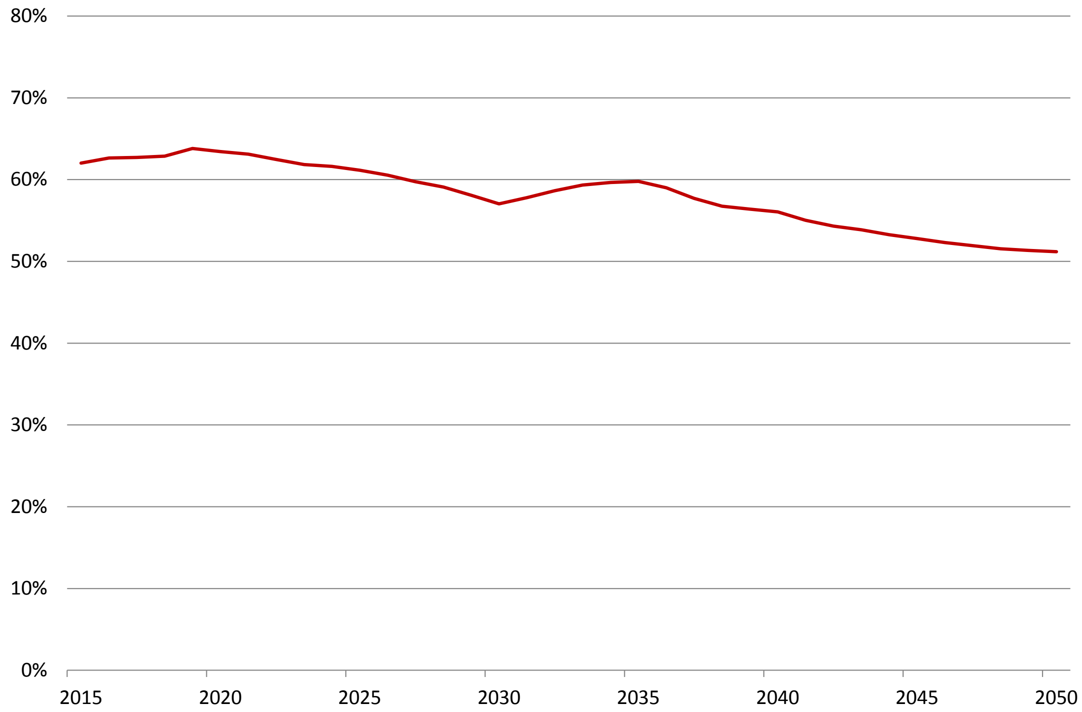


Figure 37: Implied aggregate utilisation of the grid in Scenario 3

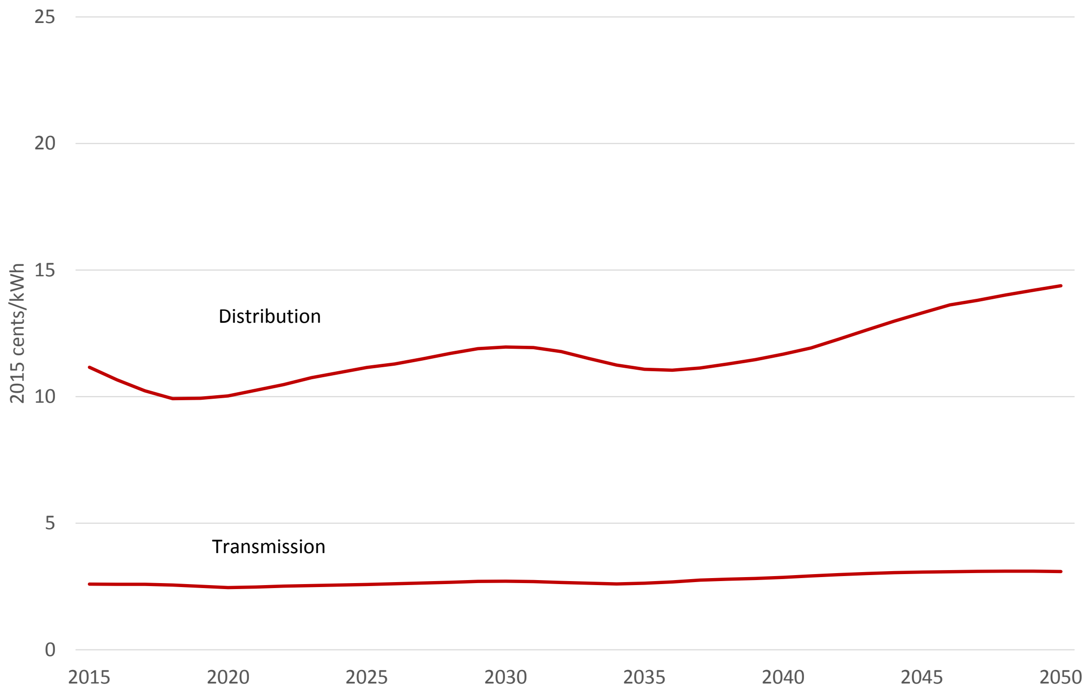


Figure 38: Projected average residential network costs in Scenario 3

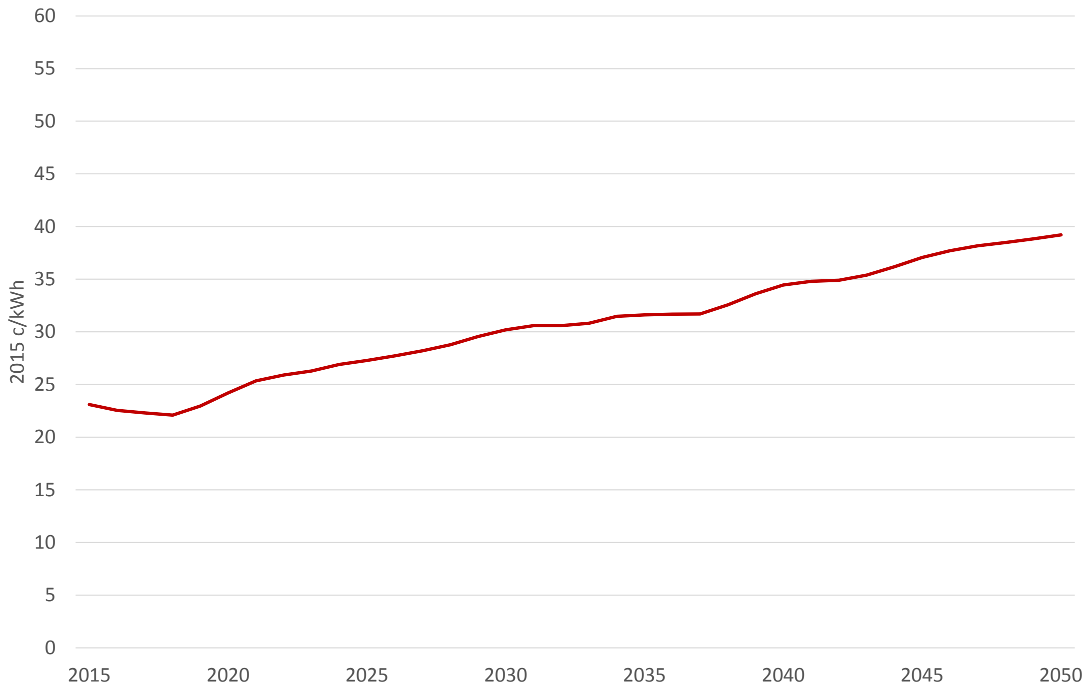


Figure 39: Projected average residential retail price in Scenario 4

Results for Scenario 4: Renewables thrive

Demand

Renewables thrive has the highest total electricity consumption by design as we assumed higher adoption of electric vehicles to reflect the greater adoption of battery storage overall and lower battery storage costs (which would be reflected in electric vehicle prices). Figure 40 shows projected NEM electricity consumption for Scenario 4 after on-site generation has been subtracted to show the amount that needs to be supplied by the grid. It indicates a stable level of consumption up to 2025 and moderate growth for the remainder of the period to 2050. This indicates that as electric vehicle adoption accelerates from 2025, this assists in offsetting the negative impact of growth in on-site generation on grid-supplied consumption.

Figure 40 also shows the projected level of NEM peak demand after the impact of demand management. Although there is significant demand management in this scenario which has reduced peak demand growth, the projection indicates that peak demand grows steadily throughout the projection period, recovering from the recent reductions since 2010.

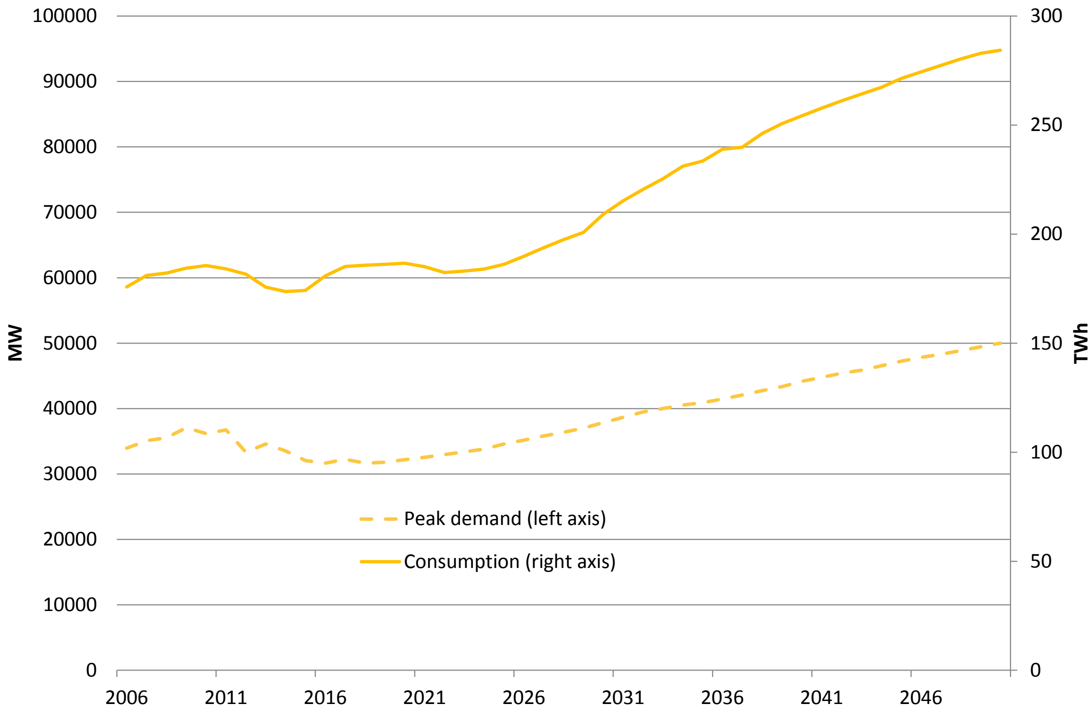


Figure 40: Projected NEM peak demand after demand management and consumption after on-site generation in Scenario 4

Generation

Renewables thrive includes an extended Renewable Energy Target which requires all centralised electricity generation to be from renewables (i.e. a 100% target) by 2050. To support achieving this goal, and consistent with the scenario narrative, we assume battery storage is deployed to support intermittent renewables. The projected centralised and on-site generation technology mix under these assumptions is shown in Figure 41. The uptake of renewables commences with roof-top and large scale solar panels and wind which expand fairly steadily up to around 2040. From around 2035 we see some emerging technologies in wave, advanced geothermal and offshore wind join the technology mix which halts the growth of onshore wind but less so solar photovoltaics. Given the emerging nature of these technologies their selection in the modelling should not be regarded as a guarantee that they would contribute under such as scenario. Wave and geothermal are yet to be demonstrated at large scale. Additional wind and solar photovoltaics or other technologies such as solar thermal could take their place if they prove unsuccessful.

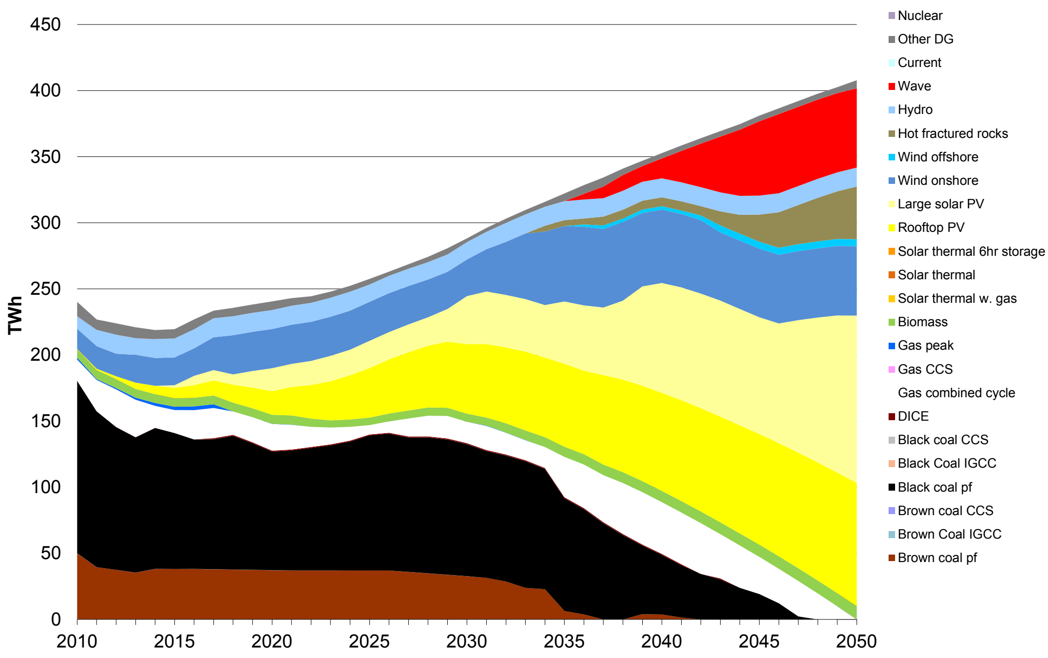


Figure 41: Projected centralised and on-site electricity generation technology mix in Scenario 4

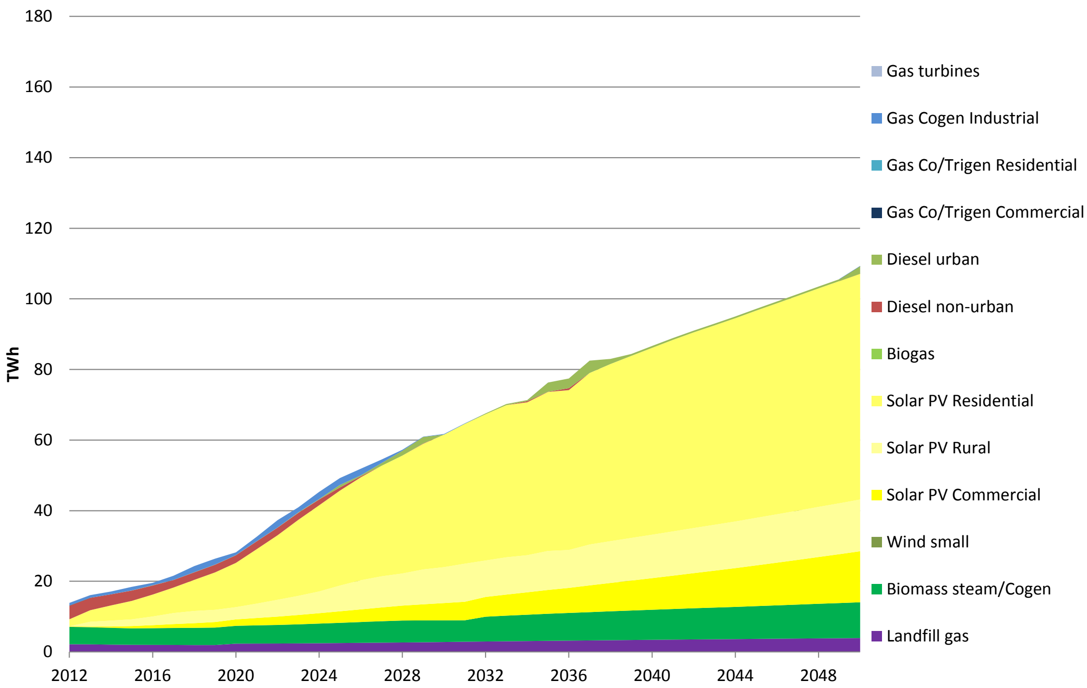


Figure 42: Projected on-site electricity generation technology mix in Scenario 4

Figure 42 provides more detail on the breakdown of on-site generation technologies. Under the design of the scenario we only allow some diesel generation to persist on the basis it may be required for some circumstances where solar and battery technology is not appropriate, but gas is disallowed. Biomass and solar dominate on-site generation in any case as we have seen in Scenarios 1 to 3 and so even with some fossil on-site generation remaining, overall the electricity system is very near to 100 percent renewable.

