GOVERNMENT OF WESTERN AUSTRALIA

Energy Transformation Taskforce

Whole of System Plan

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Energy Transformation Taskforce

On 20 May 2019, the Hon Bill Johnston MLA, Minister for Energy established the Energy Transformation Taskforce to deliver the Western Australian Government's Energy Transformation Strategy. The Taskforce reports directly to the Minister for Energy and comprises five members, including an Independent Chair and four senior State Government officials:

- Mr Stephen Edwell – Independent Chair
- Mr Michael Court – Deputy Under Treasurer, Department of Treasury
- Ms Kate Ryan – Executive Director, Energy Policy WA
- Mr Brett Sadler – Director, Economic, Environment and Industry, Department of the Premier and Cabinet
- Ms Katharine McKenzie – Principal Policy Adviser to the Hon Bill Johnston MLA, Minister for Energy

Contents

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

TERM	DEFINITION
Access Code	Electricity Networks Access Code 2004
AEMO	Australian Energy Market Operator
capex	Capital expenditure
CO_2-e	Carbon dioxide equivalent
CCGT	Combined Cycle Gas Turbine
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DER	Distributed Energy Resources
DSM	Demand Side Management
DSOC	Declared Sent Out Capacity
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
ESS	Essential System Services
ETIU	Energy Transformation Implementation Unit
ETS	Energy Transformation Strategy
FOM	Fixed Operating and Maintenance costs
GW	Gigawatts
GWh	Gigawatt hours
GSOO	Gas Statement of Opportunities
IRR	Internal Rate of Return
LFAS	Load Following Ancillary Services
LRR	Load Rejection Reserve
Mt	Megatonne
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NPC	Net Present Cost
OCGT	Open Cycle Gas Turbine
PFR	Primary Frequency Response
PV	Photovoltaic
RoCoF	Rate of Change of Frequency
SIL	System Interruptible Load
SRAS	Spinning Reserve Ancillary Service
SRMC	Short Run Marginal Cost
SWIS	South West Interconnected System
the Taskforce	The Energy Transformation Taskforce
USE	Unserved Energy
VOM	Variable Operating and Maintenance costs
WEM	Wholesale Electricity Market
WOSP	Whole of System Plan

Chair's foreword

The revolution in renewable energy technology is profoundly changing energy systems globally.

In Western Australia, our stellar solar and wind resources provide a wonderful opportunity to benefit from low emission, low marginal cost energy from both large-scale facilities and small generation and storage resources located within the distribution system and on customer premises.

The Western Australian Government has wisely recognised this transition needs a plan and careful management. In May 2019, the Minister for Energy, the Hon. Bill Johnston MLA, announced an Energy Transformation Strategy (ETS) and established an Energy Transformation Taskforce (the Taskforce) to implement it.

The presentation of this report to the Minister is a major implementation milestone. It follows the Government's release of the Distributed Energy Resources (DER) Roadmap earlier this year and the ongoing redesign work for a new Wholesale Electricity Market (WEM) to commence in 2022.

From an investment, power system planning and energy policy perspective this transition gives rise to some interesting questions. These include:

- How is the capacity mix of generation facilities likely to evolve and where is new generation likely to be located?
- What will be the investment requirement for new power generation and in what technology types?
- How big a role will customer-owned generation play in the future mix?
- What opportunities are there for energy storage in a power system with increasing intermittency?
- How reliant will the power system be on gas-fired generation for energy firming to meet demand and keep the system stable?
- What is the outlook for coal-fired generation?
- What level of network upgrades will be needed to accommodate new generation and where?
- What is the trajectory for carbon emissions under current Government policy settings?

If you are interested in these questions you will hopefully enjoy reading this Whole of System Plan (WOSP) report.

This WOSP provides a macro perspective on the South West Interconnected System (SWIS) transition dynamics as the power system becomes increasingly influenced by the revolution in renewable energy technology. The fundamental task we set for the WOSP was to provide an unbiased outlook on the evolution of the power system – specifically, what is the lowest cost mix of capacity resources and transmission network augmentation that meets electricity demand and keeps the power system secure?

The WOSP provides this SWIS outlook based on the physics and the economic empirics under existing policy settings – in other words, based on reasonable assumptions regarding the functionality and future cost trajectories of different generation and storage technologies and the constraints imposed by power system physics, including inter-regional constraints on the high voltage network.

The aim of the Taskforce was to test the resilience of the power system to respond to high and low demand growth futures and not to present a particular 'base' case that we think more likely to occur. It is up to stakeholders to make their own interpretation of the results.

The WOSP is based on arguably the most comprehensive modelling of the SWIS ever undertaken. We have covered the two decades to 2040 in granular detail under four possible future states. A few telling statistics about the model are that it includes:

- demand forecasts for end-user consumption and a rooftop solar production for 108 Western Power substation connection points across the SWIS, taking account of electric vehicle charging and behind-the-meter batteries;
- 100,000 individual power system and network constraint equations;
- nine years' historical reference of solar irradiation and wind data;
- 20 iterations of the resource planning model, each with 90 hours of run time; and
- generator and storage dispatch at 30-minute intervals for 20 years for the four demand scenarios.

One challenge for us has been the undertaking of the WOSP modelling in parallel with Taskforce policy development on relevant market elements such as energy storage and essential system services (ESS). I think we have made a reasonable fist at this integration. Subsequent WOSPs will be able to improve on this first attempt.

The Taskforce has made ten high level observations from the modelling. Overall, my perspective is that the WOSP, in conjunction with the implementation of the DER Roadmap actions and the new market design, demonstrates the SWIS will have the market structures to accommodate high levels of renewable energy provided we continue to plan and manage the transition.

The modelling underpinning this report is the result of a highly collaborative effort involving market agencies, industry participants, technology businesses, future investors and finance institutions. We have had over 120 meetings with stakeholders, 20 team workshops to refine the WOSP modelling structure and parameters, and two industry forums. We have been provided high quality data and private stakeholder perspectives that have greatly assisted our work. The Taskforce is very appreciative of this broad spectrum of support.

I particularly want to acknowledge the invaluable input from folk at Western Power and the Australian Energy Market Operator (AEMO) and the people at EY who met our scope with a first class model of the SWIS and operated the WOSP model as part of the project team.

Project Director Noel Ryan, Project Lead Miles Jupp and the Energy Transformation Implementation Unit team have applied their extensive commercial and technical skill to perform above and beyond in the delivery of this project.

I especially need to thank my fellow Taskforce colleagues for their commitment and insightful contribution to the development of this report over many meetings.

Stephen Edwell
Chair, Energy Transformation Taskforce

Executive summary

Whole of system planning is integral to managing the energy transformation happening in Western Australia. Having an informed view on what Western Australia's principal electricity system (the SWIS) might look like over the coming decades, and the types of investment to achieve lower-cost, lower-emissions electricity, is immensely helpful to shape the future of our power supply.

This inaugural WOSP report, and the extensive modelling that informs it, presents four scenarios of how the SWIS may evolve through to 2040. Each scenario; Cast Away, Groundhog Day, Techtopia, and Double Bubble, contains a range of assumptions of electricity demand growth based on economic climate, demographic changes, and DER uptake.

The exhaustive WOSP modelling and analysis – the most comprehensive ever undertaken on the SWIS – takes these scenario inputs and produces a mix of the lowest cost to supply for transmission, generation and storage capacity required to meet demand under each scenario.

This view of the lowest cost to supply for each scenario can be used as a guide to investment and energy policy decisions necessary to capitalise on the benefits of low emission, low marginal cost renewable energy whilst keeping the power system reliable and secure.

In all four scenarios, rooftop photovoltaic (PV) uptake is assumed to continue to increase, but at differing levels. Under the lower demand scenarios, relatively little additional generation capacity is required before 2030 as there is more than enough rooftop PV and existing large-scale generation in the system to meet demand. In the higher demand scenarios, the lowest cost to supply solution includes a significant amount of large-scale renewable generation, complemented by some new flexible gas-fired facilities. There are no transmission capacity increases required over the study period under the lower demand scenarios and little required in the first ten years of the higher demand scenarios. It is only when operational demand doubles in the SWIS that the first of several large transmission capacity increases takes place. Energy storage plays an important role in the provision of ESS and capacity in all scenarios, but at differing scale. Emissions intensity of electricity production decreases in all scenarios.

The inaugural WOSP Report presents four scenarios of how the SWIS may evolve to 2040

Cast Away

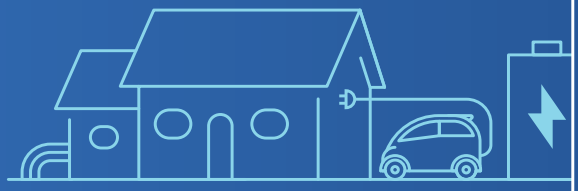
Muted economic growth coupled with greater decentralisation

Groundhog Day

Distributed energy resources thrive, but reliance on the network remains high

Techtopia

Technological change flattens the increasing energy demand profile



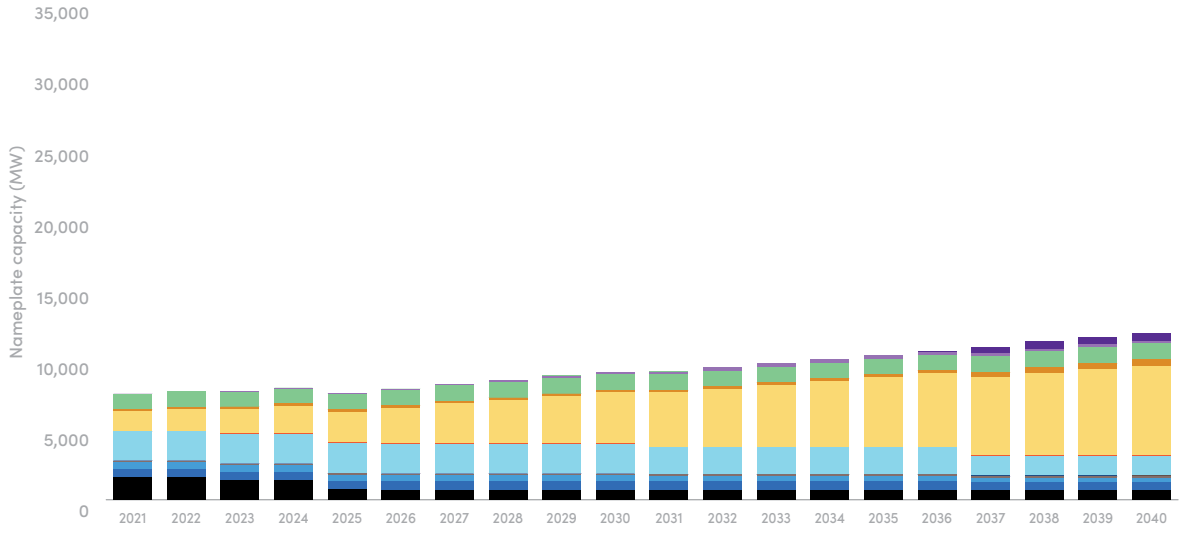
Double Bubble

Ongoing strong economy results in largest growth in demand

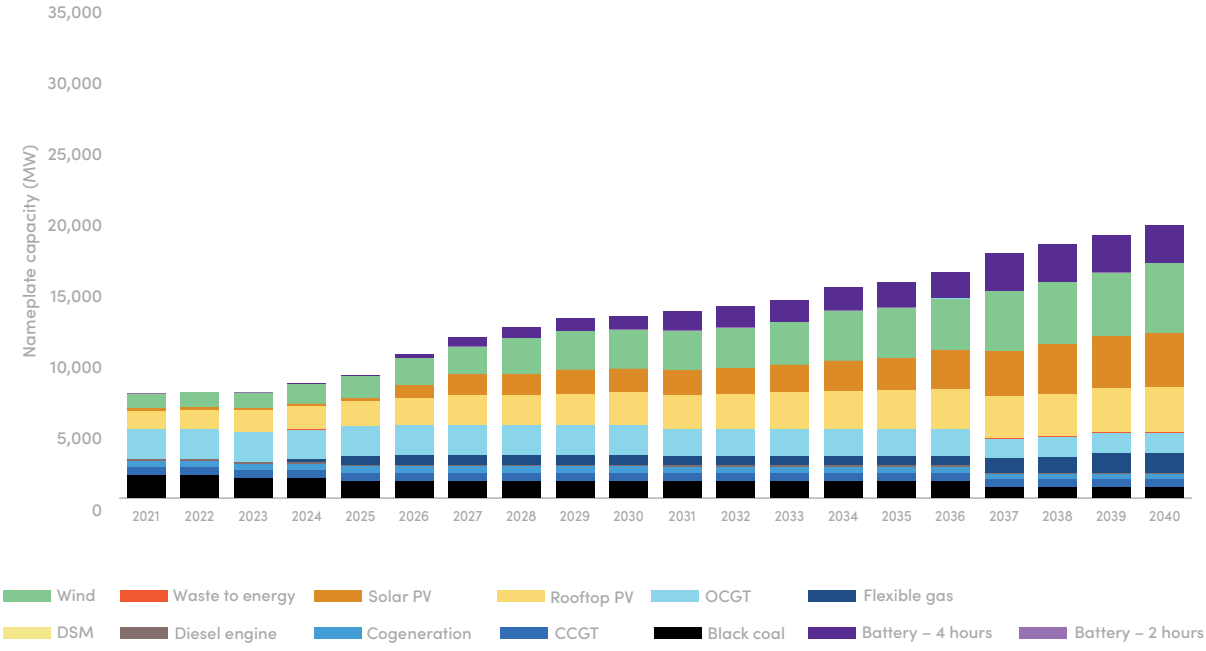
WOSP modelling scenarios

The following charts show the evolution of the generation and storage capacity mix under each scenario over the 20 year period.

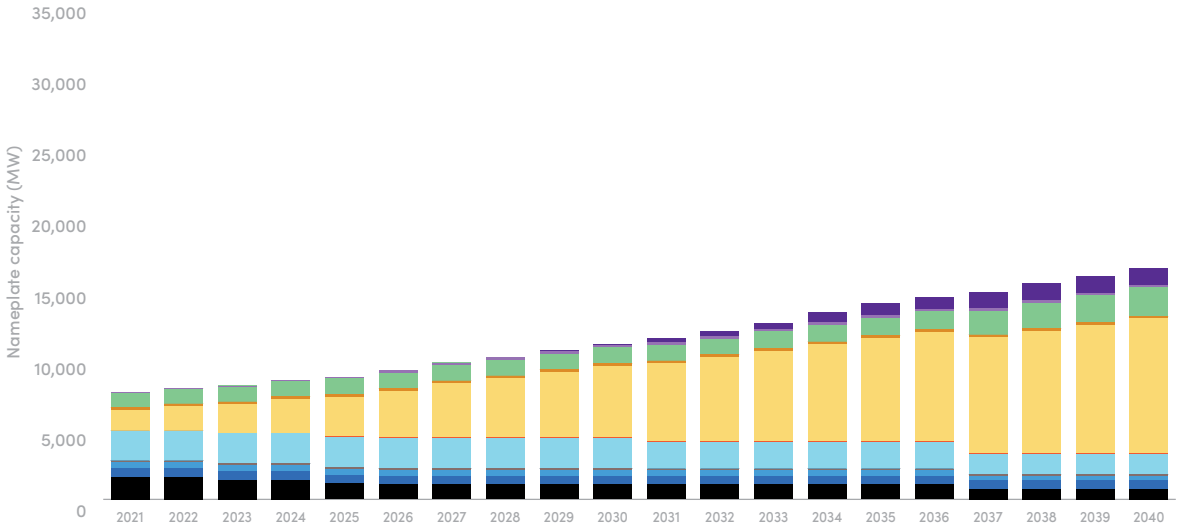
Cast Away



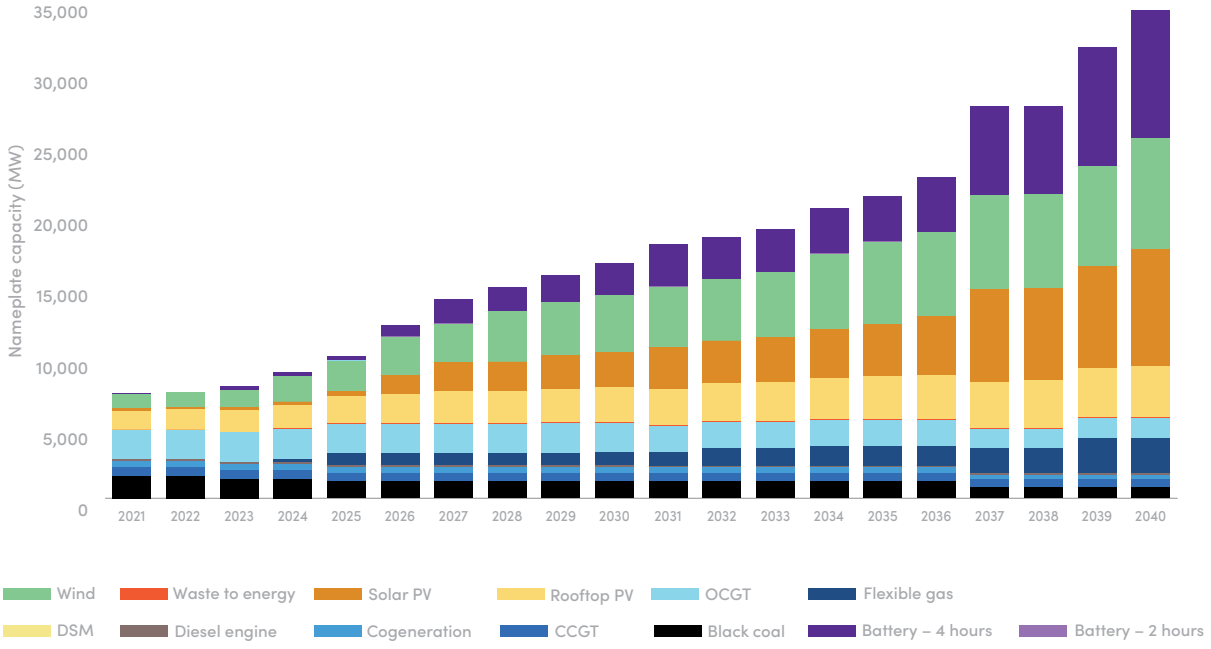
Techtopia



Groundhog Day



Double Bubble

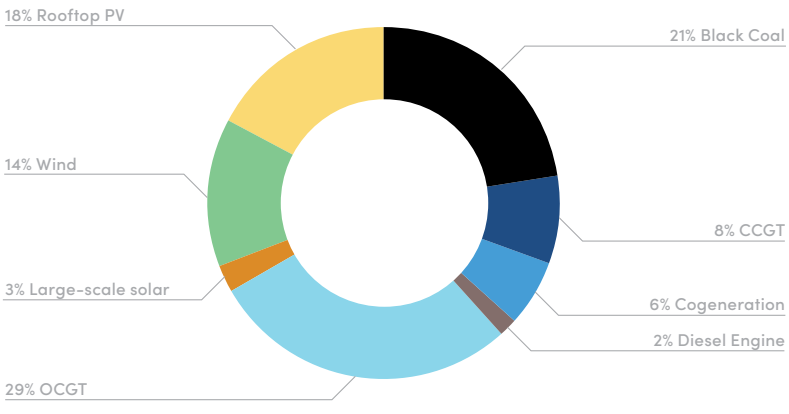


The Taskforce has identified ten highlights or key findings from the WOSP model outputs.

HIGHLIGHTS

1. The SWIS already has a strong mix of renewables, with renewables comprising 34% of installed capacity at the beginning of the modelling period
2. Under all four modelling scenarios, over 70% of generation capacity is renewable by 2040
3. Rooftop PV will continue to displace other forms of generation, most significantly coal and large-scale solar
4. Growth in renewables reduces emissions over the study period, despite the overall increase in end-user demand
5. Growth in intermittent generation is supported by firming from storage and gas facilities
6. New generation connections are best located in the South West transmission network zone to utilise existing network capacity and add generation diversity
7. Coal-fired generation declines under all scenarios, and partially exits the market in the mid-2020s in the low demand growth scenarios
8. There is opportunity for storage and renewables to provide ESS
9. As new ESS and capacity mechanisms are embedded, revenue streams for generation will become more diverse
10. Little or no major transmission network augmentation is required in the near future

The capacity mix in the SWIS is already in a strong position. In 2020 there is a healthy mix of renewable and thermal generation. Gas remains the largest capacity provider, accounting for 52% of large-scale generation. However, our reliance on coal and other forms of thermal generation is decreasing. By the end of 2020, renewable generation comprises 2,494 MW (34%) of installed capacity, of which rooftop PV makes up more than half (1,291 MW).



2020 SWIS generation capacity mix

Under all scenarios, most new generation capacity is renewable. This is because the WOSP modelling selects new generation capacity based on the lowest overall cost to supply the system, which considers (among other things) fuel availability, network capacity, connection, installation and operating costs. Large-scale renewable generation such as wind and solar are the least expensive forms of capacity to construct and operate.

However, rather than select new generation types purely based on the cost to install and connect to the network, the WOSP modelling simulates how often new capacity is likely to be dispatched, and what its potential revenue streams and costs might be in the new energy market post-2022. This paints a picture of whether installing a particular technology in a certain location is likely to be an economic and fundable investment.

On this basis, the WOSP modelling selects wind generation as the preferred form of new large-scale capacity over the study period in all scenarios, with additional new wind facilities by 2030 ranging from 60 MW in the lowest demand scenario (Cast Away), to 3,002 MW in the highest demand scenario (Double Bubble). In comparison, no new thermal generation capacity is required under either of the lower demand scenarios (Cast Away and Groundhog Day), but between 667 MW and 867 MW of new gas-fired generation is required in the higher demand scenarios by 2030.

The WOSP modelling selects the South West transmission network zone as a lower cost solution for connecting new wind generation facilities on the combination of available transmission network transfer capacity and wind resource availability in that location.

Most notably, no new large-scale solar generation facilities are selected in the lowest cost to supply energy mix before 2030 under Cast Away or Groundhog Day.

Rooftop PV is assumed to form a dominant part of the future generation capacity mix. The reason for this is two-fold. Firstly, there is no market cost attributed to installing new rooftop PV capacity – the systems are paid for and installed by individual customers. Secondly, the surplus energy produced by rooftop PV spills out into the network throughout the day, meaning it is effectively 'dispatched' ahead of all other capacity and displaces all forms of large-scale generation, subject to ESS requirements on the system.

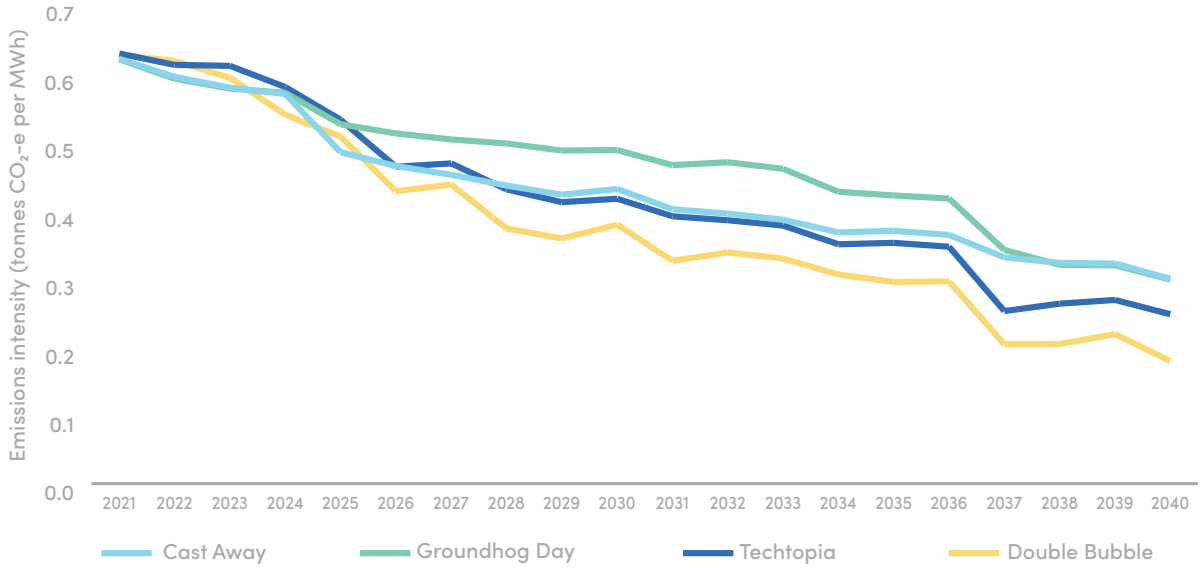
As a result, even when large-scale generation capacity leaves the system the void is filled by rooftop PV and existing gas-fired generation, which also provides firming for the greater levels of intermittency resulting from rising renewables.

Given the increasing role of rooftop PV the WOSP modelling validates actions outlined in the DER Roadmap, which will enable rooftop PV to be integrated into the power system and the aggregation and orchestration of DER more generally.

The modelling also identifies an opportunity for energy storage facilities such as batteries to enter the market (across all scenarios), mainly to provide particular energy services such as frequency control. The modelling shows large-scale storage, specifically 2-hour and 4-hour duration battery storage, has an increasingly influential role in the SWIS over the study period. New storage systems form part of the lowest cost to supply almost immediately, with around 50 MW of 2-hour duration battery capacity entering the market in year one under Cast Away, Groundhog Day and Techtopia, and around 20 MW of 4-hour duration battery capacity under Double Bubble – in each case to provide ESS.

The new ESS market, a key component of the ETS, will enable greater diversity in the facilities that can provide ESS in the WEM. Currently, ESS are provided exclusively from thermal generation plant. Large-scale storage offers an alternative to thermal generation in the provision of ESS as it can be used to respond very quickly to fluctuations in the power system, which will be increasingly important as the levels of intermittent generation increase. Beyond 2030, operational demand increases to a level where battery storage can play a more prominent role in providing energy services.

The WOSP modelling highlights the economic pressure on coal-fired generation, which has been declining as a proportion of overall electricity generation for much of the past decade, as daily demand profiles have changed and more lower-cost and flexible forms of generation have entered the market. Coal-fired generation works best between a minimum and maximum level of output. The increase in rooftop PV means coal-fired plants are dropping below their minimum output more often and will have to increasingly shut down and then restart.



Annual emissions intensity to meet end-user demand, tonnes CO_2-e per MWh

This level of cycling of coal-fired generation facilities drives up operating and maintenance costs which puts pressure on the economics of this type of baseload plant.

The WOSP modelling shows the displacement of coal-fired generation is likely to continue over the next 20 years, however coal still has a role to play. The marginal cost of existing coal-fired generation is low, and the generation assets are a sunk cost. This means coal will remain part of the lowest cost energy supply mix for the foreseeable future.

Under all modelled scenarios, emissions reduce over the study period. Overall emissions levels fall most rapidly in the lower demand scenarios (decreasing by up to 41% in Cast Away). However, emissions intensity, which is a measure of the amount of Carbon Dioxide equivalent (CO_2-e) attributed to the production of a MWh of electricity, decreases by at least 50% under all scenarios. This is due to the continued introduction of renewable generation as a replacement for ageing thermal generation.

The final highlight to note from the modelling is that no transmission network augmentation is required to meet the two lower demand scenarios over the study period. Under the two higher demand scenarios, an augmentation to increase transfer capacity between the South West and the Eastern Goldfields transmission network zones is required by 2025, followed by an augmentation between the South West and Metro zones by 2029. Further augmentations across the network would be required after 2030, where demand doubles under Techtopia and Double Bubble.

Energy storage, when located effectively, can be used to maximise the utilisation of network assets and intermittent generation. As overall generation capacity increases, it would be reasonable to expect a significant amount of network augmentation would be required. However, the relatively low cost of batteries compared to network augmentation means the modelling has located storage and intermittent generation to maximise the utilisation of existing network and avoid or delay network augmentation.

Western Power Control Centre. Source: Western Power.

A further reason for the low level of transmission augmentation is the new proposed constrained network access regime. This promotes more efficient utilisation of existing network capacity, meaning new generation capacity can connect without the need for the extensive transmission system augmentation within or between zones that would have been required under an unconstrained network access regime.

In this respect, the WOSP modelling again validates the work currently under way as part of the ETS to introduce a constrained network access regime for the SWIS. Indeed, one of the recurring features of the extensive WOSP modelling is that it highlights the importance of delivering all of the actions under the ETS as planned. This includes the actions under the DER Roadmap, tariff pilots, and the reformed WEM and ESS markets.

Modelling outputs point toward the WEM reforms as being integral to managing the security and reliability impacts of our ongoing energy transformation. All four scenarios clearly indicate a need for continued diversity in generation capacity, greater use of energy storage, and the benefit of broader energy and ESS market participation. The ETS is designed to allow this evolution to happen.

The guidance in this WOSP report, coupled with continued whole of system planning will play an important role in managing the transition from traditional energy sources to lower-cost and lower-emissions technologies, helping shape a brighter energy future for Western Australia.

1. Background and Context

This is the inaugural WOSP for the SWIS. The WOSP has been developed by the Taskforce, with detailed input from Western Power and the AEMO.

The Western Australian energy sector is transforming. Renewable and DER accounted for an estimated 21% of electricity used in the SWIS in 2019-20[1], compared to an estimated 12% in 2015-16, and will likely continue to supply an increasing share of the SWIS' energy needs.

Over the coming decades more renewable generation will enter the market, energy storage technology will continue to improve, and older generation plant will need to be retired. Given the inevitability of this ongoing transformation it is vital to have a consolidated longer-term perspective of the entire power system to guide investment, planning and policy development.

The WOSP provides a view on the lowest cost mix of generation, storage and network augmentation requirements for the SWIS under four different electricity demand scenarios over the next 20 years. It presents the findings of detailed power system and electricity market modelling, which identifies what electricity generation and storage capacity opportunities exist, when and in which region that capacity is best located, and what network investment is required to allow it to connect.

Most importantly, the WOSP is a guide to how Western Australia's principal power system can continue to provide safe and reliable electricity to the approximately 1.1 million customers that depend on it, at the lowest overall system cost.

The WOSP is a first for Western Australia. It is based on arguably the most rigorous modelling undertaken to date of the State's main power system. It provides a granular, forward-looking view of SWIS requirements, using data and information from a wide range of sources, including from parties who build, operate and participate in Western Australia's energy sector.

The WOSP is a complement to existing planning tools such as AEMO's *Electricity Statement of Opportunities*, (ESOO) or Western Power's *Network Development Plan*.

However, because of its comprehensive and impartial analysis of the SWIS as an integrated power system, the WOSP and the modelling outputs that sit behind it will inform future infrastructure investment requirements, energy policy, and energy market development initiatives. Of course, forces influencing electricity systems are constantly changing, which is why the WOSP and the modelling behind it will be updated periodically.

Findings in this inaugural WOSP and future plans will be especially relevant to managing the security and reliability impacts of transitioning from traditional energy sources to intermittent, distributed, lower-emissions technologies, helping shape a brighter energy future for Western Australia.

1 21% includes sent-out large-scale renewable generation and an estimate of the output of rooftop PV based on installed capacity per month for 2019-20.

1.1 The WOSP and the broader Energy Transformation Strategy

The WOSP is the product of one of three work streams currently under way as part of the Western Australian Government's ETS.[2] The three work streams are:

- Whole of System Planning;
- Foundation Regulatory Frameworks;[3] and
- Distributed Energy Resources.

The ETS is delivering a number of wide-ranging reforms to the SWIS, including changes to the WEM. These reforms will impact the way electricity generators access the grid, are scheduled and dispatched, as well as how new technologies will be fully integrated into the power system.

The three work streams are progressing in parallel. Where possible, developments in other parts of the ETS have been factored into this inaugural WOSP.

For example, work is currently under way to develop a new ESS market for Western Australia. The WOSP modelling takes into account the availability of potential revenue streams from the ESS for new generation and storage facilities as an input into determining the lowest cost capacity mix. The model uses assumptions taken from the draft design of the ESS market, including the revised ancillary service definitions and parameters, and uses these to simulate co-optimised dispatch of ESS and energy requirements. Incorporating the latest ESS assumptions in this way helps improve the rigour and relevance of the modelling outputs (refer to section 4.9 for detail on how ESS are factored in the modelling).

However, some elements of the ETS implementation were not finalised at the time modelling for this inaugural WOSP was undertaken. Only inputs and decisions that had been endorsed by the Taskforce and published at the time of formulating the WOSP have been incorporated, where relevant.[4] The design elements from the ongoing ETS that have been factored into this inaugural WOSP are described in the WOSP methodology outlined in Appendix A.

Subsequent iterations of the WOSP will encapsulate further elements of the ETS, through to delivery of the new WEM[5] and beyond.

1.2 How to use the WOSP

This document presents discussion on the key findings and observations developed from the detailed demand and power system modelling undertaken as part of the WOSP. The WOSP should therefore be read in conjunction with the modelling input data and assumptions, provided in Appendix B.

The WOSP presents four scenarios. Each scenario represents a credible view of what electricity demand[6] in the SWIS could look like depending on the economic environment and what technology uptake occurs (refer to section 2.3 for an overview of the four modelling scenarios).

2 Information on the ETS is available at: https: //www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

3 To improve the operation of the WEM and enhance the security and reliability of the power system (under *Delivering the Future Power System*) and facilitating more equitable and efficient use of capacity on the Western Power network (*Improving Access to the SWIS*).

4 The Taskforce's most recent publications can be found on the Energy Policy WA website: https: //www.wa.gov.au/government/document-collections/taskforce-publications.

5 Due to commence from 1 October 2022.

6 The scenarios are not forecasts of electricity demand, rather they are detailed assumptions of potential demand developed for the purpose of forecasting what generation and network requirements would be needed if that level of demand materialised.

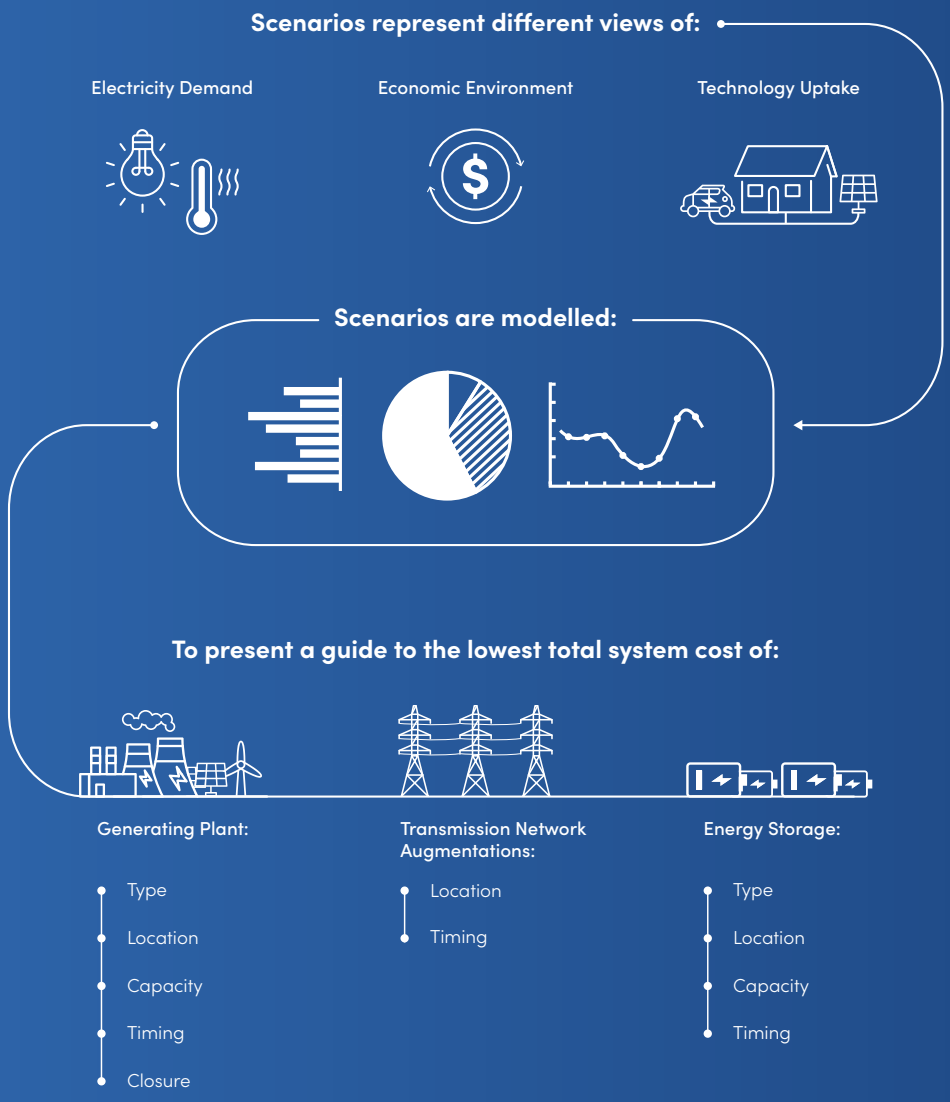


Figure 1.1: High level overview of how the WOSP works

The scenarios are then modelled and the outputs used to present a view of the lowest cost mix of generation and storage capacity to meet electricity demand over the next 20 years. This includes the timing and location of new capacity, and generation facility retirements. The scenario modelling also presents a view of efficient transmission network augmentation[7] that may be required to allow new generators or loads to connect without impacting system security or reliability.

This modelled view of the lowest cost mix of capacity and network augmentation under each scenario is referred to throughout this document as the **lowest cost to supply.** Refer to section 2.4 for a more detailed explanation of how the model determines the lowest cost to supply for each scenario.

Figure 1.1 presents a high-level overview of how the WOSP works and what it tells us. For detail on the WOSP modelling methodology, including consideration of ESS, refer to Appendix A. The WOSP modelling outputs are provided in Chapter 4 and Chapter 5.

What actually occurs in the SWIS over the coming years can be expected to lie somewhere in between the four scenarios modelled in the WOSP. The WOSP outcomes are simply a guide to what the lowest cost capacity mix and transmission network augmentation requirements would be under each scenario.

7 The WOSP does not consider transmission asset replacement and augmentation within a transmission network zone, or distribution network augmentation or distribution network constraints.

For example, if an investor or generation business is seeking to develop a wind project to connect to the network, they can look at the outcomes under each scenario in the WOSP and use these (along with the many investment considerations they would usually undertake) to help guide where the best region to locate might be and the optimal time to connect.

This ability to guide and inform is the true value of the WOSP. It presents information by transmission network zone and by generation type. The WOSP is technology agnostic and provides an impartial view of the SWIS and its development, driven by the economics and physical needs of the power system. It brings together robust data from the network owner, power system operator, market participants, and other credible sources, and provides a well-informed, empirical outlook of how the power system might evolve under a set of reasonable and credible scenarios.[8]

1.2.1 Identifying priority projects

The Taskforce has recommended the introduction of the 'priority project' concept as part of its proposed changes to the Electricity Networks Access Code 2004 (Access Code) to support the delivery of the ETS.

It is intended that priority projects are large-scale transmission network related projects[9] only. In some circumstances the WOSP modelling might identify that power transfer capacity between major regional sections of the transmission network[10] needs to be increased in order to allow new generation capacity to connect in certain parts of the power system. These upgrades would be identified in the WOSP as efficient and critical for timely development.

No priority projects have been identified in this inaugural WOSP. However, it is likely that priority projects will be identified in future iterations of the WOSP.