Up until 2035, the main driver of cost increases in the generation sector is the carbon price which is the same as all scenarios although, obviously by 2050 it has no impact on the centralised generation since there are no carbon emitting technologies in the technology mix by that date. The projected generation costs are shown in Figure 43 and increases steadily to 2035. From 2035 the extended Renewable Energy Target is the main cost driver and perhaps surprisingly its immediate impact is to reduce generation costs. However, this just reflects the market response to any mechanisms that force in capacity. That is, new capacity tends to weaken the market demand-supply balance towards excess supply and weaker prices. However, this is just a short term dynamic and within a few years the generation cost is rising.

The projected generation cost in 2050 is $188/MWh which is significantly above the long run cost of the best renewable sites, even taking into account storage costs, and reflects the assumption that renewable resources will become more expensive as the volumes that are required increase. The quality of renewable resources deployed declines as the best locations are used first.

The outcome for greenhouse gas emissions is shown in Figure 44 and it shows that emissions reduce to near zero as expected under the scenario with just a small amount of fossil generation remaining in the on-site generation sector. Overall emissions are 98.7 percent below 2010 levels.

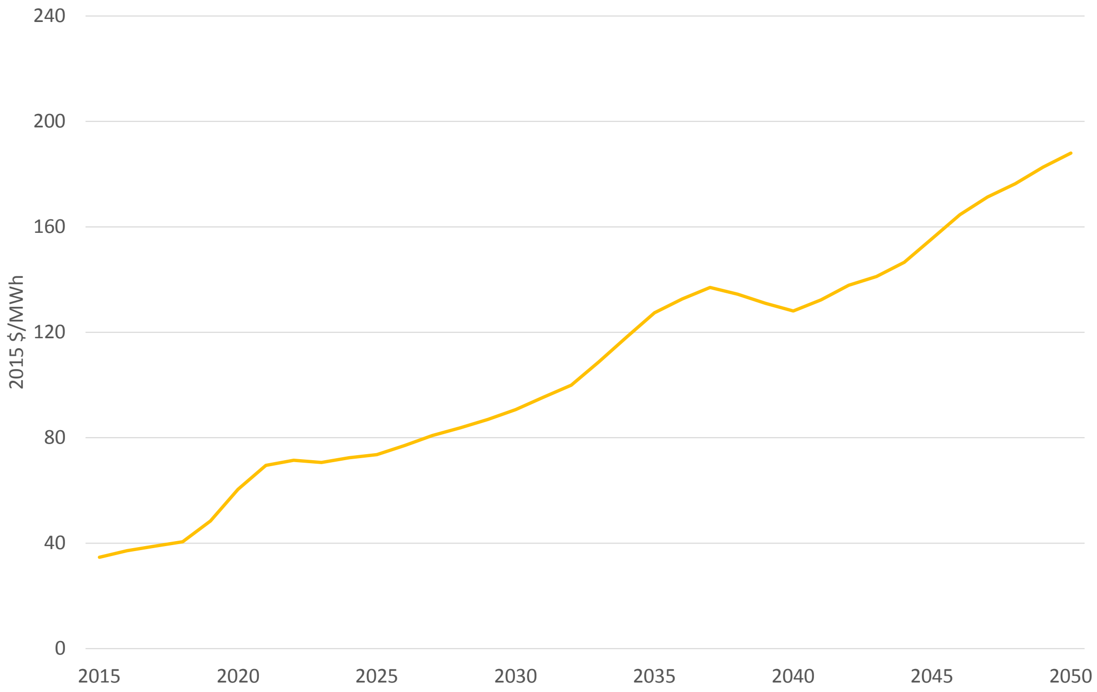


Figure 43: Projected wholesale electricity unit costs in Scenario 4

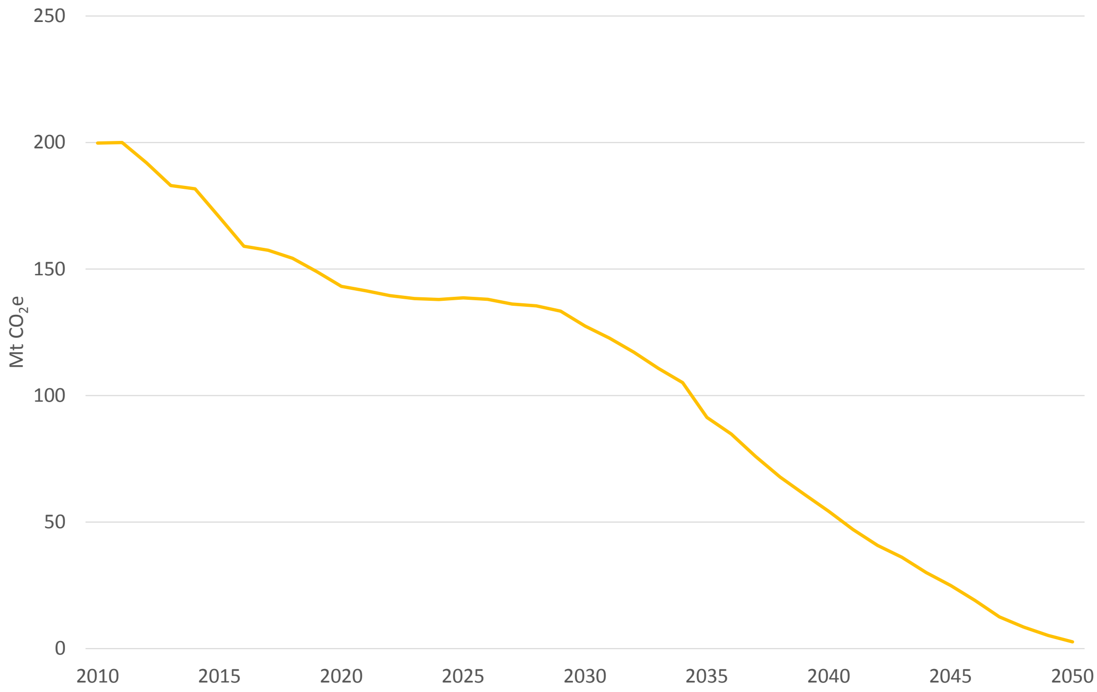


Figure 44: Projected electricity sector greenhouse gas emissions in Scenario 4

Distribution and transmission

The distribution and transmission networks are built to meet peak demand but at present recovers a significant amount of its revenue from the residential sector through volumetric prices (this is due to change in the near term). It is therefore relevant to consider how volume is changing relative to peak demand and to that end we have projected the implied aggregate utilisation of the grid for Scenario 4 in Figure 43. It shows that utilisation reduces steadily to 2030 and then stabilises at 54 percent continuing to 2050. This reflects that growth in peak demand and consumption are in balance from around this period.

A natural consequence of declining grid aggregate utilisation is that we would expect that distribution networks would need to increase volumetric prices. Figure 44 shows that under Scenario 4 there is a modest increase in residential distribution costs to 12.6 c/kWh in 2015 dollars, by 2050, a modest 14 percent increase on 2015 levels with most of this increase occurring by 2030.

The change in transmission costs is greater in percentage terms at around 70 percent higher by 2050. This reflects the substantial extension of the transmission grid required to support 100 percent renewable centralised generation. The projected augmentation plan to achieve this is outlined in the 2013 Future Grid Forum modelling (Graham et al, 2013).

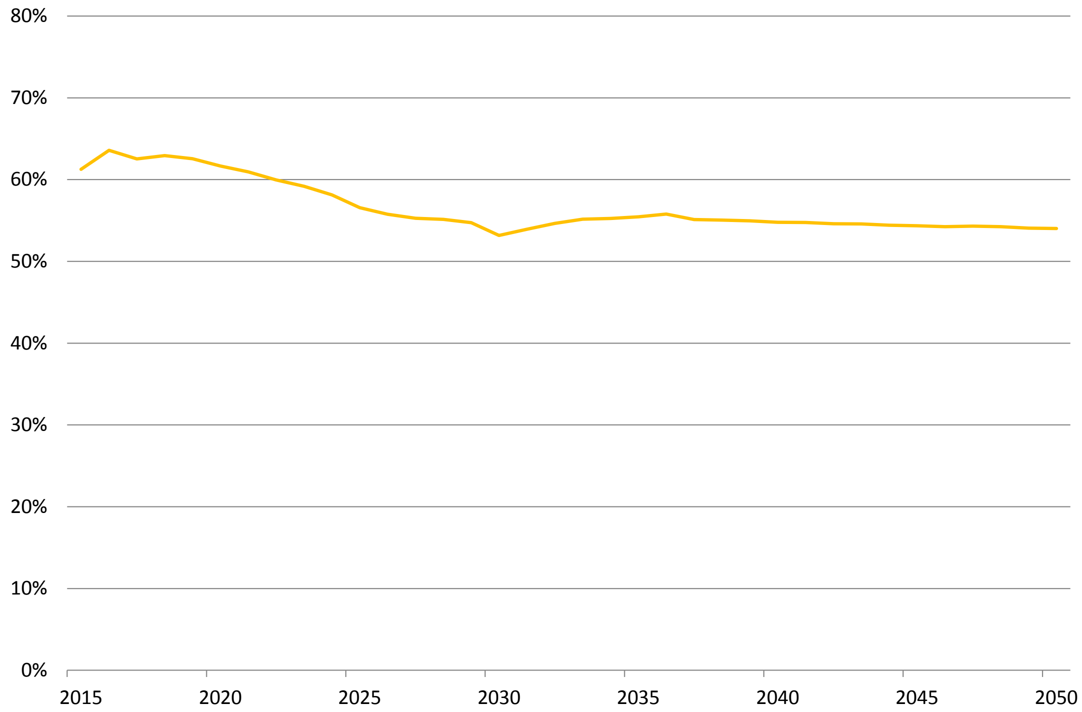


Figure 45: Implied aggregate utilisation of the grid in Scenario 4

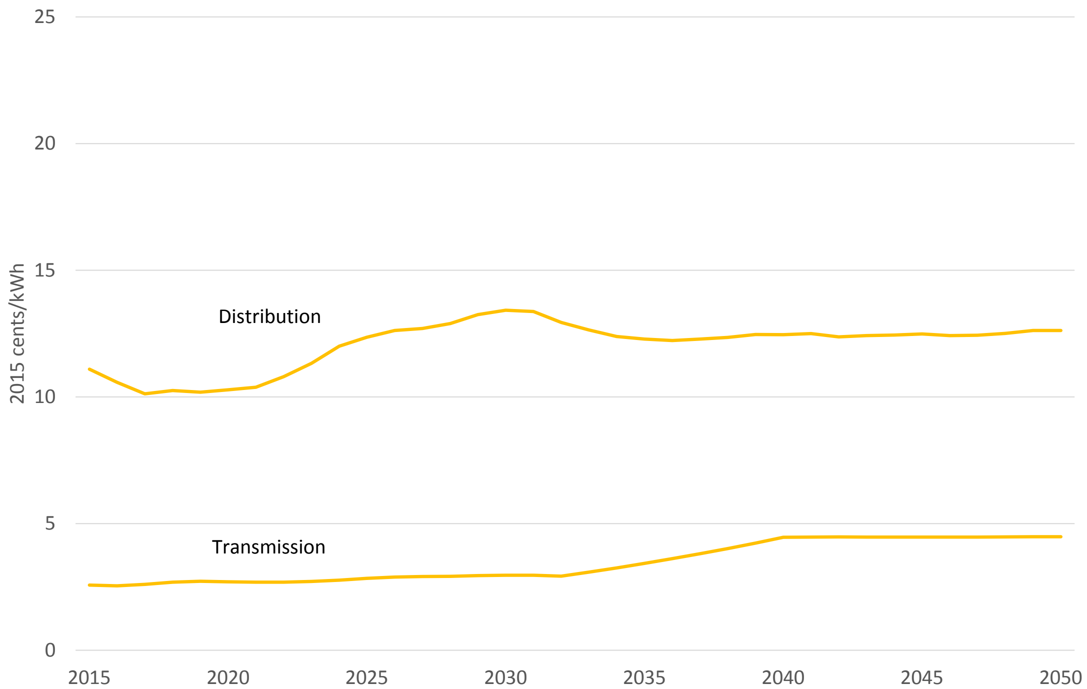


Figure 46: Projected average residential network costs in Scenario 4

Retail

The national average volume based retail price is shown in Figure 47. However it should not be interpreted as the complete picture of impacts on residential customers because that can only be determined with further consideration of changes in customer demand, tariff selection and technology ownership which are all evolving significantly in each scenario. However, the average residential retail price is useful for stacking up the changes in costs in the network and generation sectors to understand their combined effects. A retail margin has been assumed.

Figure 47 shows that under Scenario 4, retail electricity prices are projected to increase by 88 percent between 2015 and 2050 with the increase in generation costs contributing the major part of that outcome (generation costs are around five times higher while distribution costs are only 14 percent higher).

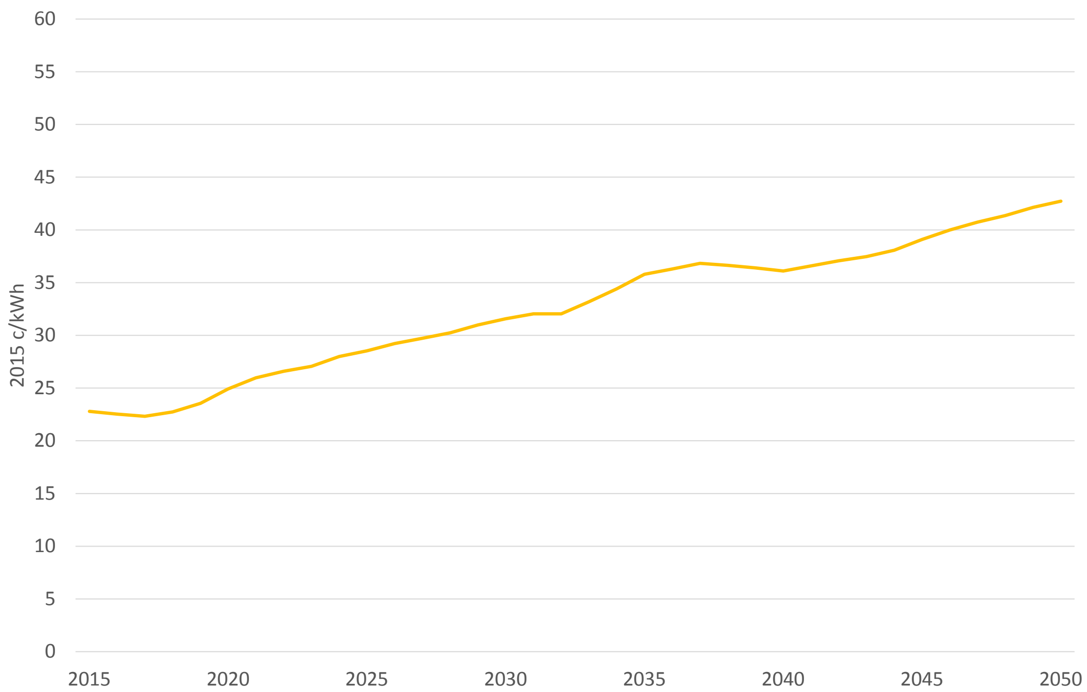


Figure 47: Projected average residential retail price in Scenario 4

Scenario comparison

In the material above we have discussed the result for each scenario individually. In the following material we present the scenarios together so that they may be compared more easily and provide some discussion.

Demand

As discussed in the assumptions section of this report, the projections of growth in consumption in the 2015 scenario set are partly assumed and partly modelled. We assume that underlying growth in consumption in all scenarios matches the 2015 medium case projections from the Australian Energy Market Operator (AEMO) and the Independent Market Operator (IMO), but we've used transport modelling to project an additional level of consumption on to this assumed growth due to electric vehicle adoption. This begins around the mid-2020s (a five year delay compared with 2013 Future Grid Forum assumptions, recognising the impact of lower oil prices but arriving at a similar level by 2050). Based on our review of available projections, including those from CSIRO and other organisations, and the increasing confidence in battery storage costs going down, we believe electric vehicle adoption is more likely than not and is therefore justifiably included in the 2015 scenarios (although not yet part of AEMO's and IMO's demand projection methodology).

The resulting Future Grid Forum National Electricity Market (NEM) consumption projections are shown in Figure 48 and the AEMO (2015) projection is included for comparison. Scenarios 1 to 3 ('Set and forget', 'Rise of the prosumer' and 'Leaving the grid') are each assigned the same level of road vehicle electrification, but Scenario 4 ('Renewables thrive') is assigned a higher level given it has a low cost of storage (resulting from the wider deployment of storage in that scenario).

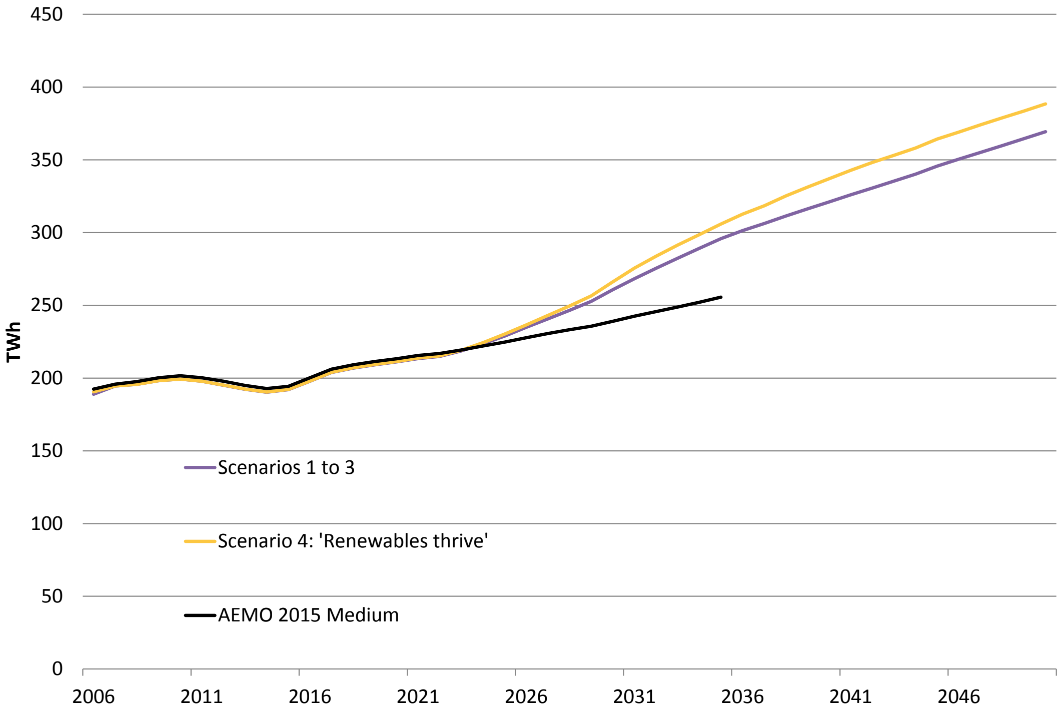


Figure 48: NEM states' grid and on-site consumption under AEMO 2015 medium projection and the FGF scenarios

The level of on-site generation is partly a result of least cost economic choices in the modelling, but also partly a result of adjusting non-price related assumptions to achieve the intended outcome for the scenario. That is, any on-site generation projected in each scenario is economically viable, but there are different pricing structures and attitudes expressed as adoption constraints across the scenarios which change the level of projected uptake. The projected uptake is shown in Figure 49. Reflecting the continued cost reductions in rooftop solar panels, not surprisingly around 84–87 per cent of on-site generation across the scenarios is solar, and the remainder is gas and biomass-fuelled.

After on-site generation is taken into account in total consumption, the remainder is the amount of consumption that electricity supplied from the grid must meet. This is shown in Figure 50. Note under scenario 3 ('Leaving the grid'), in the period between 2030 and 2050 all customers with on-site generation gradually disconnect from the grid.

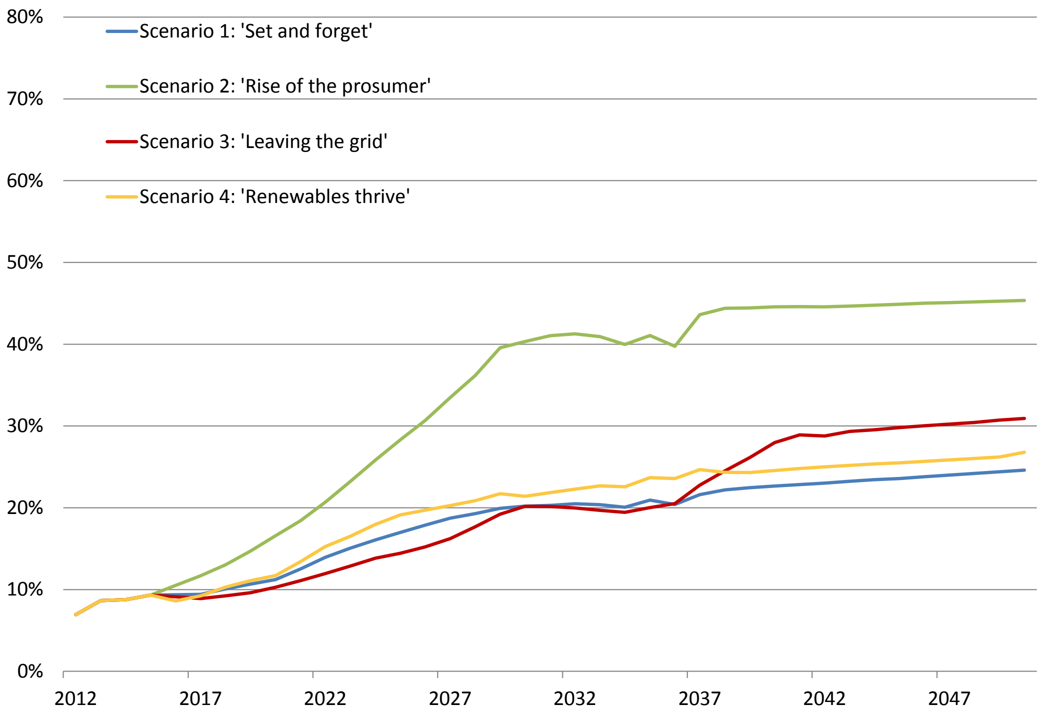


Figure 49: Projected share of on-site generation (mostly rooftop solar panels), by scenario

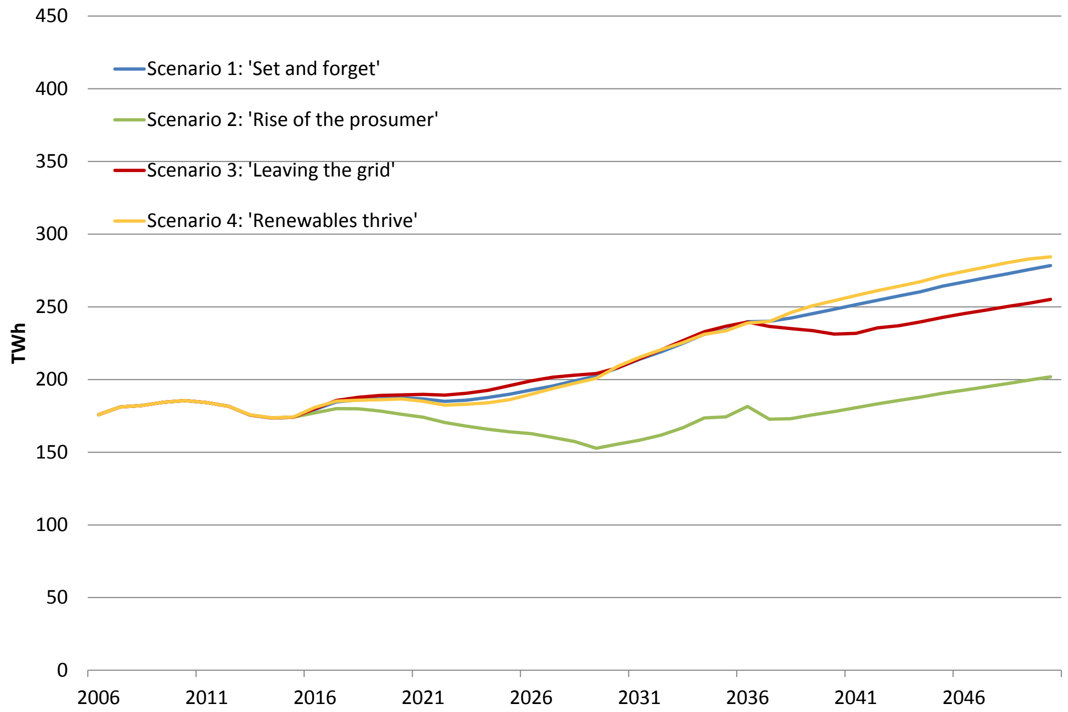


Figure 50: Projected consumption that only the grid must meet (after on-site generation is removed from total consumption)

Consistent with the approach outlined above, we determined the level of demand management activity (including battery storage adoption) in each scenario by:

- the social attitude captured the scenario captures
- the subsequent openness of customers to alternative electricity service pricing structures and associated demand management opportunities
- underlying or market led growth in smart meter adoption.

The projected growth in peak demand in the NEM based on these assumptions is shown in Figure 51.

Scenario 1 ('Set and forget) has the highest level of demand management, followed by scenario 4 ('Renewables thrive'), but we project the lowest peak demand will occur in scenario 3 ('Leaving the grid') in the period from 2035 as a result of customers completely removing their volume and their peak demand from the grid through disconnection. Scenario 2 ('Rise of the prosumer') has the highest peak demand given an assumed bias towards existing, volume based pricing of electricity services for small customers.

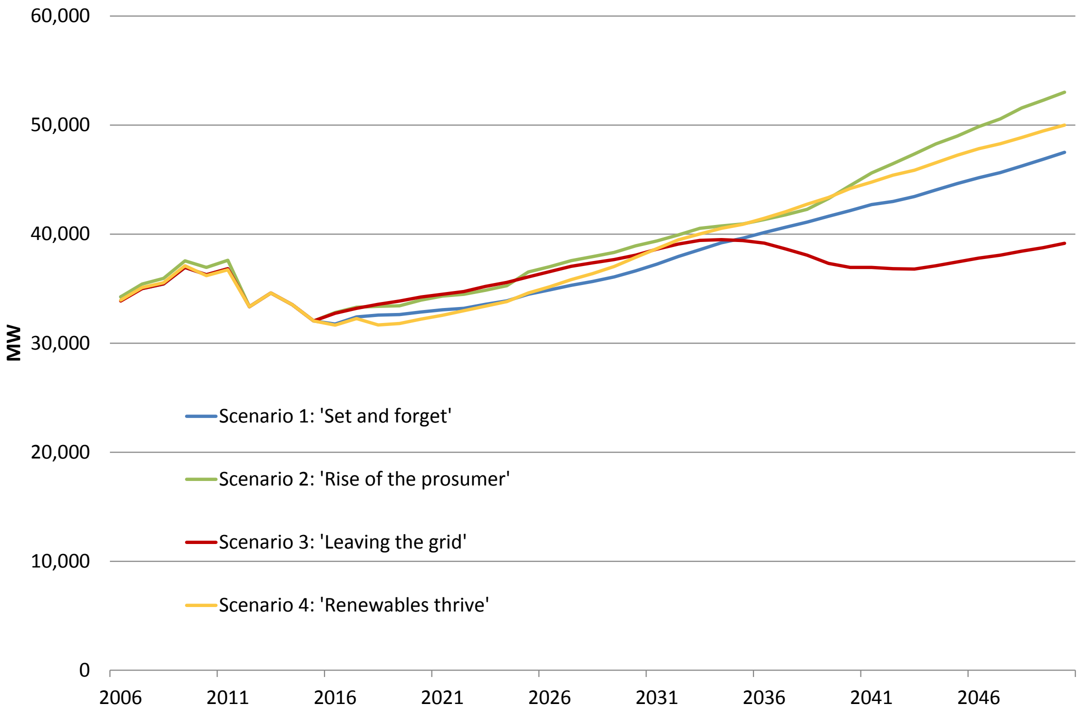


Figure 51: Projected NEM peak demand, by scenario

Implied grid utilisation

As in the FGF 2013 report, total system costs and customer bill outcomes under all scenarios reflect both the investment in distributed energy resources and the grid infrastructure required to support the electricity system. Consequently, different scenario assumptions of the take up of distributed energy resources and demand managements will have consequences for grid utilisation. As in the 2013 report, we calculated an aggregate measure to indicate how the combination of electricity pricing structure and technologies is likely to impact grid utilisation. By calculating the ratio of the projected volume to be carried through the grid with its carrying capacity that will be built to meet projected peak demand, we project the implied aggregate utilisation of the grid, shown in Figure 52. It indicates that the more limited growth in on-site generation and strong demand management in scenario 1 ('Set and forget') could result in maintaining the grid at slightly lower than its current utilisation. But in the remaining scenarios the degree of demand management, while significant, has not been sufficient to significantly offset the impact of on-site generation on volume growth.

As in the 2013 FGF scenario analysis, the worst case outcome for efficient investment is Scenario 2 ('Rise of the prosumer') where there is both high on-site generation and more limited adoption of demand management. Scenario 3 ('Leaving the grid') and scenario 4 ('Renewables thrive') lie between the two extreme results, Scenario 3 has the greater on-site generation and demand management, although 'demand management' in this scenario is achieved by customers which would otherwise contribute to peak demand leaving the grid altogether, rather than through grid facilitated actions.