There are two main considerations for determining a priority project in the WOSP:

1. **urgency** – where there is a network limitation or technical constraint that is likely to cause significant system stability or reliability issues within the next five years and, importantly, whether there are barriers that make the likelihood of the project going ahead uncertain; and
2. **impact on electricity users** – where the network limitation (whether network capacity or stability) is a significant barrier to major loads or generators connecting to that part of the transmission network, or where the network limitation is a barrier to future growth and connection of innovative or alternative technologies to deliver the lowest cost energy to users.

The purpose of including priority projects in the WOSP is to help streamline the process for getting them done. If a priority project is identified in the WOSP, it will no longer be subjected to a Regulatory Test for approval by the Economic Regulation Authority (ERA).[11] This is because the WOSP modelling provides a reasonable and robust substitute for the Regulatory Test, in that the WOSP modelling:

- applies reasonable market development scenarios which incorporate varying levels of demand growth;
- uses reasonable timings and alternatives for project construction/commissioning dates; and
- considers the net benefit to those who generate, transport and consume electricity, after considering alternative options.

8 The WOSP and the modelling outputs that inform it are provided as a guide only. It is for energy sector stakeholders (WEM participants, investors, government departments, technology suppliers etc.) to form views on what they believe will materialise in the market and what investments are most prudent for them.

9 Greater than $38.7 million consumer price index adjusted from 2004 as per the Regulatory Test.

10 Referred to as transmission network zones.

11 ERA, Guideline for Application of the Regulatory Test: https: //www.erawa.com.au/electricity/electricity-access/guidelines/regulatory-test-guidelines.

These are all requirements of the current Regulatory Test. It therefore follows that if the WOSP modelling identifies a particular transmission network augmentation as a priority project, that project will satisfy the Regulatory Test criteria, and the formal application of the Regulatory Test can be bypassed. This means Western Power can proceed with the work more quickly.

The ERA will still be required to review the efficiency of the investment Western Power has made via the New Facilities Investment Test.[12] There will therefore remain sufficient incentives and tests to ensure Western Power delivers the project prudently and efficiently. Identifying priority projects in the WOSP and allowing Western Power to bypass the Regulatory Test is aimed to ensure priority network projects proceed without unnecessary delay.[13]

1.2.2 WOSP structure and content

The structure and content of the WOSP is summarised below.

- **Chapter 1** – provides the background and context for the WOSP, including an overview of the SWIS and the transmission network zones used for modelling.
- **Chapter 2** – describes the process undertaken to develop the WOSP, and a high-level overview of the demand scenarios, modelling approach, and key assumptions.
- **Chapter 3** – shows the highlights and key findings of the WOSP in visual format. It provides a series of charts to show the generation and storage capacity mix required to meet demand at the lowest cost to supply under each modelling scenario.
- **Chapter 4** – describes the SWIS-wide findings and outputs from the WOSP modelling, including observations on costs.
- **Chapter 5** – describes findings and observations at a regional level, presented by transmission network zone.

1.3 The SWIS and transmission network modelling

The WOSP is a detailed study into the current state and the future of the SWIS.

The SWIS is the principal power system in Western Australia, supplying electricity to more than 1.1 million homes, businesses and major industrial energy users. It reaches as far north as Kalbarri, east to the Goldfields and south to Albany. It is one of the largest isolated electricity systems in the world.

For the purpose of the modelling, the SWIS is separated into eleven transmission network zones as illustrated in Figure 1.3.

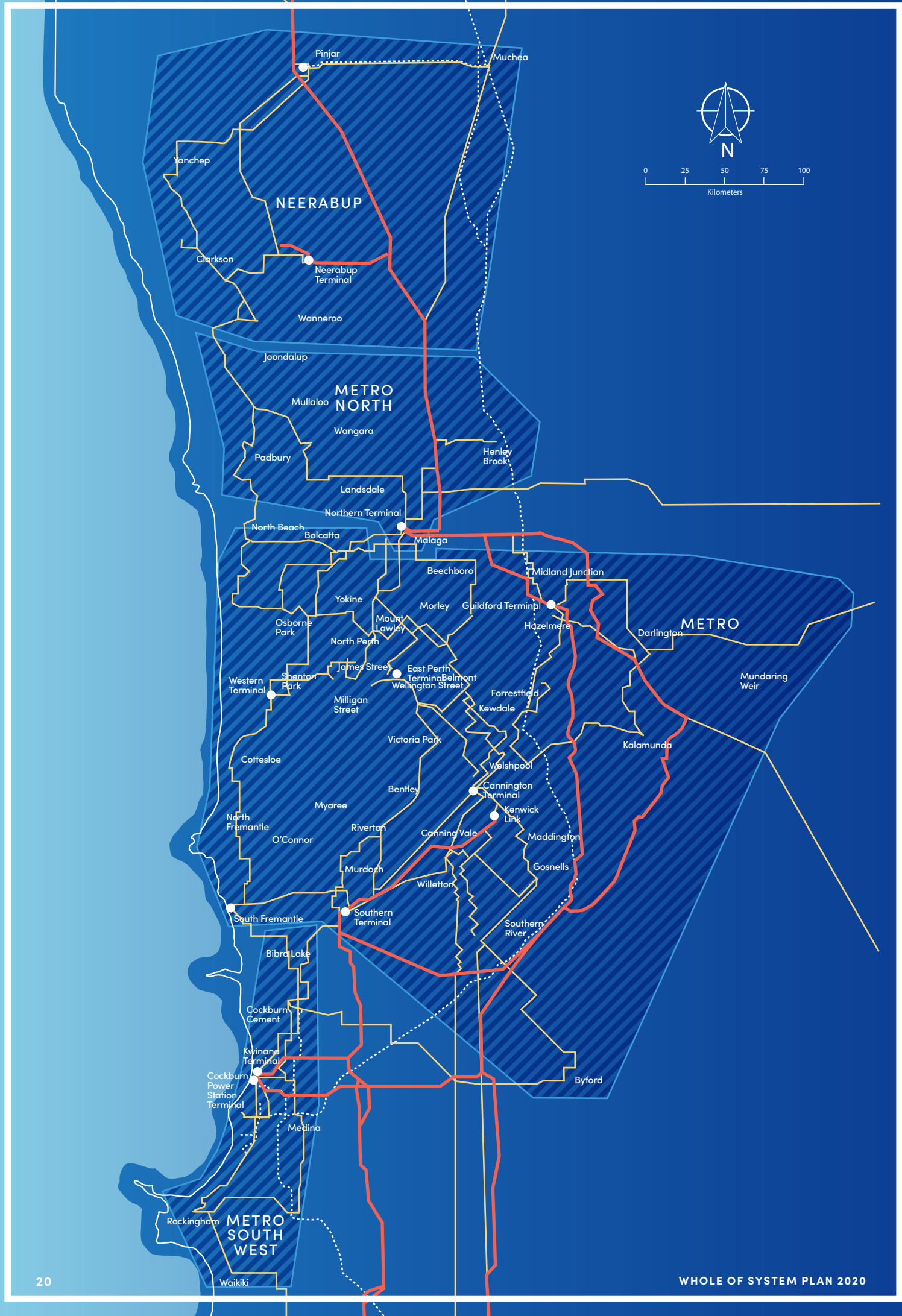
The boundary of each transmission network zone is based on the power transfer limit between different sections of Western Power's transmission network.

Key assumptions, findings and observations are presented by zone, and include discussion of the necessary augmentations between each transmission network zone, under each scenario.

12 Section 6.52, Access Code.

13 Whether a project has passed the Regulatory Test or is explicitly included in Western Power's determination or not does not prevent Western Power from undertaking that project. However, it can inhibit Western Power's access to funding or expose Western Power to the risk that it may not be able to recover the costs of delivering the project from network tariffs in the future. Historically, this has proven to slow down the network project approval and delivery process.

The WOSP is the most comprehensive modelling study ever undertaken into the future of the SWIS, bringing together key players to deliver a shared vision for our system and network.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METRO NORTH
Mullaloo
Wangara
Padbury
Henley Brook
Landsdale
Northern Terminal
North Beach
Balcatta
Malaga
Beechboro
Midland Junction
Yokine
Morley
Guildford Terminal
Mount Lawley
Osborne Park
Hazelmere
METRO
Darlington
North Perth
James Street
East Perth Terminal
Belmont
Wellington Street
Western Terminal
Shenton Park
Mundaring Weir
Forrestfield
Milligan Street
Kewdale
Victoria Park
Kalamunda
Cottesloe
Welshpool
Bentley
Cannington Terminal
Myaree
Kenwick Link
North Fremantle
Riverton
Canning Vale
Maddington
O'Connor
Murdoch
Gosnells
Willetton
South Fremantle
Southern Terminal
Southern River
Bibra Lake
Cockburn Cement
Kwinana Terminal
Cockburn Power Station Terminal
Byford
Medina
Rockingham
METRO SOUTH WEST
Waikiki

Map of the SWIS and the Transmission Network Zones

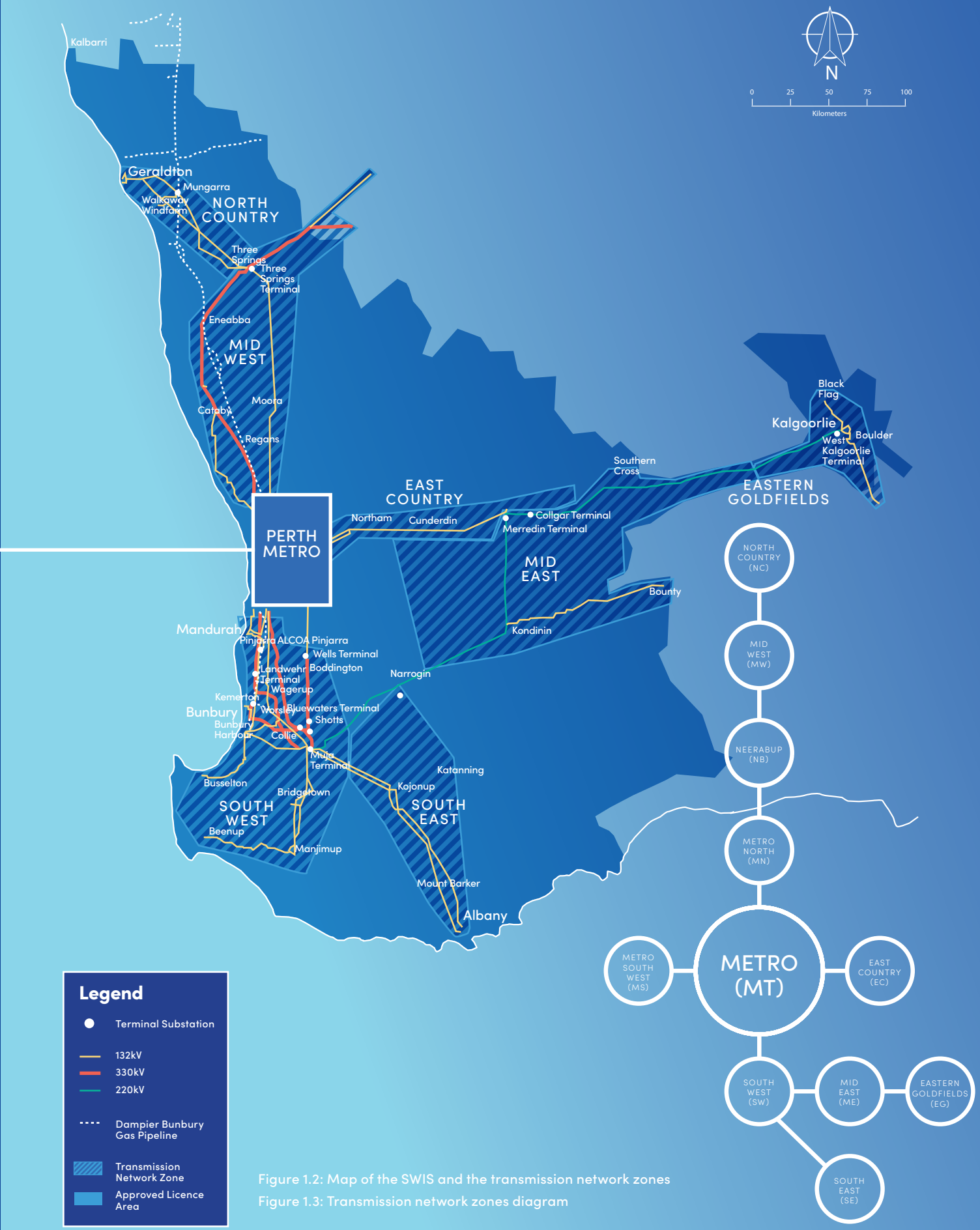


Figure 1.2: Map of the SWIS and the transmission network zones

Figure 1.3: Transmission network zones diagram

1.3.1 The SWIS today

The generation capacity mix in the SWIS at the commencement of the modelling period is diverse and reasonably well balanced. Gas is the largest capacity provider, accounting for 52% of total large-scale generation capacity (noting that gas accounted for 44% of sent-out large-scale generation during 2019-20).[14] Coal accounts for 26% of installed large-scale generation capacity, but reliance on coal-fired generation has declined over the past decade. Coal provided 44% of sent-out large-scale generation in 2019-20, compared with 51% in 2009-10.[15]

The decreasing reliance on coal and other forms of thermal generation is due to the rapid rise of renewables, particularly rooftop PV generation. By the end of 2020, renewable generation comprises 2,494 MW (34%) of installed capacity, of which rooftop PV makes up more than half (1,291 MW).

The rapid uptake of rooftop PV has caused operational demand to decline in recent years, where previously it had been increasing. Minimum operational demand has also been decreasing, with record lows being observed in each of the last three years. Each of these record minimums were observed during daytime hours that corresponded with periods of high rooftop PV generation. Minimum operational demand in 2019-20 was 1,138 MW, down from 1,451 MW in 2016-17.[16]

1.4 Supporting documents

While the WOSP is a focal point for power system planning, it should be read in conjunction with the various other plans and reports produced by Western Power, AEMO and other relevant organisations. Key supporting documents are listed in Table 1.1.

Table 1.1: Supporting documents

DOCUMENT(1)	OWNER	UPDATE FREQUENCY
DER Roadmap	Energy Policy WA	As necessary. Current roadmap covers 2020 to 2024
Access Code	Minister for Energy	As necessary
WEM ESOO	AEMO	Annually
Network Development Plan	Western Power	Annually

Note:
(1) This is not a definitive list. Additional planning and policy documents may be released as part of the ETS or by Western Power or AEMO.

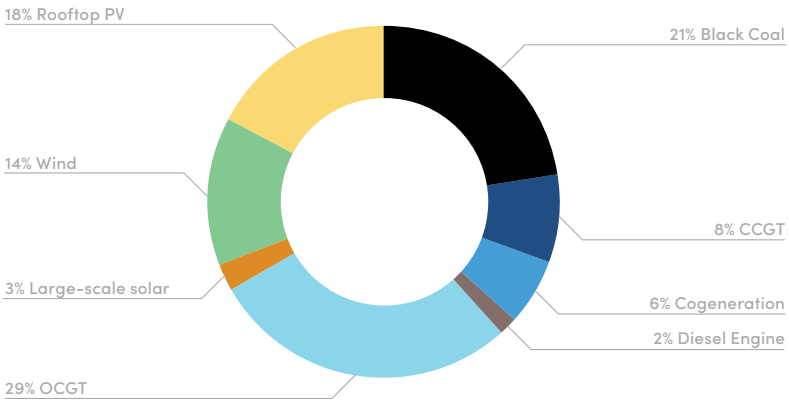


Figure 1.4: Modelled SWIS generation capacity mix (MW) at 1 July 2020

14 Source: AEMO Market Data. http: //data.wa.aemo.com.au/.

15 Ibid.

16 Source: AEMO, 2020 ESOO. https: //aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

1.5 Summary of stakeholder engagement

The WOSP modelling inputs have been developed and tested in over 120 meetings with more than 20 energy sector stakeholders. This included an initial industry forum testing the demand scenarios, and one-on-one meetings with industry participants, technology developers, investors and advocacy groups. Regular updates were also provided via existing industry consultation bodies such as the Market Advisory Committee and ETS Strategic Consultative Group.

Stakeholders have enthusiastically engaged in the consultation process throughout the WOSP development and have provided feedback on the modelling scenarios and various inputs and assumptions.

In many cases, stakeholders have shared important data such as operating costs, expected returns and plant characteristics. This information has helped improve the quality of the WOSP modelling inputs and therefore the robustness of modelling outputs. A virtual industry forum was held on 31 July 2020 where preliminary findings from the modelling and key themes were shared. Approximately 250 people attended the forum.

The Taskforce appreciates the collaborative approach and support provided by stakeholders to date and highlights that sensitive information provided by third parties will remain strictly confidential.

Energy Transformation Taskforce, Source: Energy Policy WA.

2. Overview of the WOSP

Our energy system is changing. In Western Australia, like many other parts of the world, the way electricity is generated, transmitted, stored and consumed is being transformed by technological advances, changing customer behaviours, and a drive towards a lower carbon economy.

The WOSP is designed to help inform and guide how we manage that transition in the SWIS.

2.1 The WOSP objectives

The WOSP will:

- identify the best options for investment in our power system, to maintain security and reliability at the lowest sustainable cost;
- assist in the transition to a lower-emissions power system by guiding the efficient integration of renewable generation and identifying opportunities for energy storage, which will play an increasing role in meeting our essential electricity needs; and
- provide guidance to regulators and industry regarding efficient power system investment, and to policy makers on the future needs of the power system.

Over the past decade there has been a shift away from the traditional electricity model. A system dominated by large thermal generators is being displaced by a model where rooftop PV, battery storage and other forms of DER are increasingly prevalent. It is important to understand how best to integrate new technologies to either replace or complement the existing generation mix, and how to retire ageing generation fleet in a prudent and orderly manner.

The WOSP modelling considers different energy technologies and presents a 20-year outlook of the lowest cost combination of generation, storage, and network augmentation required for supply to meet demand while maintaining system security. This **lowest cost to supply** considers the costs of developing, connecting, and operating the different types of generation and storage facilities, as well as the commercial viability of running those facilities over the next 20 years.

The WOSP is designed as a guide. The WOSP and the modelling outputs that sit behind it provide a view of likely outcomes, generation and storage additions, generation retirements, and network augmentations that may be required under each scenario. Some outcomes of the WOSP will be common across all scenarios, others will vary depending on the demand, technology and economic outlook.

The information in the WOSP gives energy sector stakeholders a framework for decision making. It can be used to inform infrastructure investment requirements, policy direction and manage the transition to a brighter energy future.

The WOSP modelling explores how to deliver electricity supplies at the lowest sustainable cost within the reliability and security standards over a 20 year period

Guide **policy, market and regulatory changes** to assist in the energy transition

Guide **future investment** in generation, network infrastructure and new technology

Inform stakeholders (market participants, customers, future investors, regulators and Government) and help them **make informed decisions**

Figure 2.1: Value of the WOSP

2.2 Scope of the WOSP

The WOSP applies to the SWIS only. It models a 20-year horizon from 2020 to 2040. It is developed based on data provided by Western Power, AEMO, WEM participants and prospective WEM entrants, and financial institutions as at May 2020.

The outputs of the electricity market modelling:

- provide a view of the lowest cost generation and storage capacity mix (reflective of the lowest cost to supply) that will meet demand, while considering constraints associated with power system operation, transmission network transfer limits, and the value of unserved energy (USE)[17];
- demonstrate the impact of ESS constraints on total system costs and the generation technology mix; and
- show the proportion of annual energy dispatched from renewable energy sources, and annual emissions attributable to each scenario the WEM.

The WOSP provides a view on generation and transmission network investments that may be required to meet future demand and system security requirements under four scenarios: *Cast Away, Groundhog Day, Techtopia and Double Bubble* (outlined in section 2.3).

The WOSP uses a view of electricity demand developed by Western Power, based on a 'bottom-up' forecast by zone. The demand scenarios use contemporary information including forecasts on the uptake of behind-the-meter rooftop PV capacity, battery storage, electric vehicles, and additional major loads expected to connect during the study period.

The WOSP does not present a forecast of electricity demand. Instead, the WOSP modelling makes an informed assessment of what electricity demand may look like depending on the economic environment and technology uptake (e.g. DER, electric vehicles) under each scenario. The WOSP modelling output is then a forecast of the technologies and investment required to meet the assumed electricity demand – it is not a forecast of demand itself.

For a forecast of electricity demand in the SWIS, refer to AEMO's ESOO, which presents forecasts and analysis of peak demand and operational consumption in the SWIS for the next ten years. The ESOO will continue to be produced on an annual basis and will be an important input for future rounds of WOSP modelling.

An overview of what is and is not included in the WOSP modelling scope is provided in section 2.4.4 and 2.4.5.

17 USE refers to electricity that is required by customers but not supplied because of insufficient generation, or demand side management capacity, or the inability of the network to deliver it.

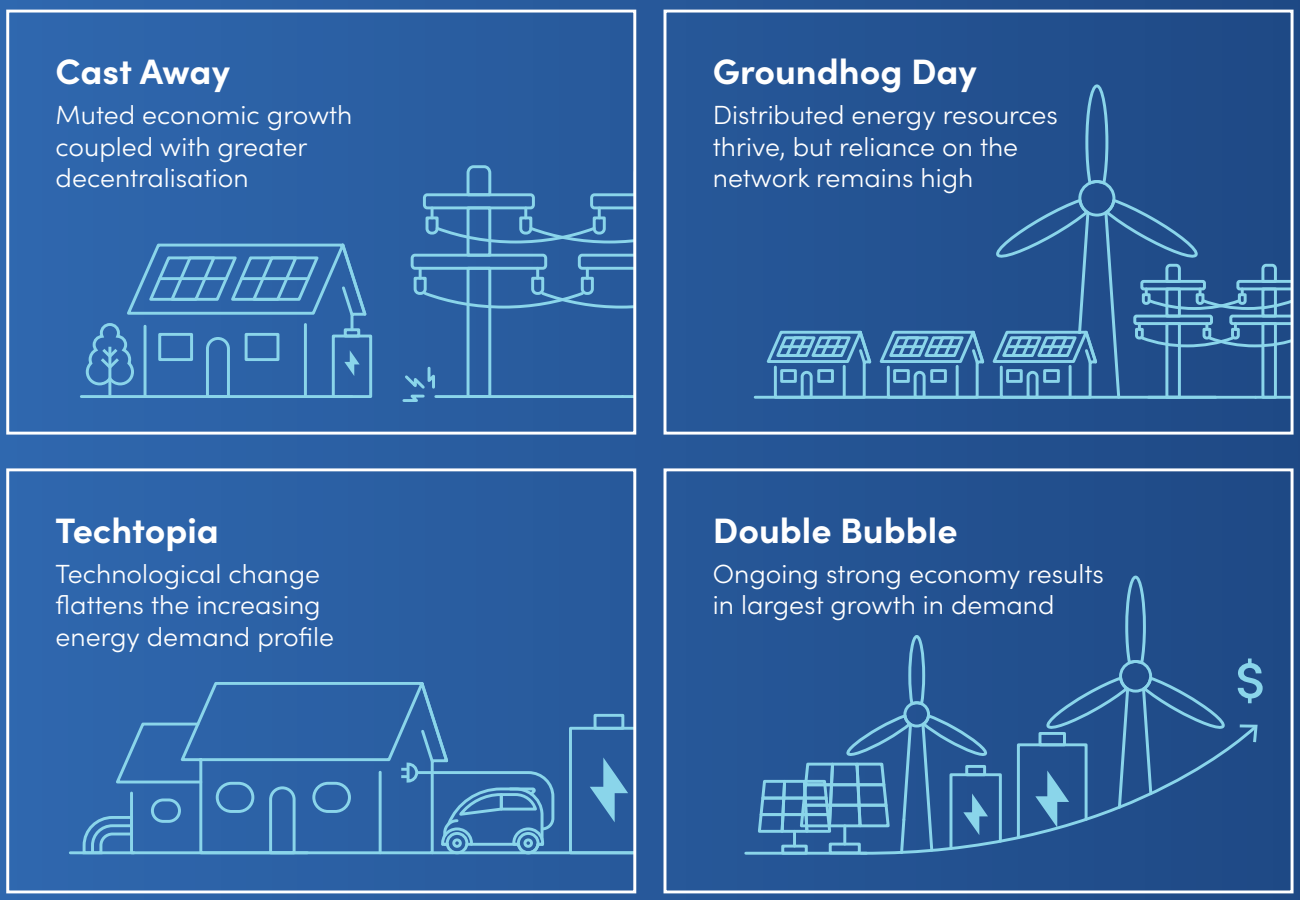


Figure 2.2: WOSP modelling scenarios

2.3 Modelling scenarios

The inaugural WOSP is based around four modelling scenarios. The four scenarios are:

- Cast Away
- Groundhog Day
- Techtopia
- Double Bubble

The Taskforce has developed four scenarios that provide an outlook of electricity demand and technological developments in the SWIS and form the basis for modelling what future investment requirements might look like. These scenarios were tested with a range of stakeholders, including in a public industry forum on 12 July 2019,[18] and are broadly supported by stakeholders as a reasonable set of assumptions to test in the WOSP model.

The assumptions of demand under each scenario are drawn from analysis undertaken by Western Power. Demand data is produced for individual substations and large industrial or commercial loads within each of the transmission network zones. Demand assumptions are modified for seasonal impacts before being adjusted for the effect of behind-the-meter DER during each 30-minute interval over the 20-year study period. The DER generation adjustments are based on nine years of weather data including satellite-derived solar insolation data on a 5 km grid across the SWIS.[19]

This gives the WOSP modelling a realistic view of demand in each of the four scenarios to be used as an input to the modelling. Figure 2.3 and Figure 2.4 show annual peak demand (in MW) and operational demand (in GWh per annum) incorporating these adjustments.

18 https: //www.wa.gov.au/sites/default/files/2019-08/Whole-of-System-Plan-Industry-Forum-Presentation-12-July-2019.pdf.

19 This is obtained from the Bureau of Meteorology along with weather station data of temperature and wind speed.

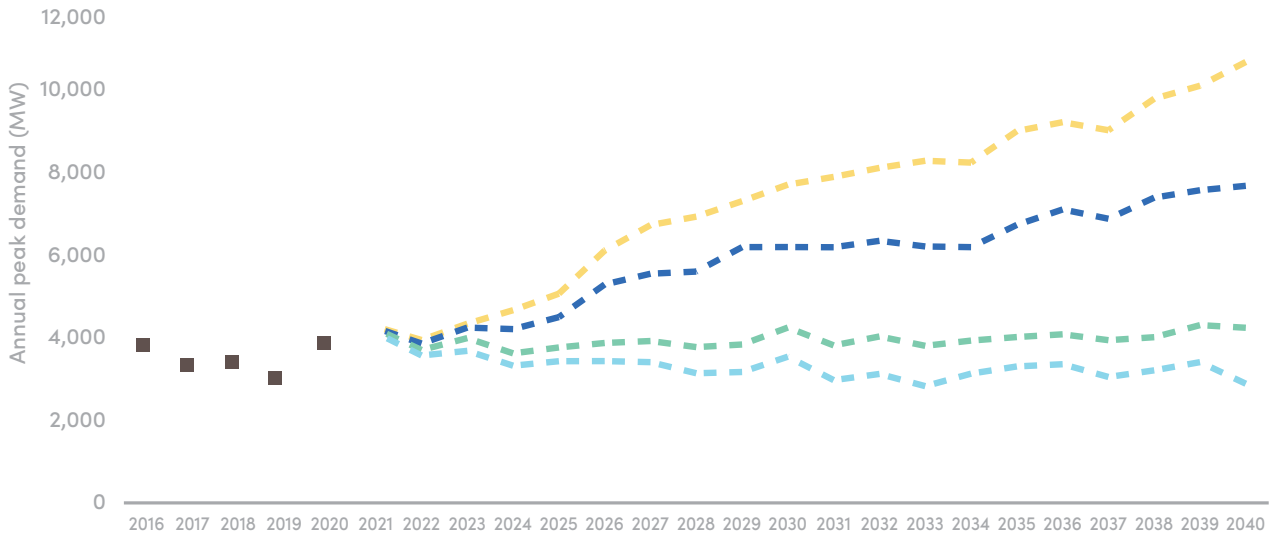


Figure 2.3: Annual peak demand for all scenarios 2020-2040

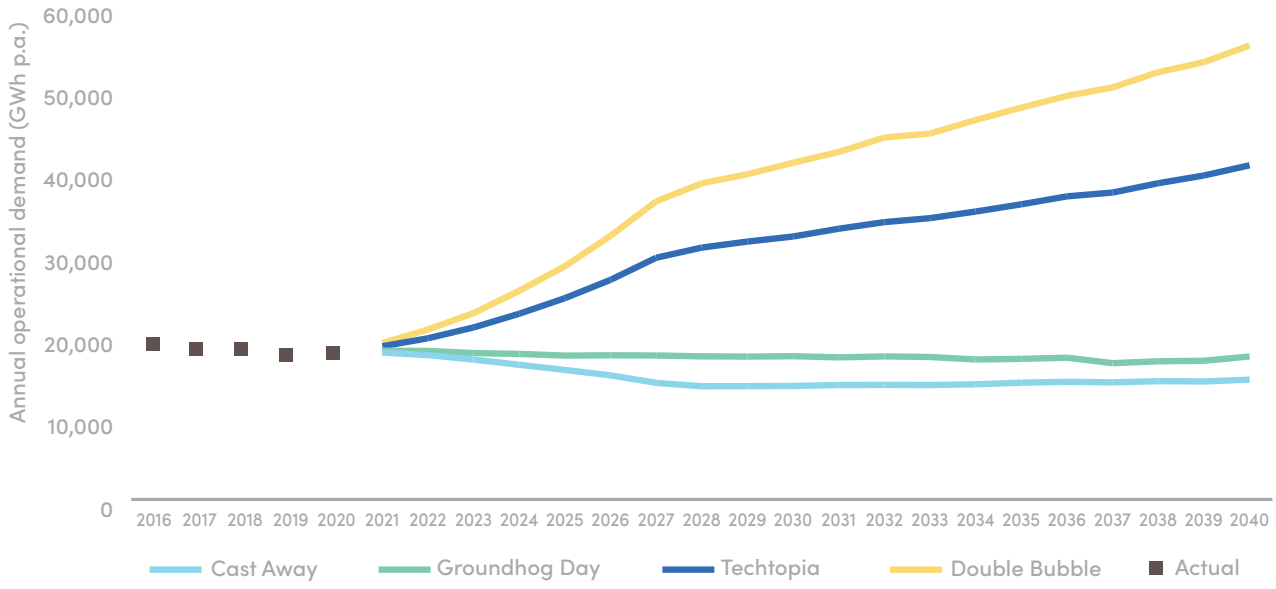


Figure 2.4: Annual operational demand for all scenarios 2020-2040

Peak demand is an important consideration in the WOSP scenarios, as it drives the reserve capacity and network capacity requirements in the SWIS. As shown in Figure 2.3, the peak demand varies significantly between scenarios.

Operational demand is the demand required to be met by the generation mix via the transmission network. Operational demand differs from end-user demand in that it does not include the demand being met by behind-the-meter energy sources such as rooftop PV or behind-the-meter storage. End-user demand is the amount of the electricity being consumed by the user at the power socket.

The gap between operational demand and end-user demand is due to the amount of behind-the-meter DER assumed in the system. The greater the assumed behind-the-meter DER uptake, the bigger the gap. All four modelling scenarios include assumptions of both operational and end-user demand.

The WOSP does not contain an 'expected case' scenario. This is because the WOSP is designed to inform decisions on the future of the SWIS by providing a framework of data that can be interrogated and used by industry participants and stakeholders to help determine the optimal or lowest cost approach to investing in the system.

If an expected case were to be developed, there is a risk too much focus would be placed on whether that expected case was correct or not, which would detract from the overall value of the WOSP. It would also be extremely challenging to produce an expected case on which all parties would agree.

Over time, as more data is gathered and each iteration of the WOSP increases in maturity, it may be possible to develop scenarios that more narrowly define the direction the SWIS is heading. However, in the short term, the value of the WOSP is the modelling data it produces and the decisions that can be made using it.

In the time since the demand scenarios were formulated the COVID-19 pandemic has led to speculation that electricity demand will decrease in coming years. However, the range of future demand represented is broad enough to encapsulate the likely effect of any decrease in demand.

An overview of the four scenarios is provided in the following sections.

	CAST AWAY	GROUNDHOG DAY	TECHTOPIA	DOUBLE BUBBLE
	Muted economic growth coupled with greater decentralisation	Distributed energy resources thrive, but reliance on the network remains high	Technological change flattens the increasing energy demand profile	Ongoing strong economy results in largest growth in demand
Economic growth	Low	Medium	Medium	Strong
DER uptake	High	Extremely high	Medium	Medium
Demographic forecast[20]	Urban sprawl	Urban balanced	Urban balanced	Extreme climate

Figure 2.5: Comparison of WOSP modelling scenarios

20 Detailed explanation of the drivers Western Power used to develop the scenarios was provided at the industry forum held on 12 July 2019.

2.3.1 Cast Away

Muted economic growth coupled with greater decentralisation

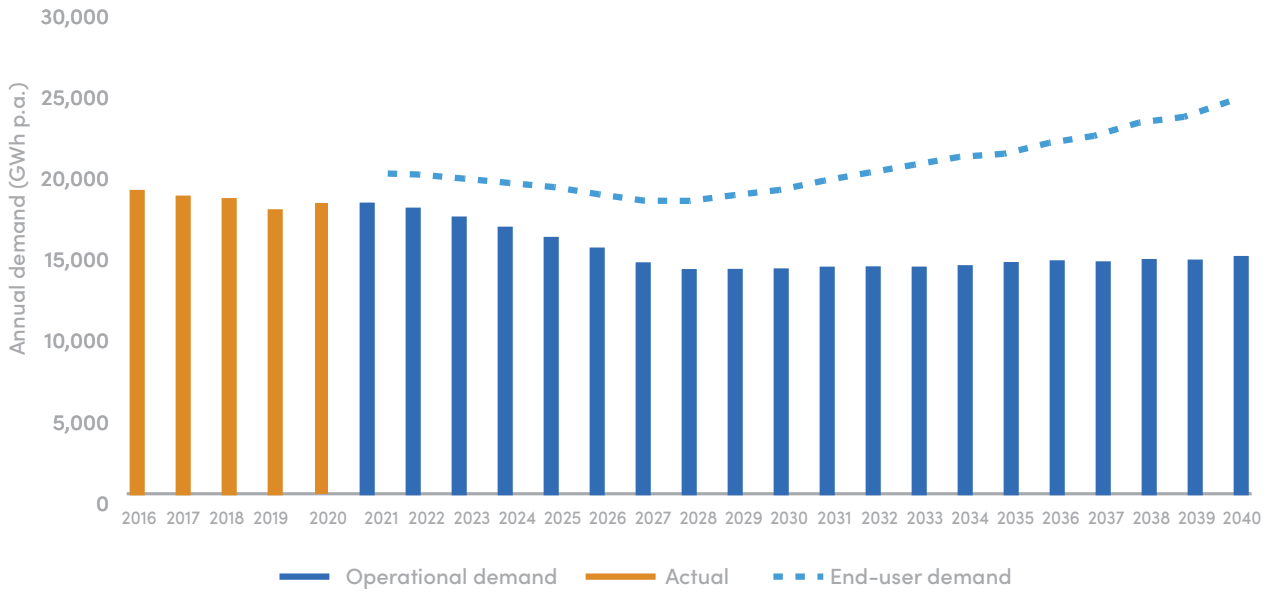


Figure 2.6: Annual operational and end-user demand to 2040 – Cast Away

The Cast Away scenario assumes a subdued economy characterised by lower economic growth in the mining and non-mining sectors, along with minimal population growth. End-user consumption grows over the period, indicating there is some growth in demand for electricity. However, the amount of operational demand and peak demand being met by energy transmitted over the network declines over the study period. Any change in demand due to COVID-19 impacts on the economy are not expected to decrease demand below the levels seen in this scenario.

The decrease of grid supplied demand in the Cast Away scenario is in part due to a demographic shift where a number of residents leave Perth's (and surrounds) densely populated urban areas and disconnect from the network. Customers that remain in urban areas install larger residential rooftop PV systems. The reduction in grid connected residential customers dampens the effect of rooftop PV on minimum daytime loads.[21]

Larger connections are generally muted, although there is some growth in energy metal refining and processing operations.

21 This is also known as the 'duck curve'. The duck curve is a description of the shape of the SWIS daily load profile due to the decreasing amount of energy drawn from the grid during the middle of day (when rooftop PV output is high) followed by a sharp increase in the late afternoon when people return home at the same time as rooftop PV output decreases. See page 30 of the DER Roadmap – https: //www.wa.gov.au/sites/default/files/2020-04/DER_ Roadmap.pdf.

2.3.2 Groundhog Day

Distributed energy resources thrive, but reliance on the network remains high

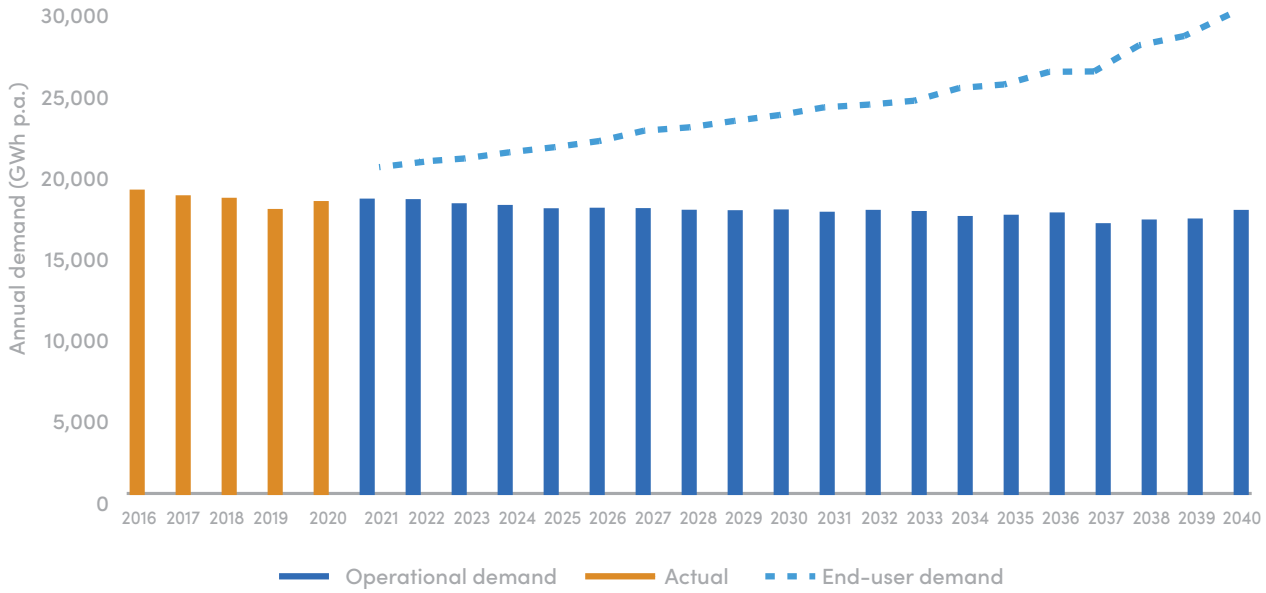


Figure 2.7 Annual operational and end-user demand to 2040 – Groundhog Day

Of the four scenarios, Groundhog Day is the one that most closely resembles the pre-COVID-19 environment.[22] Under the Groundhog Day scenario, a moderate increase in mining spurs medium economic growth. Commensurate growth occurs in the non-mining sector as activity in the overall Western Australian economy increases.

While Groundhog Day sees growth in end-user demand of almost 50% over the 20 years, it has very high uptake of DER, which meets the majority of end-user consumption growth over the period. As a result, operational and peak demand remain relatively flat from current levels.