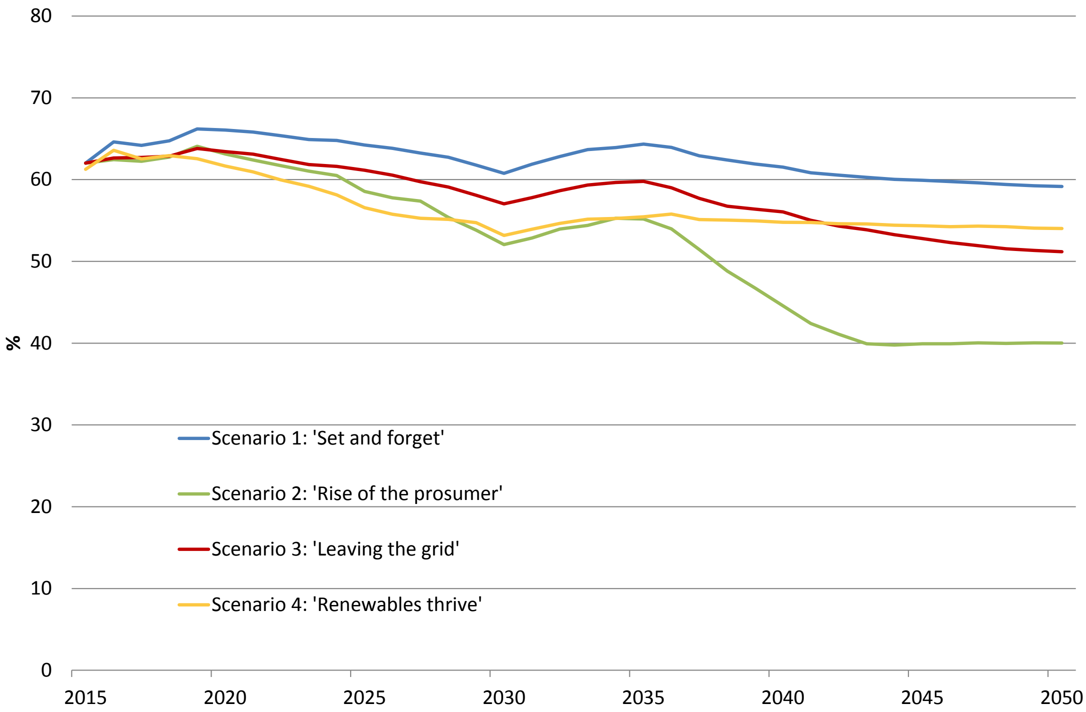


Figure 52: Projected implied grid utilisation

Greenhouse gas emissions

Each of the scenarios assume a carbon constraint which is implemented via a carbon price as a proxy for the possible set of greenhouse gas emission reduction mechanisms that might be implemented. The constraint is assumed to start from 2020. The level greenhouse gas emissions is a result of the change in electricity generation mix that the carbon price and other factors incentivise. The carbon price signal is the same for all scenarios, except that Scenario 4 includes an additional policy which phases out non-renewable centralised generation between 2035 and 2050 down to zero. As a consequence of these assumptions the main reason for differences in Scenarios 1 to 3 is that stronger uptake of on-site generation in the form of solar panels tends to lead to lower emissions because it weakens the demand for centralised generation, lowering generation market prices, forcing existing coal fired generation to retire faster. This is particularly so for Scenario 2, whereas the differences in on-site generation uptake in the other scenarios are not as great. In the period beyond 2035, Scenario 4 abatement begins to accelerate due to the expanded renewable target and becomes the lowest greenhouse gas emission scenario by 2050. Scenarios 1 and 3 are the highest emissions reflecting their lower on-site generation, which sustains higher grid demand for centralised generation and consequently supports more coal and gas fired generation emissions. In absolute terms, the difference between the highest and lowest emission scenario is 32MtCO_2e.

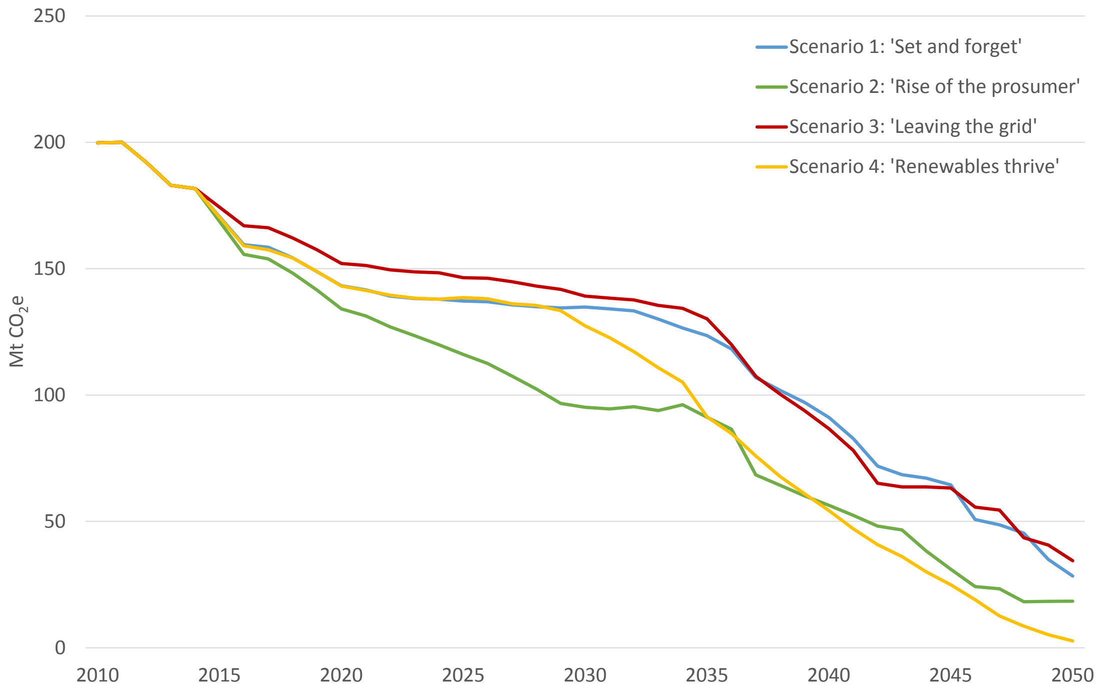


Figure 53: Projected electricity sector direct greenhouse gas emissions by scenario

Prices

All the 2013 scenarios include a carbon price in their modelling as a proxy for any one (or a combination) of the many possible policy mechanisms the government might eventually introduce to reduce greenhouse gas emissions in the electricity sector. The FGF took this approach to simplify the modelling rather to state a preference for any particular policy mechanism. It was necessary to include some carbon constraint in the modelling since the 2013 scenarios included that in their design – reflecting the fact FGF participants did not believe it plausible to have a future without a carbon constraint.

The effect of the carbon price is to increase the cost of fossil based technologies (particularly those without carbon capture and storage) and make it possible for other low emissions technologies to compete. While the projected costs of some low emission technologies (such as solar photovoltaics) have significantly reduced, each scenario experiences an increase in generation costs as a result of the introduction of low emission technologies.

Scenario 4 ('Renewables thrive') has an additional policy mechanism forcing all electricity to be generated from renewable sources, implemented as an extension of the Renewable Energy Target to 100 per cent by 2050 beginning from 2035. To overcome the intermittency of some renewable electricity generating technologies, we used battery storage in this scenario as the main load-following technology since it is emission free, and gas peaking (the conventional back-up capacity method) is not. Recent analysis indicates the projected reductions in battery costs could mean that such an approach would come at no additional cost relative to gas peaking (Brinsmead *et al.* 2015). Overall, however, adopting renewables to the exclusion of other technologies in scenario 4 does lead to higher costs relative to scenarios 1–3. By 2050, the projected generation costs are over $40 per MWh higher (or 28%

higher) than in the other three scenarios (Figure 54). The trade-off is an emission-free electricity sector (except for a minor amount of diesel-based on-site generation which is assumed not to be subject to the policy mechanism) compared with an average 14 per cent of emissions remaining in the other scenarios relative to 2010.

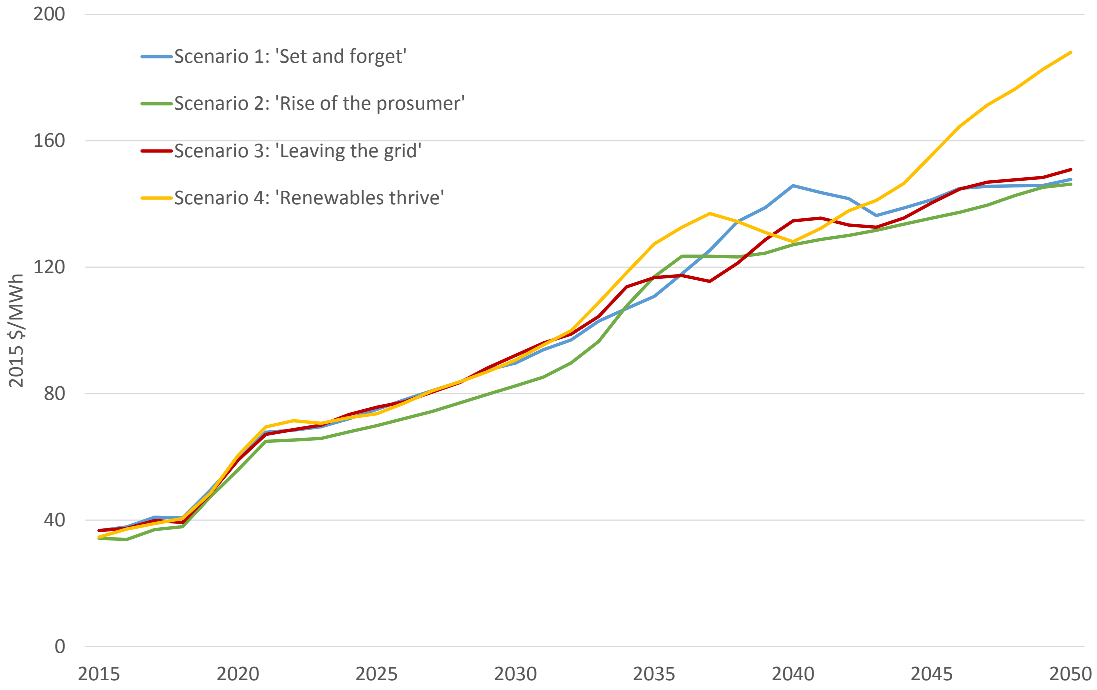


Figure 54: Projected generation costs by scenario

Given the recent increase in residential network prices, it's important to consider what may happen to those prices under each scenario. Taking into account common structural factors (such as the turnover of capital stock in each network region and current allowable costs, as well as scenario-specific changes like the level of grid utilisation), we have projected average residential network prices in dollars per kilowatt hour. It is unlikely networks will charge their services in this type of pricing structure in the future given the structure's poor relationship to a cost base which does not change with the level of energy (watt-hour) throughput. But we illustrate the price in this form because it gives an indication of the extent to which network utlisation could drive retail price increases (since poor utilisation would mean a higher price per watt-hour) relative to pressure for price per watt-hour increases from the generation sector, just discussed.

The result, shown in Figure 55, are network prices which are somewhat lower than those forecast under each scenario in the 2013 FGF Scenarios. The anlaysis indicates that network costs are likely to be reduced and maintained in the medium term, reflecting limited growth in peak demand. The scenarios begin to experience price increases, particularly in the period from the late 2030s as a result of declining network utilisation, less so for scenario 1 ('Set and forget') where grid utlisation is stronger. For distribution costs, the worst outcome is associated with Scenario 2: 'Rise of the prosumer' where the price in 2050 is 53 per cent higher than in 2015. However, the highest transmission cost outcome is Scenario 4: ''Renewable thrive' which experiences a 74 percent increase by 2050. This rise reflects the need to extend the transmission system significantly, to connect a greater number and diversity of renewable electricity generation sources.

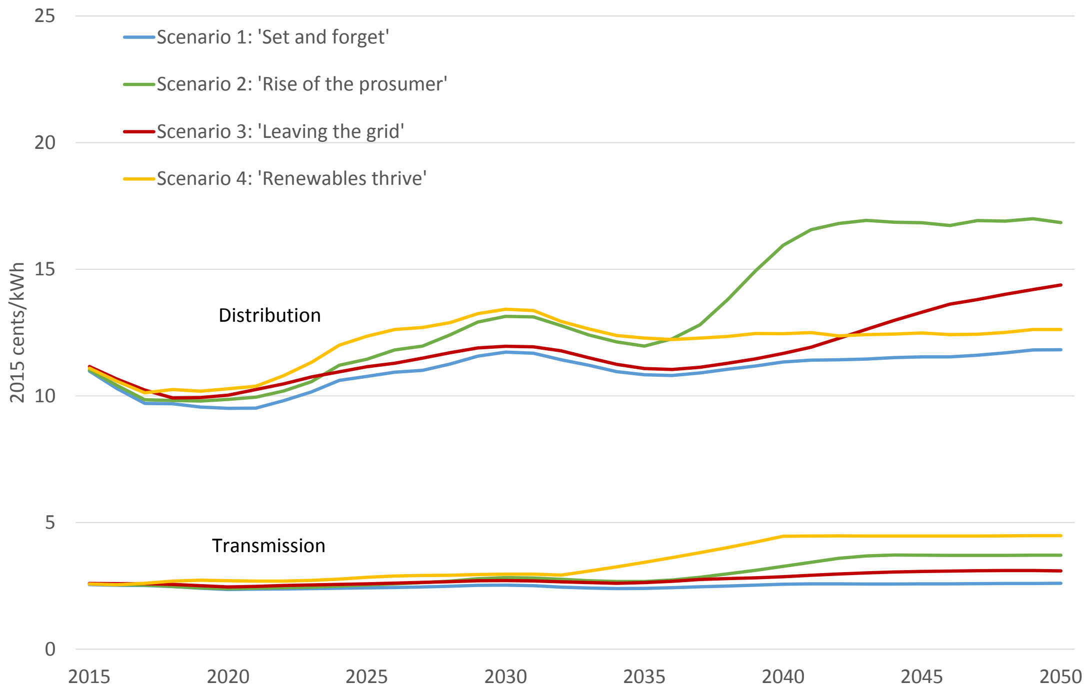


Figure 55: Projected residential network costs by scenario

The combined effect of the generation cost and distribution cost increases shown across the scenarios (together with other smaller retail price components such as transmission and retail margin that make up the retail price) means residential retail electricity prices are likely to increase, but this is a poor indicator of customer impact because there is much more to an electricity bill than the retail price. The mitigating factors for an increase in the residential retail electricity price are:

- changes in electricity consumption (for example, through more energy efficient electrical appliances and passive building efficiency)
- changes in electricity use (through on-site generation and demand management)
- changes in the structure for pricing electricity services to the customer.

We present a better indicator of customer impact, electricity bills in the next section. However, to understand the combined impact of the cost increases in the generation, transmission and distribution sectors we present the projected average volume based residential retail price in Figure 56. A retail margin has been assumed. By 2050 the lowest residential retail price outcome is associated with Scenario 1 because it has the lowest increase in network costs and no greater increase in generation costs than the other scenarios. The highest retail prices are associated with Scenarios 2 and 4, the former due to having the highest distribution costs and the latter due to the highest generation and transmission costs. Scenario 3 lies in between Scenarios 2/4 and Scenario 1 by 2050 because while it has the second highest distribution costs, its lower generation costs than Scenario 4 so that the retail cost is not as high.

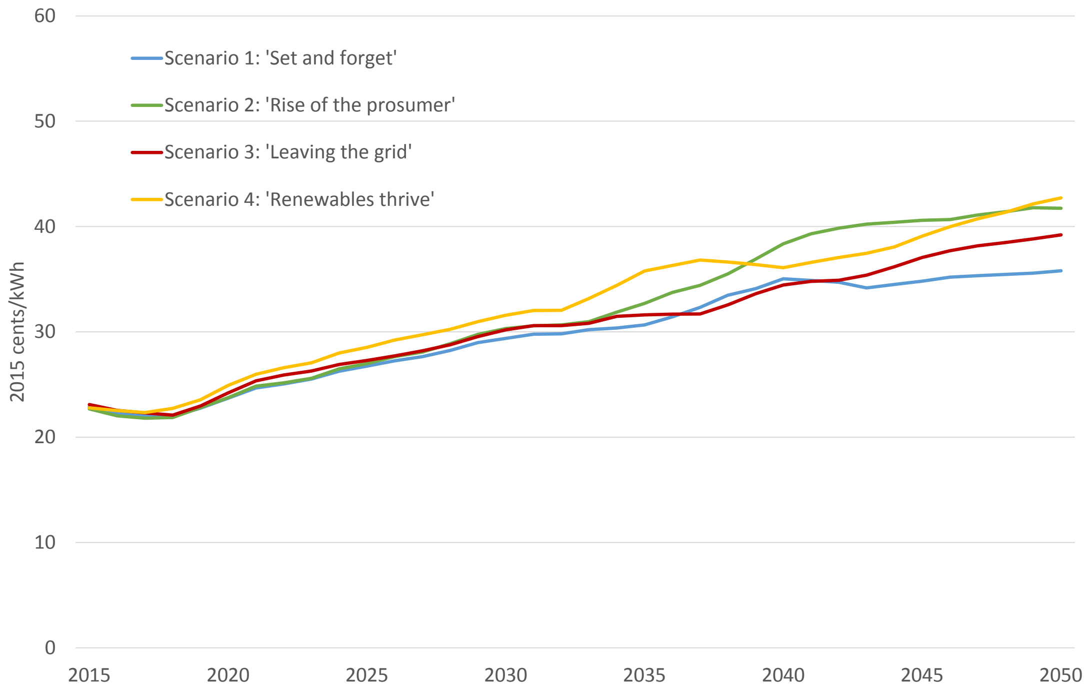


Figure 56: Projected average volume based residential retail prices by scenario

Commercial and industrial electricity retail prices are structured differently to residential customers and they are differentiated by customer size. We have projected an index of changes in those retail prices in Figure 57. The projection indicates that the outcomes for commercial customers are not significantly different across scenarios for up until 2030 but costs increases are generally higher for industrial customers. The reasons for both outcomes is that under pricing structures for commercial and industrial customers generation costs are a larger share of the bill, even more so for industrial customers, and generation prices are not very different by 2030. The exception is perhaps Scenario 2 which has lower generation costs in 2030. By 2050 we begin to see a greater divergence in a single scenario. That is, reflecting the higher generation costs of Scenario 4 and the dominant impact of generation costs in the tariff structure this scenario has the highest commercial and industrial price index outcome.

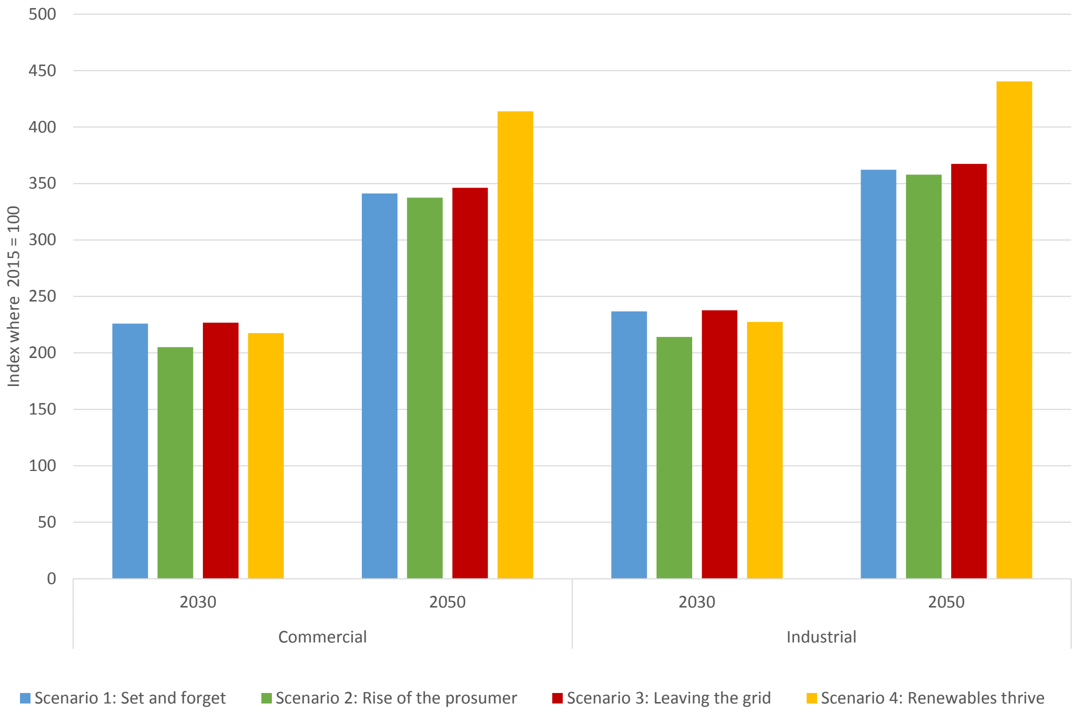


Figure 57: Projected index of commercial and industrial retail electricity prices

Total system expenditure

While the retail price is one indicator of the system cost we can also look at total system expenditure. Total system expenditure includes all expenditure on capital costs, fuel costs and operating and maintenance costs. These are in different proportions for different parts of the supply chain. The projected cumulative electricity sector investment and operating expenditure to 2050 and the percentage of each supply chain component, by scenario, is shown in Figure 58.

It shows total system expenditure (including capital and operating expenditure) of $954 to $1,136 billion over the next 35 years. Between $224 and $469 billion is required in onsite or off grid expenditure by customers and their agents. Significant distribution and transmission network expenditure of $283 to $336 billion is also required, which represents about one-third of total system expenditure in all scenarios.

While very large numbers, across the economy this range of electricity sector expenditure projections equate to around $1000 per capita per annum to 2050. This is commensurate with the current level of expenditure and does not represent an unaffordable level of expenditure (indeed, as with the 2013 Future Grid Forum modelling, household electricity bills are projected to remain the same share of household income as they are now, approximately 2-3 percent). Rather it identifies that even small improvements in the efficiency with which the electricity sector operates can deliver substantial, multi-billion dollar dividends to the economy and directly to end-users who are expected to play a larger direct role in technology investment.

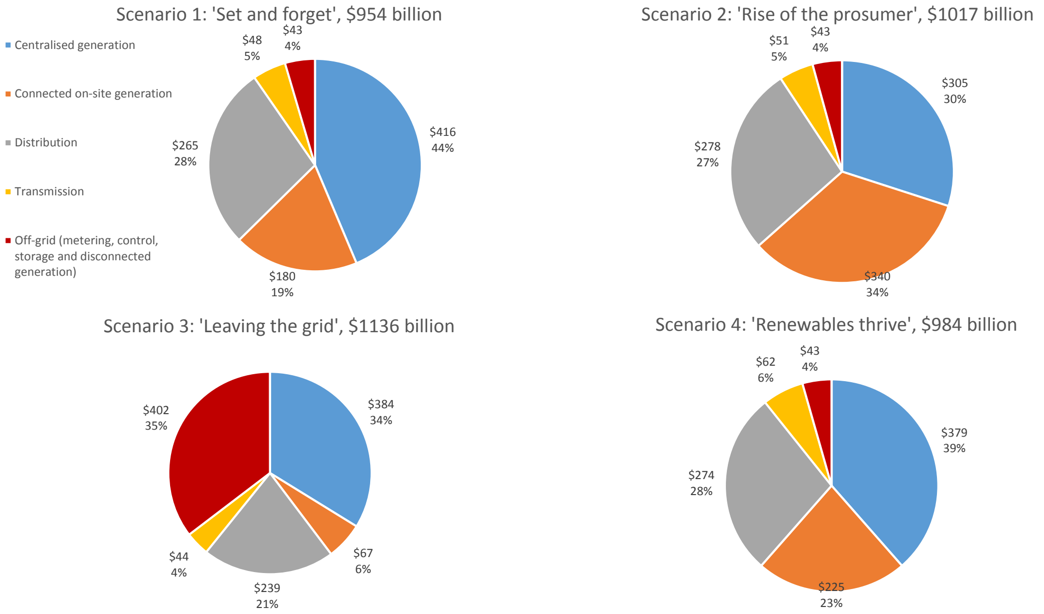


Figure 58: Projected cumulative electricity sector investment and operating expenditure to 2050 and the percentage contribution of each supply chain component, by scenario

Customer bills

To understand the financial impact of electricity sector changes on the customer, we must consider electricity system costs, customer demand changes, technology adoption and alternative tariff types. To this end, we have projected future electricity bills with these factors included in different combinations. As discussed, while the scenarios assume a dominant type of customer, each scenario will also have a smaller share of customers with different behaviours, technologies and retail electricity service contracts. Where technology is included in the customer's profile, we include the annualised costs of purchasing and installing that technology and any required enabling technology in the annual bill.

The projected average residential electricity bills for different types of customer tariffs and technology ownership are shown in Figure 59, Figure 60 and Figure 61. The bill is constructed for the average size residential customer in 2030 and 2050 and includes:

- the projected costs for generation and network costs
- assumed feed-in tariffs guided by generation costs
- a retail margin.

We assume all tariffs or pricing structures would be set so they recover the same amount from the representative customer who has no technology. This may not be the case but is a useful simplification to give us a common starting point irrespective of the tariff type before we add technologies to the mix.

In Figure 59 we project the electricity bill for customers with volume only tariffs who have no additional technology, install rooftop solar or install a rooftop solar–storage bundle. We also compare these to the 2030 FGF projections, which only included the first two customer types. Under the assumptions, installing rooftop solar leads to an improvement in their electricity bill relative to no technology in 2030, and a much greater improvement by 2050 because electricity system costs have increased and the cost of solar panels has fallen further.

In the case of the combined solar–storage bundle, the storage helps to reduce exports and minimise imported electricity in order to maximise the value of solar. Adopting this bundle leads to a modest bill improvement relative to no technology by 2030, but most certainly improves a customer's bill by 2050. Initially, larger customers are likely to find a bundle approach more worthwhile than the average customer because there's a high level of equipment costs needing to be offset by avoided electricity contract costs.

Overall customer bills are lower than was estimated in the 2013 FGF projections and the relative merit order of scenarios has changed. This is because network costs are lower in the updated projections, reflecting stronger confidence in the system's ability to implement demand management, particularly through battery storage, to reduce the rate of decline in grid utilisation. As a consequence, the increases in generation costs to achieve different emission reduction outcomes more strongly dominate changes in residential bills so that scenario 4 is the highest cost (but lowest emission) scenario for residential bills in this update compared with scenario 2 in the 2013 projections which has the highest network costs.

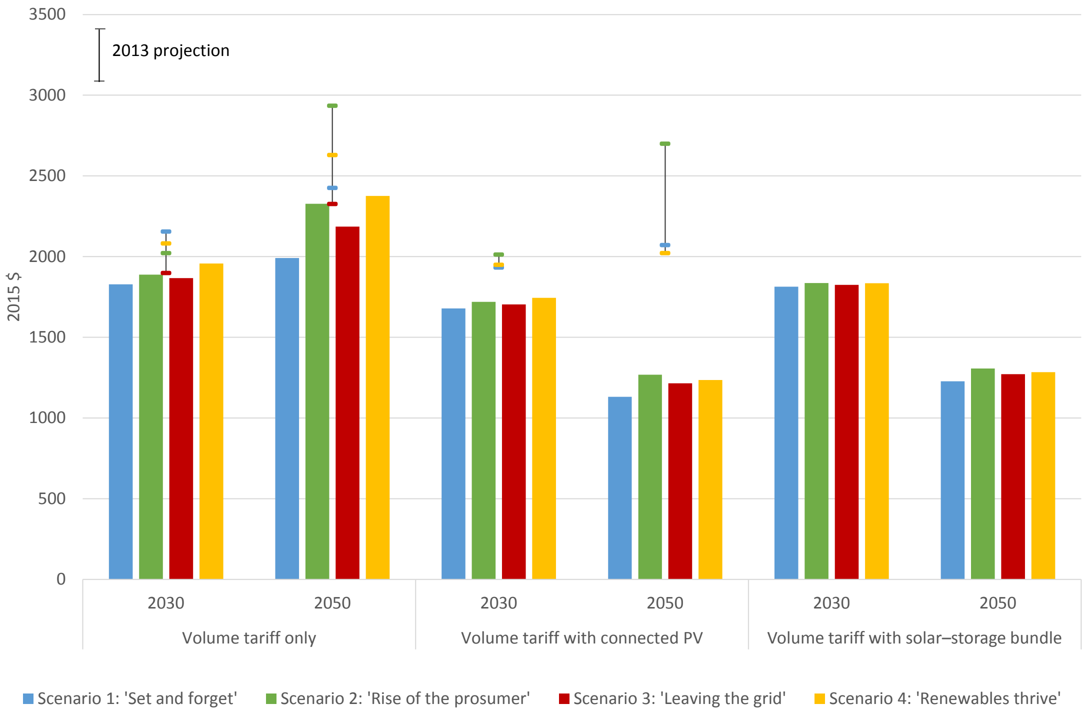


Figure 59: Projected average residential electricity bills under volume tariffs, by technology ownership and comparison with the 2013 FGF projections

In Figure 60 we examine a customer who selects a combined volume and capacity tariff where the customer is charged for both their volume and individual peak demand (the capacity of the network they use), but their volume charge is reduced so that their bill, with no technology, is the same as in the previous volume only tariff example. In this case we are interested in how installing battery storage might reduce their exposure to peak demand charges and reduce their bill. They have not installed solar and so this option might reflect someone who lives in an apartment or dwelling that's less amenable to solar than the average house. Under the specific assumption we used, relative to the no technology case, we find this customer's bill is slightly lower in 2030 but more noticeably lower by 2050 with storage.