The high uptake of DER in this scenario causes daytime operational demand to fall sharply and leads to a large surplus of rooftop PV energy production. Another feature of this scenario is the peak shifting to winter (in some of the weather reference years), where there is insufficient rooftop PV production to fully charge behind-the-meter battery storage.

22 The WOSP modelling was conducted using data prior to May 2020.

2.3.3 Techtopia

Technological change flattens the increasing energy demand profile

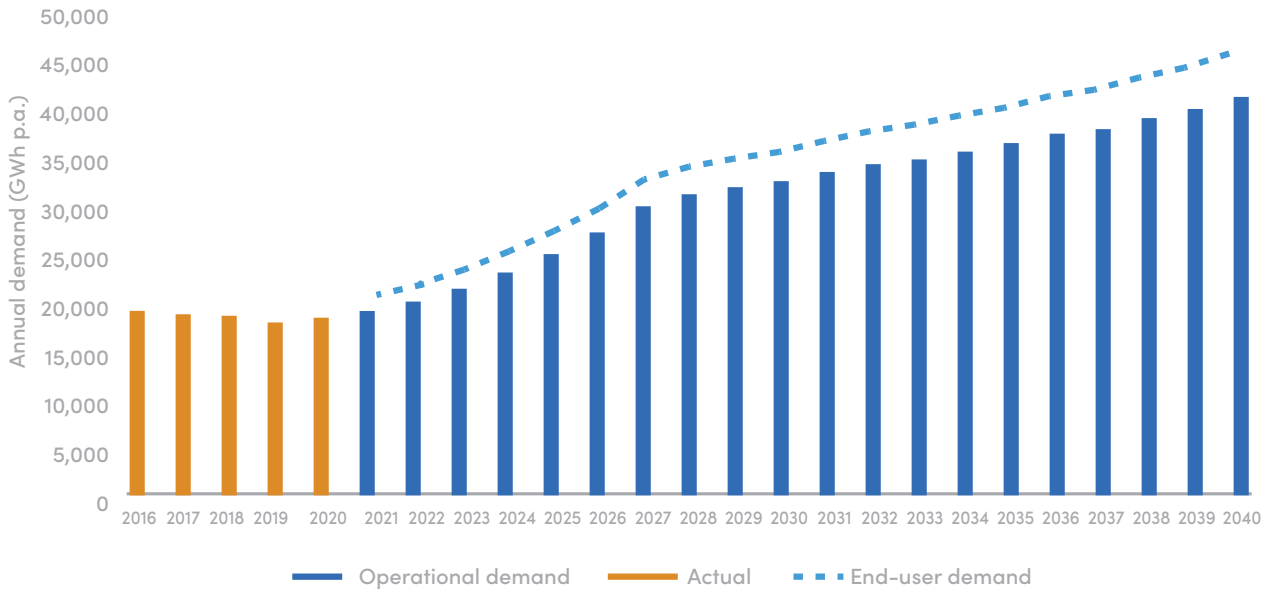


Figure 2.8: Annual operational and end-user demand to 2040 – Techtopia

The Techtopia scenario has medium to strong economic growth, driven by increasing activity in both the mining and non-mining sectors. Techtopia sees a proportionate increase in population growth, evenly balanced between metropolitan and regional centres.

This scenario assumes greater economies of scale in large-scale generation compared to lower demand scenarios. This, together with increased levels of home automation, places downward pressure on end-users' electricity bills. As a result, the uptake of DER is assumed to be lower than in the other modelling scenarios.

This means the gap between end-user demand and operational demand is smaller than in the Cast Away and Groundhog Day scenarios. There is strong growth in the uptake of electric vehicles.

Initially, due to the increased role of home automation energy systems and the resulting smoothing out of demand, there are fewer instances of the demand troughs that occur in the daily load profile. However, as operational and peak demand continue to grow, the shape of the load curve begins to undulate again to the traditional peak and trough.

2.3.4 Double Bubble

Ongoing strong economy results in largest growth in demand

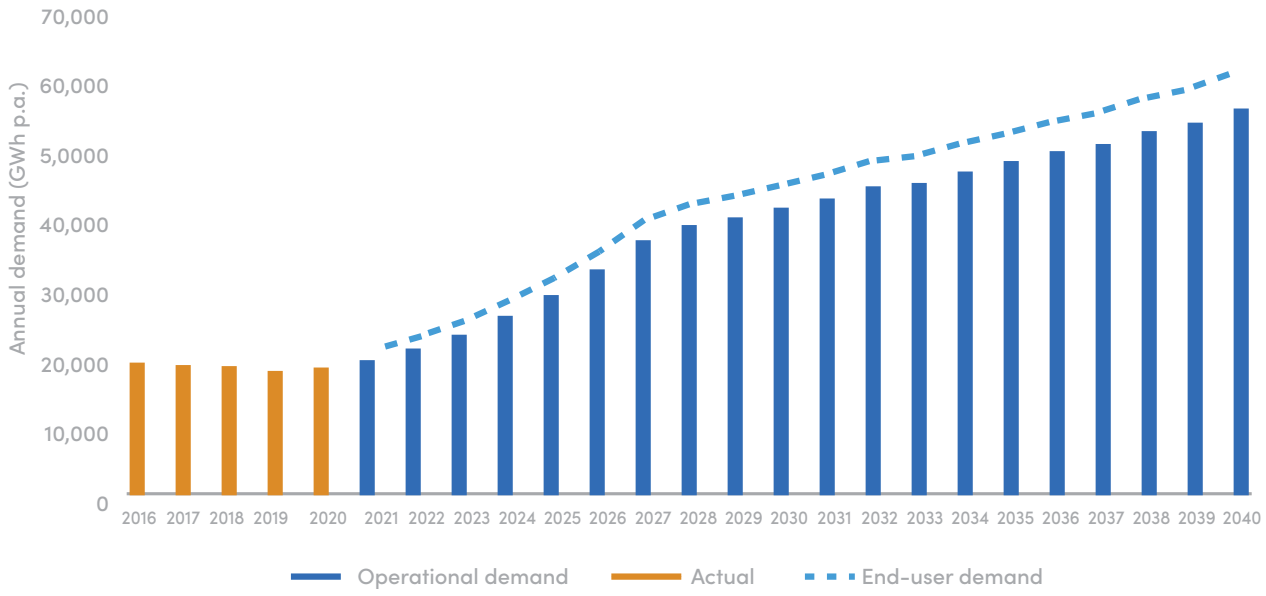


Figure 2.9: Annual operational and end-user demand to 2040 – Double Bubble

Under the Double Bubble scenario, ongoing strong economic growth in both mining and non-mining sectors drives a significant increase in population and therefore overall energy consumption, operational and peak demand in the SWIS. This scenario therefore provides opportunity to test the upper bound of generation, storage and network capacity requirements.

The significant population growth reflects both economic opportunities and immigration. From a demographic point of view, there is higher population growth in the south west compared to the northern parts of the SWIS.

Though there is an increase in uptake of rooftop PV generation and batteries, this growth appears low as a proportion of overall demand growth within the SWIS.

2.4 Modelling approach

Two models are used in the WOSP modelling exercise:

- a network and generation resource planning model (resource planning model); and
- a market dispatch model (dispatch model).

2.4.1 Resource planning model

The resource planning model is used to calculate total system costs[23] and produce outputs that can be used to inform the optimal generation, storage and network investment plan necessary to sustain the power system under each modelling scenario. The model selects the capacity mix that forms the lowest cost to supply electricity across the whole of the SWIS.

23 Total system costs relate to the cost of network, generation and storage infrastructure and comprise capital expenditure (capex), total fixed operating and maintenance costs (FOM), total variable operating and maintenance costs (VOM), retirement costs, total fuel costs, and USE.

The resource planning model repeatedly simulates the operation of the SWIS over the next 20 years with different levels of generation, storage and network capacity. It uses locational weather data and demand assumptions to determine the hourly dispatch of each transmission-connected facility in the SWIS, along with the resulting power flows between each of the model's 11 transmission network zones. The Net Present Cost (NPC) for the system as a whole is calculated and used to select the capacity mix that satisfies SWIS demand at the lowest overall cost.

The algorithm within the model is designed to identify the lowest cost to securely supply the entire power system demand. The driver for planting generation or storage capacity is demand right across the SWIS, as well as the demand within the individual transmission network zones.

The resource planning model can also select capacity to be removed from the generation capacity mix in cases where doing so would reduce overall system costs. No consideration has been given to the profitability of existing generation facilities in the scenarios where the WOSP modelling has identified capacity to be removed: the capacity has been selected purely because its removal would reduce total system costs.

The dispatch model subsequently uses the outputs of the resource planning model to simulate outcomes in the WEM for each of the four generation and network outlooks. Figure 2.10 shows the inputs and outputs of the resource planning model.

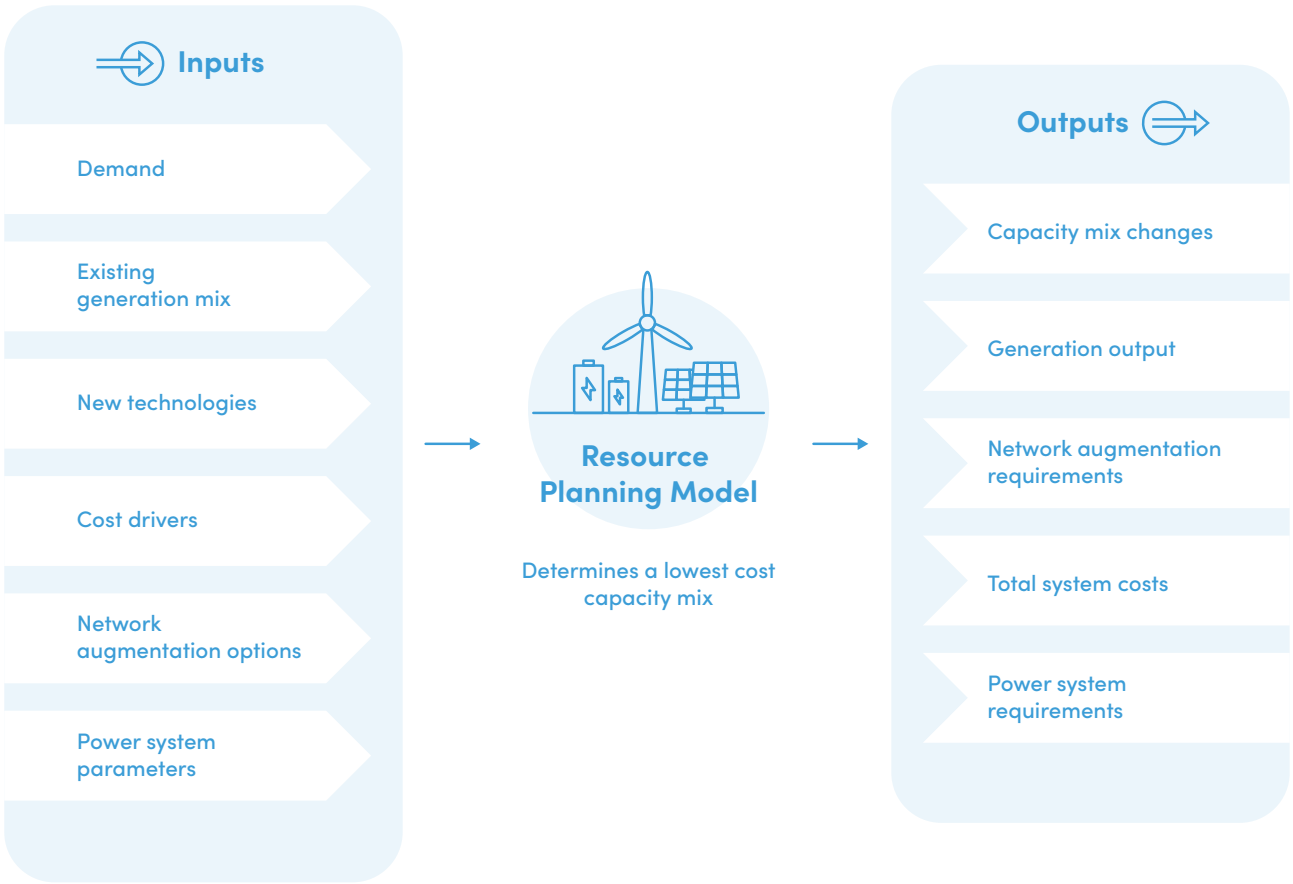


Figure 2.10: Overview of the resource planning model

2.4.2 Dispatch model

The dispatch model is used primarily to assess the market outcomes of the capacity mix produced by the resource planning model. It dispatches the capacity mix on a half-hourly basis, based on a short run marginal cost (SRMC) bidding profile. It captures the variability of renewable generation, thermal unit outages (both unplanned and planned) and ramp rate limitations, as well as the underlying changes to system demand. Transmission network limits and power system security requirements are modelled with constraint equations to ensure the power system is operated securely.

The model then co-optimises the dispatch of facilities to meet energy and ESS requirements for each half-hour interval over the 20-year study period, for each of the four scenarios.

Figure 2.11 shows the inputs and considerations of the dispatch model.

Together, the two models produce a suite of findings and observations on what different types of generation and storage capacity would be required under each scenario. The modelling also identifies when a network augmentation would be required to facilitate connection of new capacity to provide a least cost solution.

Figure 2.12 illustrates the way the two models interact.

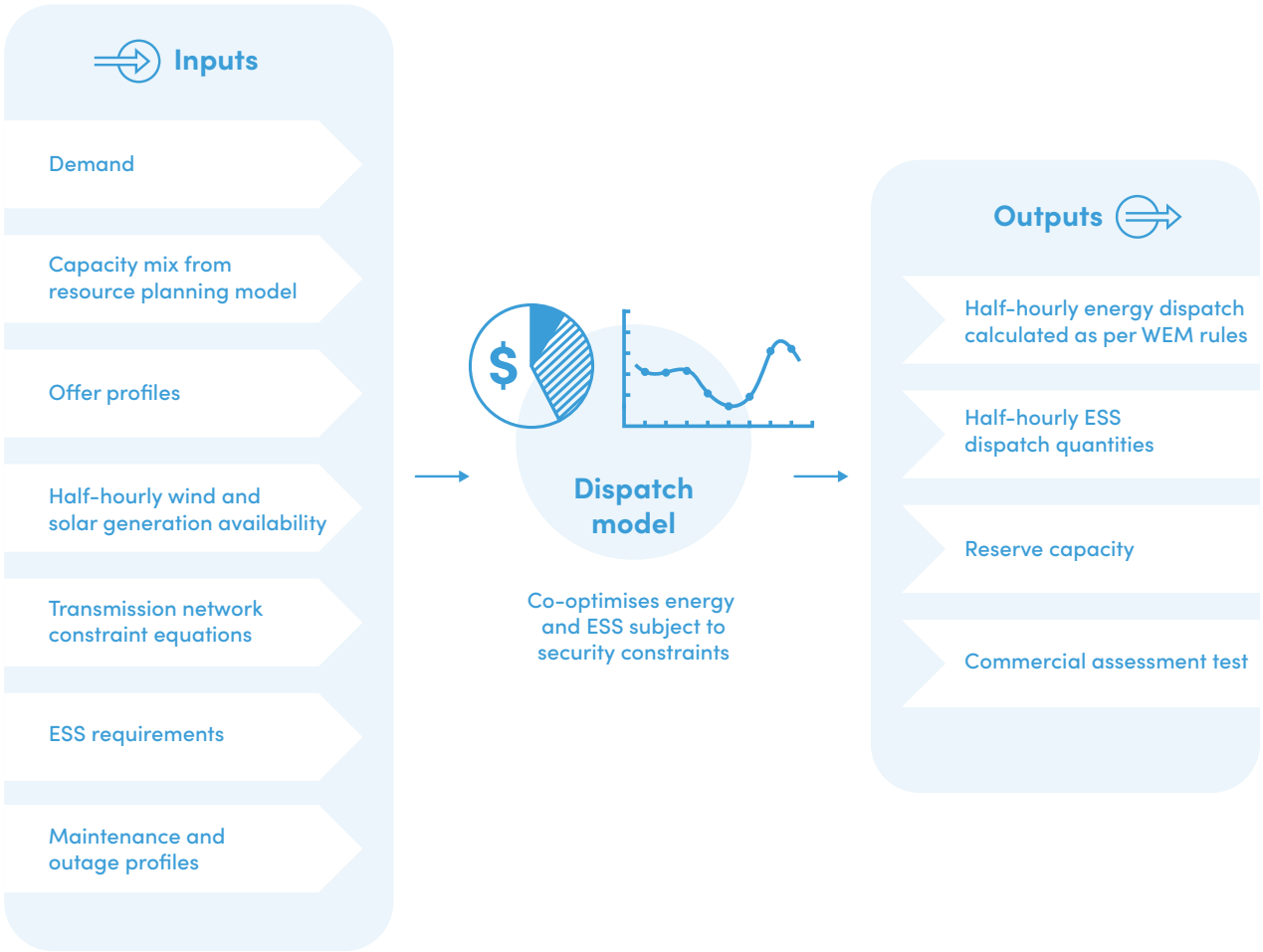


Figure 2.11: Overview of the dispatch model

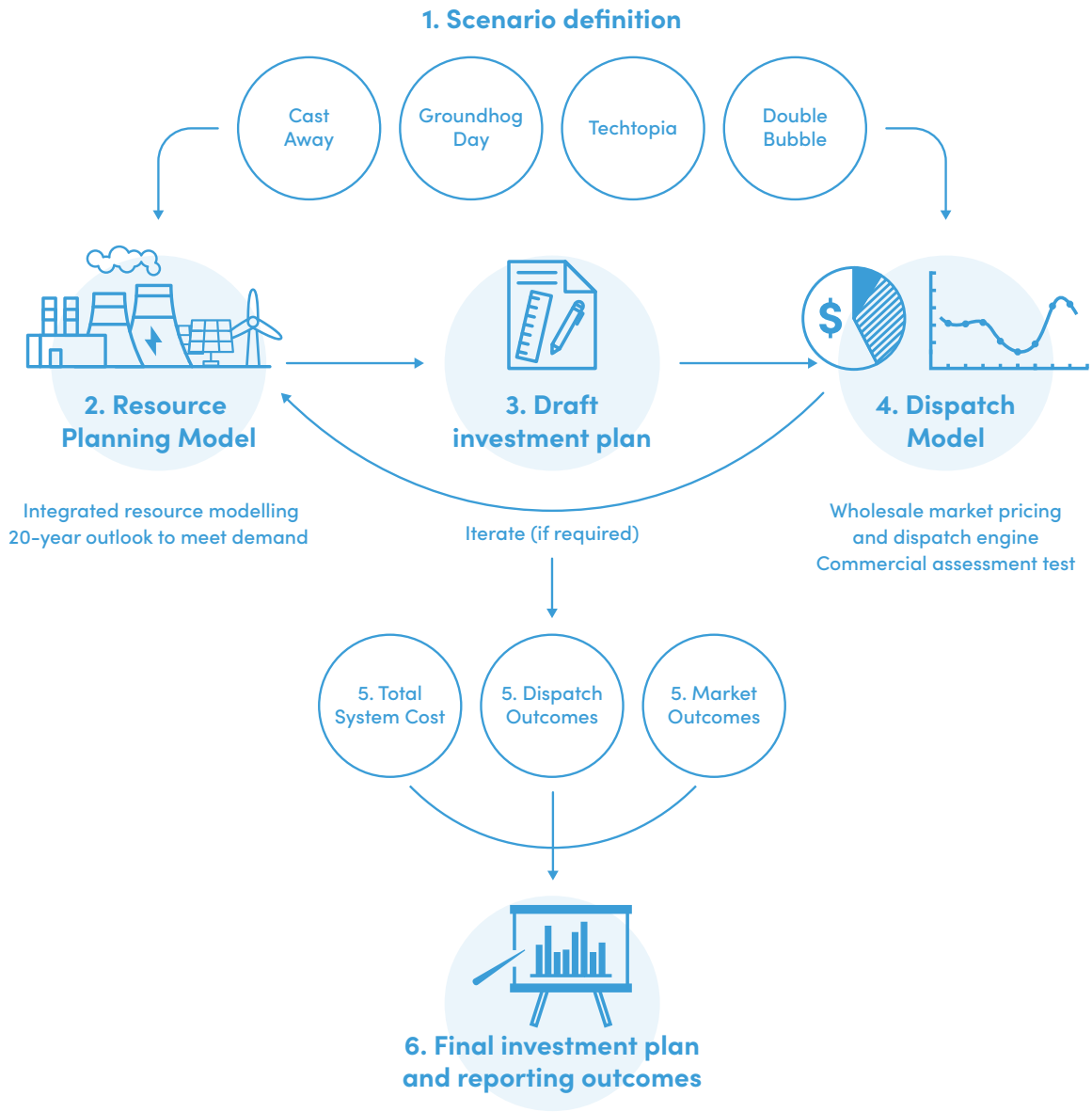


Figure 2.12: How the resource planning model and dispatch model interact within the overall WOSP modelling

2.4.3 Commercial assessment test

An important component of the WOSP modelling process is the application of a commercial assessment test.

To help improve the robustness and credibility of the capacity mix identified by the resource planning model, the outputs have been subjected to commercial assessment.

The test takes the dispatch outcomes, and based on a series of assumptions on the risk profile, rate of return, operating costs and modelled revenue streams for each type of new facility, assesses whether it is likely to be commercially viable.

If the test identifies that a new facility selected by the resource planning model would not be commercially viable, then that facility is taken out of the mix and replaced with the next lowest cost option.

The commercial assessment test is applied to new facilities only. It assesses whether the new generation or storage facilities proposed under each scenario will reflect commercial and fundable businesses. The assessment considers the internal rate of return (IRR) required by each facility, together with the risk profile facing the facility. The risk profile is determined based on:

- the level of market risk faced by facilities;
- the diversification of revenue streams – three revenue streams are potentially available to facilities, ESS revenues, energy revenues, and capacity payments. A facility that is assumed to have access to all three revenue streams has a lower risk profile than a facility with one revenue stream only;
- whether the technology type is established or new – established technology is a less risky investment than newer technologies, therefore access to funding would be easier;
- the level of IRR;
- when the facility is being built;
- where the facility is being built;
- the facility size and capacity; and
- which scenario it is being planted under.

The methodology was discussed with WEM participants and investors during the initial stakeholder engagement phase of the WOSP development. The commercial assessment test inputs have also been informed by meetings with financial institutions and their credit departments, to ensure that they reflect real-world considerations.

2.4.4 What is in the modelling scope?

The WOSP modelling is scoped to identify the lowest sustainable cost of new generation and transmission infrastructure required to meet demand and power system security standards in each modelling scenario across the 20-year study period (2020-2040).

2.4.4.1 System costs

The overall system cost is determined by calculating the NPC of generation and network supply in the SWIS. The NPC is the sum of capex, FOM, VOM, fuel supply costs and USE over the entire 20-year study period. The NPC is minimised by determining the lowest cost generation dispatch for each hour of the study period, along with the charging and discharging of storage whilst also minimising capex.

2.4.4.2 Generation facilities

The WOSP models all existing generation facilities, committed generation projects and announced generator retirements (as at May 2020). Projects are considered to be committed[24] based on AEMO's 2019 reserve capacity certification process and whether they have reached financial close. Committed generation projects are modelled based on a fixed commercial operation date.

The cost of adding new capacity considers locational costs such as land access and network connection costs, as well as fuel availability. Limitations for new generation entry and investment in energy storage are also considered for each region of the SWIS. These are based on an assessment of available generation and storage technologies, informed by connection applications made to Western Power, information from developers, government agencies and technology providers, and insights from AEMO's registration processes.
The energy efficiency of technologies has been

24 That is, if a project has been allocated capacity credits, it has demonstrated it has met key project milestones such as having a network access contract, offtake agreement, evidence of fuel contracts and/or commercial funding.

assumed to improve throughout the study period, allowing for additional generation capacity in some locations.

The modelling also identifies where a particular type of generation no longer forms part of the lowest cost to supply. This may be due to either reaching the end of its technical life[25], or the declining economics of that generation. Where the modelling selects generation capacity for economic exit, this is because that form of capacity is no longer in the lowest system cost option to supply electricity to the SWIS, as it can be displaced by cheaper forms of generation (such as wind or large-scale solar). This is purely an outcome of the economic construct of the WOSP modelling. In reality, there are other factors that would influence a facility closure, including offtake agreements. Any decision to retire or scale back an individual generation facility is a matter for the facility owner. It is not within the scope of the WOSP to recommend individual generator retirements.

2.4.4.3 **Technology in the WOSP**

The WOSP modelling considers a range of generation and storage technologies, the cost of connecting (or planting) these facilities and the optimal location for them. The existing technologies considered in the modelling are:

- coal-fired generators;
- combined cycle gas turbines (CCGT);
- open cycle gas turbines (OCGT);
- large-scale solar PV; and
- wind turbines.

Additional technologies considered in the modelling are:

- reciprocating gas engines; and
- large-scale storage facilities (battery, pumped hydroelectric, and compressed air).

New hydrogen electrolysis facilities have not been considered in the modelling for this WOSP. Renewable hydrogen technologies have the potential to decarbonise some industries and transport applications.

There is broad agreement from stakeholders that the hydrogen industry has potential in the future to use growing amounts of electricity and, possibly, store energy to meet peak demand. However, at the time of modelling, cost forecasts had a large range of uncertainty making deployment rates too difficult to predict.

When selecting a particular form of generation or storage capacity, the modelling seeks to identify the lowest cost mix to meet supply across the whole of the SWIS (based on cost and technical inputs provided by industry). The modelling is technology agnostic and simply selects the technology that features in the lowest cost to supply under each scenario. It does not advocate one technology over another on subjective grounds. Technical capabilities are factored in the commerciality of one type of capacity over another.

If a WEM participant or proponent is exploring other types of technology to those included in the WOSP modelling, or believes the costs of a generation type that the WOSP modelling has not selected are lower than assumed, then the WOSP does not prohibit that technology from being connected. Alternative technologies may still be commercial, even though they do not feature in the WOSP lowest cost to supply.

2.4.4.4 **Network augmentation**

The WOSP models the transfer capacity between the transmission network zones. This is the maximum amount of electricity (in MW) that can be transferred between two transmission network zones before the capacity of the transmission network is exceeded.

Western Power has developed a number of potential augmentation options between each transmission network zone. The resource planning model can then assess the best way to serve the demand in each zone, comparing network augmentation with other available options such as generation or storage. Where practical, potential augmentation projects can be staged, so that transfer capacity (and the associated investment costs) can be developed over time as demand increases.

The augmentations are based on standard network building blocks wherever possible. The cost for each individual augmentation project is used to calculate a $/MW unit cost of transmission network augmentation that is unique to each part of the network.

25 The assumed technical life of different technology types is published in Appendix B.

2.4.5 What is out of scope?

There are a number of exclusions in the modelling conducted for this WOSP. A non-exhaustive list of exclusions is provided in Box 1.

Box 1: Modelling exclusions

- **Consideration of network constraints within a transmission network zone and related network investment.** Network capacity and constraints within the transmission network zones did not form part of the analysis and are not considered. The WOSP only assesses the transfer capacity of the SWIS transmission network between zones.
- **Consideration of the distribution network**. While the impact of DER uptake on demand forecasts is factored into the calculation of demand under each scenario, network limitations or constraints at the distribution level are not considered in the WOSP modelling.[26]
- **Certain market design aspects associated with the ETS.** Implementation of the ETS will result in large-scale changes to the design of the WEM, changing the way energy and capacity is dispatched and procured. This ETS work is developing alongside the WOSP modelling. Where possible and practical to do so, the WOSP includes Taskforce approved market design elements in the modelling methodology.
- **Modelling certain design elements of the new ESS markets.** Not all parameters of the new ESS market have been captured in the WOSP modelling. The aspects of the ESS market that have been modelled in the WOSP is described in section 2.4.6.4.
- **Quantification of overall net market benefits associated with individual network augmentation candidate options provided by Western Power.** The WOSP modelling reports on the total system cost associated with developing the system as a whole. It does not consider differences in total system costs between different network augmentation options and a net benefit assessment of different combinations of network augmentation projects.
- **Modelling a change in the dispatch cycle from 30 minutes to five minutes**. Modelling five-minute dispatch involves preparing five-minute input data for demand, wind and solar generation and solving the same algorithm used for 30-minute and 60-minute modelling over a five-minute period. In the modelling outcomes, generator ramp rate limitations may be more likely to bind over a five-minute period compared to a 30-minute and 60-minute period which can change dispatch outcomes. However, modelling five-minute dispatch would not produce materially different outcomes for the purpose of the WOSP.
- **Future changes in transmission marginal loss factors as a result of the network and generation investment development in the market over the study period**. Existing generator marginal loss factors have been modelled based on proposed changes to the Regional Reference Node to obtain margin loss factors referred to the Southern Terminal.[27]
- **Future government policy**. Existing government policy[28] has been included. As there is no explicit climate or emissions reduction policy targeting the electricity sector, no State or Federal target or carbon price has been included in the modelling. Future WOSPs will incorporate any changes in government policy that have occurred during the intervening period.

26 Distribution network limitations are considered in the DER work stream of the ETS.

27 https: //www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Foundation-Market-Parameters.pdf.

28 As at May 2020.

2.4.6 Modelling inputs and assumptions

The primary data inputs and assumptions used in the WOSP modelling are:

- **customer demand** – the forward-looking view of half-hourly operational demand in the SWIS over the study period;
- **network augmentation** – the approximate costs of network augmentation, including assumptions on transfer limits between transmission network zones;
- **generator and storage costs** – the cost assumptions of existing and potential new facilities; and
- **power system requirements** – system constraints and estimated frequency regulation and contingency reserve requirements.

The WOSP Data and Assumptions Workbook is provided at Appendix B. The workbook provides an overview of high-level inputs and assumptions, using publicly available data.

The following sections provide an overview of the key modelling inputs and assumptions. Detail on modelling inputs and an explanation of any changes in assumptions since the modelling approach was shared with stakeholders over the period November 2019 to January 2020, and is provided in Appendix B.[29]

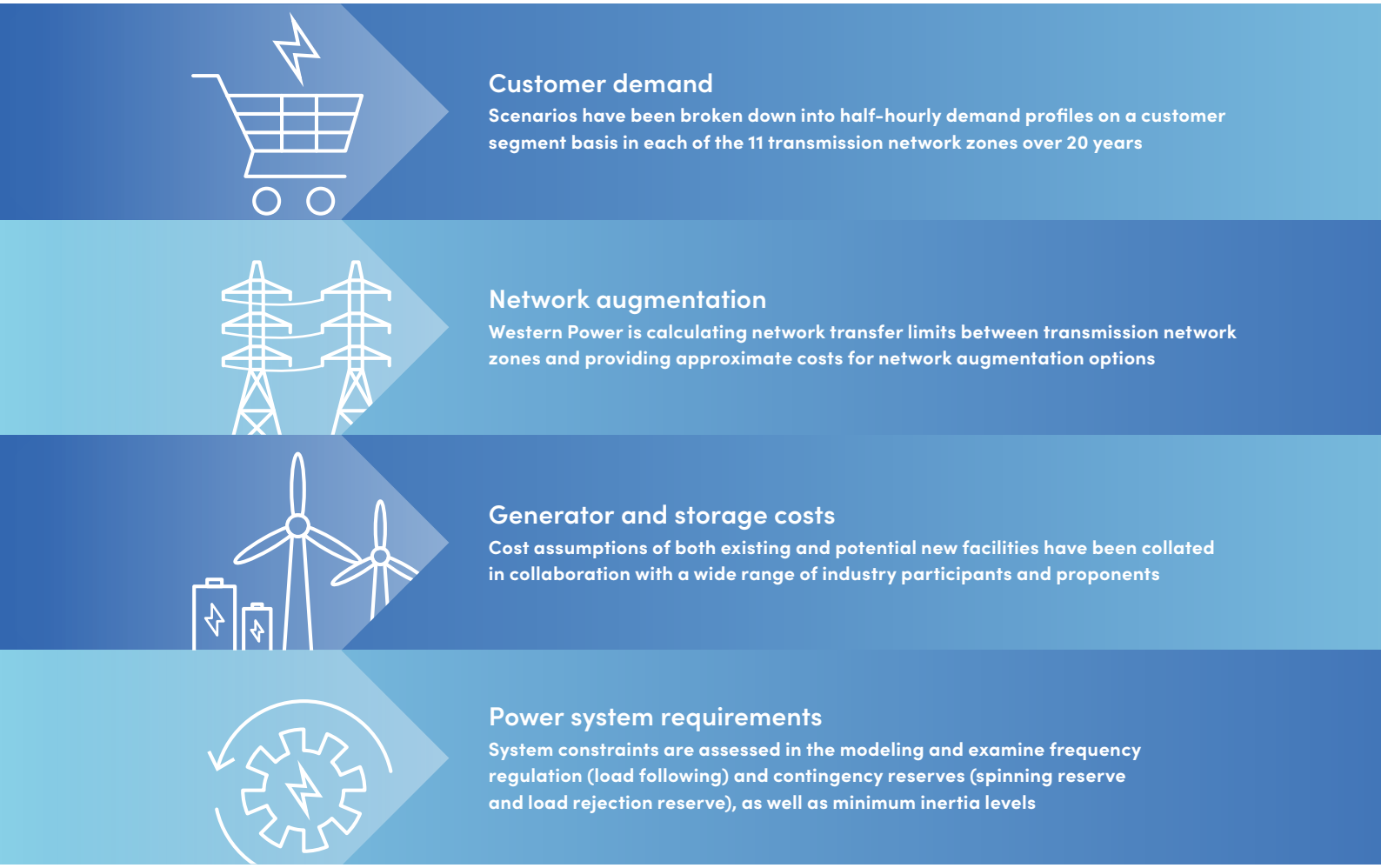


Figure 2.13: Key modelling inputs and assumptions

29 Confidential and/or commercially sensitive information provided by market participants during the course of the WOSP development will not be published.

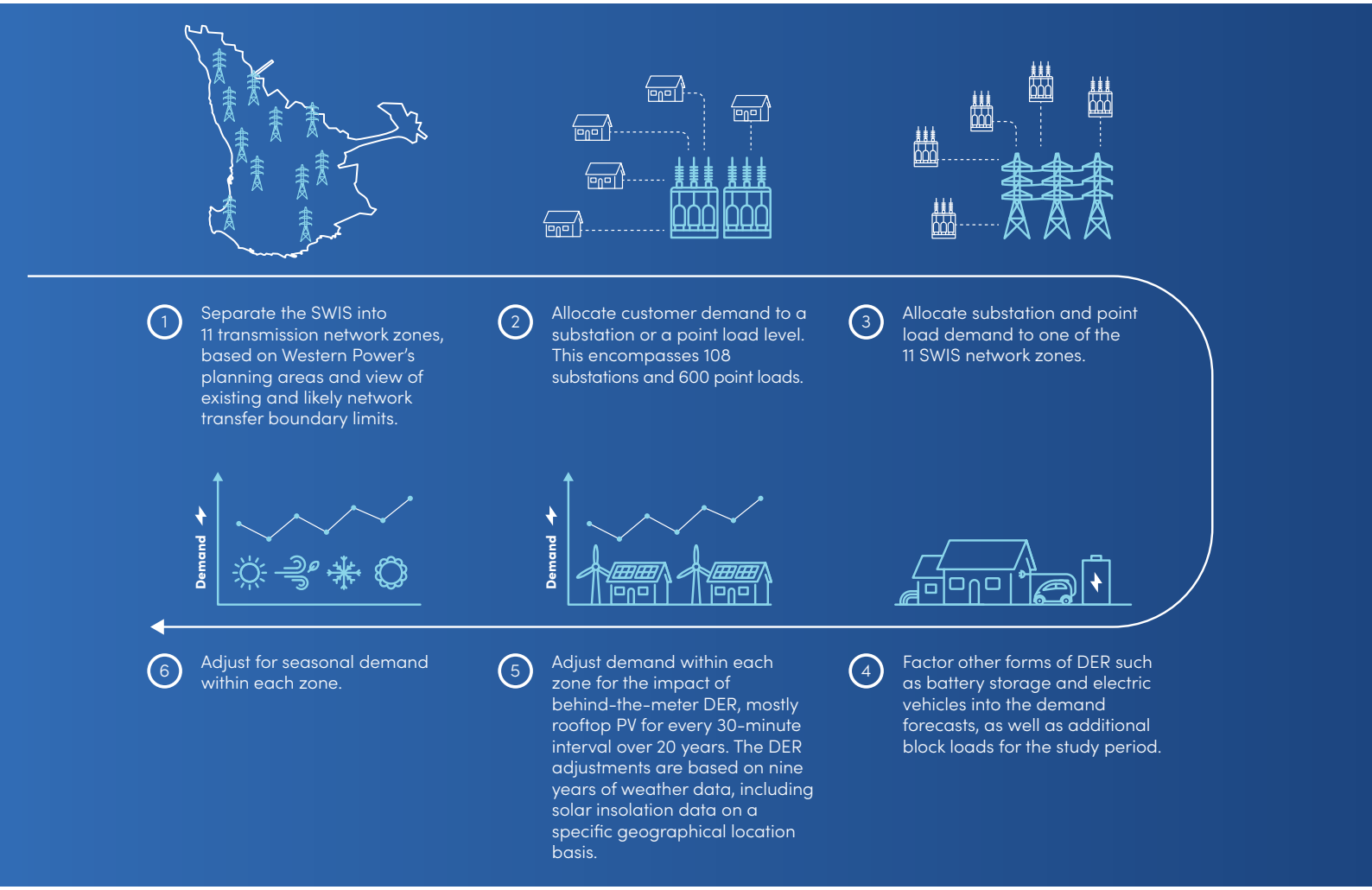


Figure 2.14: Customer demand allocation process

2.4.6.1 Customer demand

For each scenario, the Taskforce has developed an estimate of demand for the next 20 years. While forecasting electricity demand for a 20-year period will always be subject to imprecision, to provide a reasonable and robust estimate the following steps have been taken as outlined in Figure 2.14 above.

This zonal forecasting approach means the demand inputs consider electricity usage at the local level and can produce an estimate of future demand that is more likely to reflect customer's actual (micro) consumption behaviours than macro-level estimates. As discussed at the WOSP Industry Forum in July 2019[30], a range of economic, demographic and technological drivers and data sources have been used to inform the demand estimates.

2.4.6.2 Network augmentation

A critical input into the WOSP is the potential cost of network augmentation under each scenario. Western Power has identified the transfer capacity between the 11 transmission network zones and developed potential augmentation options, along with their costs, to increase the transfer capacity. Wherever practical a large augmentation has been split into phases to give the modelling more flexibility.

The resource planning model considered these augmentation options alongside potential investments in generation and storage facilities to determine which network augmentation projects are required between which zones and at what time, under each scenario.

30 https: //www.wa.gov.au/sites/default/files/2019-08/Whole-of-System-Plan-Industry-Forum-Presentation-12-July-2019.pdf.

2.4.6.3 Generator and storage costs

The actual and forecast costs of generators currently connected or expected to connect to the SWIS are an important input into the WOSP. The ongoing cost of different generation and storage types is vital when providing meaningful data to inform future investment decisions.

The ETIU conducted a series of one-on-one meetings with generators and investors, to test a range of generation assumptions.

For existing plant, the following inputs have been validated by the generation facility owners:

- ramp rates[31];
- heat rates[32];
- FOM; and
- VOM.

Stakeholders have generally agreed on the fuel price outlook for gas and provided detailed information on the SRMC of operating gas plant. A number of infrastructure investors and debt providers were engaged, and shared their views on the risk adjusted returns on investments. This information is used to inform the most appropriate rate of return inputs to apply to the WOSP modelling.

The WOSP modelling takes into account of the cost of building new facilities in Western Australia, which can be higher than in other parts of Australia.

2.4.6.4 Essential system services

ESS[33] are required to support the secure and reliable delivery of electricity from generators to customers. ESS include services to help the power system respond to a sudden loss of generation or load, as well as normal load following services to balance the inherent variability in electricity supply and demand.

As the generation capacity mix includes more intermittent, non-controllable and non-synchronous technologies, ESS will become more important to ensure a secure power system.

The Taskforce has developed a new suite of ESS to be implemented as part of the new WEM design. The reforms being introduced through the ETS, including the actions under the DER Roadmap, will support the changes required to integrate increasing levels of non-synchronous generation.

The WOSP modelling considers how future ESS requirements may impact total system costs, generation dispatch and the required generation capacity mix for the following services:

- Frequency Regulation Raise (currently referred to as Load Following Ancillary Service (LFAS) up);
- Frequency Regulation Lower (currently referred to as LFAS down);
- Contingency Reserve Raise (currently referred to as Spinning Reserve Ancillary Service (SRAS); and
- Contingency Reserve Lower (currently referred to as Load Rejection Reserve (LRR).

Rate of Change of Frequency (RoCoF)[34] Control Service requirements are considered through minimum system inertia constraints and different technology response times in the resource planning model.

For each scenario, the WOSP modelling considers the impact of the generation mix (including DER and behind-the-meter generation such as rooftop PV or behind-the-meter storage) on ESS requirements. The modelling then determines the technically optimal mix of facilities to provide each of the four ESS, to ensure system security in each dispatch interval over the planning horizon.

31 The ramp rate is how quickly a generation facility can increase or decrease its output, which is usually measured in MW per minute.

32 The heat rate is a measure of the efficiency of a thermal generation facility (such as a coal or gas-fired generator). The heat rate is the amount of energy used to generate one kilowatt hour (kWh) of electricity.

33 Formerly referred to as Ancillary Services.

34 The need for RoCoF and other frequency control ESS is outlined in the Information Paper *Frequency Control Technical Arrangements:* https: //www.wa.gov.au/sites/default/files/2019-08/Information-paper-Frequency-Control-Technical-Arrangements.pdf.

The historical costs of comparable services for existing facilities and benchmark costs for new facilities are then used to develop an economic merit order, and that order is used to prioritise dispatch for those facilities capable of providing the services in the resource planning model.

The dispatch model produces a marginal price for each service for each 30-minute interval and the quantity of energy dispatched for each service. The product of the price and quantity determines a total cost for each service, as well as an annual revenue stream for each facility dispatched in the ESS market.

Figure 2.15 provides an overview of the ESS modelling process.

In factoring ESS in the modelling, the WOSP:

- considers the contribution that different supply technologies make to ESS requirements, and the costs associated with ensuring ESS requirements are met;
- values the unique performance characteristics available from different technology types and their ability to meet future ESS demands;
- takes into account the impacts and benefits that behind-the-meter DER has on ESS requirements;
- ensures dispatch of generation facilities based on ability and lowest cost capability to operate within the technical envelope set by system operators;
- provides a view of the potential requirement of the different ESS markets over the study period under different scenarios;
- considers the additional costs, and revenue available, from ESS markets for individual generation and storage facilities; and
- ensures the modelled dispatch of generation facilities provides adequate contingency reserves and regulation requirements.

By co-optimising[35] the ESS and energy requirements in the SWIS, the WOSP modelling takes account of the physics of the power system and, therefore, selects a least cost solution that is consistent with power system operational constraints.

Figure 2.15: Overview of ESS modelling process

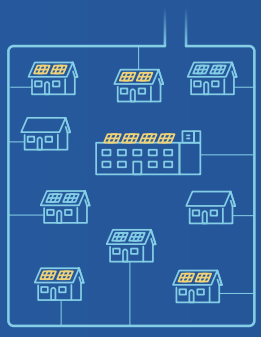
35 The degree of co-optimisation possible in the WOSP modelling is based on the historical costs and assumptions available at the time of modelling. While it is not possible to model the post-2022 co-optimised market accurately at this time, the WOSP modelling provides a reasonable proxy using the best information available.

3. Highlights

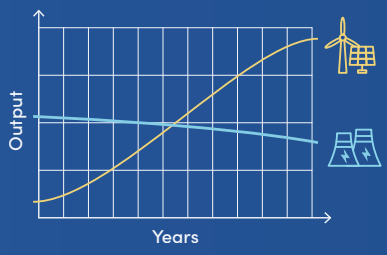
Western Australia is embracing renewable generation for a brighter energy future

The SWIS already has a strong mix of renewables, comprising 34% of installed capacity at the beginning of the modelling period

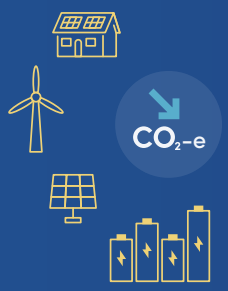
Under all four modelling scenarios, over 70% of generation capacity is renewable by 2040



Rooftop PV will continue to displace other forms of generation, most significantly coal and large-scale solar



Coal-fired generation declines under all scenarios, and partially exits the market in the mid-2020s in the lower demand scenarios



Growth in renewables reduces emissions over the study period, despite the overall increase in end-user demand

The key findings and observations for the SWIS over the 20-year study period

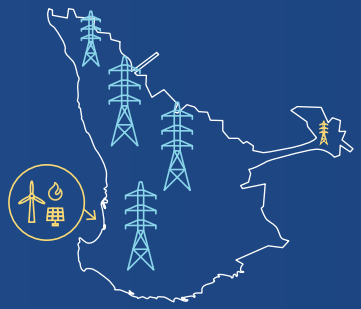
New market design creates opportunities to better meet power system needs

Growth in intermittent generation is supported by firming from storage and gas facilities

There is opportunity for storage and renewables to provide ESS

As new ESS and capacity mechanisms are embedded, revenue streams for generation and storage will become more diverse

Maximising the value of existing transmission network infrastructure in the SWIS



New generation connections are best located in the South West transmission network zone to utilise existing network capacity and add generation diversity

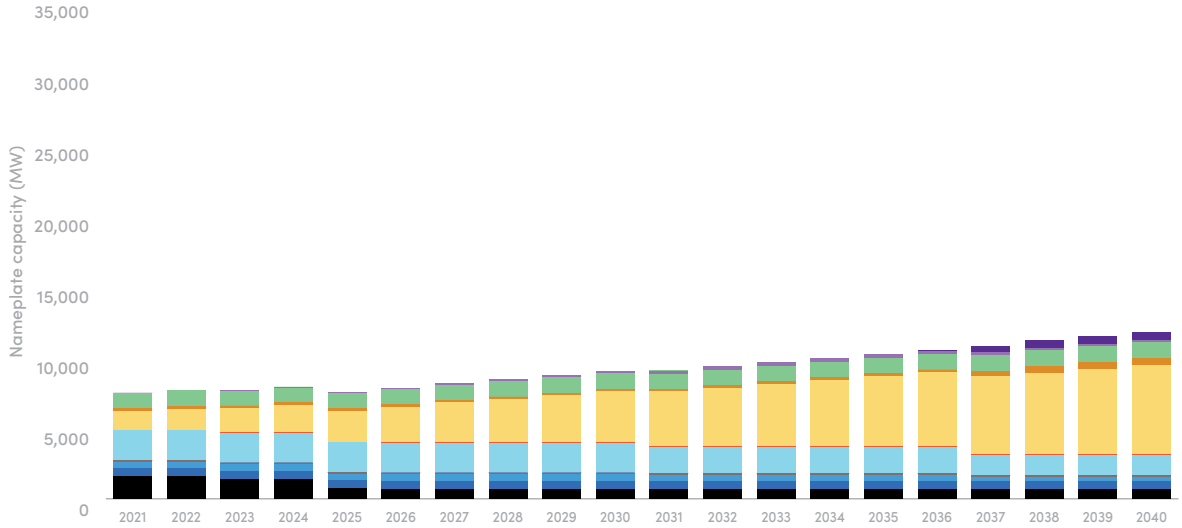
Little or no transmission network augmentation is required in the near future

SWIS capacity mix

The charts below show the modelled capacity mix for each scenario from 2020 to 2040. Rooftop PV uptake is an input assumption. Renewables (wind and solar) are selected ahead of thermal generation as part of the lowest cost capacity mix. Emissions intensity decreases in all scenarios.

Cast Away

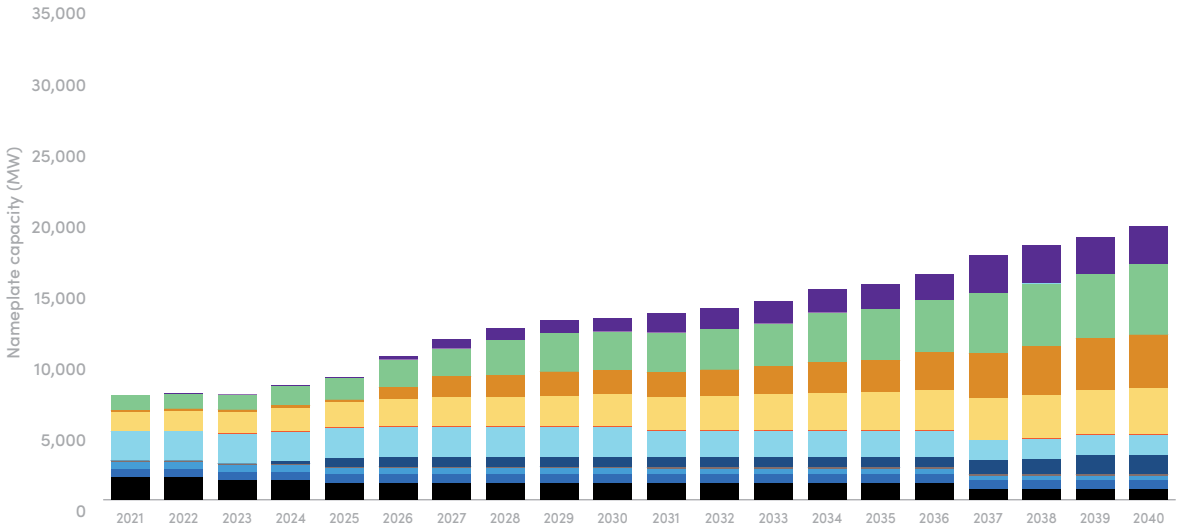
Muted economic growth coupled with greater decentralisation



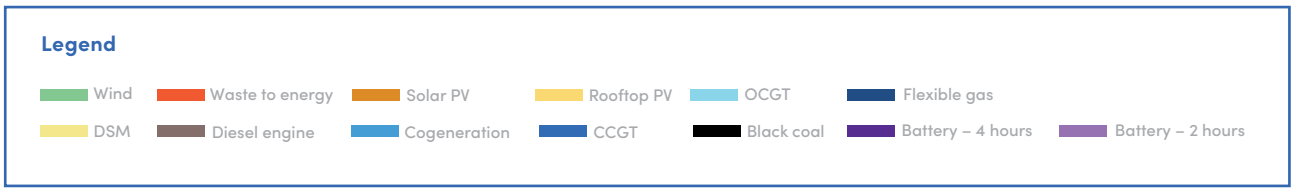
- Operational demand is the lowest of all scenarios
- Wind is the only new large-scale capacity required before 2030 (60 MW)
- No new large-scale solar required until after 2030 as it is crowded out by rooftop PV
- 500 MW coal-fired generation is displaced by cleaner, cheaper capacity by 2025
- Storage plays a role in the ESS market
- No network augmentation is required
- Emissions reduce steadily over the study period, declining by 41% by 2040

Techtopia

Technological change flattens the increasing energy demand profile

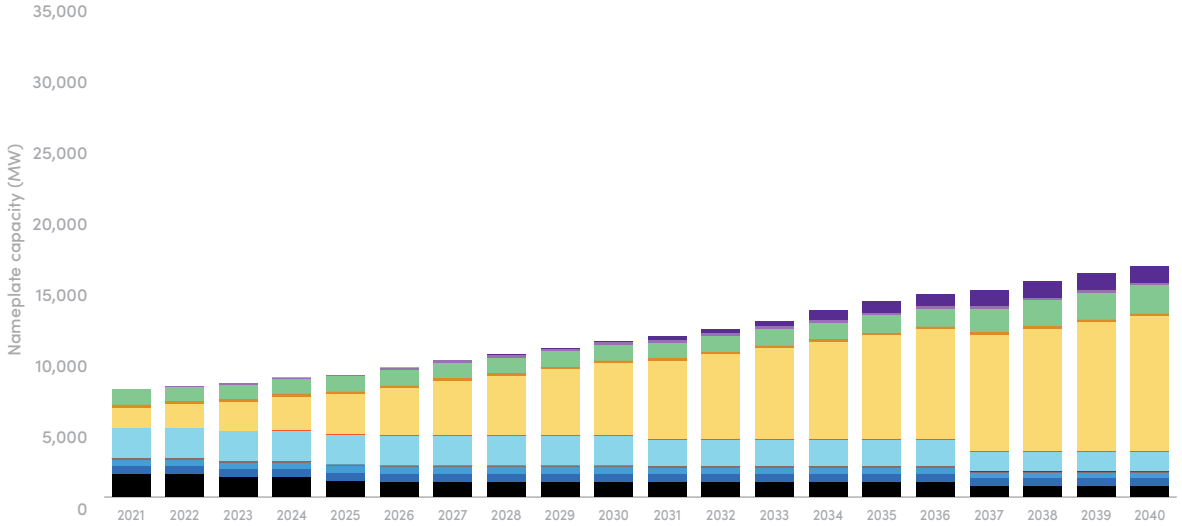


- Operational demand increases, rooftop PV uptake is lower than other scenarios
- 3,196 MW of new large-scale renewable generation (wind and large-scale solar) required by 2030
- 667 MW of flexible gas capacity is connected by 2030 to meet demand and aid firming
- No economic exit of coal-fired generation
- Storage plays a role in the ESS market and as a substitute for network augmentation towards end of study period
- Some network augmentation is required, initially to the Eastern Goldfields
- Emissions remain steady, but fall by 13% by the end of the period as thermal generation retires



Groundhog Day

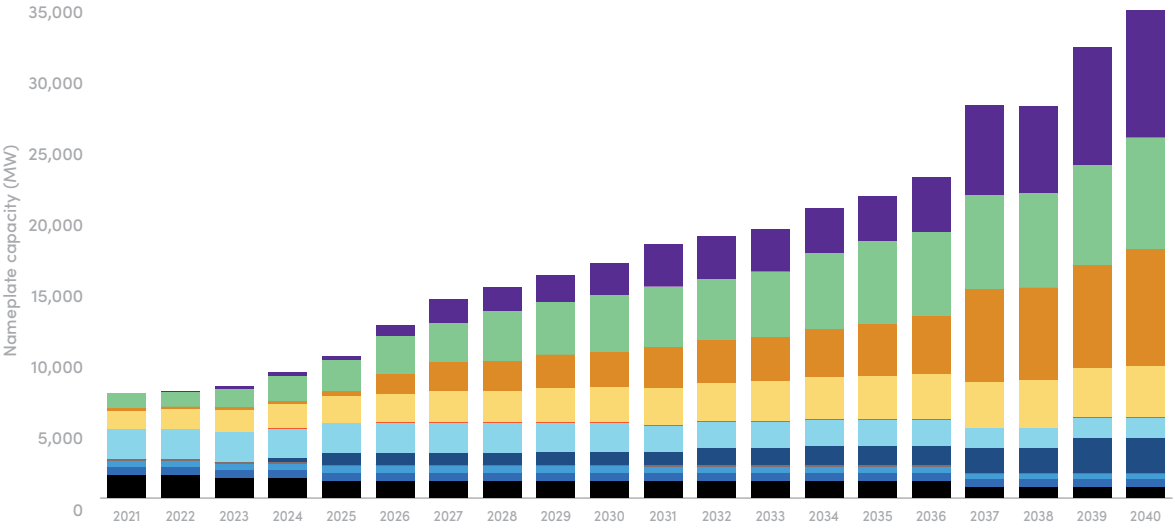
Distributed energy resources thrive, but reliance on the network remains high



- Operational demand low, highest uptake of rooftop PV
- Wind is the only new large-scale capacity required before 2030 (80 MW)
- No new large-scale solar required as it is crowded out by rooftop PV
- 132 MW coal-fired generation is displaced by cleaner, cheaper capacity by 2025
- Greater requirement for storage than Cast Away, primarily for ESS market
- No network augmentation is required
- Emissions reduce steadily over the study period, declining by 29% by 2040

Double Bubble

Ongoing strong economy results in largest growth in demand



- Operational demand is huge, additional renewable and gas-fired capacity is required immediately
- 5,264 MW of new large-scale renewable generation (wind and large-scale solar) required by 2030
- 867 MW of new flexible gas capacity is connected by 2030 to meet demand and aid firming
- No economic exit of coal-fired generation
- Storage is critical in ESS and energy markets and to offset need for some network augmentations
- Network augmentation to Eastern Goldfields required by 2025, and from the Metro through to the Mid West by 2030
- Emissions initially increase, but fall by 17% by the end of the period as thermal generation retires

4. SWIS-wide findings and outputs

This chapter describes the key findings and observations drawn from the WOSP modelling. It discusses the common themes that occur across the different scenarios and the highlights of the modelling outputs. This chapter also includes an overview of the total system costs modelled for each scenario.

The findings and observations provided in the WOSP are technology agnostic. There is no bias towards any particular generation type and the modelling process has not favoured one particular technology over another, other than selecting the lowest cost solution to meet power system needs.

As described in section 2.3, for each of the four scenarios (Cast Away, Groundhog Day, Techtopia and Double Bubble), the modelling identifies the lowest cost combination of generation, storage, and transmission network augmentation required to meet electricity demand while maintaining system security.

The assessment of the lowest cost to supply considers the costs of constructing, connecting, and operating the various generation and storage facilities, as well as testing the commercial viability of running those facilities over their technical lives.

The following sections present the findings and the major outputs from the WOSP modelling across the entire SWIS, under all four scenarios. An important take-out from these findings is that they validate the work currently underway in delivering the ETS.

4.1 Renewables in the SWIS and increasing diversity

SUMMARY

- The SWIS already has a strong mix of renewables, with renewable generation accounting for an estimated 21% of SWIS generation in 2019-20[36]
- Renewables comprise 34% of installed capacity at the beginning of the modelling period
- Under all four modelling scenarios the majority of new entry capacity is renewable generation
- Gas and new storage capacity firm intermittency
- Rooftop PV is expected to be the fastest growing form of new capacity
- Wind is the most common form of new large-scale capacity
- No additional thermal generation is required under the lower demand scenarios
- Rooftop PV and other renewables displace other forms of generation

36 21% includes sent-out large-scale renewable generation and an estimate of the output of rooftop PV based on installed capacity per month for 2019-20.

An important observation is that modelling commences with a strong mix of renewable and thermal generation capacity in the SWIS. Year 1 of the WOSP modelling is 2020. As described in section 2.4, the WOSP modelling assumes all committed large-scale renewable generation capacity to be available from Year 1.

This means the combined 524 MW of new wind and large-scale solar capacity from the Greenough River, Merredin, Warradarge and Yandin generation facilities, is included in the opening SWIS capacity mix (see Table 4.1).

Table 4.1: New large-scale renewable capacity assumed in the modelling from 1 July 2020

FACILITY NAME	TRANSMISSION NETWORK ZONE	TECHNOLOGY	MODELLED CAPACITY (MW)
Greenough River Solar	North Country	Solar	30.0
Merredin Solar	Mid East	Solar	100.0
Warradarge	Mid West	Wind	180.0
Yandin	Mid West	Wind	214.2

Yandin Wind Farm, a RATCH/Alinta Energy Investment, managed by Alinta Energy. Source: Alinta Energy.

Including these facilities means the capacity mix in the SWIS on Day 1 of the modelling (in all scenarios) features 1,203 MW of large-scale solar and wind capacity.

Table 4.2 shows the requirement for new generating capacity over the next 10 years, excluding rooftop PV, as part of the lowest cost to supply under each modelling scenario. It also shows the associated estimated operational demand.

Table 4.2: New capacity requirements by 2030 for each modelling scenario

SCENARIO	CAST AWAY	GROUNDHOG DAY	TECHTOPIA	DOUBLE BUBBLE
Operational demand at 2020[37]	17,777 GWh p.a.	17,777 GWh p.a.	17,777 GWh p.a.	17,777 GWh p.a.
Operational demand at 2030	13,780 GWh p.a.	17,390 GWh p.a.	31,920 GWh p.a.	40,873 GWh p.a.
New capacity requirements by 2030 to meet lowest cost to supply				
Wind	60 MW	80 MW	1,698 MW	3,002 MW
Large-scale solar	0 MW	0 MW	1,498 MW	2,262 MW
Storage	187 MW	261 MW	961 MW	2,235 MW
Flexible gas	0 MW	0 MW	667 MW	867 MW

37 Source: AEMO

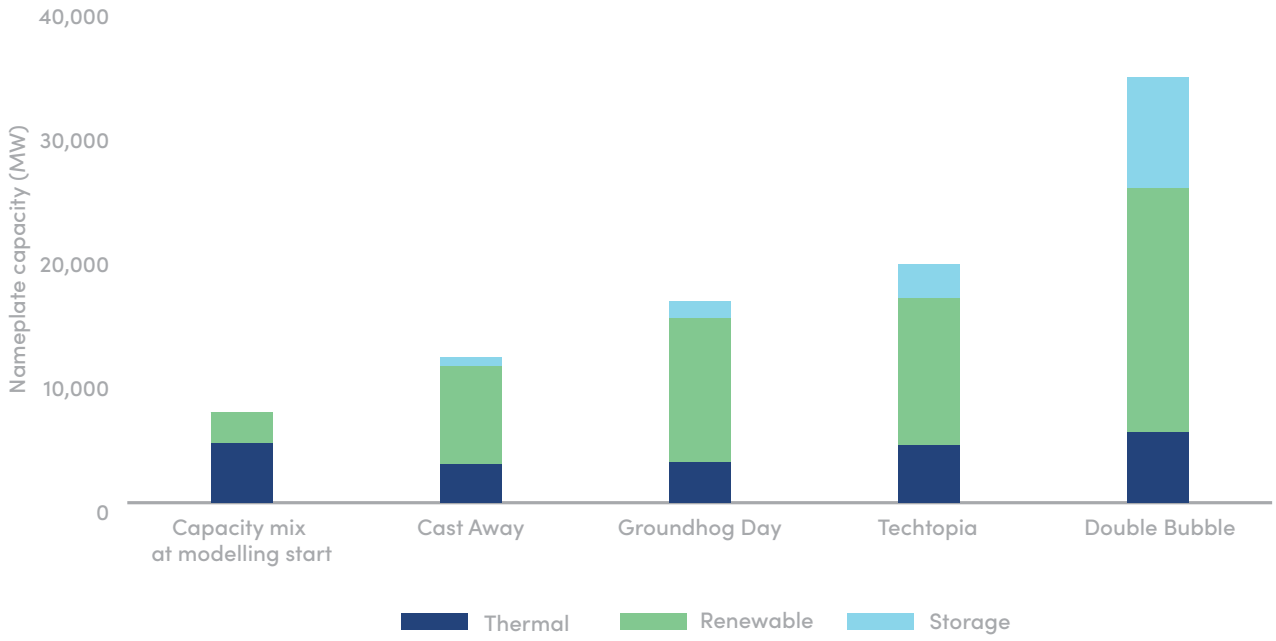


Figure 4.1: Changing SWIS capacity mix 2020 to 2040 for each scenario

A recurring theme under all four modelling scenarios is that the majority of new capacity is renewable generation. Figure 4.1 shows the changing generation mix under all modelled scenarios by the end of the study period, which results in a renewable to thermal ratio in excess of 70%, excluding storage.

No new gas capacity is selected under the lower demand scenarios. The amount of new gas capacity in the high demand scenarios is also substantially less than the new renewable capacity. Storage also contributes to capacity and supports the uptake of renewables by providing ESS to manage intermittency (see section 4.6).

This is a continuation of recent investment trends in the SWIS. It has been more than a decade since the last large-scale thermal generator designed to provide baseload power in the SWIS came online.[38]

Bluewaters' coal-fired power station near Collie commenced operations in 2009 with a nameplate capacity of 434 MW, followed shortly by a small number of gas and diesel peaking generation facilities. In the time since, 975 MW of large-scale solar and wind generation facilities have commenced operation.

Unsurprisingly then, no additional thermal generation capacity features in the lowest cost to supply under the two lower demand scenarios (Cast Away and Groundhog Day). The only new large-scale generation capacity installed under either scenario over the first ten years of the modelling period is wind.

38 Three large peaking facilities were built between 2009 and September 2012, but these only run part of the time and primarily rely on capacity income. There have also been some smaller diesel peaking generation built in the time since.

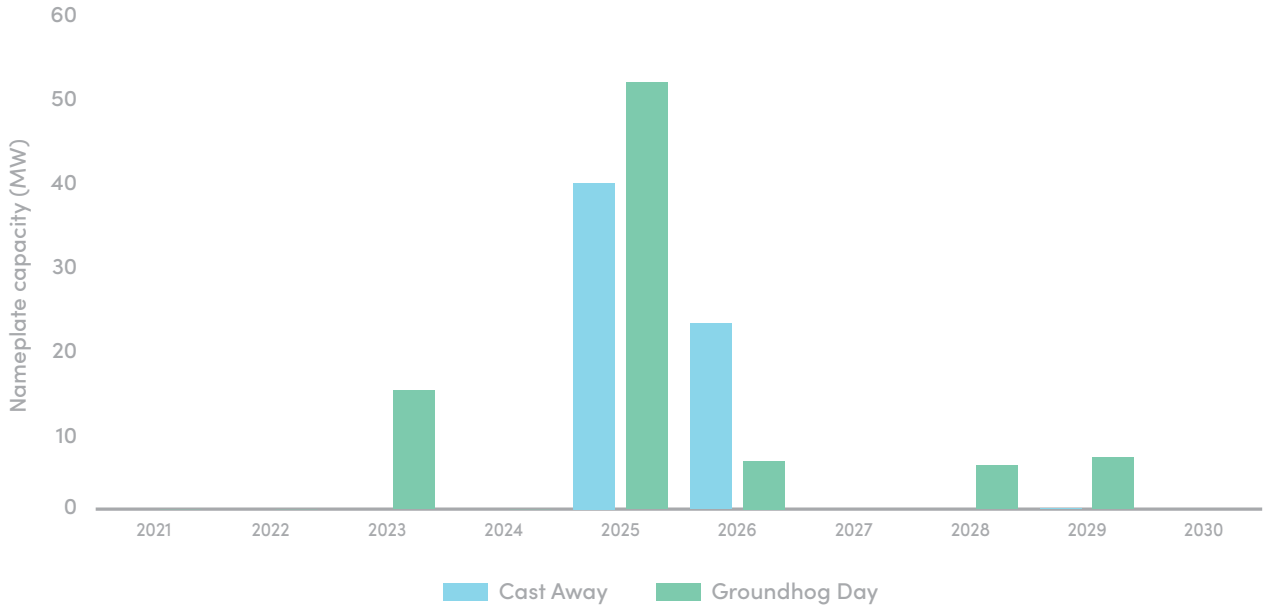


Figure 4.2: Cast Away and Groundhog Day, new generation capacity requirements by 2030 (wind generation only in both scenarios)

In these lower demand scenarios, even though some coal-fired generation leaves the system early in the modelling period, there is more than enough rooftop PV and existing generation to fill most of the void.

More significantly, there is sufficient gas-fired generation already in the system to act as the firming generation to mitigate the increased intermittency posed by additional renewables.

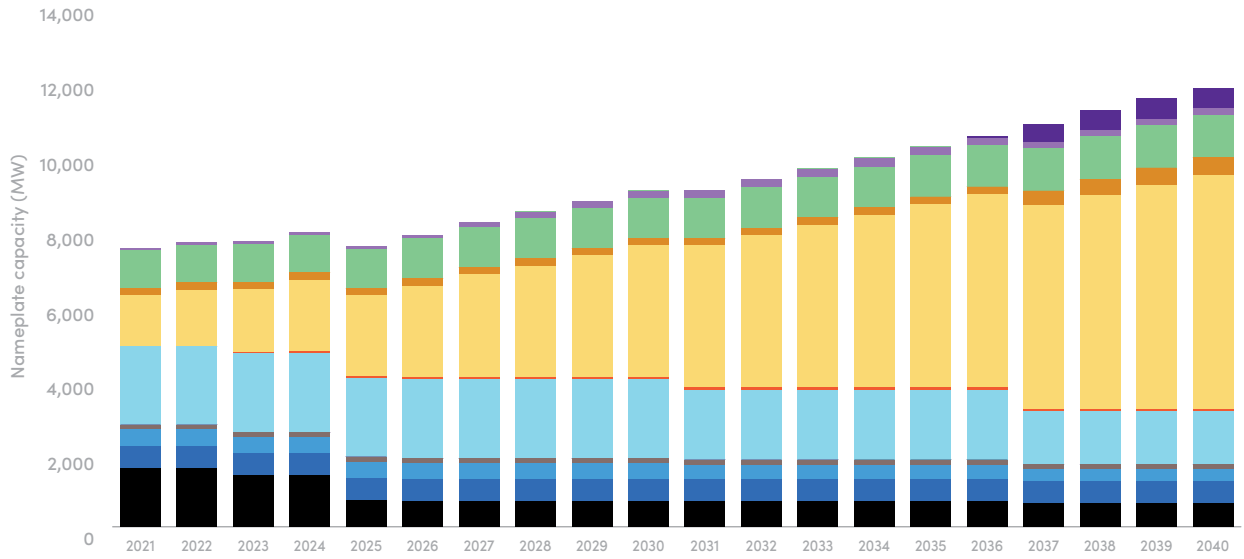


Figure 4.3: Cast Away – cumulative capacity mix 2020 to 2040

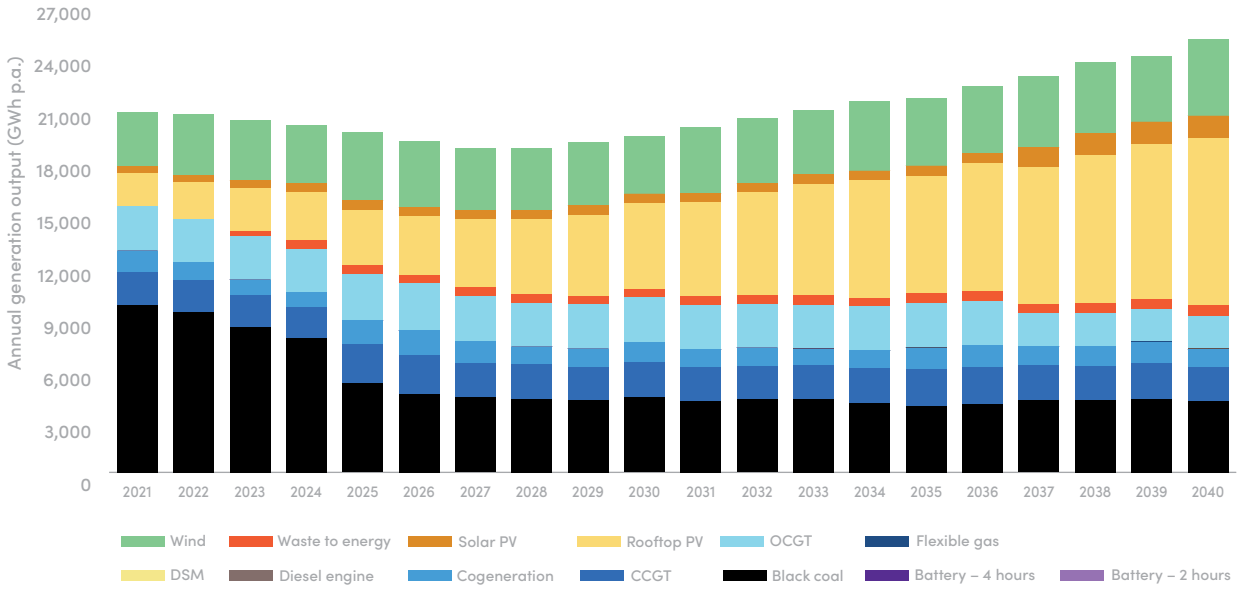


Figure 4.4: Cast Away – generation output by technology 2020 to 2040

Fast-starting gas generation tends to be flexible and better suited to firming or peaking generation than coal-fired generation. As operational demand[39] falls and coal becomes less economic to run, gas-fired generation is used more often to balance the intermittency of renewables and the fast ramp-ups required when wind or solar drops out.

No additional gas-fired generation capacity is required to meet this firming requirement. This is because there is already more than 3,000 MW of gas and cogeneration facilities in the SWIS.[40]

39 Operational demand is the amount of electricity demand required to be supplied via the network. This is distinct from 'end-user demand', which is the amount of electricity required by the end-user at their home/business. The gap between operational demand and end-user demand is typically met by behind-the-meter generation such as rooftop PV.

40 The model assumed 234 MW of OCGT and 42 MW of cogeneration capacity retires in 2031 due to technical age; with a further 457 MW of gas-fired generation capacity and 86 MW of cogeneration leaving the system in 2037 for the same reason.

The modelling of the lower demand scenarios also shows fewer additions of large-scale solar and wind capacity than expected, particularly during the first ten years of the study period.[41] For example, Cast Away and Groundhog Day only see between 60 MW and 80 MW of new wind generation connecting by 2030, and no new large-scale solar features in either scenario over the same time period.

As shown in Figure 4.3 to Figure 4.6, the renewable capacity in the SWIS at the start of the modelling period, along with the increasing levels of rooftop PV, is more than sufficient to meet the low levels of operational demand in both the Cast Away and Groundhog Day scenarios.

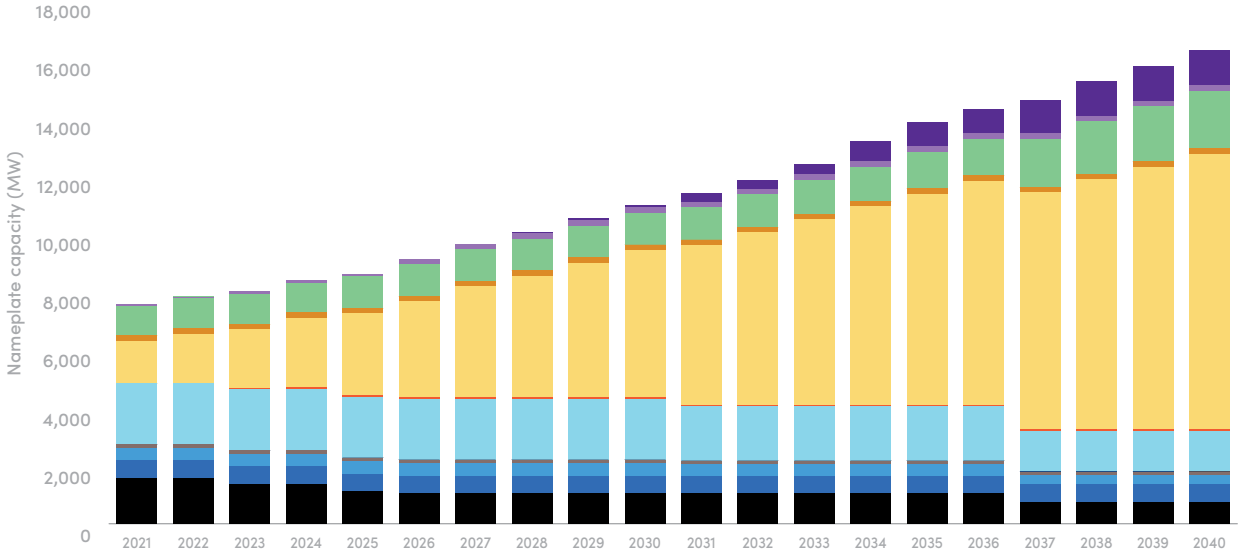


Figure 4.5: Groundhog Day – cumulative capacity mix 2020 to 2040

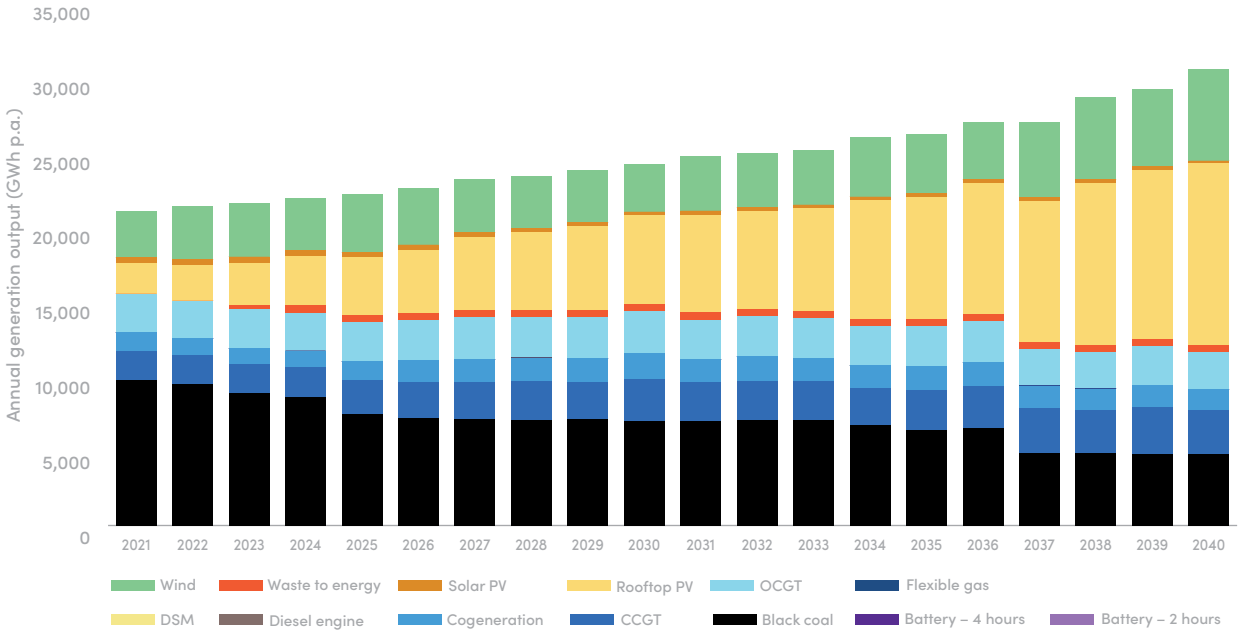


Figure 4.6: Groundhog Day – generation output by technology 2020 to 2040

41 This is primarily due to the entry of the new Greenough River Solar, Merredin Solar, Warradarge and Yandin Wind facilities in 2020, comprising 524 MW of new renewable installed capacity.

The story is different under the higher demand scenarios. In both Techtopia and Double Bubble, operational demand is much higher than in Cast Away and Groundhog Day, with lower levels of rooftop PV uptake. Consequently, the combination of existing generation capacity and new rooftop PV is not sufficient to meet demand, and substantial investment in new generation and storage is required (see Figure 4.7 to Figure 4.12).

As with the lower demand scenarios, the majority of new generation capacity built is renewable. However, the level of new investment seen in the higher demand scenarios is considerably higher, with 1,698 MW to 3,002 MW of new wind capacity connecting by 2030. Unlike in the lower demand scenarios, large-scale solar PV is also a significant contributor to new capacity, as 1,498 MW and 2,262 MW connects by 2030 in Techtopia and Double Bubble respectively (see section 4.2).