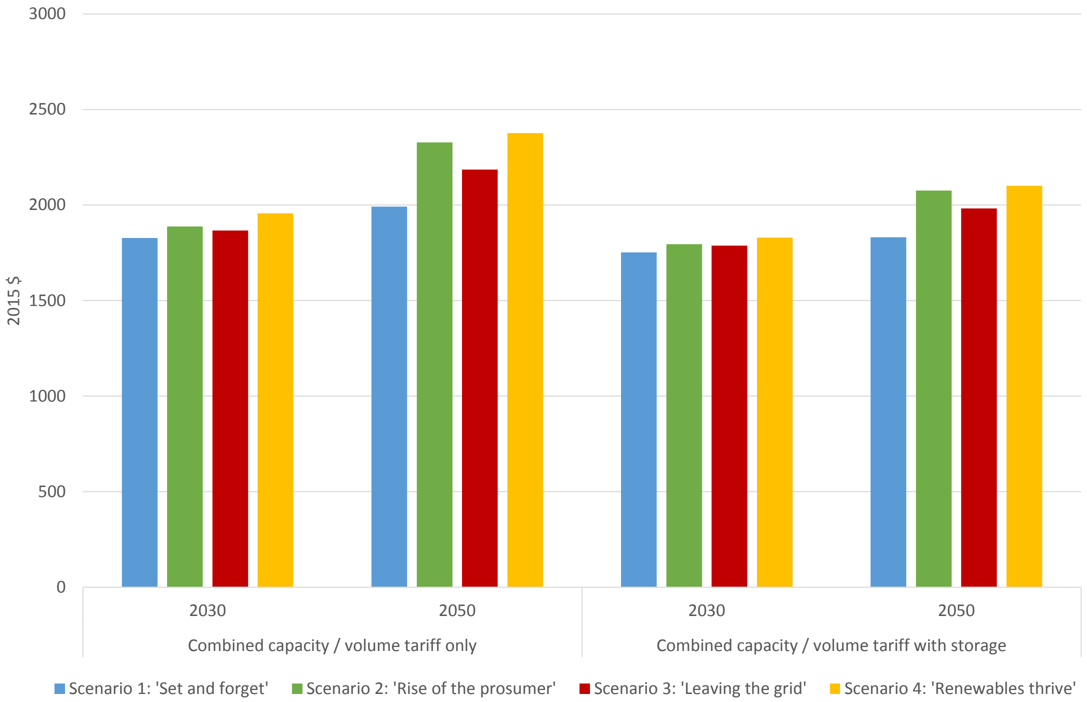


Figure 60: Projected average residential electricity bills under combined capacity and volume tariffs, by technology ownership

In Figure 61 we examine a customer with a combined fixed network charge and volume tariff. The customer bill includes a fixed charge independent of the amount of electricity consumption, which could represent the cost of fixed network assets, and is charged a smaller volume rate so that, with no additional technology, their bill is the same as in the previous two examples. To allow Scenario 3 ('Leaving the Grid') to be assessed, we assumed this to be the mandated tariff type for customers with grid-connected technology installed.

This tariff recovers the cost of serving the customer reflecting the fixed cost structure of the network and is likely to provide little incentive to install a solar and storage bundle. This is because the effect of solar and storage (reducing the volume of electricity imported) only partially reduces the bill (because of the fixed component of the tariff structure) and is not enough to offset the annualised cost of installing those technologies. However, this type of tariff structure is susceptible to encouraging customers to leave the grid when it becomes economic to do so. A customer facing this tariff profile could choose to increase the value they get from solar and storage technologies by disconnecting from the grid altogether, as demonstrated in the bill for a customer who is disconnected with a solar–storage–generator bundle. This option is projected to be economically unviable in 2030, but by 2050 (with parity reached from around the late 2030s) leads to an improvement in the average customer electricity bill. This is consistent with the design of scenario 3 'Leaving the grid' whereby customers only begin to disconnect from the late 2030s. An important caveat here of course is that the electricity service the disconnected customer receives may meet their needs, depending on many factors, but is not the same as that delivered by the grid.

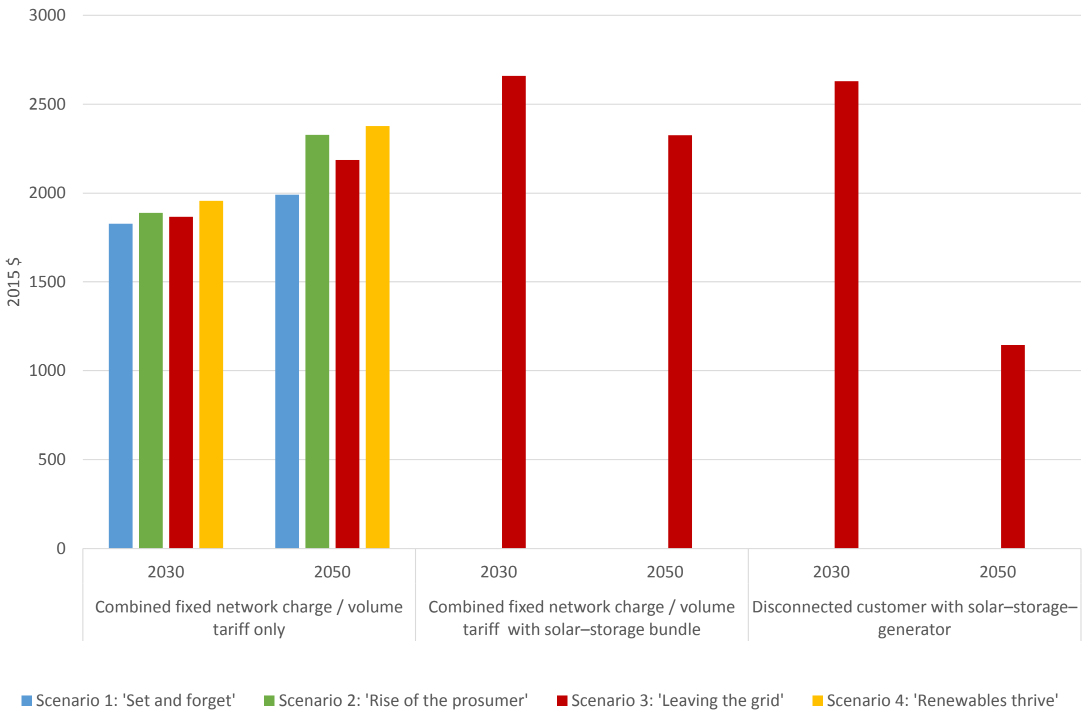


Figure 61: Projected average residential electricity bills under combined fixed network charge and volume tariff and by technology ownership

Affordability

Of course, while electricity bills will change so too does income. Affordability is a subjective concept, however one way of indicating affordability is to calculate the share of electricity expenditure as a percentage of average full time earnings. Using the Australian Bureau of Statistics measure of 2015 earnings (the latest version available was May[15]) and applying the same index of growth in earnings from the 2013 Future Grid Forum analysis we arrive at the projections shown in Figure 62.

It shows that the affordability of electricity is not expected change significantly with the income share of expenditure in 2050 being roughly the same under Scenario 1: ‘Set and forget’ at 2 percent or slightly below and modest increases to just above 2 percent under the remaining scenarios. These increases in the electricity expenditure share of income are less than was projected in 2013 which is a reflection of the lower outlook for electricity bills discussed above and shown in Figure 59.

[15] http://www.abs.gov.au/AUSSTATS/abs@.nsf/Lookup/6302.0Main+Features1May%202015?OpenDocument

Figure 62: Projected share of electricity expenditure in average earnings and comparison to 2013 projections

2025 comparison

The Roadmap focuses on the decade from 2015 to 2025 and so we have targeted modelling results at that time period (without losing sight of the longer term picture). We began with no expectations of 2025 results across the scenarios.

From the perspective of simplifying the baseline for Roadmap actions and industry planning in general, it would be beneficial if some scenario results were almost identical in 2025, and then diverged later in the projection period. Figure 63 is a cross-scenario snapshot of 2025 changes relative to 2015 comparing the key modelling projections. It highlights that the growth in share of on-site generation remains very uncertain and in 2025 could be between a half to 3 times higher than 2015. Grid consumption is expected to be slightly higher, except in the highest on-site generation adoption case (Scenario 2), but in all but the strongest demand side management case (Scenario 1) peak demand grows faster leading to a slight decline in grid utilisation. Residential electricity bills are expected to be between 23 to 30 percent higher in 2025 but this reflects the form of carbon abatement policy chosen. Actual implemented policy formulations may not have the same impact on electricity costs or may be compensated (e.g. with offsetting tax arrangements).

The comparison indicates that scenarios 2 and 4 (‘Rise of the prosumer’ and ‘Renewables thrive’) are the most different across the various projection parameters, and this is no surprise since they both include very strong on-site generation adoption. But if we narrow in on grid consumption and utilisation, the scenarios are fairly similar by 2025. This may serve as a useful guide on how to construct baseline comparisons in the future. For example, one could conclude that the level of on-site generation is the key differentiating factor by 2025.

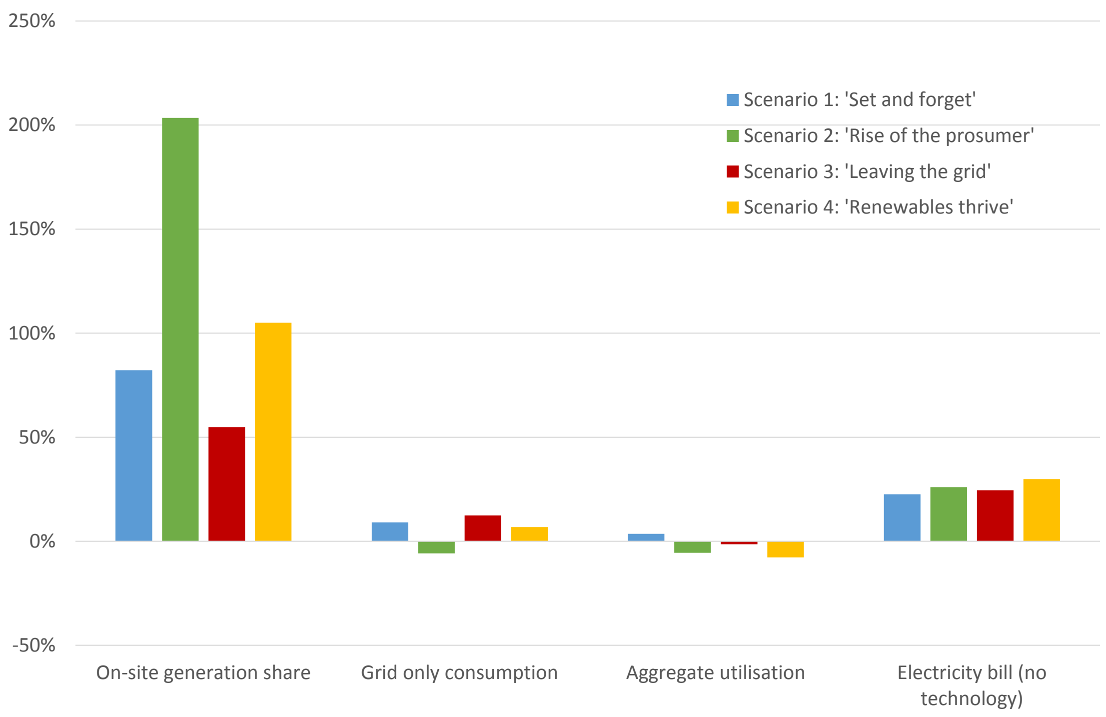


Figure 63: The percentage change in key scenario projections in 2025 compared to 2015 by scenario

Sensitivity modelling results

Scenario 4: Deep decarbonisation demand sensitivity

As discussed in the assumptions section of this report, we have included a sensitivity case on Scenario 4 which uses the electricity demand projection from the ClimateWorks Australia, ANU, CSIRO and CoPS (2014) *Australian Deep Decarbonisation Pathway* scenario. We do this by re-running Scenario 4: Renewables thrive with the higher demand projection (Figure 64). We assume the ratio of consumption to peak demand stays the same such that the increased consumption also comes with proportionally increased peak demand (remembering that Scenario 4 includes demand management and so its proportion is relatively good compared to other scenarios). Ideally a more sophisticated approach to projecting peak demand would have been used, however, most of the increased consumption in this scenario is from substituting gas use in buildings and industrial processes and from electric vehicles and it was not possible in the time available to assess how the combination of these additional electricity demand sources would impact peak demand (for some industrial gas substitution, the necessary demand profiles would also be difficult to obtain).

We also adjusted the profile of consumption slightly to take into account updated demand data in the last two years and adjusted limits on on-site generation to take account of increased electricity consumption by all customer types.

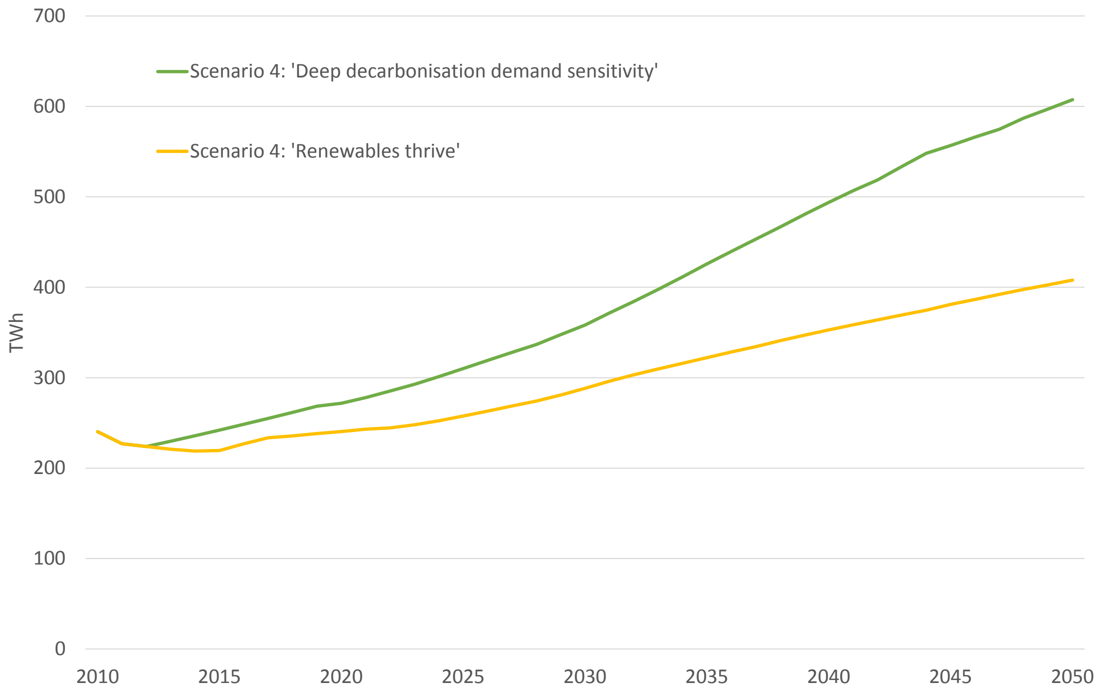


Figure 64: Assumed electricity consumption under Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation demand sensitivity

Generation

The original 2014 projection of the generation mix for deep decarbonisation is shown in Figure 65 for comparison purposes and then we show the Scenario 4: Deep decarbonisation sensitivity in Figure 66. There are four important differences between the two implementations which impact the different generation mix outcomes. The first is that the 2014 projection applied a higher carbon price[16], that led to the closure of all coal by 2035, however, this was not a part of the Scenario 4 assumptions and so was not implemented in the Scenario 4: Deep decarbonisation demand sensitivity. Secondly the 2014 implementation included a carbon price which was higher, consistent with a world that was coordinating their efforts to achieve deep decarbonisation. Thirdly the costs for solar photovoltaic panels and storage are significantly lower in the Scenario 4: Deep decarbonisation demand sensitivity implementation. Finally, the 2014 projection played close attention to available biomass resources since they were a precious resource for abatement in other sectors, whereas in Scenario 4: Deep decarbonisation demand sensitivity we place no restriction on their uptake.