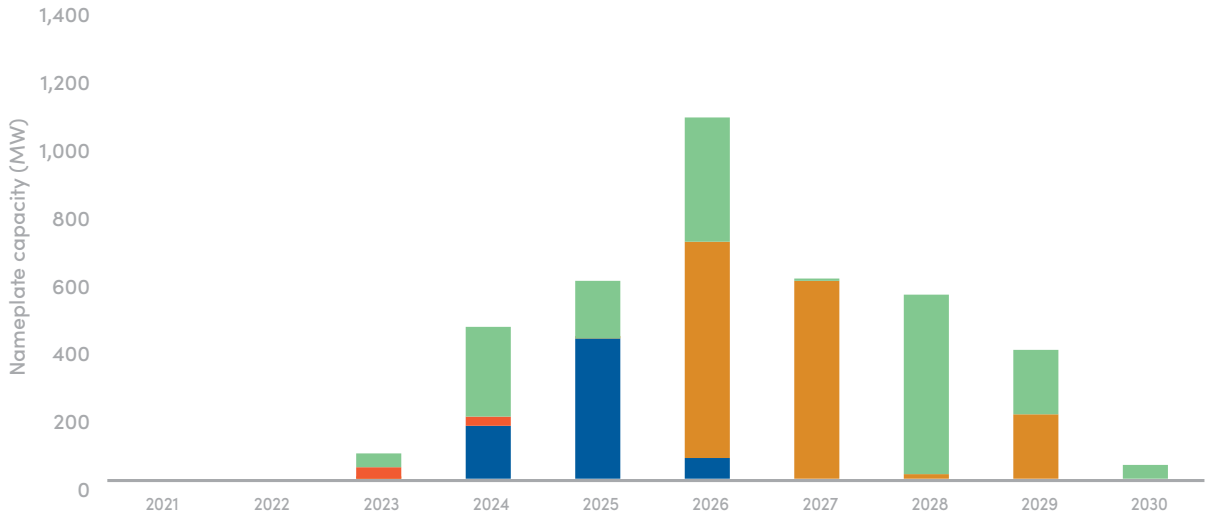


Figure 4.7: Techtopia – new generation capacity requirements by 2030 (excluding storage and rooftop PV)

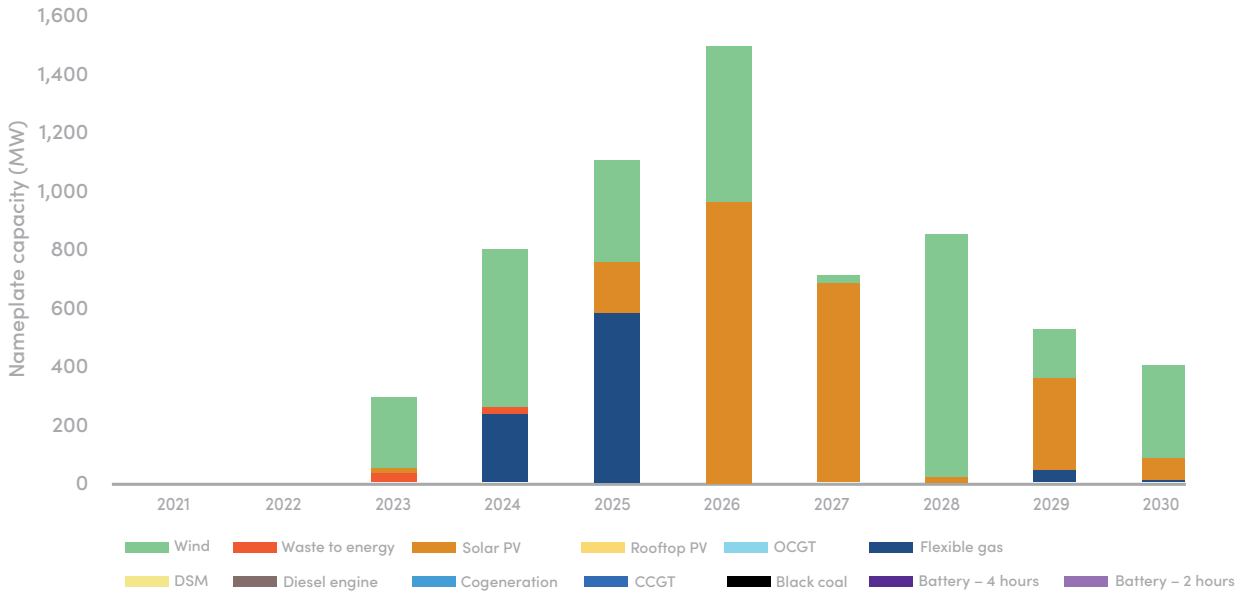


Figure 4.8: Double Bubble – new generation capacity requirements by 2030 (excluding storage and rooftop PV)

Storage uptake is also much higher in Techtopia and Double Bubble, as longer-duration storage facilities increasingly take part in the energy market as well as the ESS markets (see section 4.6).

The rapid increase in demand requires a mix of new capacity, and while the majority of this is renewable, flexible gas is also chosen to provide both energy and ESS to support the substantially increased levels of intermittent generation. Flexible gas enters the capacity mix with 163 MW in 2024 and 442 MW in 2025 in Techtopia, while the increase is 235 MW in 2024 and 580 MW in 2025 in Double Bubble.

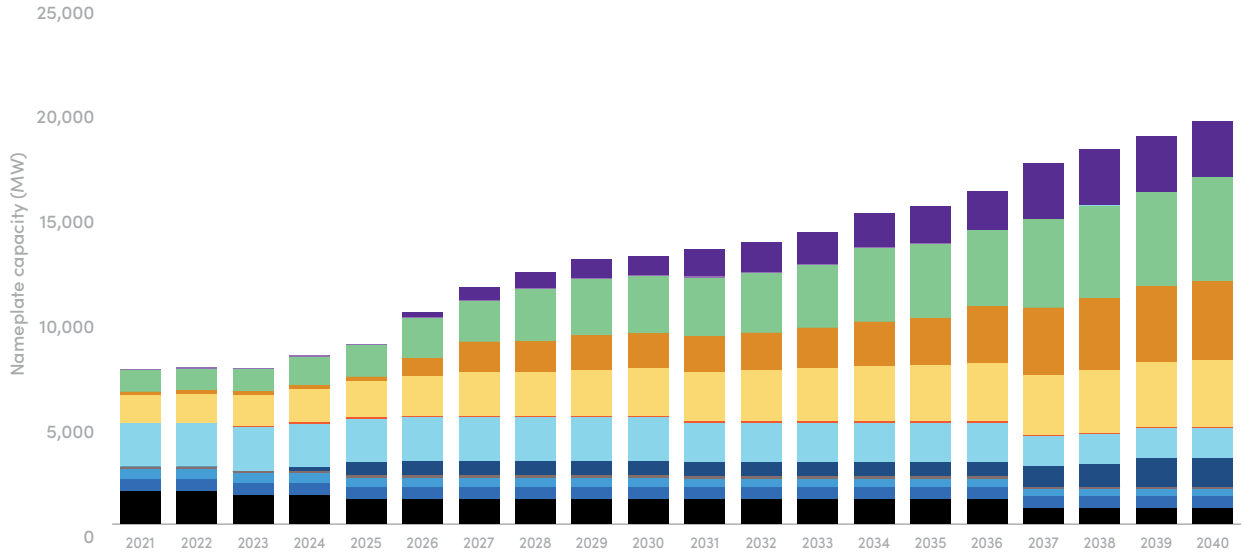


Figure 4.9: Techtopia – cumulative capacity mix 2020 to 2040

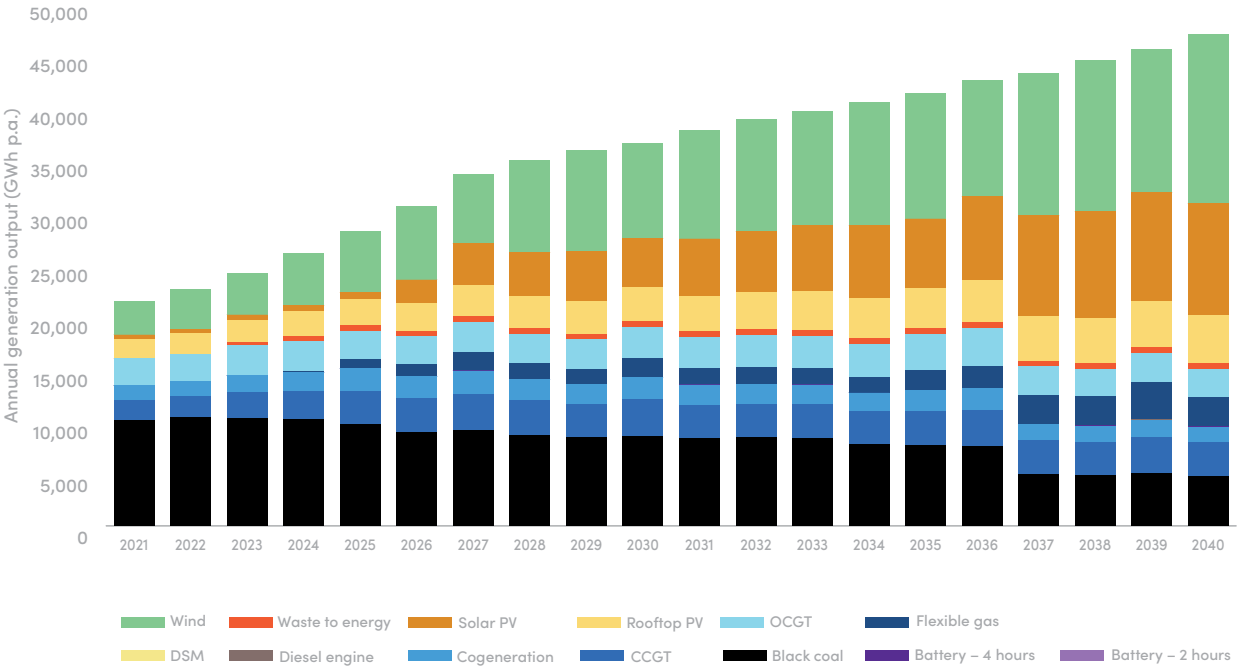


Figure 4.10: Techtopia – generation output by technology 2020 to 2040

In Double Bubble, new flexible gas capacity is built, along with longer-duration storage, following the end of technical life retirement of 276 MW of existing gas generation capacity in 2031, and 968 MW existing gas and coal-fired generation capacity in 2037.

Under Techtopia, which has lower demand growth than Double Bubble, no further flexible gas capacity is built after 2026 until the end of technical life retirement of the existing gas and coal-fired generation capacity in 2037. No flexible gas generation capacity is built following the 2031 retirements as the model chooses to replace this capacity primarily with storage.

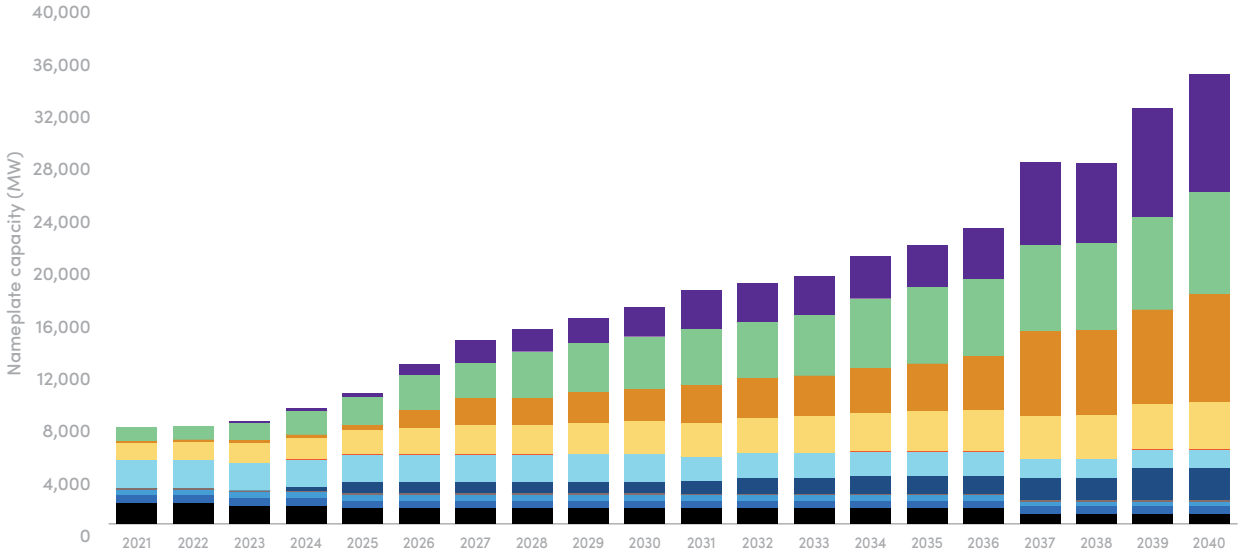


Figure 4.11: Double Bubble – cumulative capacity mix 2020 to 2040

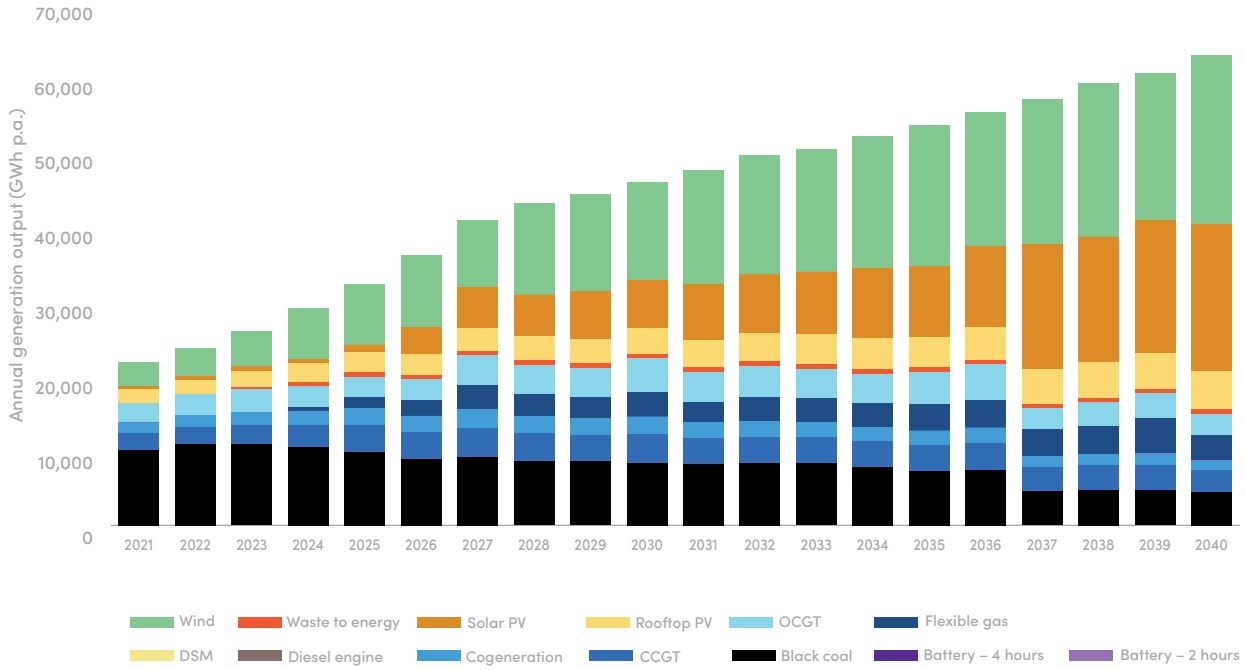


Figure 4.12: Double Bubble – generation output by technology 2020 to 2040

Aerial view of residential rooftop PV. Source: Synergy.

4.2 The dominance of rooftop PV

SUMMARY

- Rooftop PV capacity is assumed to increase by around 1,000 MW and 4,000 MW by 2030 and will continue to displace large-scale generation - particularly coal and large-scale solar
- Rooftop PV partially fills the void left by retired coal plant, reducing the need for new replacement large-scale generation facilities
- New large-scale solar generation only features where there is lower rooftop PV relative to overall demand

As described in the Taskforce's DER Roadmap, the growth of rooftop PV is having a profound impact on the power system, presenting both challenges and opportunities. The WOSP modelling is therefore designed to test how rooftop PV influences the system and market under different trajectories of electricity demand growth.

For each scenario, a level of rooftop PV uptake has been assumed and is a key modelling parameter, along with operational demand, economic environment and population growth.

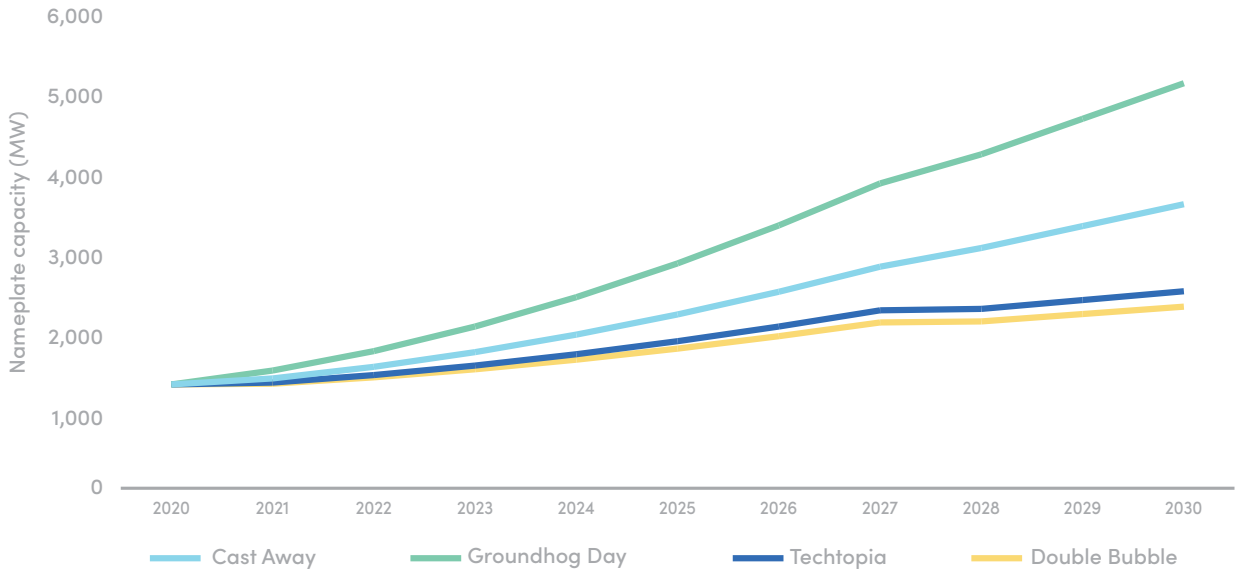


Figure 4.13: Rooftop PV uptake cumulative capacity 2020 to 2030

The modelling also assumes rooftop PV systems automatically form part of the lowest cost to supply. The reason for this is two-fold. Firstly, there is no cost attributed to installing new rooftop PV capacity – the systems are paid for and installed by individual customers. Secondly, the surplus energy produced by rooftop PV systems spills out into the network throughout the day, meaning it is effectively 'dispatched' ahead of all other capacity, displaces all forms of large-scale generation and imposes additional ESS requirements on the system.

The overarching assumption is that under all scenarios, the amount of rooftop PV capacity in the SWIS will continue to grow. In 2020, 1,291MW of rooftop PV is assumed to be in the system. By 2030 this increases to between 2,258 MW and 5,037 MW (see Figure 4.13).

The growth in rooftop PV in Groundhog Day outstrips what is required to meet both end-user and peak demand. This has allowed the WOSP to test the implications of extreme rooftop PV growth, levels of curtailment and impact on power system security.

Aggregated rooftop PV is a dispatchable generator in the lowest cost model and is actually dispatched first after taking into account minimum requirements for system operation. Accounting for these requirements, all other generation will be curtailed before rooftop PV. Groundhog Day is the only scenario where significant curtailment occurs when installed rooftop PV capacity exceeds 2,700 MW from 2025.

Under all scenarios, a common theme is that the volume and density of rooftop PV in the grid provides an opportunity for large numbers of individual systems to be aggregated and coordinated to provide energy and ESS, where capable, into the WEM.

The rooftop PV modelling in the WOSP validates actions outlined in the DER Roadmap, which will enable the aggregation and orchestration of DER including rooftop PV.

The scenarios with the lowest level of rooftop PV growth are Techtopia and Double Bubble. They are also the two higher demand scenarios.

The unique circumstances of these high demand but lower PV uptake scenarios provides an opportunity for large-scale solar generation. Ordinarily, rooftop PV decreases the operational demand required to be met by large-scale generators during daylight hours, which is when large-scale solar is available to be dispatched. However, the very high demand trajectory in Techtopia and Double Bubble means the relative impact of rooftop PV on operational demand is less pronounced and operational demand is sufficient for large-scale solar capacity to enter the market. In both scenarios large-scale solar becomes a prominent part of the capacity mix.

This is because large-scale solar is relatively low cost to install and operate, which makes it a viable alternative to other generation types.

Under Techtopia 1,686 MW of large-scale solar forms part of the capacity mix by the end of the decade. The outcome is even greater under Double Bubble, with 2,450 MW connected by 2030. See Figure 4.14 and Figure 4.15.

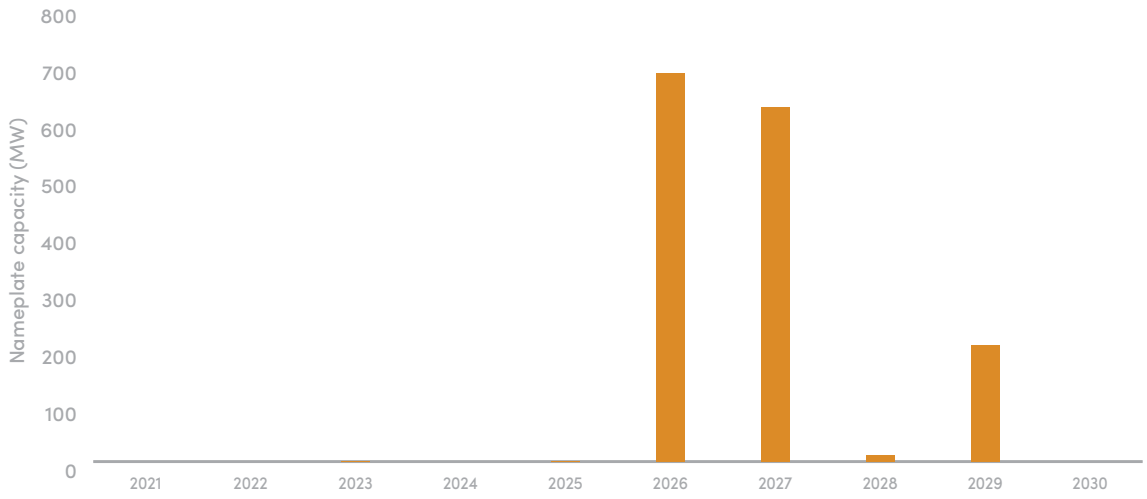


Figure 4.14: Techtopia, additional large-scale solar capacity 2020 to 2030

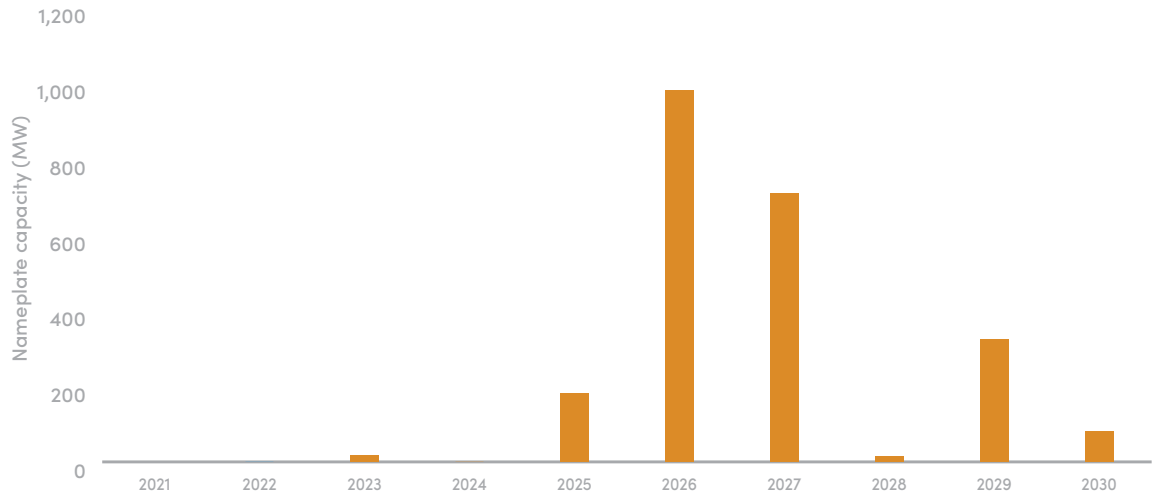


Figure 4.15: Double Bubble, additional large-scale solar capacity 2020 to 2030

If demand and market conditions emerge that have similar characteristics to Techtopia or Double Bubble, large-scale solar could be a commercial option in the SWIS. However, the modelling indicates that new large-scale solar capacity only becomes viable if operational demand is high and rooftop PV installation is not as high as assumed.

Under the two lower demand scenarios (Cast Away and Groundhog Day), new large-scale solar capacity is not a significant feature of the generation mix. See Figure 4.16 and Figure 4.17.

The Cast Away and Groundhog Day scenarios see very high levels of rooftop PV uptake. This means rooftop PV meets a larger portion of end-user demand and causes operational demand to flatten or decrease.

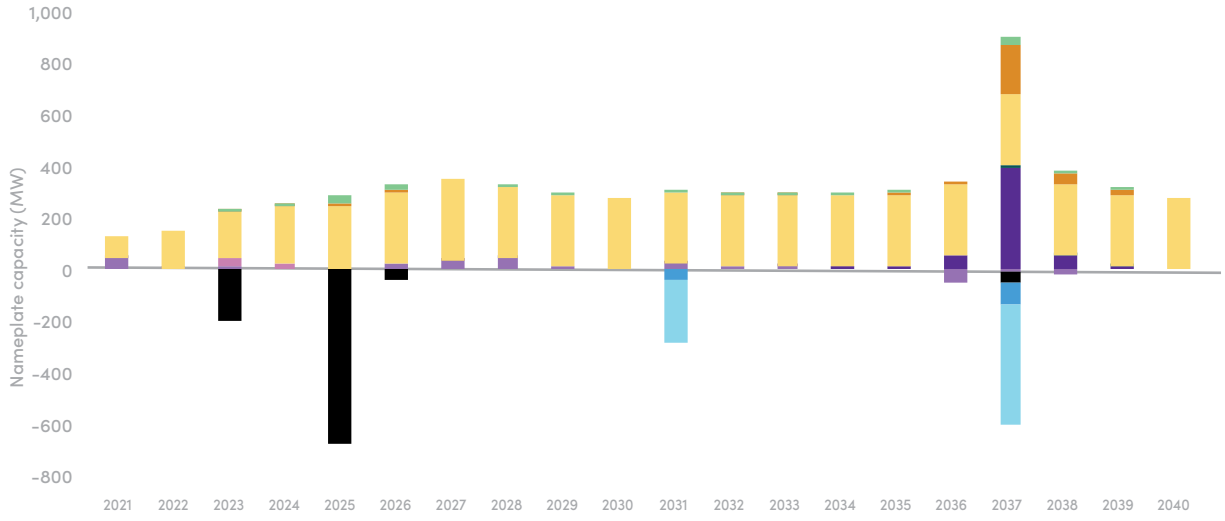


Figure 4.16: Cast Away, capacity changes 2020 to 2040

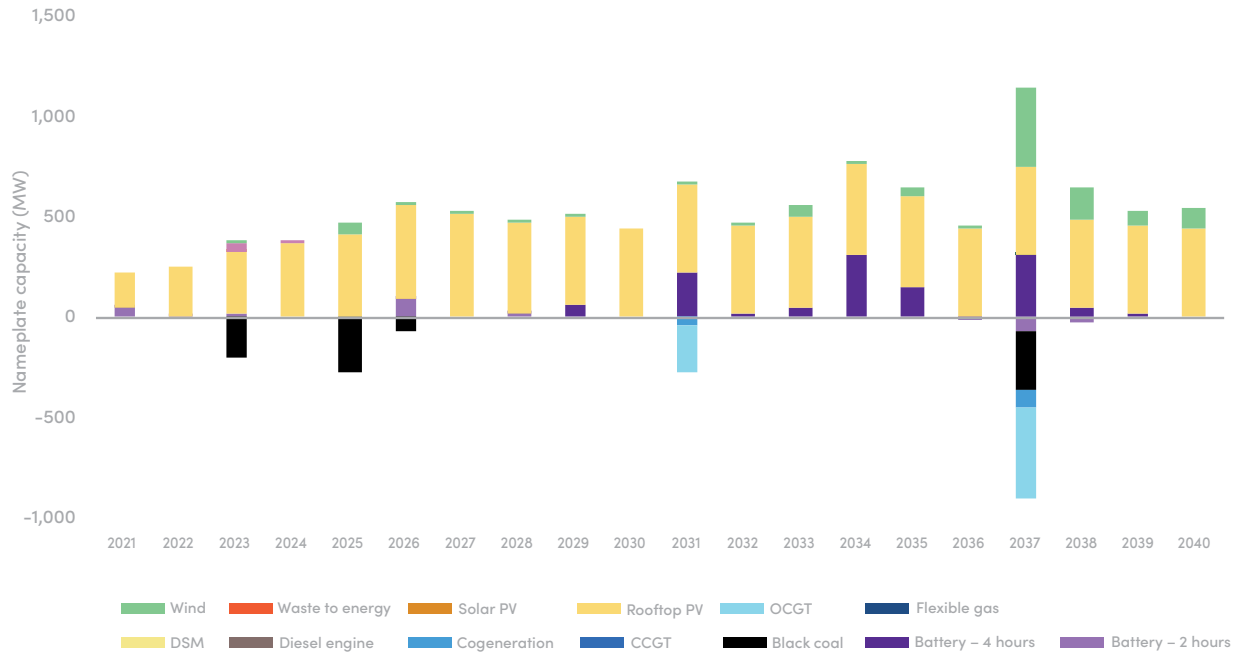


Figure 4.17: Groundhog Day, capacity changes 2020 to 2040

Albany Wind Farm. Source: Synergy.

At the beginning of the modelling period, there is already 188 MW of large-scale solar capacity in the system.[42] In Groundhog Day, new large-scale solar does not appear in the lowest cost to supply as end-user demand during daylight hours is supplied predominantly by rooftop PV. Where operational demand is low, wind generation capacity is selected ahead of large-scale solar as it is a more diverse form of generation (discussed in section 4.2.3). Some large-scale solar generation enters the market in Cast Away, but it is limited to the end of the study period.[43]

4.3 Wind generation in the south

SUMMARY

- The modelling identifies wind opportunities in the South West transmission network zone
- The recently installed wind capacity in the north has sufficiently utilised the existing network capacity, which means it is a lower cost to the system to build new wind capacity in the southern areas of the SWIS to utilise existing network capacity
- Additional wind capacity in the south would improve the diversity of wind generation across the power system

42 Greenough River (40 MW) and Merredin Solar Farm (100 MW) are assumed to be available capacity from day one of the model (1 July 2020).

43 The WOSP modelling is technology agnostic and selects the forms of generation capacity that will make up the lowest cost to supply. This does not mean large-scale solar and other forms of thermal generation are not commercial.

Western Australia has some of the world's best wind resources, with 1,015 MW of wind generation capacity connected to the network at the beginning of the modelling. Wind has distinct profiles in different areas across the SWIS, which provides additional 'security' in terms of being able to meet demand at different times of day or year. Solar generation has comparatively less diversity in that it generates at a reasonably consistent level across the SWIS and stops generating when the sun goes down.

Adding wind generation in areas of the SWIS where there is currently little or no wind capacity installed would provide the benefit of extra diversity of supply and strengthen the overall capacity mix. Essentially, having more generating facilities spread around the SWIS will enable more wind energy to be captured throughout the day and night.

The modelling identifies the South West transmission network zone as the optimal location to build new wind facilities to achieve the lowest cost to supply over the next ten years. Currently, there is no wind capacity installed in the South West transmission network zone. All wind capacity in the south of the SWIS (40 MW) is in the South East transmission network zone (see Figure 4.18).

Figure 4.18: Existing wind farm locations in the SWIS

The South West transmission network zone modelled in the study is connected via a network of bulk transmission lines to the Metro, Mid East and South East transmission network zones. The combination of available transmission network transfer capacity and wind resources means the modelling selects the South West zone as a lower cost solution for connecting new wind.

Under the lower demand scenarios (Cast Away and Groundhog Day) the amount of new wind generation featuring in the lowest cost to supply by 2030 is relatively small. 60 MW of new wind generation is added in Cast Away, and 80 MW of new wind generation is added in Groundhog Day.

This is primarily due to low operational demand caused by high rooftop PV uptake and relatively high levels of existing generation capacity, including the 394 MW of new wind capacity (Warradarge and Yandin) already incorporated in the modelling in 2020.

Under the two higher demand scenarios (Techtopia and Double Bubble) new wind capacity is significantly larger at 1,698 MW and 3,002 MW respectively. This is driven by the extremely high growth in demand across the SWIS until around 2024.

Figure 4.19 shows the placement of new wind capacity as part of the lowest cost to supply in each scenario by 2030.

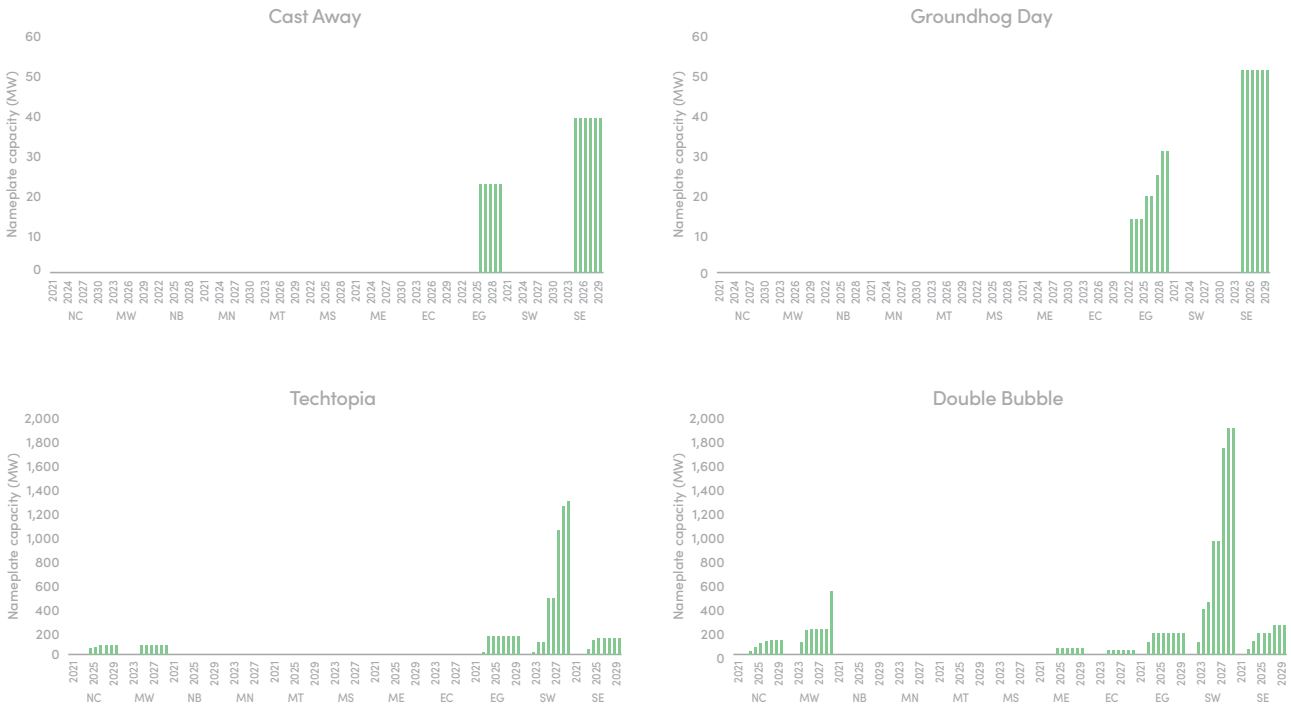


Figure 4.19: New wind capacity by transmission network zone*, by 2030

* Refer to Figure 1.3 for transmission network zone abbreviations

When determining the lowest cost to supply, the modelling takes into consideration existing network capacity as well as the cost of any transmission network augmentations that may be required to allow new generators to connect. As a result, new generation capacity gets placed in the south of the SWIS, where there is significantly more network capacity available than the north. A significant benefit of adding new wind capacity in the south is that it promotes geographical diversification of energy supply.

One of the critical differences between wind and large-scale solar generation is the diversity of wind supply across different geographical areas of the SWIS. Figure 4.20 and Figure 4.21 show the assumed relative availability of wind generation over the course of two years in 2025 and 2027 for the east, north and south of the SWIS, based on two of the nine different historical reference years used in the WOSP.

The two figures show the annual average by time of day availability[44] for six generic wind farms in the SWIS and the resulting generation based on two different historical weather patterns of wind speed. These generic wind farms consist of two in the east (East Country/Mid East), two in the north (Mid West/North Country) and two in the south (South West/South East).

From these figures it can be observed that wind farms in the south have a flatter profile relative to others and generally increase in availability from midday to afternoon/night. Wind farms in the north have higher outputs during the afternoon and night but lower outputs during the middle of the day compared to wind farms in the south, and wind farms located in the east have close to their highest output overnight with the lowest output during the 11am to 6pm peak.

44 Availability is how many MWs could be dispatched if the wind farm was 'in-merit' and not subject to network/power system constraints. That is, it provides the maximum output of a 1 MW wind farm on an annual average time of day basis. The availability has been normalised to 1 MW for comparison purposes.