When combined these different approaches have led to some significant differences between the 2014 projection and the Scenario 4: Deep decarbonisation demand sensitivity projection for the electricity generation mix:

- Coal fired generation is phased out much more slowly in Scenario 4: Deep decarbonisation sensitivity and gas generation plays a slightly smaller role as a consequence.
- Solar panels play a much more significant role in electricity generation and as a consequence, this has reduced the need for enhanced geothermal (which is also assumed to be higher cost than in 2014).
- The role of biomass is significantly increased in Scenario 4: Deep decarbonisation demand sensitivity

We also allowed wind a slightly better contribution of capacity at peak demand times based on Brinsmead et al (2015) which has improved its share in the last two decades in Scenario 4: Deep decarbonisation sensitivity relative to the 2014 implementation.

While there are differences, some key similarities remain:

- Solar photovoltaic and solar thermal power has a key role to play in deep decarbonisation, being less limited by resource constraint and reaching a competitive cost point
- Emerging technologies such as wave energy and onshore wind have a similar opportunity to contribute under this type of scenario.
- Nearly all technologies are required to make an efficient transition to a zero emission, high demand centralised electricity generation sector.

[16] The price difference is strongest in the early years. The deep decarbonisation scenario carbon price is \$60/tCO_2e in 2020, whilst the Future Grid Forum price is \$60/tCO_2e.

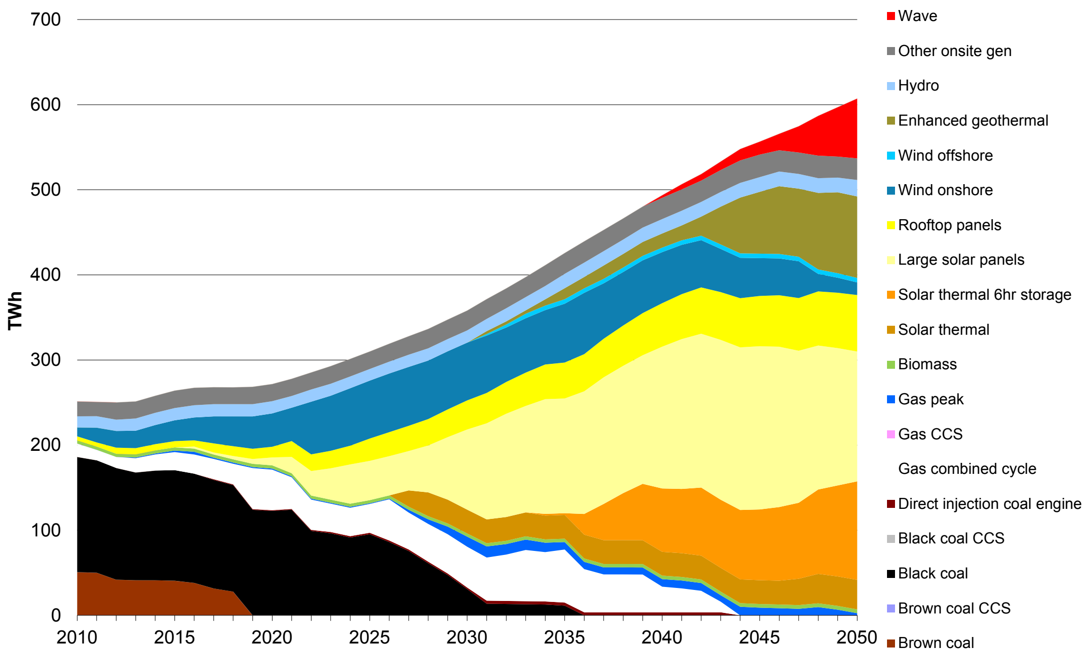


Figure 65: 2014 Deep decarbonisation projected electricity generation mix

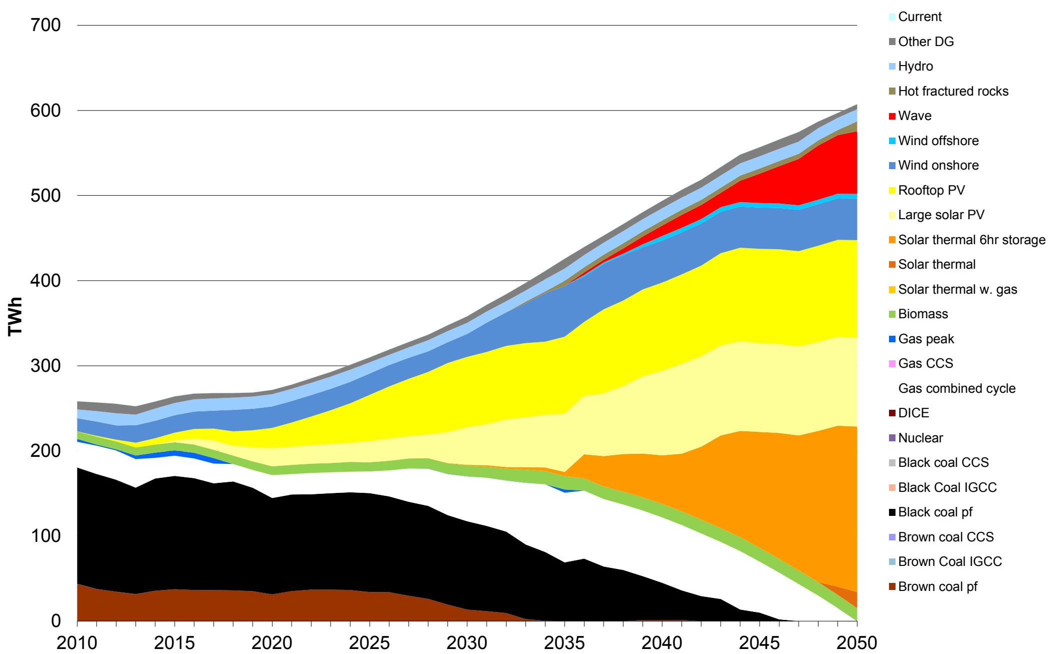


Figure 66: Projected electricity generation mix under Scenario 4: Deep decarbonisation demand sensitivity

The breakdown of on-site generation technology is shown in Figure 67. On-site generation is dominated by solar panels with new gas generation not allowed by design. In absolute terms the level of on-site generation is high. The commercial sector also plays a larger role compared to Scenario 4: Renewables thrive. However, these outcomes mostly reflect the greater electricity consumption in Scenario 4: Deep decarbonisation demand sensitivity. On a percentage share basis, Figure 68 shows that the amount of on-site generation in Scenario 4: Deep decarbonisation demand sensitivity is fairly similar to Scenario 4: Renewables thrive. On-site generation uptake is faster, reflecting stronger demand and higher centralised generation prices which encourage more on-site generation. The shares cross again at 2045 indicating solar panel adoption is reaching a saturation point (the assumed limits to solar uptake under Scenario 4) much sooner in the higher demand Scenario 4: Deep decarbonisation demand sensitivity.

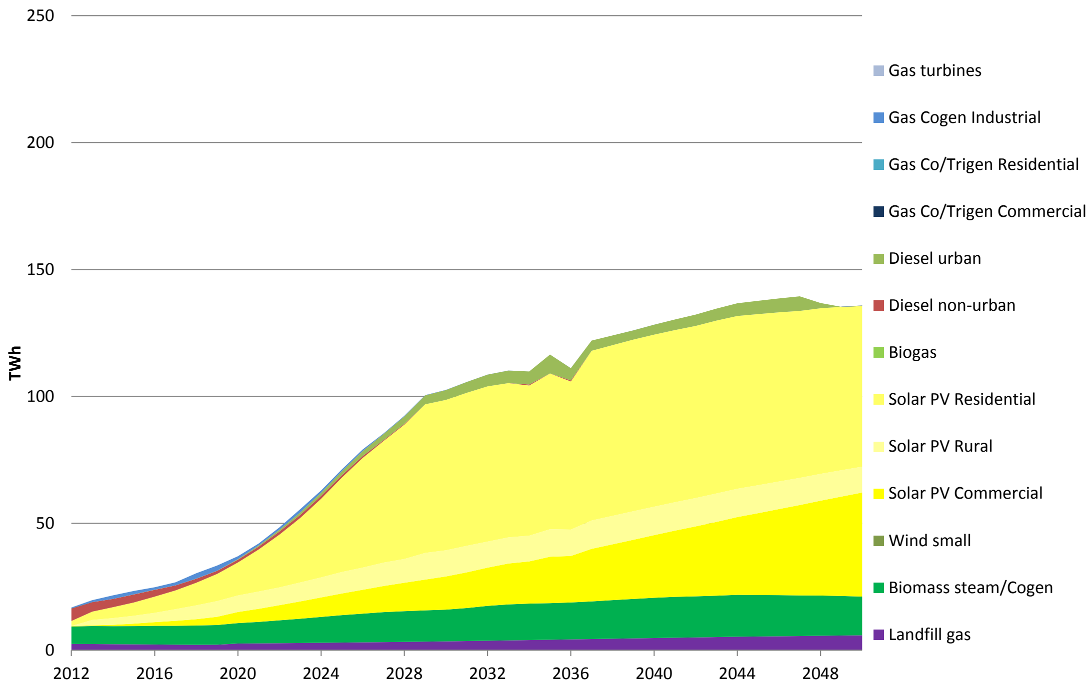


Figure 67: Projected on-site generation technology mix under Scenario 4: Deep decarbonisation demand sensitivity

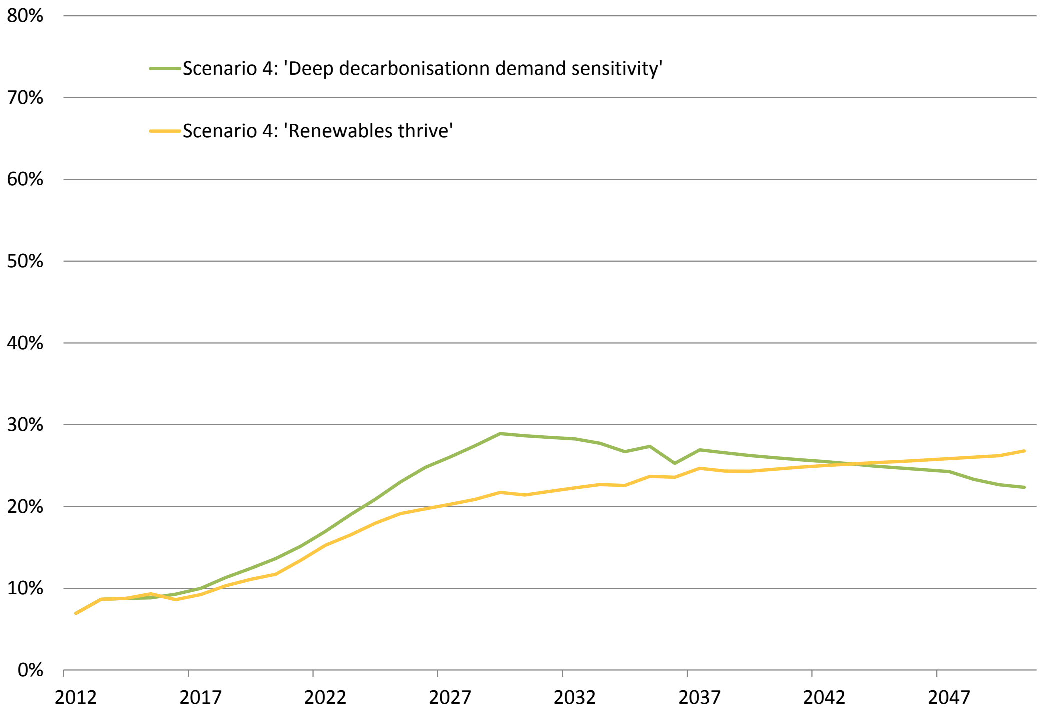


Figure 68: Comparison of on-site generation share under Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation demand sensitivity

Greenhouse gas emissions

In Figure 69 and Figure 71 we compare the annual and cumulative electricity sector greenhouse gas emissions for:

- Scenario 4: Renewables thrive
- Scenario 4: deep decarbonisation demand sensitivity, and
- The 2014 implementation of the Deep decarbonisation pathway scenario

Figure 69 shows that the 2014 deep decarbonisation implementation reduced emissions the fastest from around 2020 owing to the faster retirement of coal fired generation. This was part of the scenario design which was not only concerned about reaching a zero emission centralised generation sector but also *cumulative* emissions along the way which are the more important outcome when judging emission performance (and whether a particular pathway is consistent with reaching any given global greenhouse gas concentration level). There is no cumulative emission constraint or target in the two implementations of Scenario 4, in keeping with the original Future Grid Forum assumptions.

The deep decarbonisation implementation of Scenario 4 has higher emissions to 2030, similar emissions to 2035, and higher emission again until reaching a similar level just before 2050. The higher emissions in Scenario 4: deep decarbonisation demand sensitivity largely reflects higher electricity volumes (Figure 64), however by 2050 the volume becomes less relevant as emission intensity approaches zero (Figure 70). In fact Scenario 4: deep decarbonisation demand sensitivity has a lower emission intensity than Scenario 4: Renewables thrive starting from around 2020.

In the year 2050, the level of greenhouse gas emissions of the 2014 deep decarbonisation implementation lies above the two scenarios by 2050, reflecting higher fossil based on-site generation in that modelling and therefore a slightly higher final emission intensity. Otherwise it is lower in both the level and intensity of greenhouse gas emissions from just before 2020.