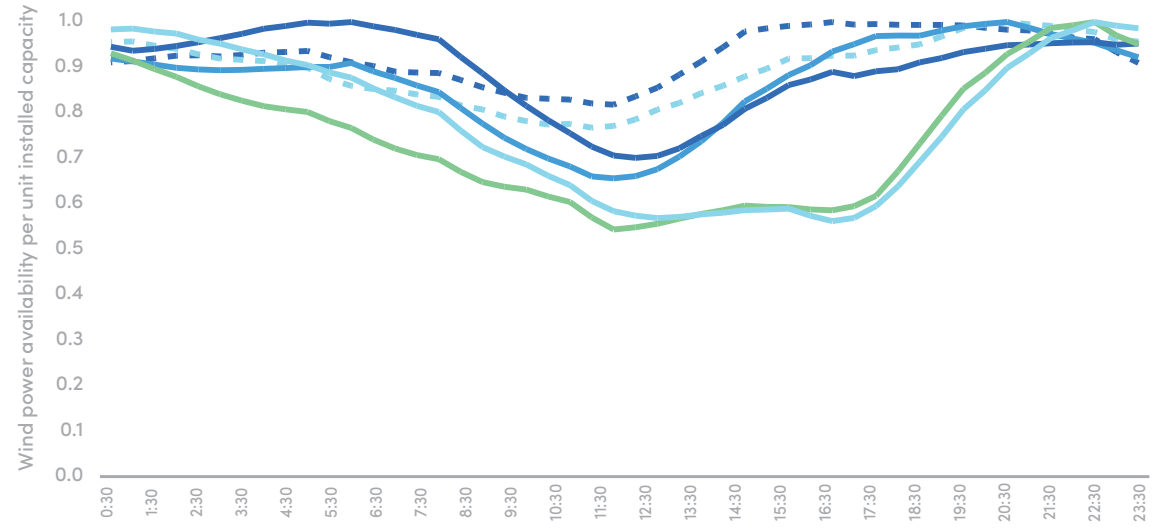


Figure 4.20: Assumed time of day wind availability in 2025 based on historical weather patterns

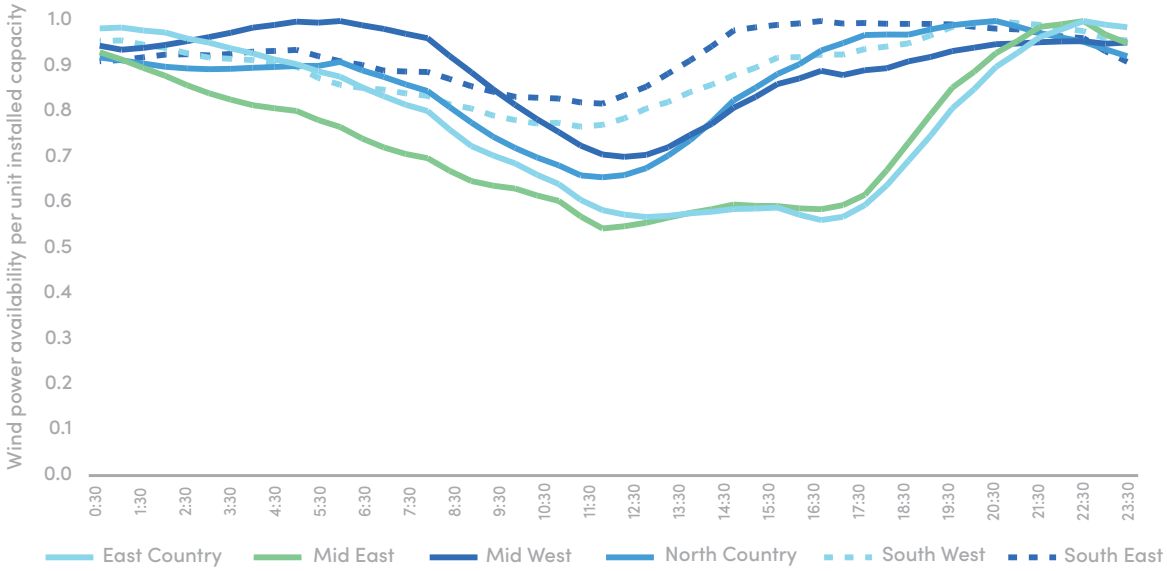


Figure 4.21: Assumed time of day wind availability in 2027 based on historical weather patterns

A transmission network augmentation to the Mid West or North Country, to allow for additional wind and solar generation to be built in the northern transmission network zones, does not occur in the lowest cost modelling until the existing network capacity in the south is fully utilised and the operational demand in the SWIS exceeds 35,000 GWh p.a.

4.4 Economic pressure on coal-fired generation

SUMMARY

- Currently there is 1,569 MW of coal-fired generation capacity installed in the SWIS
- Coal still has a role in the generation mix, but it becomes less economic over time due to displacement by lower cost technologies
- Muja C will be retired by the end of 2024, as announced by the Government in 2019, removing 392 MW of coal plant from the generation mix
- Under higher demand scenarios, there is no additional economic closure of coal plant, however annual output continues to decrease
- Under lower demand scenarios, between 132 MW and 500 MW of coal plant would no longer feature in the lowest cost to supply from 2025 over and above the closure of Muja C

Currently, there is 1,569 MW of coal-fired generation capacity in the SWIS. In 2019-20, coal accounted for 44% of large-scale electricity generation, with gas also accounting for 44%.[45] See Figure 4.22.

Coal-fired generation has been declining as a proportion of overall electricity generation for much of the past decade, as more flexible forms of generation such as wind, solar and gas have entered the market. The growing influence of rooftop PV has transformed the energy mix.

Coal-fired generation works best at a constant level of output.[46] The increase in rooftop PV generation has displaced coal and other forms of large-scale generation and means coal-fired plants are having to be cycled more often during the course of the day. Having to regularly start up or shut down coal-fired generation facilities drives up operating and maintenance costs and can lead to a generation unit becoming economically unviable.

The cost of starting up and shutting down a coal-fired generator can range between $50,000 and $150,000 for each start-up. Restart times are long, taking up to 24 hours. Multiple starts also increase the frequency of a plant's fixed operations and maintenance schedule. In comparison, an OCGT costs around $2,000 to start up and can be at maximum output within minutes.

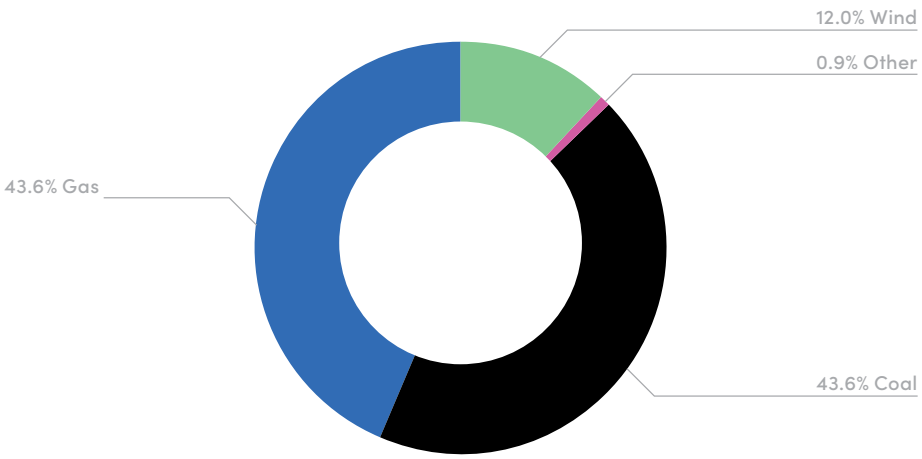


Figure 4.22: Large-scale generation sent-out energy 2019-20

45 Source: AEMO Market Data.

46 AEMO describes coal as 'baseload generation' because these units have a minimum generation limit below which they cannot generate, and are not designed to ramp up or down quickly or cycle on and off – see page 26 of *Integrating Utility scale Renewables and Distributed Energy Resources in the SWIS* , available at https: //aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/integrating-utility-scale-renewables-and-distributed-energy-resources-in-the-swis.

Muja Power Station. Source: Synergy.

The WOSP modelling shows the displacement of coal-fired generation is likely to continue over the next 20 years, however coal still has a role to play in electricity generation. The marginal cost of existing coal-fired generation is low, and the generation assets are a sunk cost. This means coal will remain part of the lowest cost generation mix for the foreseeable future.

Notwithstanding this, the displacement of coal-fired generation as a technology by less expensive or more flexible forms of generation means the economics of coal-fired generation decreases over time, and more rapidly in a lower demand future.

The McGowan Government announced the scaling back of Muja Power Station from 2022 in August 2019.[47] The modelling therefore removes 392 MW of coal-fired generation capacity from the market by the end of 2024 in all four scenarios.

The closure of the two Muja C units (Muja 5 and 6) is an economic decision. Muja units 5 and 6 are more than 40 years old and utilisation of these two units has declined dramatically in recent years.

From a system supply perspective, these coal-fired generators do not need to be replaced as there is sufficient capacity from renewables and gas generation in the system to fill the void left by their exit.

In the two higher demand scenarios (Techtopia and Double Bubble) there is no economic closure of coal-fired generation facilities. Muja C closes in 2022 and 2024,[48] and the modelling assumes the Muja D units (425 MW) will cease operation at the beginning of 2036-37 as they reach the end of their 50-year design life.

However, these are end of technical life retirements. Where operational demand remains high, the modelling shows no coal-fired generation capacity would need to be closed from a purely economic perspective[49] to the end of the study period (see Figure 4.23).

47 https://www.mediastatements.wa.gov.au/Pages/McGowan/2019/08/Muja-Power-Station-in-Collie-to-be-scaled-back-from-2022.aspx.

48 As these occur in October 2022 and 2024, they appear on the charts in the 2022-23 and 2024-25 financial years.

49 The model assumes Bluewaters G1 and G2, and Collie G1 will continue to operate beyond 2040, however they will be nearing the end of their technical lives.

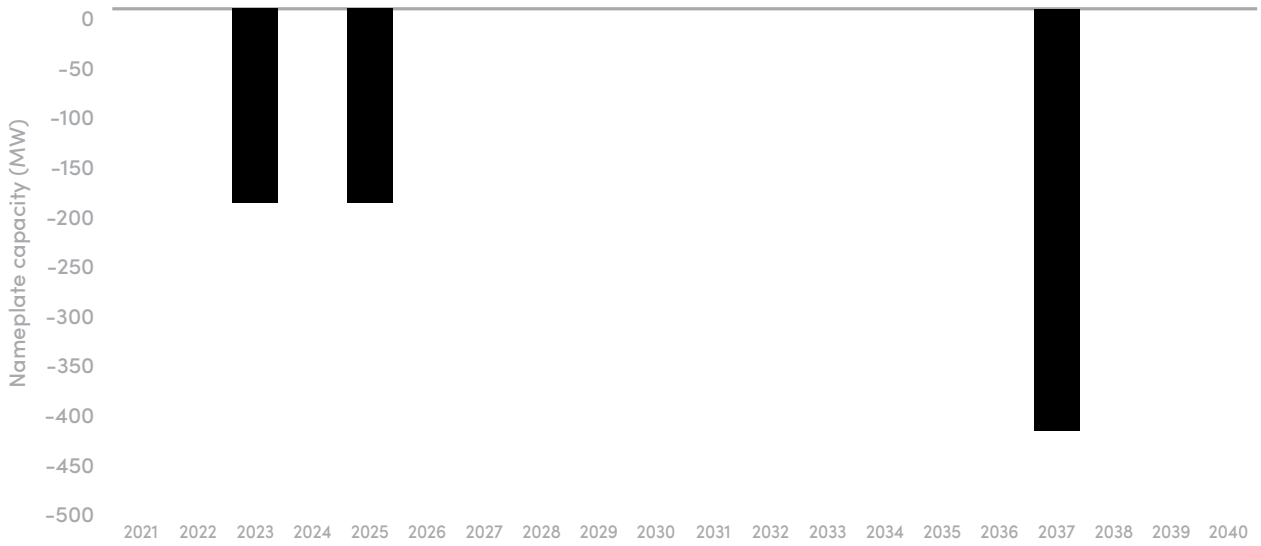


Figure 4.23: Techtopia and Double Bubble, coal capacity changes 2020 to 2040

In both Techtopia and Double Bubble, while the predicted output from coal-fired generation decreases, there remains sufficient demand for electricity to make it economical to continue to run coal-fired generation as part of the lowest cost to supply. In both these scenarios, the proportion of end-user demand being supplied by the power system (as opposed to behind-the-meter generation) is high. This means there is a sufficiently large 'gap' between end-user demand and the amount of demand that can be met by other forms of generation, such as renewables and gas, for there to be an economic role for coal-fired generation.

However, even under the higher demand scenarios, coal-fired generation facilities would be unlikely to operate at full capacity. For example, under Double Bubble a coal facility with a nameplate capacity of 200 MW may only run at 110 MW – but it would at least run continuously. Essentially, Double Bubble and Techtopia provide sufficient headroom within operational demand to allow coal-fired generation to avoid having to be frequently cycled up or down.

Under the two lower demand scenarios (Cast Away and Groundhog Day), coal-fired generation becomes a less economic option more quickly and begins to feature less as part of the lowest cost to supply. In Cast Away and Groundhog Day, the amount of end-user demand being met by rooftop PV systems continues to increase. As a result, there is less opportunity for coal to operate as baseload generation and fewer coal-fired generation facilities can be run continuously.

Therefore, in the Cast Away or Groundhog Day scenarios, where operational demand has plateaued or is in decline, coal-fired generation becomes economically marginal.

In Groundhog Day, approximately 130 MW of existing coal-fired generation capacity does not feature in the lowest cost to supply from 2026 onwards. See Figure 4.24.

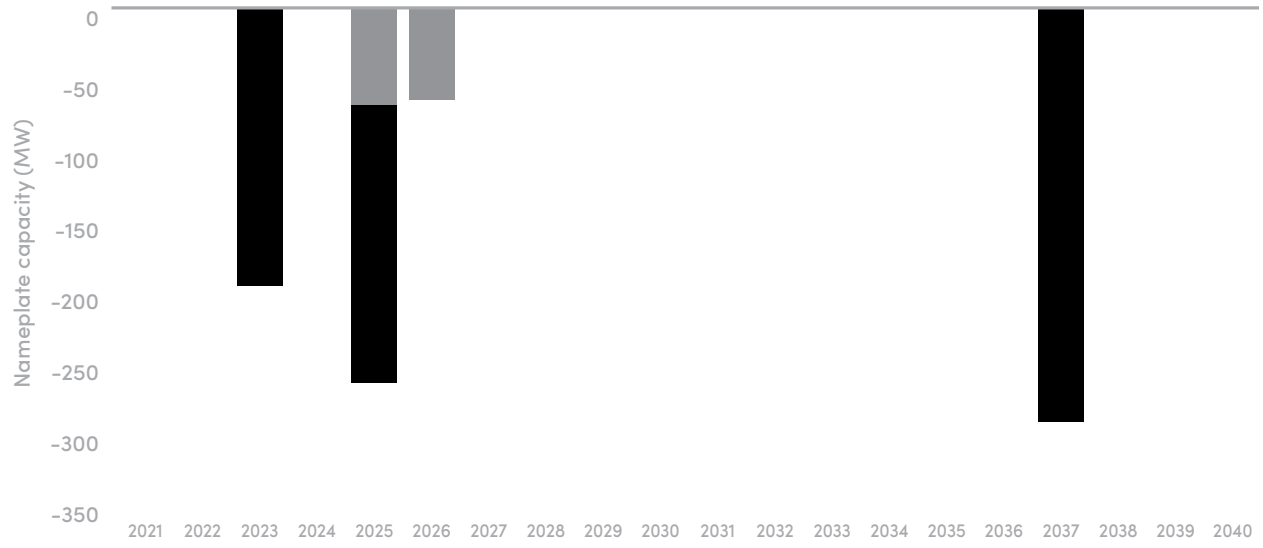


Figure 4.24: Groundhog Day, coal capacity changes 2020 to 2040

Under Cast Away, 500 MW of existing coal-fired generation capacity does not feature in the lowest cost generation mix from 2025 onwards (see Figure 4.25).

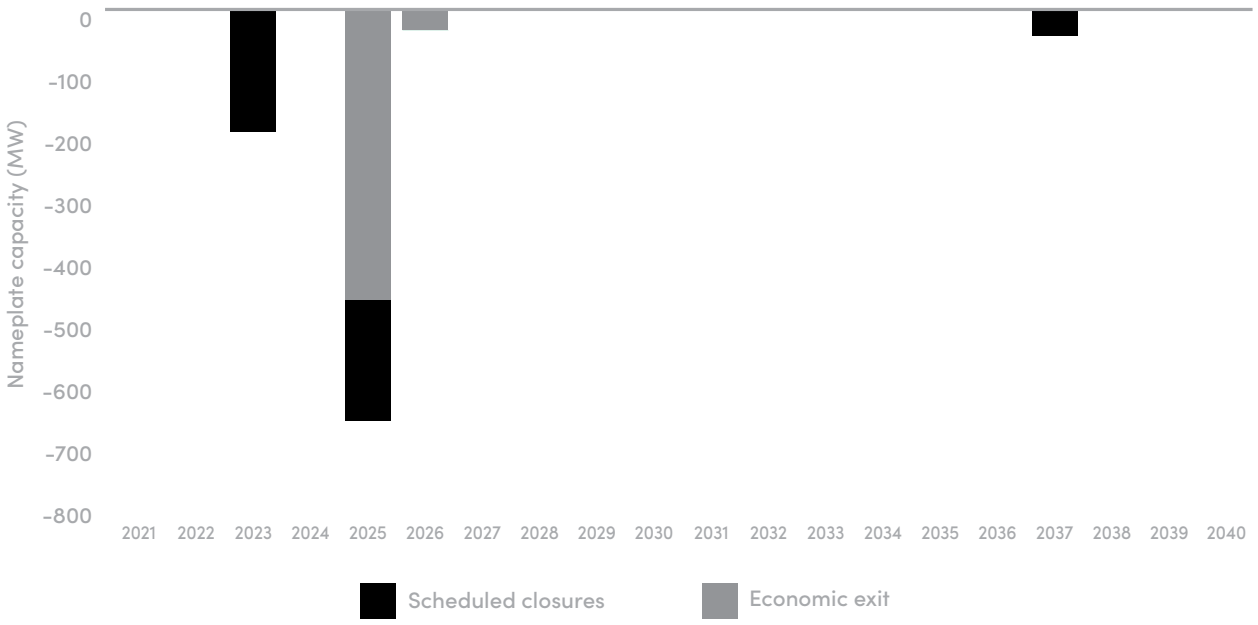


Figure 4.25: Cast Away, coal capacity changes 2020 to 2040

Under sensitivities performed in the modelling, having a higher coal price or lower gas price than assumed for the base modelling means coal-fired generation is even more economically exposed.

4.5 Emissions impact

SUMMARY

- Low-emissions technology including large-scale renewable generators and rooftop PV are the major new generation sources in the SWIS over the period
- Growth in renewables reduces emissions over the study period, despite the overall increase in end-user demand
- Storage provides ESS, which supports increased intermittent renewable generation
- Storage will allow more of the lower-emissions intermittent generation not used in real-time to be stored and used later, displacing more thermal generation
- Emissions decrease more rapidly under the lower demand scenarios
- Emissions intensity decreases substantially in all scenarios

Under all scenarios emissions are reduced from current levels by 2040 as a direct result of the introduction of predominantly renewable generation capacity, both as a replacement for the ageing thermal generation fleet and to meet new demand. In the lower demand scenarios (Groundhog Day and Cast Away), emissions decline over the next 10 years. In the higher demand scenarios (Techtopia and Double Bubble) emissions increase until 2036 (because more generation is required to meet demand), but then decline following the end of technical life retirement of several thermal generation facilities.

While emissions grow with demand growth under Techtopia and Double Bubble, the emissions intensity decreases by at least 50% in all four scenarios. Emissions intensity reflects the amount of CO_2-e attributed to the production of each MWh of energy.

Figure 4.26 shows that emissions intensity reduces over the period from over 0.6 tonnes of CO_2-e per MWh, to between 0.3 tonnes of CO_2-e per MWh under the low demand scenarios, and 0.18 to 0.25 tonnes of CO_2-e per MWh under the higher demand scenarios. The lower emissions under the higher demand scenarios reflects the increasing use of low-emissions technologies to meet demand.

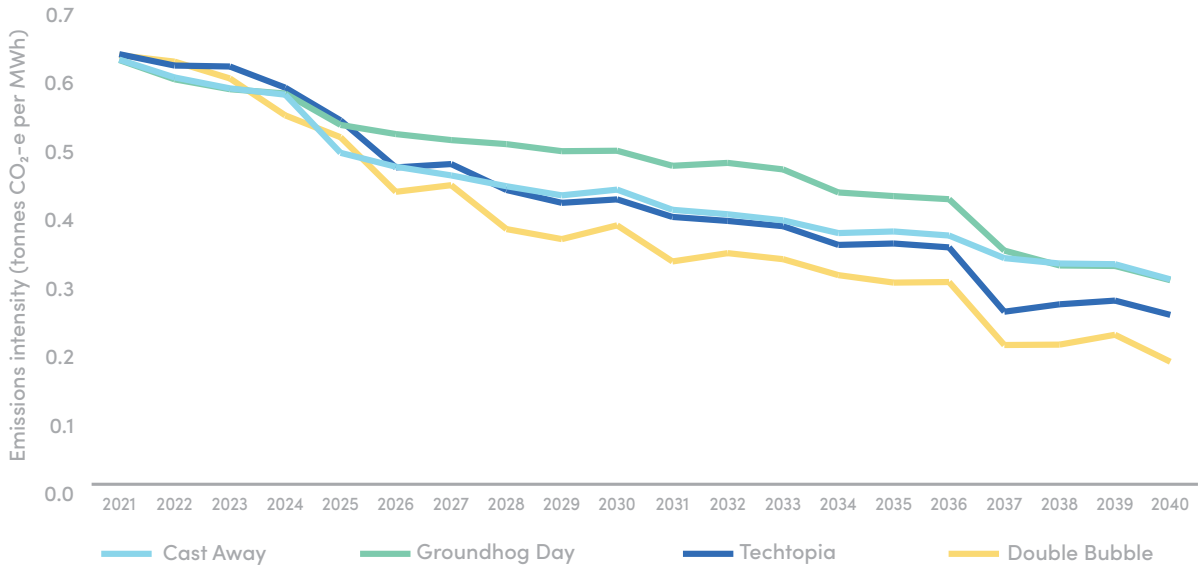


Figure 4.26: Annual emissions intensity to meet end-user demand, tonnes CO_2-e per MWh

Under Groundhog Day, emissions reduce steadily by megatonnes of by 3.7 megatonnes of CO_2-e (Mt CO_2-e) or 29% by 2040 (see Figure 4.27) as more of the demand is met by renewables.

There are two step changes in 2025 and 2037 due to the retirement of thermal generation, which is replaced largely by rooftop PV, storage and wind generation.

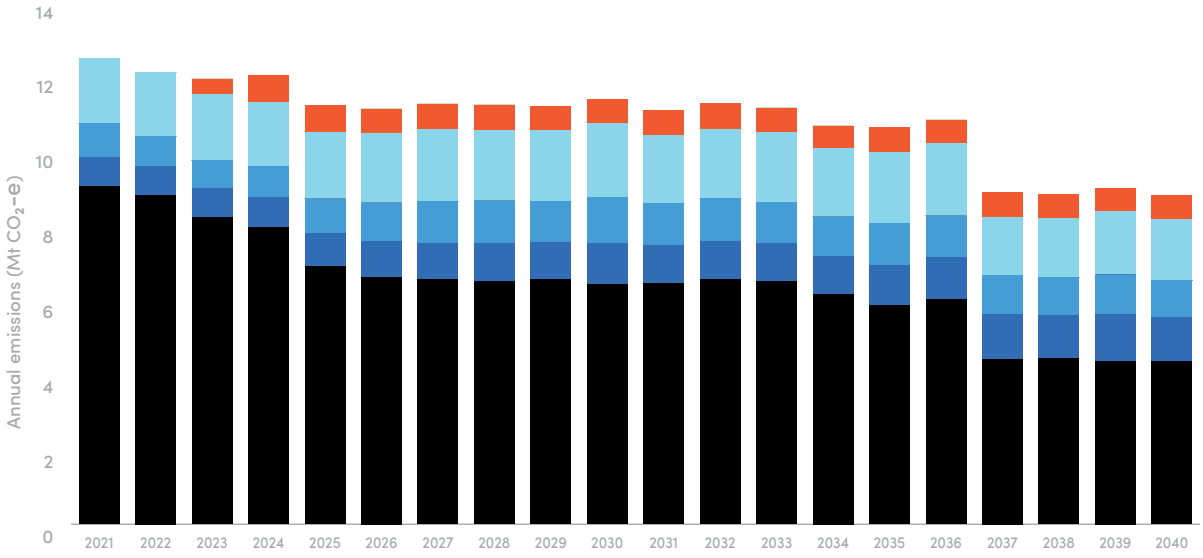


Figure 4.27: Groundhog Day – emissions profile by technology 2020 to 2040

Under Cast Away, the emissions fall to around 7.2 Mt CO_2-e (41%) by 2040 (see Figure 4.28). This is because Cast Away has the lowest assumption of operational demand, which accelerates the decline of coal-fired generation as part of the lowest cost to supply, resulting in the economic exit of 500 MW of coal-fired plant in 2025 (see Figure 4.25). As a result, much of the emissions reduction under Cast Away occurs by 2025.

The consequence of the decline in coal utilisation is that the remaining operational demand is increasingly being met by low-emissions renewables.

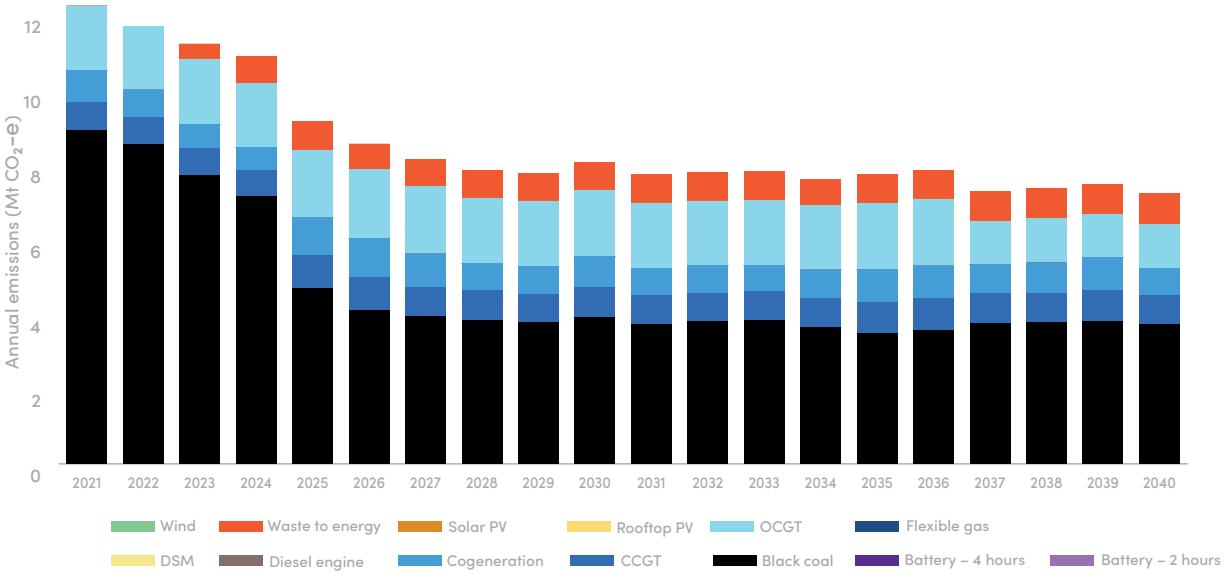


Figure 4.28: Cast Away – emissions profile by technology 2020 to 2040

Under both the higher demand scenarios (Techtopia and Double Bubble), emissions increase until 2036 as a result of the increased generation to meet the high levels of operational demand. Importantly, the increase in demand is largely met by renewable generation and battery storage.

Under Techtopia, emissions fluctuate between 13 and 15 Mt CO_2-e until 2036 (see Figure 4.29).

Over this period, the increased operational demand is largely emissions neutral as the use of thermal generation declines proportionally, being replaced by renewables.

Emissions reduce significantly in 2037 as a result of the technical life closure of almost 1,000 MW of thermal generation. In 2037, 320 MW of new flexible gas is connected to the network, which supports increased use of renewable generation to meet demand.

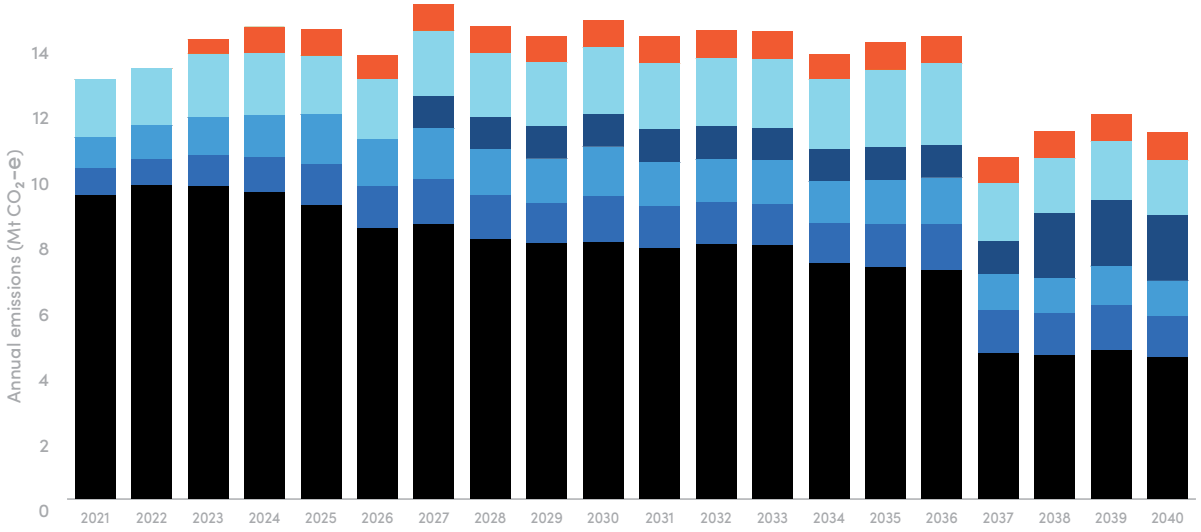


Figure 4.29: Techtopia – emissions profile by technology 2020 to 2040

Operational demand doubles by 2027 under Double Bubble, and emissions increase by 32% from 13 Mt CO_2-e to 17.2 Mt CO_2-e before reversing and ultimately decreasing overall by 17% by 2040 (see Figure 4.30). As with Techtopia, the increased operational demand is largely emissions neutral as the use of thermal generation declines, being replaced by wind and large-scale solar supported by batteries. The technical end of life closure of almost 1,000 MW of thermal generation in 2037 prompts a sharp decline in emissions at that point.

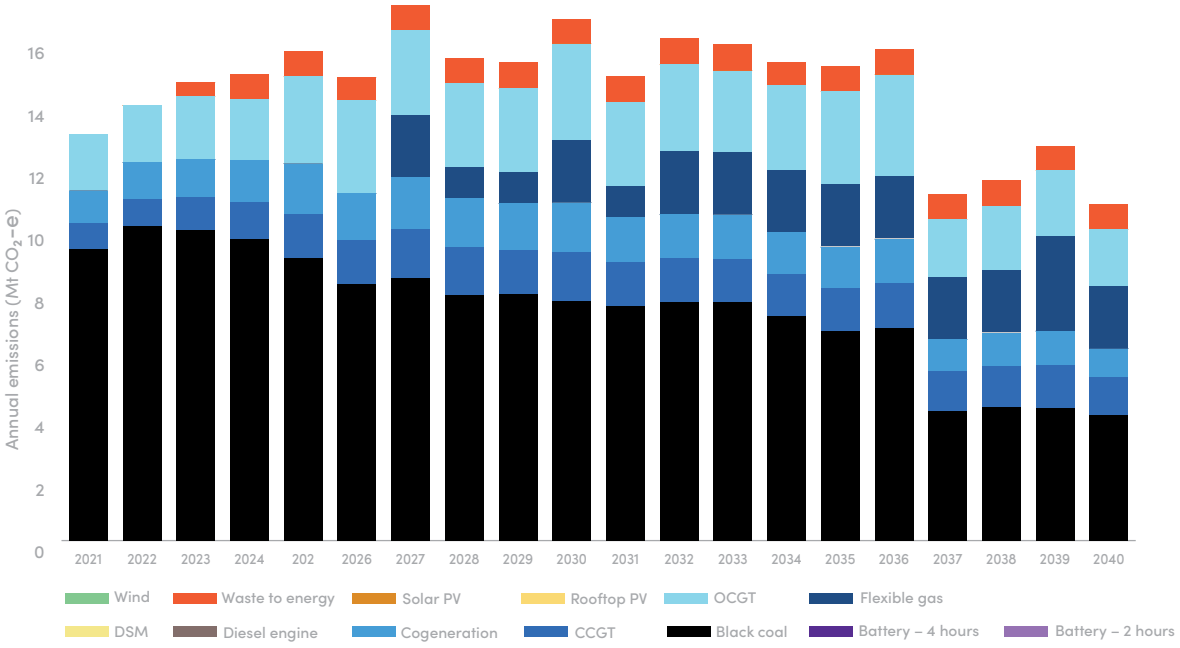


Figure 4.30: Double Bubble – emissions profile by technology 2020 to 2040

Large-scale battery storage. Source: Alinta Energy.

4.6 Energy storage plays a strong role

SUMMARY

- Storage has a valuable role to play in the provision of ESS and capacity
- The new ESS market arrangements and registration and participation framework commence in 2022 and will afford a greater opportunity for storage to participate in the WEM
- Under the higher demand scenarios, storage plays a greater role in the energy market towards the end of the study period
- The modelling selects battery storage above other storage technologies
- Large-scale storage is located to maximise the utilisation of intermittent generation and existing network transfer capacity

The modelling shows large-scale storage, particularly 2-hour and 4-hour duration battery storage, has an increasingly influential role in the SWIS over the study period. Storage forms part of the lowest cost to supply almost immediately, with around 50 MW of 2-hour duration battery capacity entering the market in year one under Cast Away, Groundhog Day and Techtopia, and around 20 MW of 4-hour duration battery capacity under Double Bubble (see Figure 4.31). The large uptake of 4-hour duration batteries in 2023 in Double Bubble is due to the assumed significant demand growth in the Eastern Goldfields early in the study period, before a network augmentation can be completed in 2024.

The WOSP modelling selects batteries as the lowest cost form of storage under all scenarios. Other large-scale storage such as pumped hydroelectric and compressed air are considered in the modelling, but are not selected as part of the lowest cost to supply under any of the scenarios.[50] This is primarily due to the shorter-duration battery storage being more modular, having higher cyclic efficiency and lower cost than its longer duration counterparts.

50 This does not mean pumped hydroelectric systems or compressed air storage are not commercially viable. The model is technology agnostic and simply selects the mix of generation and storage that forms the lowest cost to supply based on the cost inputs provided. In this instance the lowest cost option is exclusively battery storage.

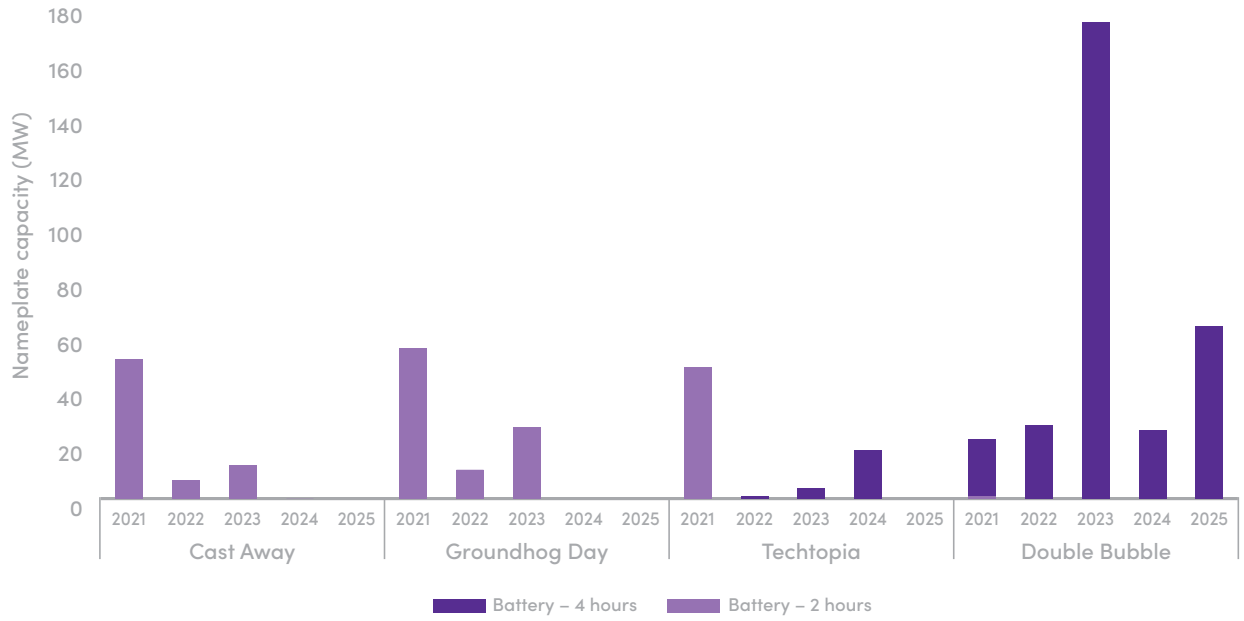


Figure 4.31: All scenarios – large-scale annual storage additions 2020 to 2025

The new ESS market, a key component of the ETS, will enable greater diversity in the facilities that can provide ESS in the WEM. Currently, ESS are provided exclusively from thermal generation facilities. Large-scale storage offers an alternative to thermal generation in the provision of ESS as it can be used to respond very quickly to fluctuations in the power system, which will be increasingly prevalent with higher levels of intermittent generation.

The modelling therefore selects battery storage under the assumption that this technology will be available for the following ESS:

- Frequency Regulation Raise;
- Frequency Regulation Lower;
- Contingency Reserve Raise; and
- Contingency Reserve Lower.

Under the two lower demand scenarios (Cast Away and Groundhog Day), battery storage is used mostly for ESS during the first ten years of the study period. The modelling selects shorter duration (2-hour) batteries as the lowest cost option, as ESS requirements are generally of shorter duration.

At the beginning of 2030-31, 234 MW of OCGT retires due to end of technical life, and operational demand increases to a level where battery storage can play a more prominent role in also providing energy services as part of the lowest cost to supply. From this point, 4-hour duration batteries become preferred over the shorter duration option. The preference for 4-hour batteries in the later years of the study period is also based on an assumption battery storage costs will decrease substantially by 2030, making the longer duration units a more economic option. Figure 4.32 and Figure 4.33 show the battery price assumptions to 2030.

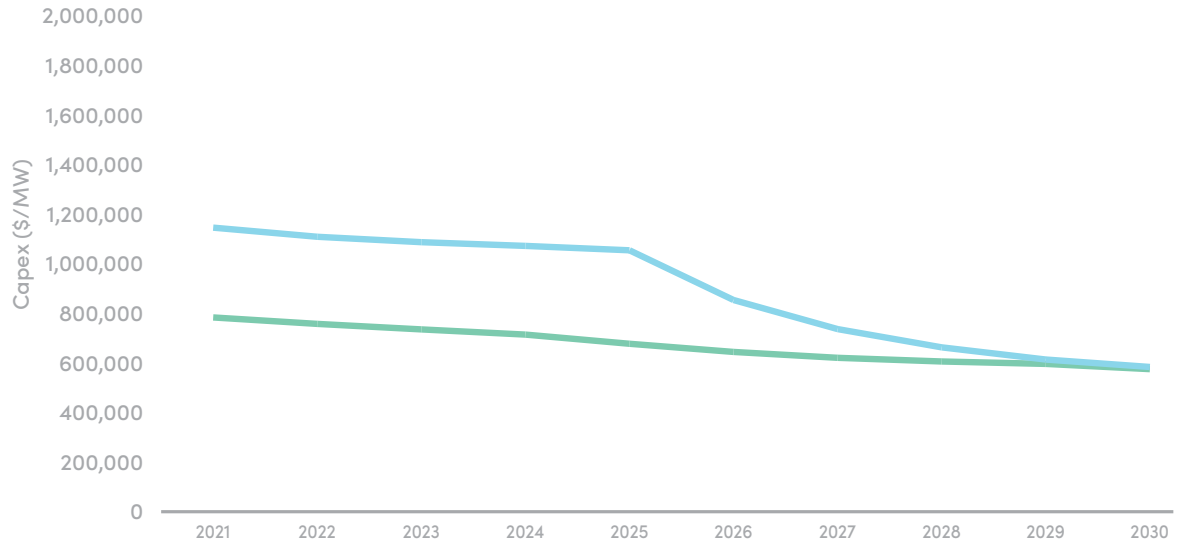


Figure 4.32: Price assumptions, 2-hour batteries

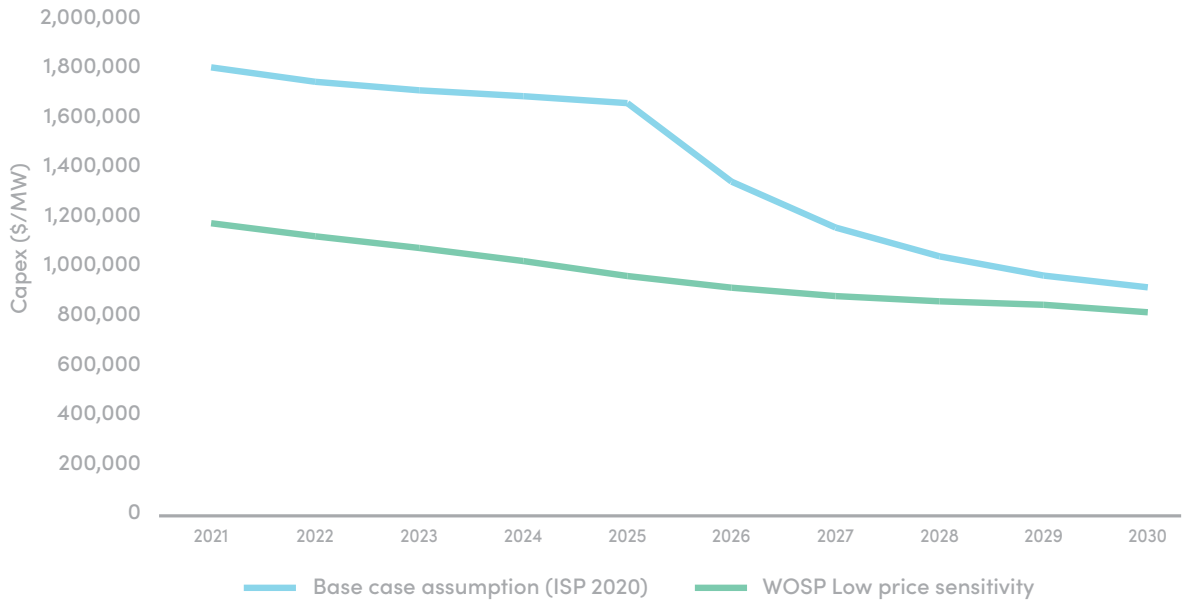


Figure 4.33: Price assumptions, 4-hour batteries

Sensitivity analysis on the battery prices shows that under a lower battery cost assumption, broad uptake across the SWIS still does not occur until after 2030 in the lower demand scenarios (Cast Away and Groundhog Day).

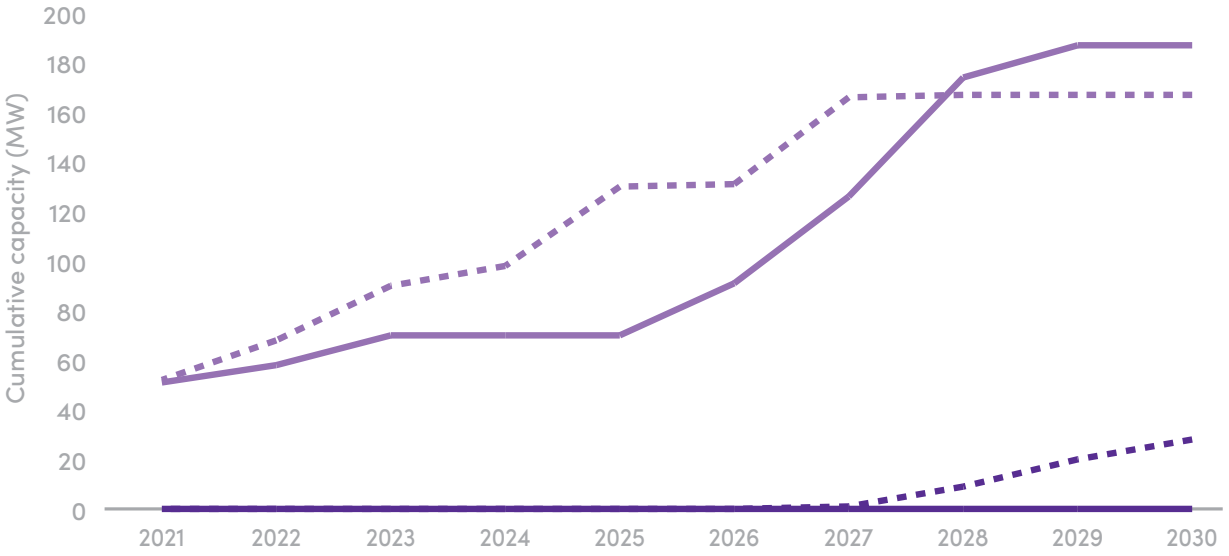


Figure 4.34: Battery price sensitivity testing Cast Away scenario

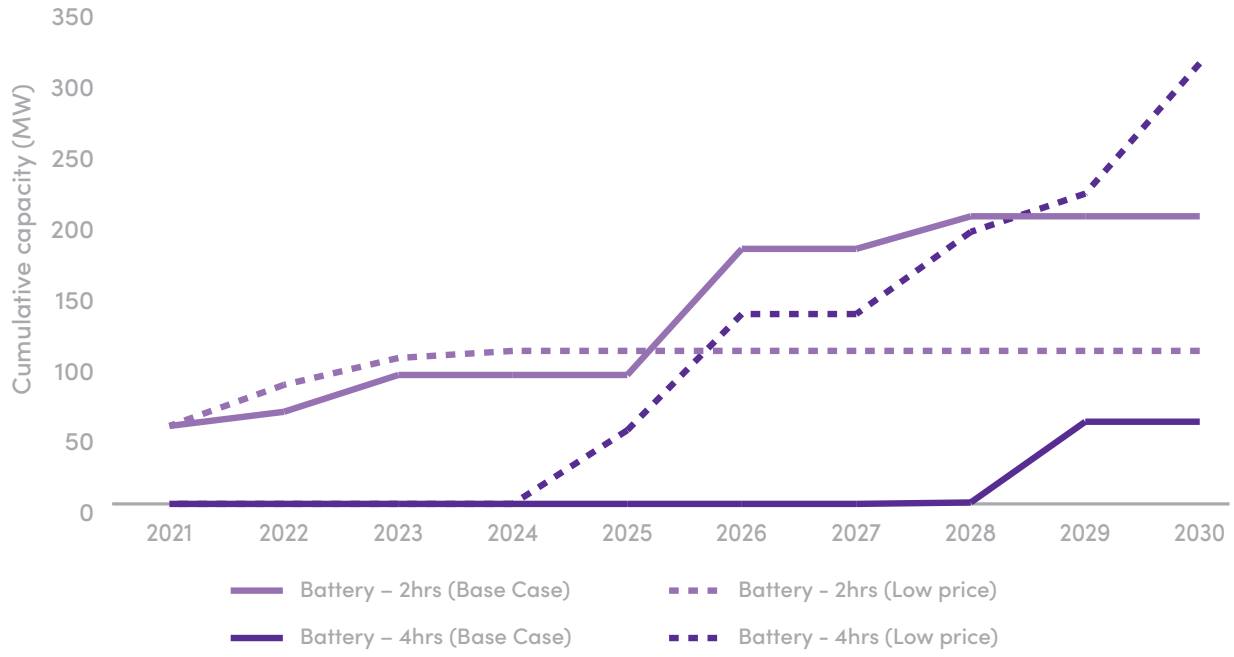


Figure 4.35: Battery price sensitivity testing Groundhog Day scenario

The primary driver for uptake of storage systems prior to 2030 is participation in the ESS market.

Storage uptake in the two higher demand scenarios sees between 961 MW and 2,235 MW of storage capacity forming part of the lowest cost of supply by 2030, of which the vast majority are 4-hour duration (see Figure 4.36 and Figure 4.37).

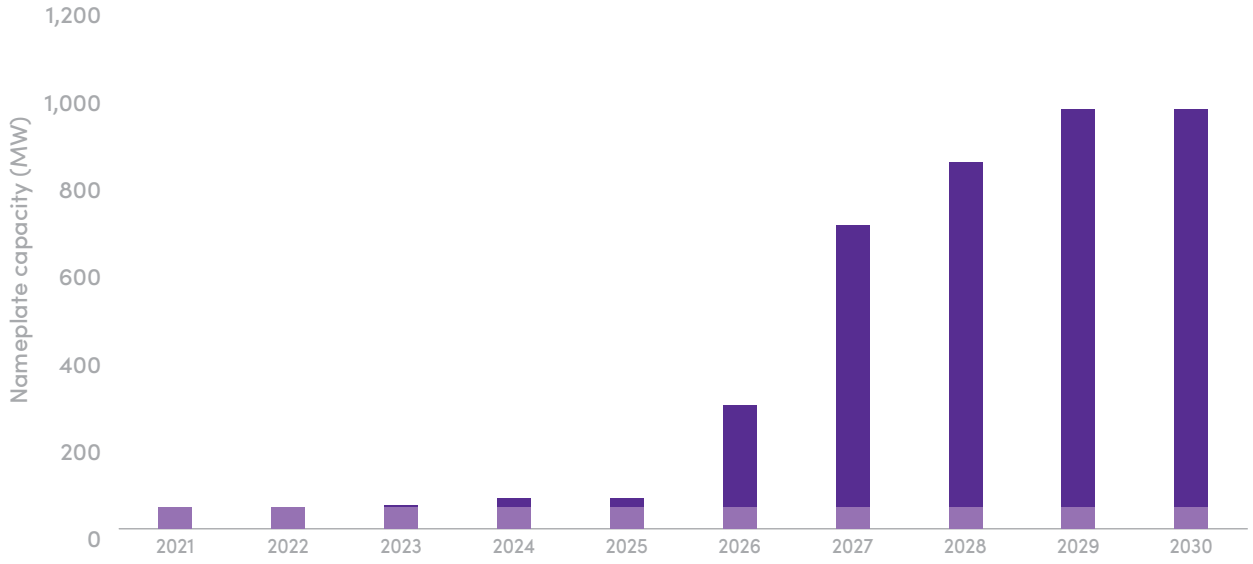


Figure 4.36: Techtopia – cumulative large-scale battery storage uptake 2020 to 2030

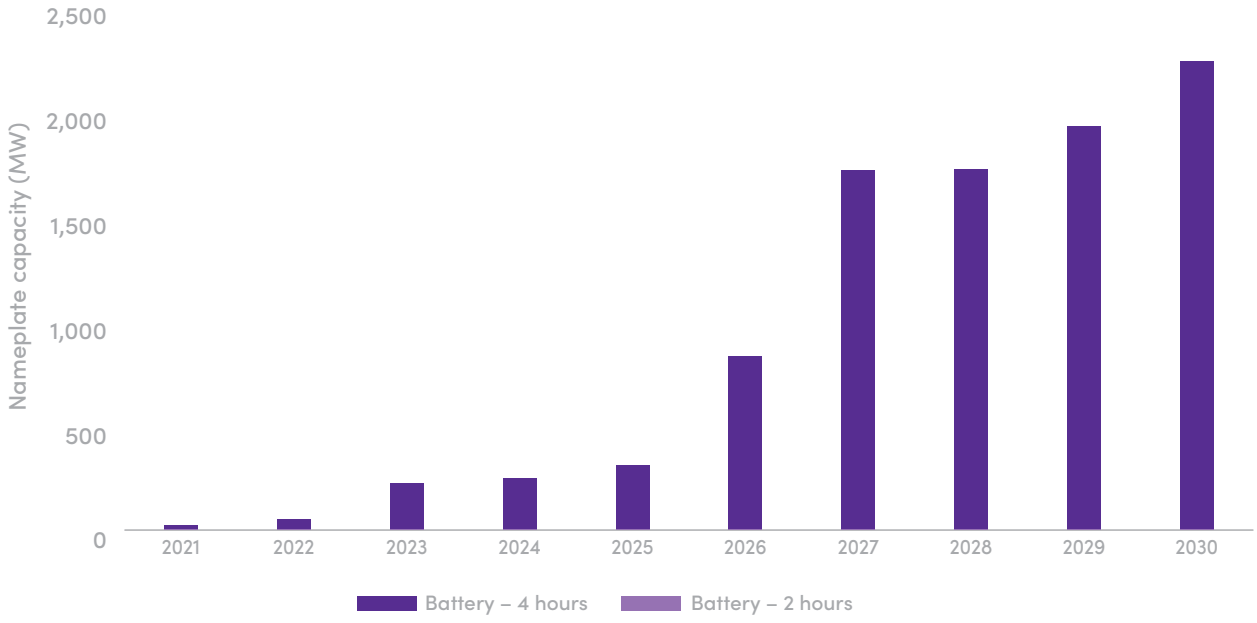


Figure 4.37: Double Bubble – cumulative large-scale battery storage uptake 2020 to 2030

An important observation from the co-optimisation of the modelling is that storage is also selected as a substitute for transmission network augmentation. In the later years of the study as the overall generation capacity increases, network augmentation is required to accommodate the new generation facilities (even under a constrained network access regime).

However, the relatively low cost of batteries compared to network augmentation means the modelling selects large-scale battery storage as an efficient substitute for network augmentation, given the additional services provided by batteries.

Figure 4.38 and Figure 4.39 show the cumulative capacity of new large-scale battery storage across each of the transmission network zones under the lower demand scenarios.

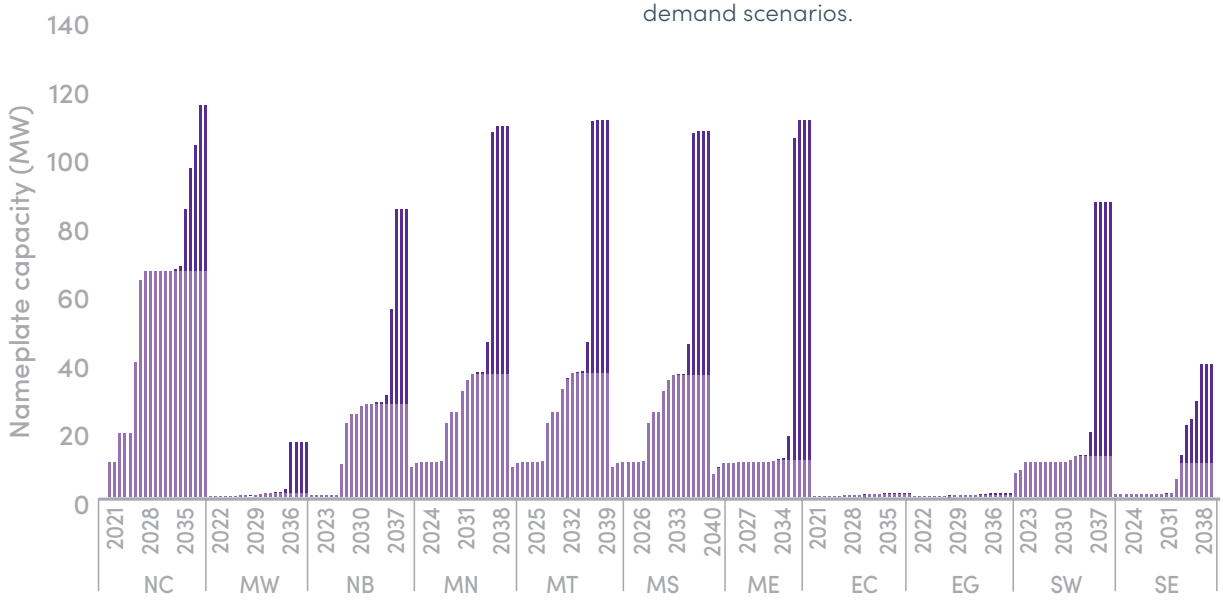


Figure 4.38: Cast Away – cumulative large-scale battery uptake by transmission network zone* 2020 to 2040

*Refer to Figure 1.3 for transmission network zone abbreviations.

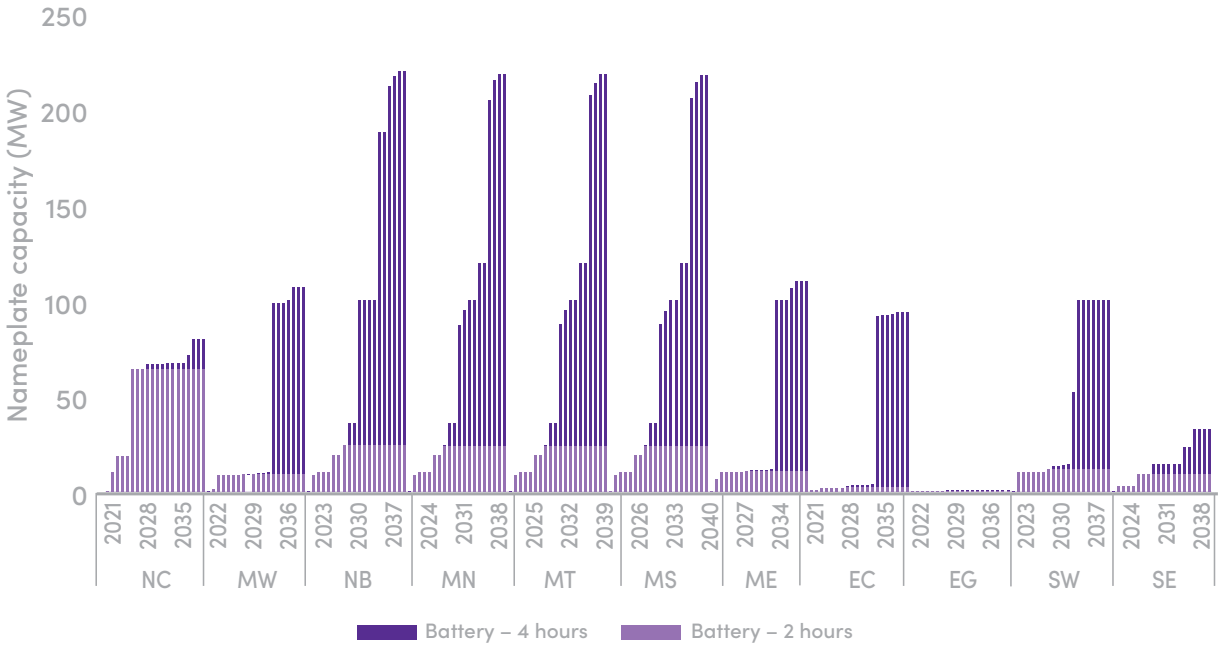


Figure 4.39: Groundhog Day – cumulative large-scale battery uptake by transmission network zone 2020 to 2040

Energy storage facilities have an advantage over network augmentations in that they can be deployed more quickly and are less constrained by location. Although there is more storage located in the metropolitan regions, the modelling disperses large-scale battery storage throughout the network.

The WOSP modelling validates the need for large-scale storage in the SWIS. Under all scenarios storage is expected to play an ongoing role in the WEM.

4.7 Transmission network augmentation requirements

SUMMARY

- There is no requirement for transmission network augmentations to increase transfer capacity between transmission network zones under the lower demand scenarios
- Under both higher demand scenarios, transmission network augmentation is required – the first of which is to increase the transfer capacity between Muja and the Eastern Goldfields
- When the existing transfer capacity in the South West transmission network zone becomes fully utilised, then a transmission network augmentation in the north of the SWIS will be required to facilitate the connection of more renewables
- Transmission network augmentations within the transmission network zones and in the distribution network did not form part of this study

No transmission augmentation is required to meet operational demand under the lower demand scenarios (Cast Away and Groundhog Day). This is because there is already sufficient network capacity to allow new generators to connect in the places the modelling identifies as the lowest cost location. Additionally, where generation facilities retire, first in the South West, and then in Neerabup zones, this frees up network capacity further.

Under both higher demand scenarios, Techtopia and Double Bubble, network augmentation would be required to facilitate the increased transfers between transmission network zones.

High levels of operational demand would mean transmission network augmentations would be required to:

- **increase transfer capacity between South West and Eastern Goldfields zone by 2025** – including installing a 330/220 kV transformer at Muja, a 220/132 kV transformer at West Kalgoorlie, installation of wide area monitoring protection and control and dynamic reactive power devices to increase the transfer capacity of the existing 220 kV line;
- **increase transfer capacity between the South West and Metro network zones by 2028-29** – including by construction of a new 132 kV transmission line between Mandurah and Pinjarra;
- **increase transfer capacity between the Neerabup and Metro North network zones by 2030 under Double Bubble, and 2036 under Techtopia** – including building a new 330 kV double circuit line from Northern Terminal to Neerabup Terminal, implementation of dynamic line ratings and further reinforcement of the 132 kV network between Pinjar and Neerabup;
- **increase transfer capacity between the Neerabup and Mid West network zones by 2030 under Double Bubble, and 2037 under Techtopia** – this is a substantial transmission upgrade that includes energising the remainder of the 330 kV circuit increasing the use of two substations, using dynamic line ratings on constrained transmission lines where possible, and upgrading transmission lines and transformers in the network between Neerabup, Eneabba and Three Springs; and
- **increase transfer capacity between the Mid West and North Country network zones by 2035 under Double Bubble, and 2040 under Techtopia** – including by constructing a new 132 kV transmission line between Three Springs and Geraldton and new terminal substation at Three Springs.

Transmission network. Source: Western Power.

In the outer years under Double Bubble, the high level of operational demand would also require transmission augmentations to:

- **increase transfer capacity between South West and South East network zones by 2032** – including by constructing new 132 kV transmission lines;
- **further increase transfer capacity between Neerabup and Mid West zones by 2035** – including by constructing new double circuit 330 kV transmission lines;
- **further increase transfer capacity between the Neerabup and Metro North zones by 2037** – including by reinforcing the 132 kV network, de-meshing the network between Northern and Neerabup terminals and constructing new lines to resupply two local substations; and
- **increase transfer capacity between the Metro and East Country zones by 2037** – including by constructing a new 132 kV transmission line between Northam and Guildford and expanding two local substations.

The relative timing of each of these projects is shown in Figure 4.40 and Figure 4.41.

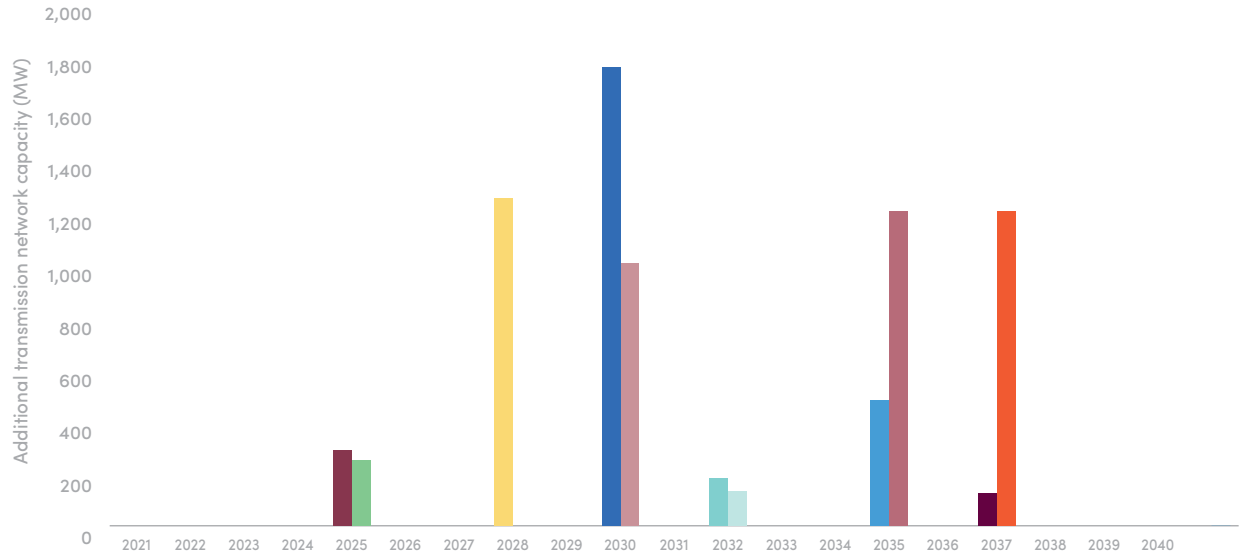


Figure 4.40: Double Bubble – transmission network augmentations 2020 to 2040

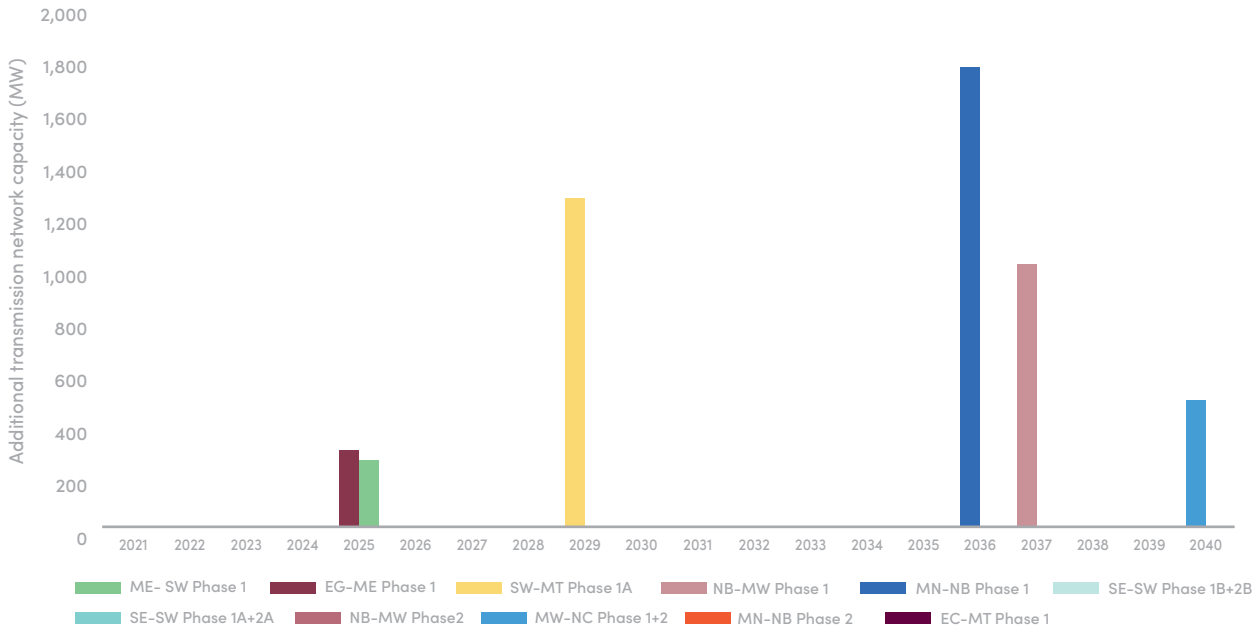
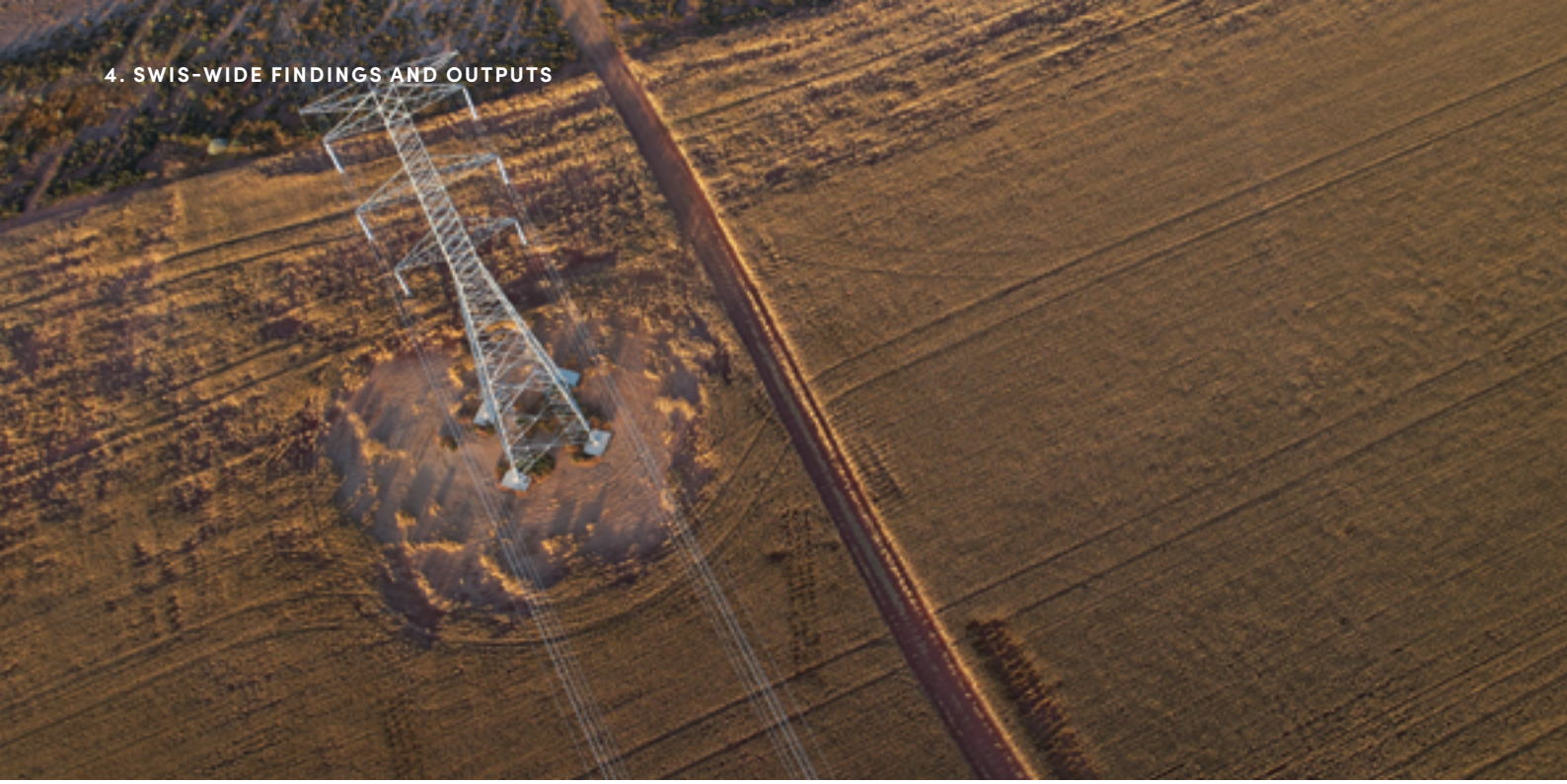


Figure 4.41: Techtopia – transmission network augmentations 2020 to 2040



Aerial view of 330 kV transmission line. Source: Western Power.

One of the reasons why relatively little transmission network augmentation is required is because of the transition to a formal constrained network access regime under the ETS. This promotes more efficient utilisation of existing network capacity and means transmission network augmentation is only necessary when it is economic.

Under a constrained network access regime, new generation capacity can connect without the need for the extensive transmission system augmentation between zones that could have been required under an unconstrained network access regime.

4.8 Total system costs

As described in Chapter 2, the WOSP modelling identifies the lowest cost mix of network, generation and storage capacity required under each scenario, within the requirements of the power system.

This section presents a summary of the cost to supply for each scenario, presented as the total annual cost to supply per MWh. The total annual cost to supply is presented over the entire study period as the sum of:

- capex - amortised over technology life;
- FOM and VOM;
- fuel supply;[51]
- provision of ESS requirements; and
- USE.[52]

This sum is then divided by the annual end-user demand for each scenario to present a per MWh cost to allow for a comparison between scenarios for each year over the 20-year study period. See Figure 4.42.

The annual costs vary over time as a result of:

- increasing gas prices, based on the forecast base case prices from the Gas Statement of Opportunities (GSOO);[53]
- the different expected annual operation of generators and storage;
- ESS requirements;
- each year's demand;
- the weather reference years applied; and
- capex incurred due to new entrant generation/ storage/network capacity.

Fuel costs make up the largest portion of the total costs in all scenarios, with capital costs making up a larger portion of costs in the higher demand scenarios. Figure 4.42 shows total annual system cost of the four scenarios and the general decreasing trend of these costs over the study period in all scenarios,

51 Fuel supply is the sum of fuel cost and transport charge.

52 USE is included in the lowest cost calculations. While USE is a notional cost, rather than a physical cost, a physical build of network, generation or storage infrastructure would be required to alleviate it. As such, USE in figure 4.42 has been amortised like a physical asset, along with the capex, to reflect the cost it would have had if a physical build had been undertaken.

53 WA GSOO 2019: https: //aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

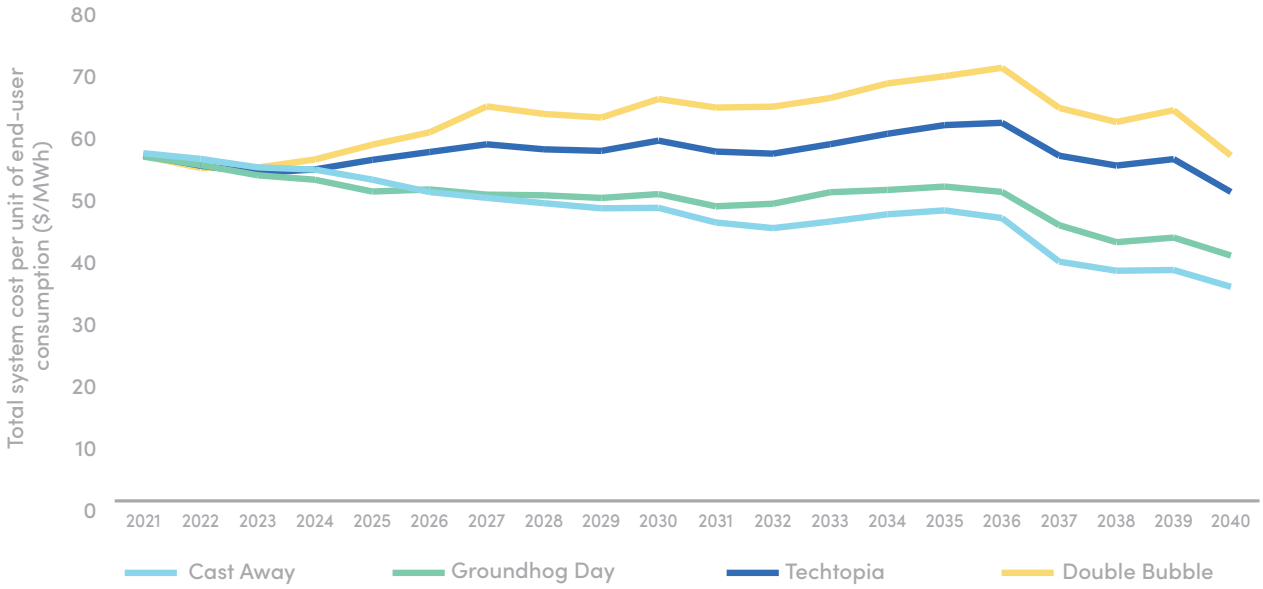


Figure 4.42: All scenarios – total annual system cost per MWh end-user demand

predominantly due to the increased generation from lower cost renewables.

A detailed breakdown of the total cost to supply by scenario is included in Appendix C.

4.9 ESS requirements and costs

The WOSP considers how ESS requirements may impact total system costs, generation dispatch and the required generation capacity mix over the study period.

ESS constraints have been formulated to be consistent with the new ESS market design being implemented as part of the ETS. These constraints are applied to the resource planning model, ensuring that the resource plan is delivered at the lowest cost within the technical limits of the system, as well as to the dispatch model and its co-optimised ESS markets.

Under the ETS, Frequency Control ESS will be acquired through a real-time market, with the introduction of the ESS markets as discussed in section 2.4.6.4:

- Frequency Regulation Raise;
- Frequency Regulation Lower;
- Contingency Reserve Raise;
- Contingency Reserve Lower; and
- RoCoF Control Service.

The WOSP dispatch model co-optimises the dispatch of energy with the above ESS markets (with the exception of the RoCoF Control Service) to achieve the optimal least-cost dispatch of energy and ESS, as will occur under the new WEM arrangements. The requirements of the RoCoF Control Service are considered through minimum system inertia constraints.

AEMO WEM Control Room. Source: AEMO.

4.9.1 Frequency Regulation requirement

The Frequency Regulation requirement is dependent on the uptake of renewable generation capacity, particularly rooftop PV. The requirement for Frequency Regulation is driven by the difference between the forecast dispatch and the actual required dispatch in any trading interval. The daytime Frequency Regulation requirement therefore increases with the introduction of new rooftop PV, large-scale solar and wind generation capacity, while the requirement at night increases with the introduction of new wind capacity.[54]

The resource planning model considers the impact that new entrant wind farm and solar capacity has on the Frequency Regulation requirement, and the resultant costs incurred in providing this additional service when determining the least cost generation mix.

The daytime Frequency Regulation requirement increases in all of the scenarios, primarily due to rooftop PV uptake, although the uptake of large-scale solar and wind generation in the Techtopia and Double Bubble scenarios also has an effect. The night time Frequency Regulation requirement increases in scenarios where substantial new wind capacity is added to the system – it remains flat in Cast Away and Groundhog Day but increases in Techtopia and Double Bubble.

Figure 4.43 summarises the Frequency Regulation requirements for the daytime and night time period in each WOSP scenario based on the outputs of the resource planning model.

54 A more detailed description of the methodology used to determine the Frequency Regulation requirement, as well as the other ESS requirements, is provided in Appendix A.

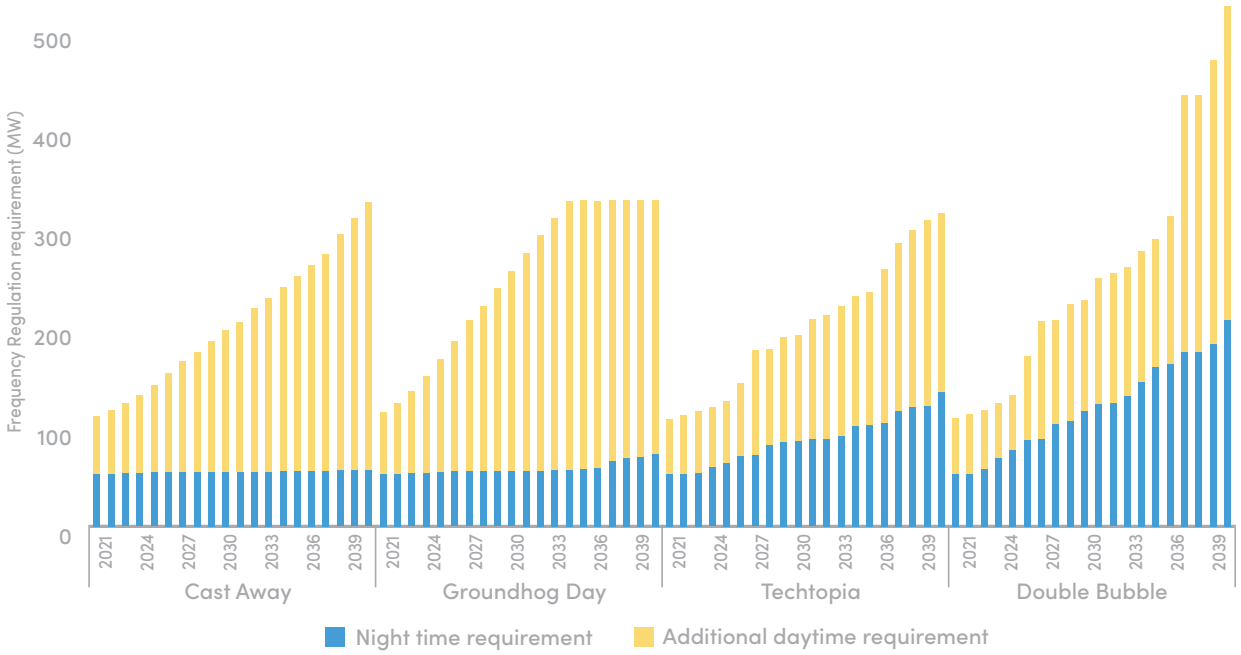


Figure 4.43: Frequency Regulation requirement (MW) for period between 5:30am to 7:30pm (daytime) and 7:30pm to 5:30am (night time)

4.9.2 Contingency Reserve Raise requirement

The resource planning model implements dispatch constraints to ensure generators are available to provide Contingency Reserve Raise in the event of a sudden loss of supply. Generation and storage facilities capable of providing a Primary Frequency Response (PFR) to meet the Contingency Reserve Raise requirement are dispatched at an operating level below their available capacity to ensure there is sufficient headroom to increase output and system frequency in response to the sudden loss of supply.