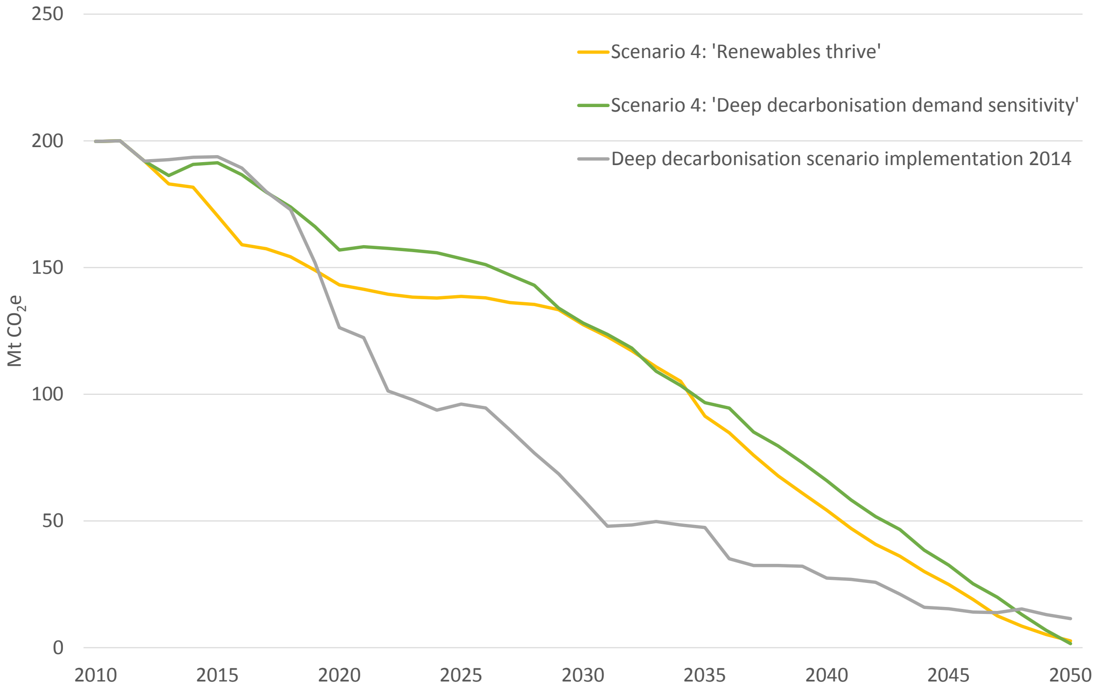


Figure 69: Comparison of annual electricity sector greenhouse gas emissions under the 2014 Deep decarbonisation scenario implementation, Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation sensitivity

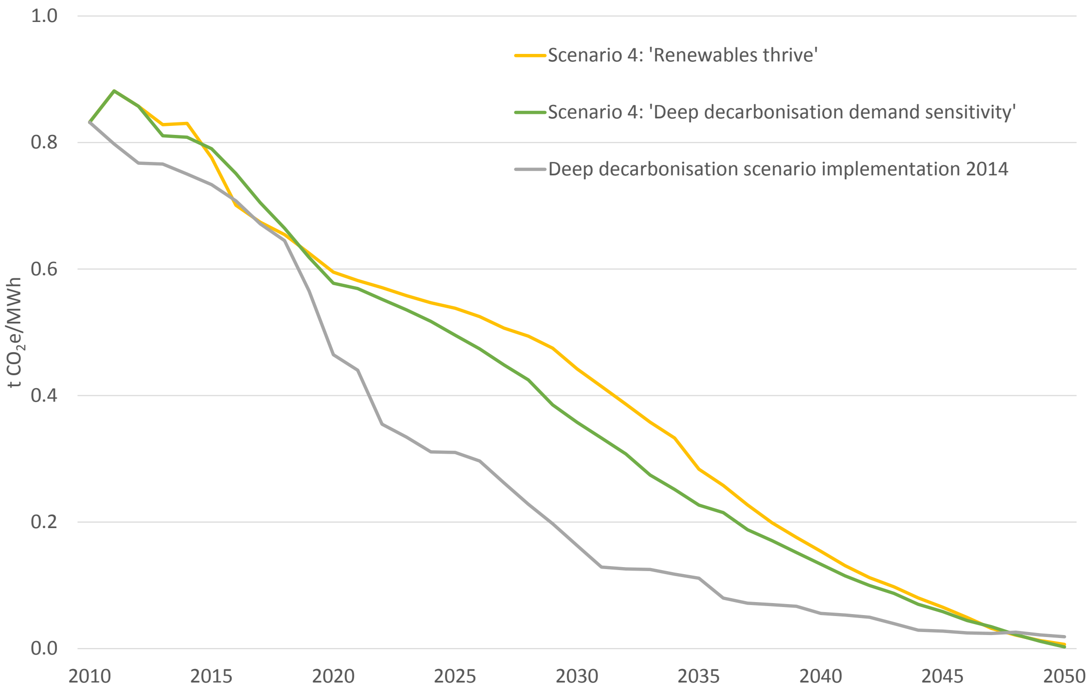


Figure 70: Greenhouse gas emission intensity of electricity generation under the 2014 Deep decarbonisation scenario implementation, Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation sensitivity

From the perspective of cumulative emissions, the 2014 implementation of the deep decarbonisation pathway has the lowest emissions by 2050 by a margin of 912 to 1291 MtCO_2e compared to the other 100 percent renewable centralised generation scenarios. This demonstrates that focussing on a target of a zero emission centralised electricity sector by 2050, which all three scenarios do, could still lead to significant variation in cumulative emissions. The results indicate that the rate of retirement of existing plant will be increasingly important from around the 2020s in determining cumulative emission outcomes. This demonstrates the risks of pursuing electrification without decarbonising the grid in tandem. It also highlights that under Scenario 4 and its sensitivity case, in order to meet the 2 degree target of the original 2014 deep decarbonisation implementation either more aggressive emission reductions will need to be pursued in other sectors or international offsets may need to be purchased.

It is also interesting to note that while Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation demand sensitivity have significantly different levels of emissions in the first two decades, their cumulative emissions run roughly in parallel for the remainder of the projection period.

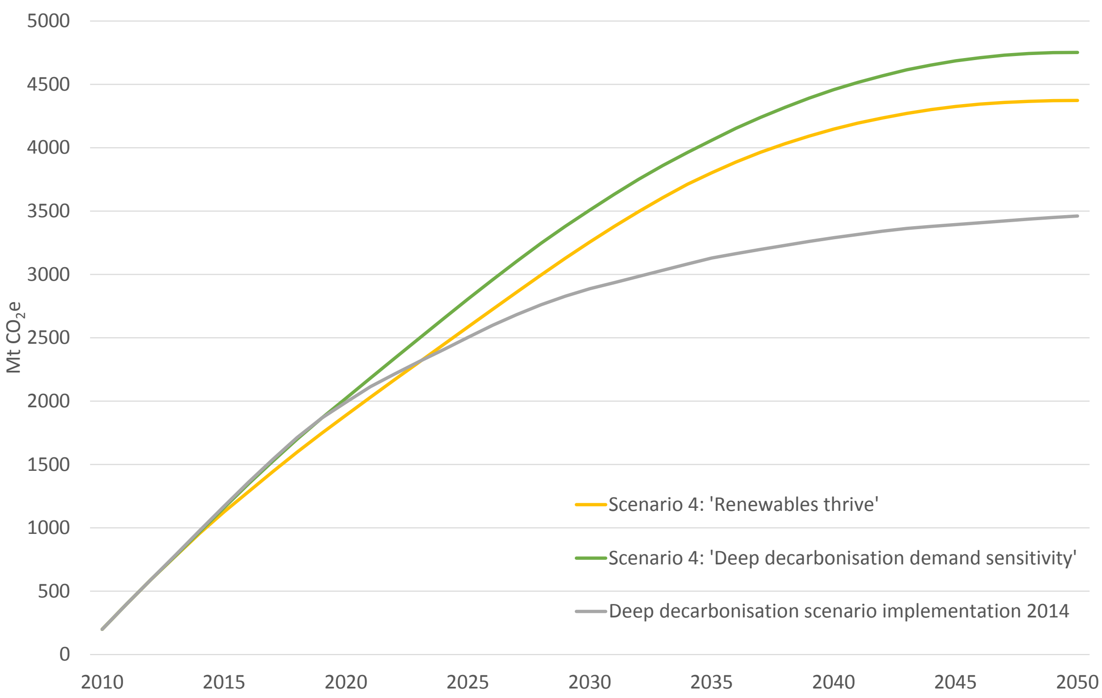


Figure 71: Comparison of cumulative electricity sector greenhouse gas emissions under the 2014 Deep decarbonisation scenario implementation, Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation sensitivity

Prices

Since the two implementations of Scenario 4 are assumed to have the same consumption to peak demand ratio, their network costs will be very similar. Consequently we only focus on their differences in generation costs. We compare the two implementations of Scenario 4 and the 2014 implementation of the deep decarbonisation scenario in Figure 72. It shows that generation costs are much lower up to the 2040s in the two implementations of Scenario 4 owing to the 2014 implementation including a much higher assumed carbon price and forced closures of coal plant. However, in the late-2040s the situation reverses such that the two Scenario 4 generation costs are higher. This appears to show that there are long term costs to beginning decarbonisation later. We have not made any further calculations to determine whether they outweigh the nearer term costs of starting sooner, but it is built into the modelling framework that it will prefer longer term costs due to the inclusion of discounting.

For most of the projection period, despite the much higher consumption growth, Scenario 4 Renewables thrive only has slightly lower generation costs than Scenario 4: Deep decarbonisation demand sensitivity. However, from the 2040s, as the quality of renewable resources declines and there is greater need to include higher cost renewables such as enhanced geothermal, offshore wind and wave energy increases to meet growth in demand, generation costs in both implementations of Scenario 4 increase. The generation price of Scenario 4: Deep decarbonisation demand sensitivity increases less rapidly because a significant amount of new demand is located in sunshine-rich states such as Western Australia where a higher reliance on good quality solar is possible under the model assumptions.

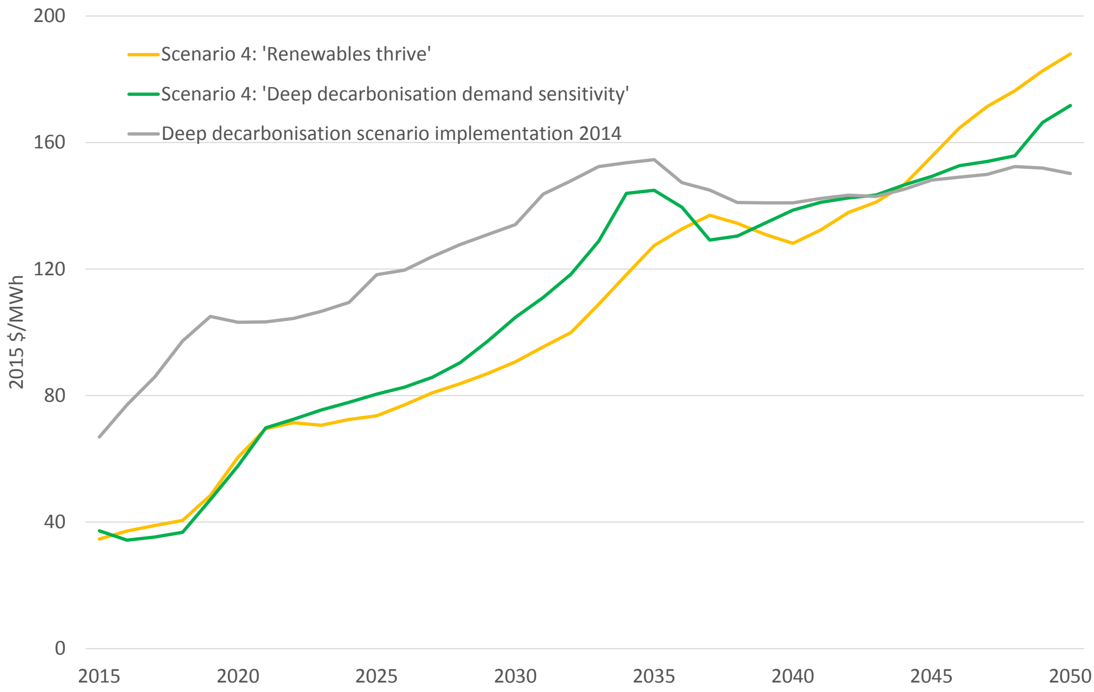


Figure 72: Comparison of generation costs under the 2014 Deep decarbonisation scenario implementation, Scenario 4: Renewables thrive and Scenario 4: Deep decarbonisation demand sensitivity

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Appendix A: Economics of grid disconnection

Industrial customers already operate off-grid in Australia, in the mining sector for example, and smaller fringe of grid customers, mainly in the rural sector, already operate Remote Area Power Systems. Instead we focus here on the less likely mainstream case for disconnection in the residential sector. If the customer was making a new connection in a regional area this would improve the economic viability enormously since some new connection costs are already in the ballpark for off-grid systems. However we focus on the more mainstream setting which is that the residence has an existing connection and the choice about whether to remain connected. Although it is acknowledged that there may be other drivers to disconnect such as environmental or independence goals the analysis below focusses purely on the economic cost using a combination of storage, solar and small engine back-up technologies.

Table 29 presents the assumptions, rationales and calculation methods for residential disconnection. Note that the solar panel and battery costs reflect the costs already described elsewhere in this document. The table shows that the projected costs for a medium consumption household to disconnect are 39 c/kWh in 2030 and 23 c/kWh in 2050. It assumes that electricity supply is primarily managed through a solar panel and battery combination. However, a back-up generator (running on diesel, natural gas or LPG) is assumed to be required for several days per year, depending on outages and household characteristics. In the long term this could equally be a fuel cell system or some other technology that has become competitive.

Disconnection costs for small commercial customers would be similar to households. While not shown further analysis of different size households did not find a strong correlation between larger electricity requirements and cost (the setup is fairly scalable). We sensitivity tested the additional cost to cover the additional electricity needs of owning an electric vehicle – this was only 1-3 c/kWh higher. There could be limits on roof space for customers with large electricity needs. However, we would also expect, community based disconnection business models, building integrated solar technologies or other technological or business innovations might address these limits.

Table 29: Estimation of the cost of an individual residential off-grid system

Item	Unit	2015	2030	2050	Rationale or explanation of assumption
Annual consumption	kWh	6000	5565	5034	6000kWh per household is the current national average with efficiency improvement assumed over time.
Generation costs					
Discount rate		0.07	0.07	0.07	This should be similar to their home loan interest rate e.g. they might fund it via a redraw or borrow against house equity
Amortisation	years	10	10	10	Some equipment will last 20 years but, like vehicles and houses, banks will require pay back well before the end of their useful life
Solar PV kit	$/kW	1900	1090	652	Includes panels & installation but inverters are in battery system
Size	kW	6.3	5.9	5.3	Needs to produce daily average consumption plus 25% buffer
Capacity factor		0.135	0.135	0.135	In most cases roof constrained so average of 0.15 is downgraded 10% for poorer angle/direction
O&M	$/kW/year	35	25	15	
Generator back-up (LPG/NG/diesel or petrol)	$	1500	1000	300	2.2 kW, 240AC. Won't allow you to run all appliances but will cover cooking, lighting and entertainment until normal services resume.
Diesel fuel equivalent fuel	$/Le	2.5	2	1.5	The future fuel might not be diesel but we use a diesel equivalent fuel price for the sake of the calculations
Generator efficiency		0.3	0.3	0.3	Assume more expensive generator is more efficient
Time generator needed	Days	30	30	30	Additional days allow for meeting occasional higher loads of larger energy users

Fuel consumption	MJ	3255	3019	2731	Days multiplied by ratio of day requiring storage multiplied by daily energy use divided by efficiency and multiplied by 3.6 to convert watt hours to joules
Diesel fuel	$	211	156	106	Consumption multiplied by diesel cost converted to $/MJ/L via diesel equivalent energy content of 38.6MJ/L
Annual cost	$	2362	1359	722	Basic amortisation formula for capital is r(1+r)^t/((1+r)^t-1) where r is the discount rate and t is the amortisation period
Storage costs					
Discount rate		0.07	0.07	0.07	as above
Amortisation	years	10	10	10	as above
Batteries, power conversion & housing/install	$/kWh	543	259	207	These costs reflect the assumed battery cost trajectory from current to 2050
Size	kWh	11.16	10.35	9.37	A function of the assumptions below
	kW	5	5	5	Allows for operation of a medium size air conditioner, oven, entertainment devices and lighting simultaneously although some preloading of air conditioning before needed via would make sense.
Consumption ratio requiring storage		0.55	0.55	0.55	With demand management shifting loads into middle of the day, this ratio is the fraction of daily consumption that storage must provide
Efficiency		0.9	0.9	0.9	Round trip efficiency for storing and discharging
Useful capacity		0.9	0.9	0.9	The capacity of the battery that can be accessed
O&M	$/kW/year	100	36	10	Essentially meant to be maintenance free but there could be some service call outs

Annual cost	$	1979	755	370	Formula as above
Demand management costs					
Discount rate		0.07	0.07	0.07	as above
Amortisation	years	10	10	10	as above
Smart meter and appliance on cost	$	300	260	225	Includes smart meter and additional costs of smart appliances, not whole appliance.
Operating	$	60	40	20	E.g. software updates
Annual cost	$	103	77	52	Formula as above
Annual electricity costs					
Total	$ p.a.	4444	2191	1144	Amortised cost per annum
Per volume costs	c/kWh	74	39	23	Cost for electricity delivered