A dynamic PFR performance factor is applied to each facility for each modelling interval, depending on the facility's technology type as well as the system inertia and the size of the largest contingency.

The system PFR requirement is modelled as a function of the maximum contingency size, the system load[55] and system interruptible loads (SIL)[56] for each modelling interval.

The annual average Contingency Reserve Raise requirement remains relatively flat in each of the WOSP scenarios. In scenarios with lower operational demand (Cast Away and Groundhog Day), there is a slight increase in the Contingency Reserve Raise requirement as the PFR available from the system load decreased over the study period.

4.9.3 Contingency Reserve Lower requirement

The Contingency Reserve Lower requirement is set by the largest load contingency minus a load relief factor, reflecting current practice. As such, the requirement does not exceed a cap of 90 MW based on an assumed 30 MW of minimum load relief made available on the system and a maximum load contingency of 120 MW.

The requirement for Contingency Reserve Lower in each trading interval is set based on system load forecasts in each scenario. The formulation that defines the requirement is assumed to be static across all scenarios and independent of the generation and network investment build.

55 The drop in frequency caused by a sudden loss of generation supply will be lower when system load is higher. This effect is known as 'load relief'.

56 There is currently 63 MW of SIL that provides PFR in the SWIS. This value is a contracted value but is not guaranteed to be available across the study period in each scenario. It could be expected that in scenarios with higher load forecasts, additional sources of SIL could be made available. However, it was considered prudent to assume the SIL in certain scenarios would be lower in lower demand scenarios. As such, the SIL assumed in each scenario is Cast Away – 0 MW, Groundhog Day – 20 MW, Techtopia – 40 MW and Double Bubble – 60 MW.

Over time, this requirement is forecast to decrease in scenarios with increasing operational demand, as more load relief is made available from the system. An inherent assumption in this modelling is that network is built to cap the largest load contingency at the current value. In scenarios with decreasing load, the load relief available from the power system is forecast to decrease and as such, the Contingency Reserve Lower requirement increases up to the maximum of 90 MW due to the minimum load relief amount.

4.9.4 ESS market costs

The same four ESS markets modelled in the resource planning model are implemented in the dispatch model. This is generally aligned with the security constrained economic dispatch design that is being implemented as part of the ETS. The dispatch model co-optimises the dispatch of energy and ESS markets, reporting on a clearing price for each ESS market and the cleared quantities for each participant in each market. These are reported on a time-sequential half-hourly basis.

The dispatch model uses the ESS requirements derived from the resource planning model as inputs. These values set the demand for each service, which is met by the facilities assumed to be technically capable of providing the service. Offer curves are determined for each facility based on a combination of SRMC and opportunity costs, consistent with the inputs and assumptions applying to the facility in the resource planning model.[57]

ESS revenues and costs are calculated and allocated to facilities on a half-hourly basis, based on their cleared quantities and cost allocation rules for the purpose of the commercial assessment test.

Figure 4.44 to Figure 4.47 show the total ESS costs, which would also be the revenue available to providers of these services, for all scenarios. Annual ESS market costs in Cast Away and Groundhog Day are relatively stable. A step reduction occurs in 2026 due to declining battery costs, despite steady growth in ESS requirements.

Further analysis of the costs applied to each individual service can be found in Appendix C.

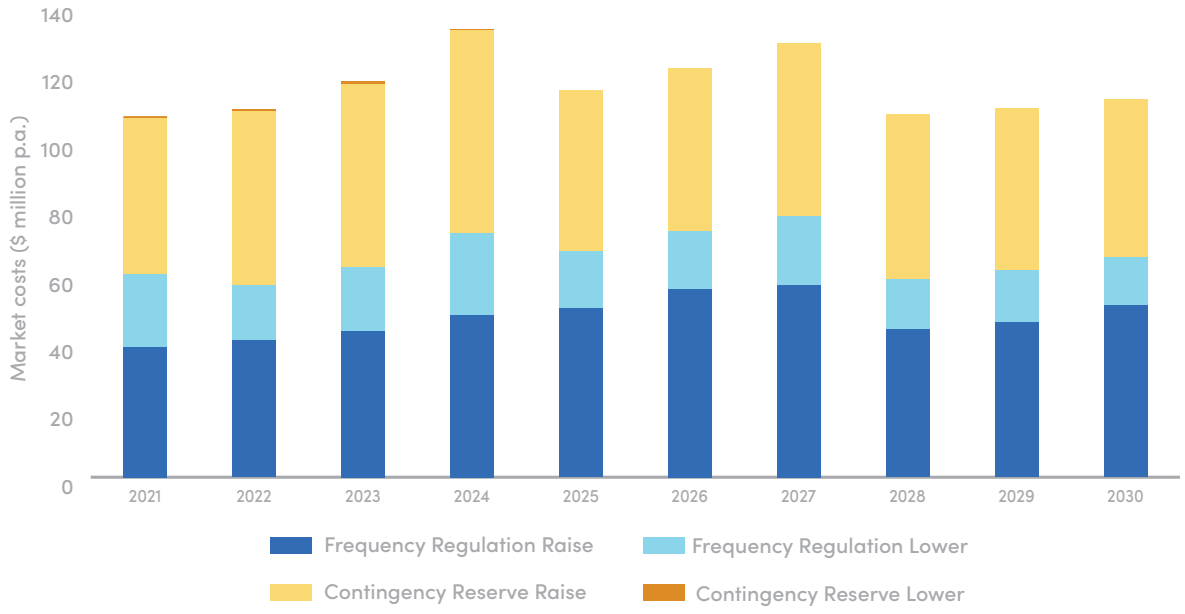


Figure 4.44: Total ESS market costs – Cast Away

57 Opportunity costs are being considered in the market dispatch modelling. See section 3.2.2 of the Information Paper – Essential System Services Scheduling and Dispatch: https: //www.wa.gov.au/sites/default/files/2019-12/Information%20Paper%20-%20ESS%20Scheduling%20and%20Dispatch%20_final.pdf.

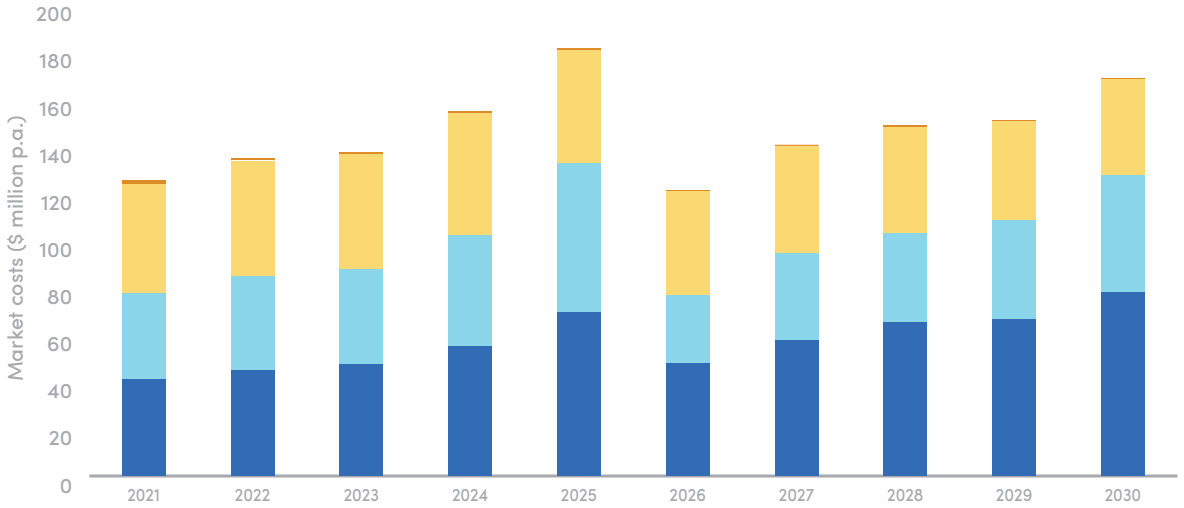


Figure 4.45: Total ESS market costs – Groundhog Day

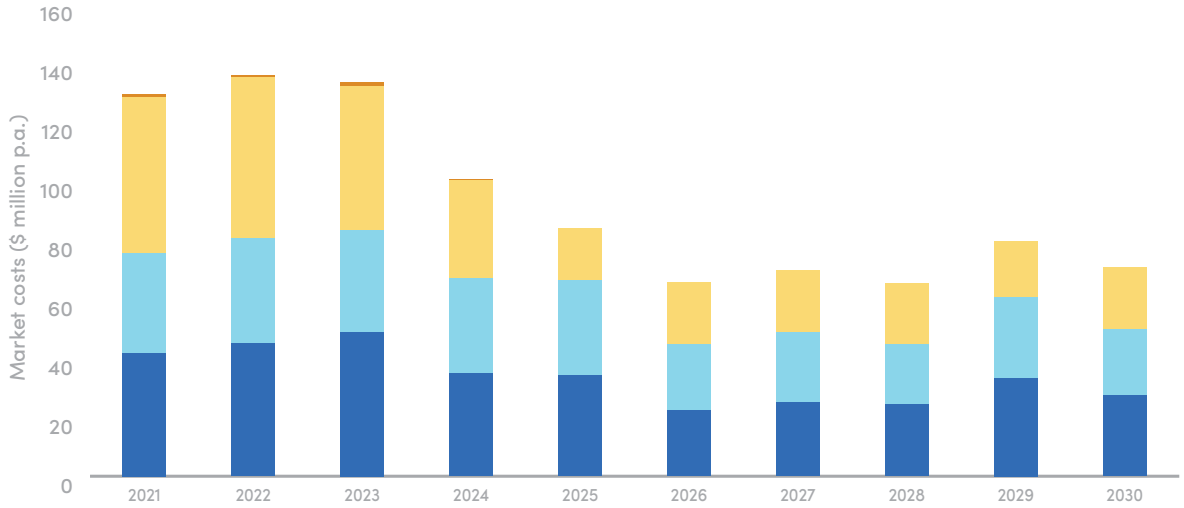


Figure 4.46: Total ESS market costs – Techtopia

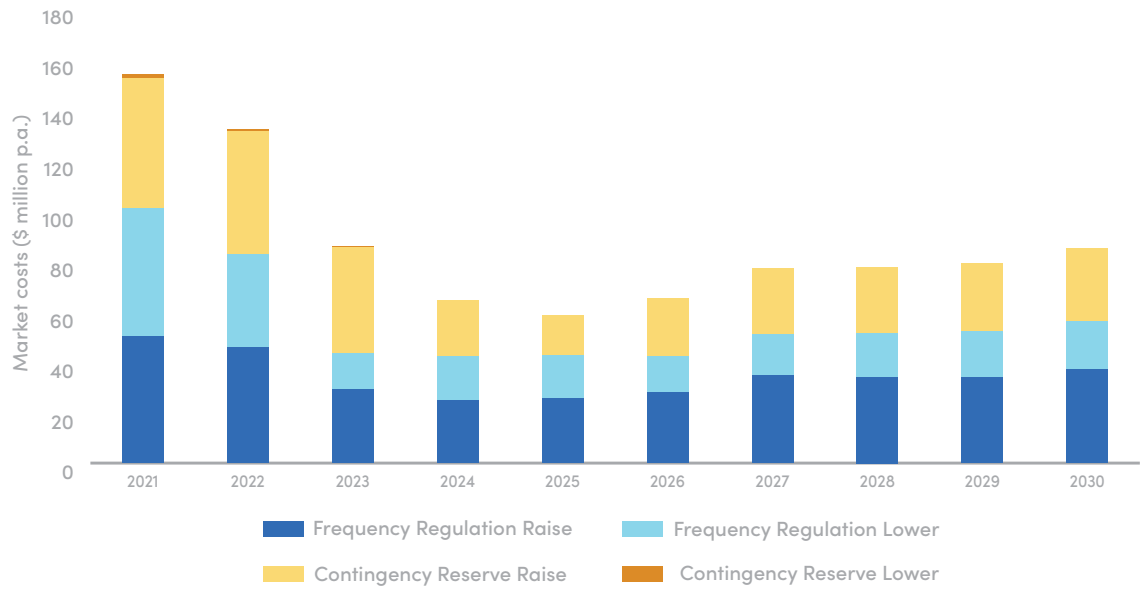


Figure 4.47: Total ESS market costs – Double Bubble

4.10 A day in the life of the WOSP

The resource planning model calculates the lowest system cost by co-optimising network, storage and generation capacity over a 20-year period. To do this it dispatches generation and storage to meet the demand on an hourly basis over 20 years in each of the four scenarios. This section shows a few of the interesting days during the study period to highlight, how the energy market is working with high levels of intermittency into the future, and the level of detail undertaken for the modelling.

As such, two examples of a daily load profile, with generation and storage dispatch to meet it, are provided from a low demand scenario (Cast Away) and a high demand scenario (Techtopia) in order to highlight this level of detail.

4.10.1 Cast Away

Figure 4.48 illustrates a summer day with an average demand profile where rooftop PV provides a large proportion of the daytime demand.

On 21 December 2026, wind output is high in the night, with base load generation and other gas units dispatched for ESS.

From 6am onwards, rooftop PV starts generating along with some large-scale solar. Utilisation of coal starts to decrease in the early hours of the morning but there is a notable fall in wind availability during the middle of the day and coal is dispatched higher. Gas units continue to provide the majority of the ESS and some additional energy.

Rooftop PV and large-scale solar start to fall away during the early afternoon, but in this case, wind is available during the afternoon ramp period. By the time night rolls around, and solar has fallen away, the system returns to a mix of wind, coal and gas.

There are negligible amounts of charging from large-scale batteries however they play a role in providing ESS.

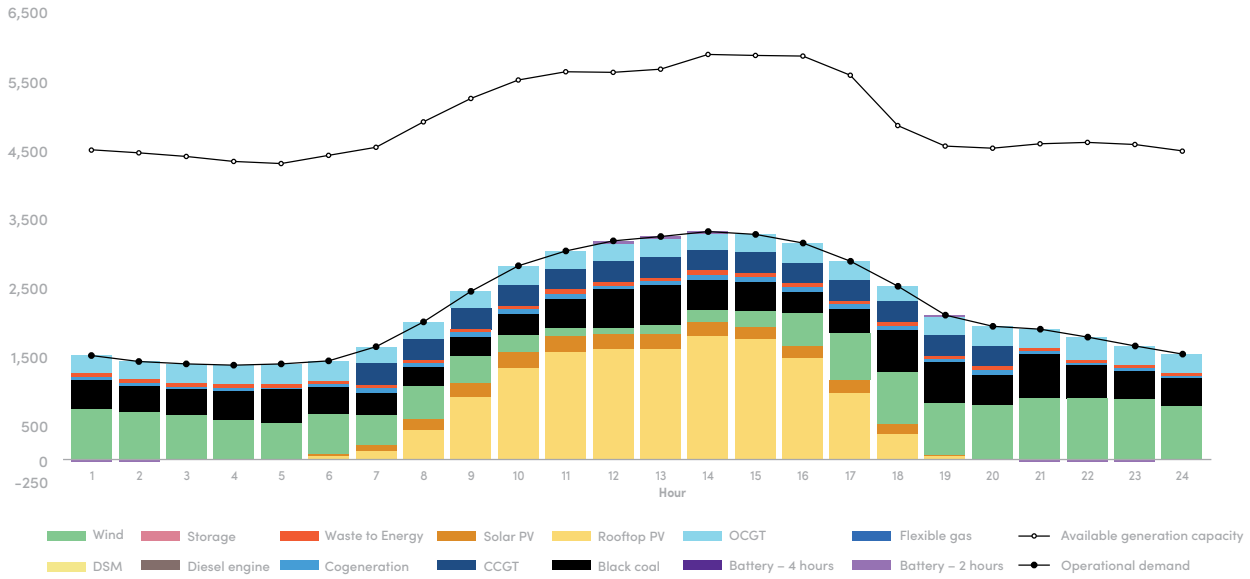


Figure 4.48: Time-of-day behaviour of demand and dispatch of generation and storage – Cast Away 21 December 2026

4.10.2 Techtopia

This is a sequence of two days, to illustrate how the system behaves on days with higher and lower output from intermittent renewable sources (wind, solar, rooftop PV) and how batteries can manage peaks.

Figure 4.49 illustrates the time-of-day behaviour of demand and dispatch of generation on 2 June 2032, a day characterised by high renewable output. On average, wind output amounts to approximately 48% of demand in the first eight hours of the day. Combined wind, large-scale solar and rooftop PV generation, with the latter commencing from 8-9am, amount to an average of 74% of demand between 9am and 5pm. The average share of renewables across the 24-hour period is 47%.

Batteries charge to provide demand to the system, also assisting in operating thermal generation above minimum stable levels and providing demand for ESS services to be dispatched. It is worth noting that the model has perfect foresight of demand and has planned to fully utilise energy storage in preparation for the following day.

Flexible gas and OCGT compensate for the decrease in wind output between 6pm and midnight.

The next day, 3 June 2032, sees low renewable output, a number of intervals with available capacity only slightly above demand, and batteries stepping in to provide supply during peak intervals at a lower cost than peaking thermal generation.

Figure 4.50 illustrates that on 3 June 2032, output from intermittent renewables, (wind, solar and rooftop PV) is lower than on the preceding day. The 24-hour average is 12% of demand, as opposed to approximately 47% across the previous day. Low renewable output results in high utilisation of thermal sources, which in most hours run at constant output levels, with flexible gas and OCGT only fluctuating in the night.

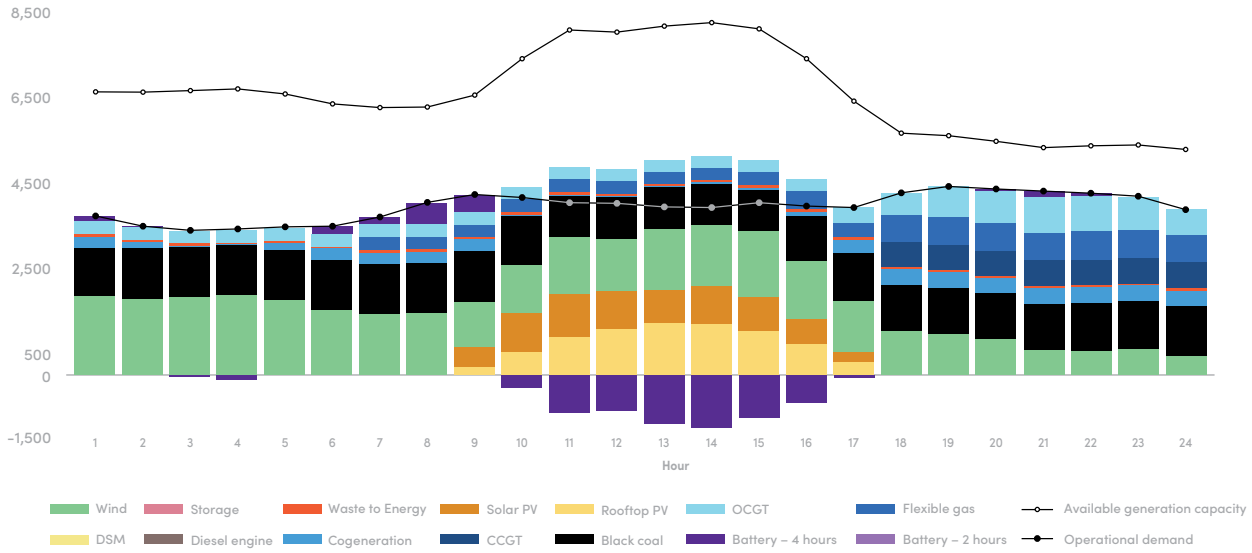


Figure 4.49: Time-of-day behaviour of demand and dispatch of generation and storage – Techtopia 2 June 2032

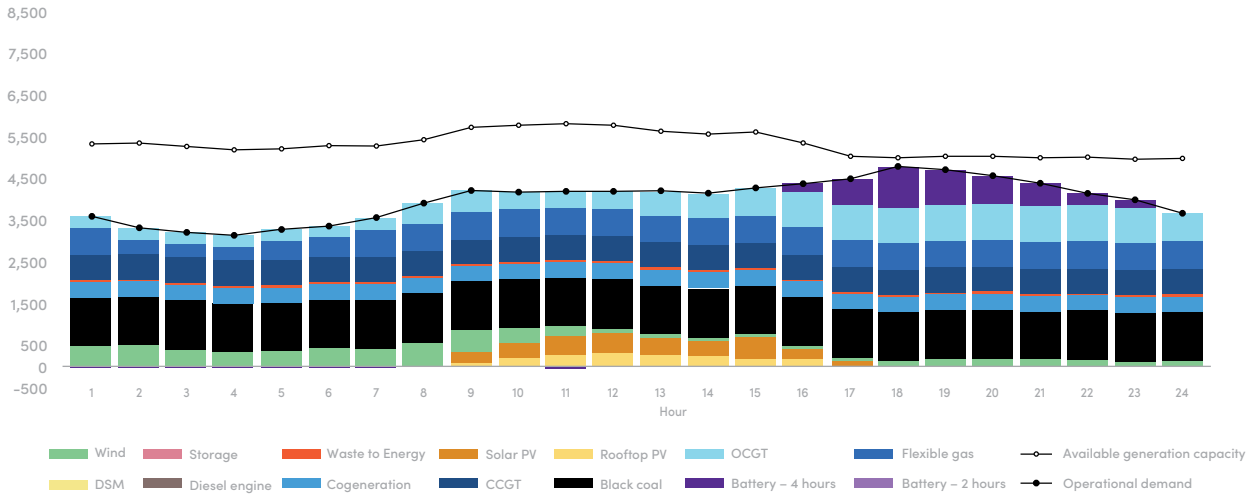


Figure 4.50: Time-of-day behaviour of demand and dispatch of generation and storage – Techtopia 3 June 2032

When demand peaks in the late afternoon and evening, between 4pm and 9pm, batteries (charged on the previous day during hours of high output from low-cost large-scale solar and rooftop PV) start discharging to meet demand in hours of a low capacity margin.

Batteries, in particular, help address a situation at 6pm (where daily demand peaks and the available generation capacity margin is at its lowest) by providing energy stored from the preceding day. In the absence of batteries, expensive thermal peaking capacity would have been required to meet demand in this peak interval.

Yandin Windfarm, a RATCH/Alinta Energy investment managed by Alinta Energy. Source: Alinta Energy.

5. Geographic zones

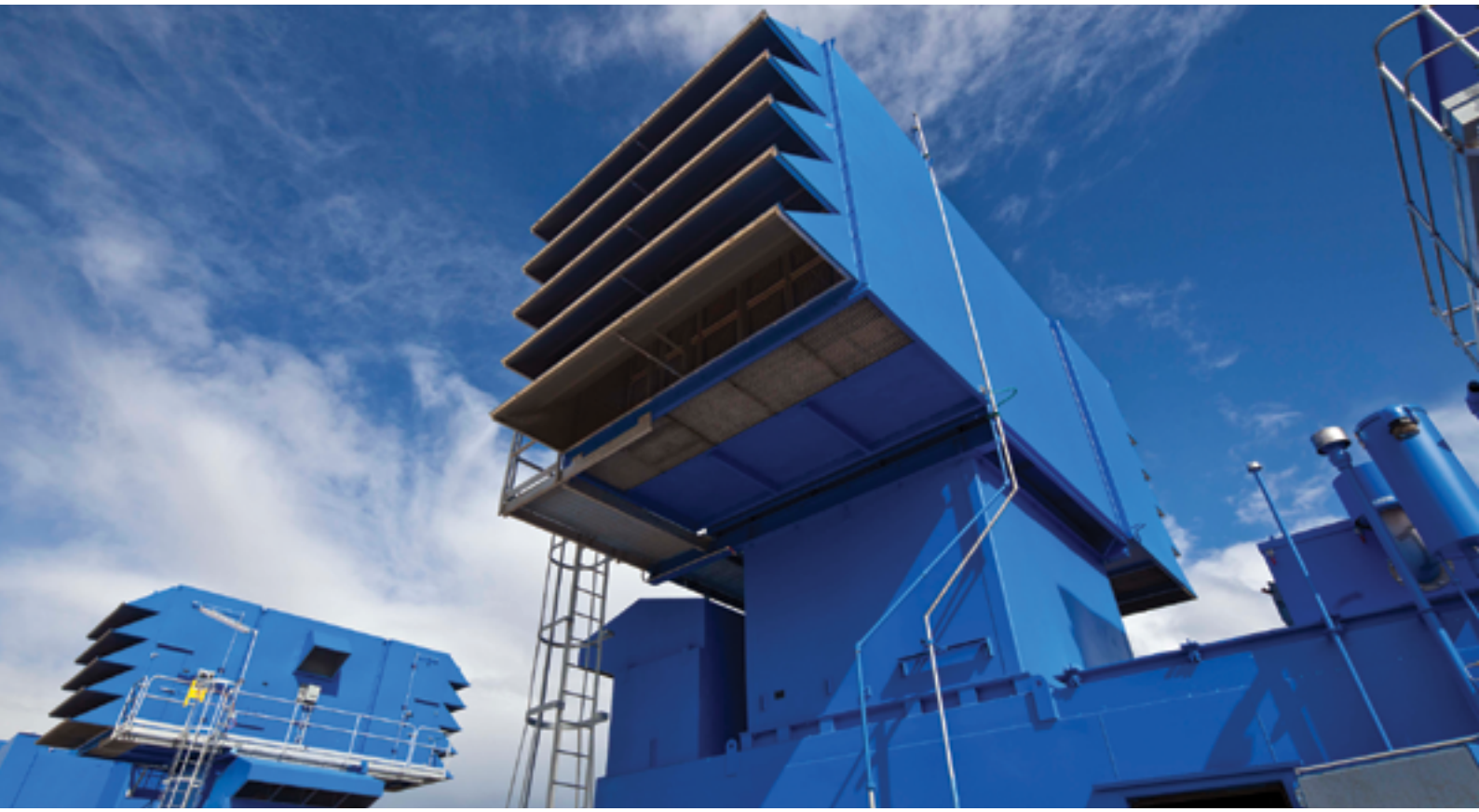
This chapter presents findings by the different geographic zones that make up the SWIS. As discussed in section 1.3, for the purpose of power system modelling, the SWIS has been separated into 11 transmission network zones based on the transfer limits between sections of the transmission network.

The following sections discuss the various input assumptions and outputs of the model by region, combining the findings of neighbouring transmission network zones, where appropriate.

5.1 Metro and Neerabup

5.1.2 Current state

This section describes the infrastructure in the Metro, Metro South West, Metro North and Neerabup transmission network zones at 1 July 2020. The region covered by the Metro and Neerabup zones extends from Pinjar in the north, to Sawyers Valley in the East and Waikiki in the South. Figure 5.1 shows an overview of the region, the location of large-scale generation, and the transmission network.



Kwinana Swift OCGT. Source: Perth Energy.

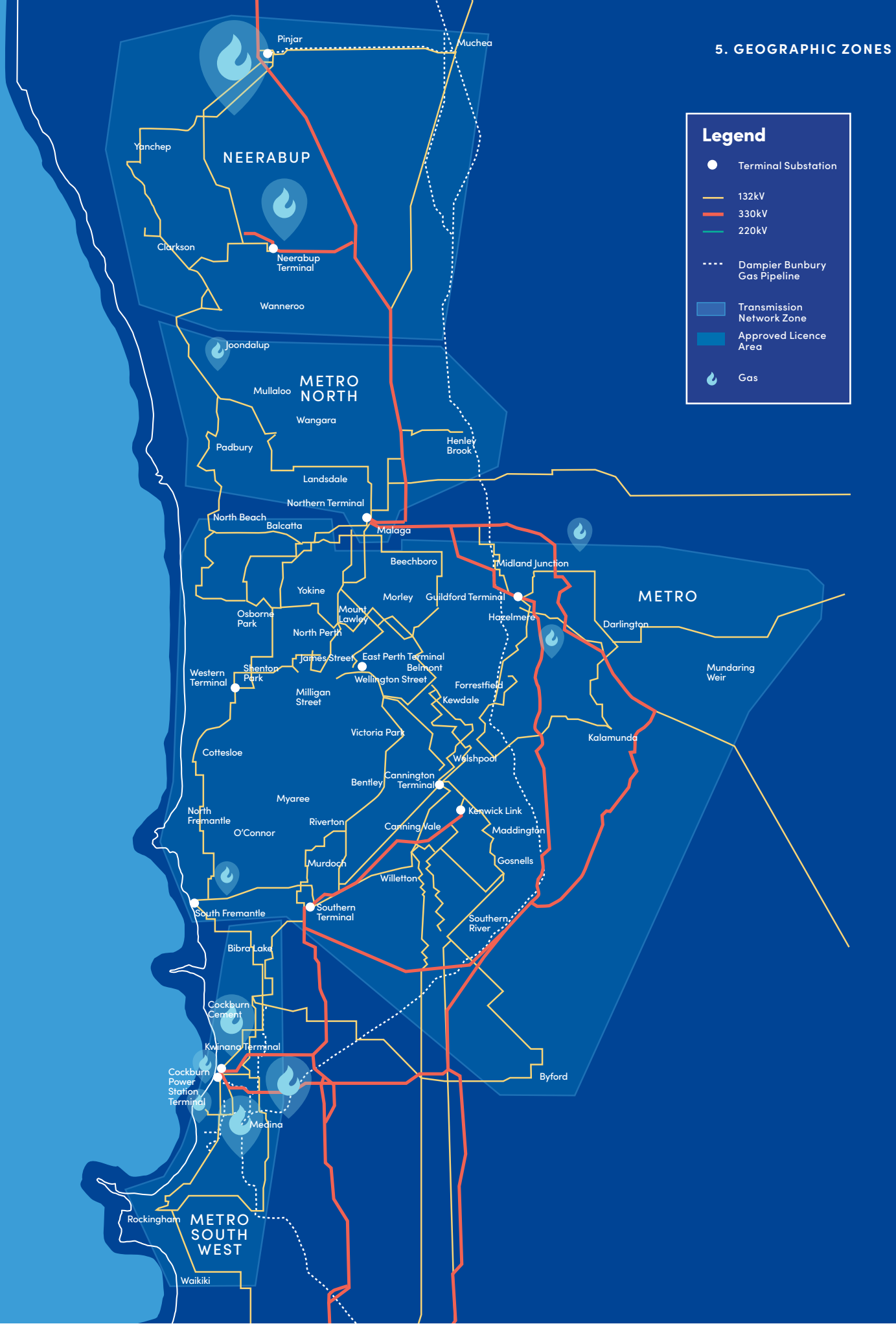


Figure 5.1: Metro, Metro South West, Metro North and Neerabup transmission network zones

The combined Metro and Neerabup zones connect 76% of the population in the SWIS, with 55% in the Metro zone alone. The zones include the majority of residential connections in the SWIS, the Perth CBD, and a number of major customers in industrial and commercial areas such as Kwinana. The Metro and Neerabup zones also have the highest concentration of rooftop PV.

The region covered by the Metro and Neerabup zones includes 26 generation facilities totalling approximately 2,000 MW of installed capacity. Seventeen of these are predominantly gas-fired generators (with some dual-fuel), and nine are the smaller landfill gas facilities.

A list of the existing facilities and the associated capacity is provided in Table 5.1.

Table 5.1: Installed generation in the Metro and Neerabup transmission network zones, by start date

FACILITY	FUEL	MODELLED CAPACITY (MW)	CAPACITY CREDITS (MW)	COMMISSION DATE
Pinjar Gas Turbine 1	Dual (Gas / Distillate)	38.5	31.0	1990
Pinjar Gas Turbine 2	Dual (Gas / Distillate)	38.5	30.3	1990
Pinjar Gas Turbine 3	Dual (Gas / Distillate)	39.3	37.0	1990
Pinjar Gas Turbine 4	Dual (Gas / Distillate)	39.3	37.0	1990
Pinjar Gas Turbine 5	Dual (Gas / Distillate)	39.3	37.0	1990
Pinjar Gas Turbine 7	Dual (Gas / Distillate)	39.3	36.5	1990
Tiwest	Gas	42.1	36.0	1990
Red Hill	Landfill Gas	3.6	2.8	1993
Pinjar Gas Turbine 10	Gas	118.2	110.6	1996
Pinjar Gas Turbine 11	Gas	130.0	124.0	1996
Pinjar Gas Turbine 9	Gas	118.2	111.0	1996
Kwinana EG1	Gas	85.7	80.4	1996
Cockburn CCGT	Gas	249.7	240.0	2003
Rockingham	Landfill Gas	4.0	2.1	2003
Gosnells	Landfill Gas	-	-	2004
Tamala Park	Landfill Gas	4.8	4.2	2004
South Cardup	Landfill Gas	4.2	2.9	2005
Atlas	Landfill Gas	-	-	2006
Henderson Landfill Gas	Landfill Gas	3.0	1.9	2006
Kwinana Combined Cycle Gas	Gas	335.0	327.8	2008
Neerabup Gas Turbine 1	Gas	342.0	330.6	2008
Kalamunda	Distillate	1.3	1.3	2010
Kwinana Swift OCGT	Dual (Gas / Distillate)	116.0	109.0	2010
Kwinana Gas Turbine 2	Dual (Gas / Distillate)	103.2	98.5	2011
Kwinana Gas Turbine 3	Dual (Gas / Distillate)	103.2	99.2	2011
CleanTech Biogas	Landfill Gas	2.0	1.7	2015
		2,000.4	**1,892.8**	

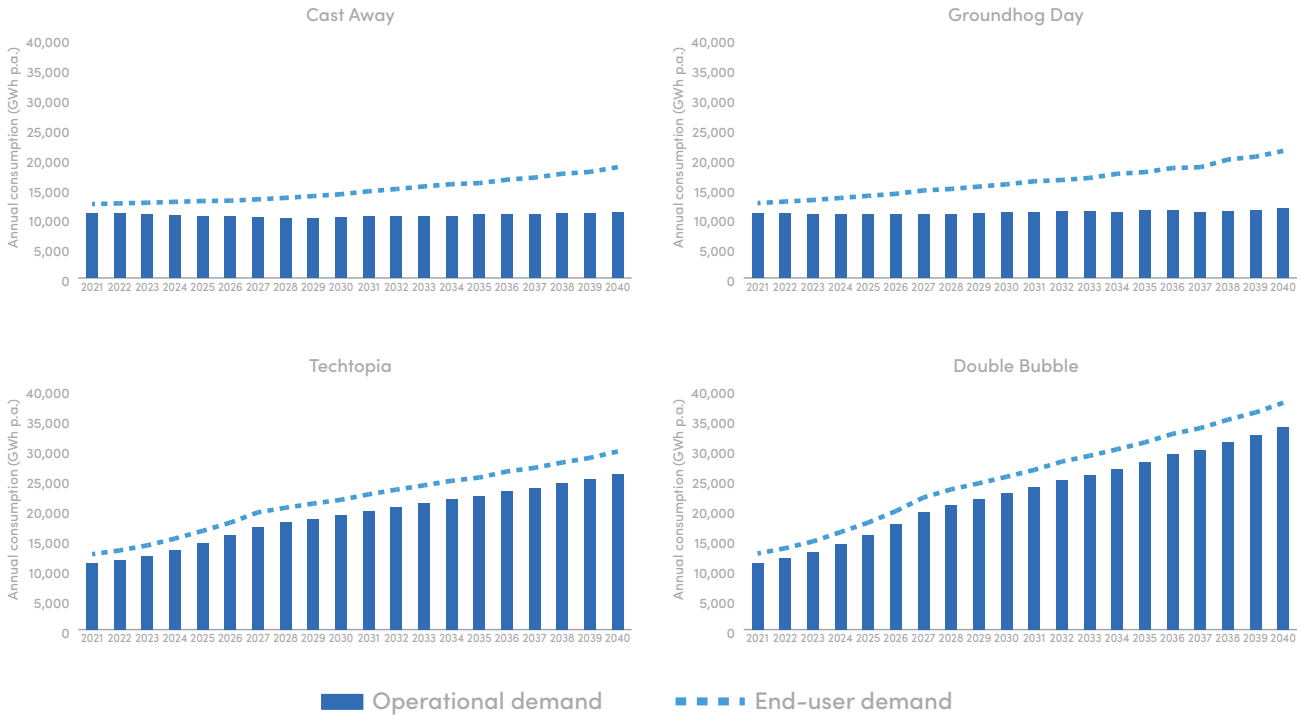


Figure 5.2: Operational and end-user demand, aggregated Metro and Neerabup zones 2020 to 2040

Western Power's network in the combined Metro and Neerabup zones includes a number of transmission lines that make up the network's 330 kV backbone system, connecting major generation areas in Neerabup and Kwinana, with key terminal substations around the load centre. These major terminals are then connected via the 132 kV network to neighbouring load areas.

5.1.2 Findings and observations

5.1.2.1 Operational demand

End-user demand is expected to increase in all scenarios. Under the lower demand scenarios, operational demand in the Metro and Neerabup transmission network zones is assumed to remain relatively flat over the study period. The Cast Away scenario assumes relatively more fringe growth as residential connections seek low density housing to maximise rooftop PV capacity and prepare for grid disconnection.

Techtopia has higher residential demand in Metro North and Neerabup, whereas Double Bubble assumes the emergence of more block loads in the Neerabup zone due to the ongoing strong economy and the use of the area for industrial loads.

Electric vehicles represent a substantial portion of demand growth in all scenarios beyond 2030, except for Cast Away where the majority charge off-grid.

Figure 5.2 shows the assumed end-user demand and operational demand in the Metro, Metro North, Metro South West and Neerabup zones (combined) under each of the four modelling scenarios.

In all the above charts, the gap between end-user demand (the amount of electricity actually consumed by the user) and operational demand (the amount of electricity drawn from the network at the connection point) is driven by the level of DER prevalent in each scenario. The most common form of DER in the system is rooftop PV.

In the two lower demand scenarios, operational demand remains flat and the gap to end-user demand widens as the uptake of rooftop PV continues.

DER will also have an impact in the two higher demand scenarios, however the gap is less extreme as the rooftop PV take up is lower than under Cast Away and Groundhog Day and the assumed level of economic growth in Techtopia and Double Bubble is higher.

5.1.2.2 Capacity mix

The overarching finding for the Metro and Neerabup zones is that unless demand increases significantly (as per the Techtopia and Double Bubble scenarios), the existing SWIS capacity is sufficient and little or no additional large-scale generation capacity is required to connect (see Figure 5.3).

The ongoing uptake of rooftop PV and other forms of DER more than accomodates all the end-user demand growth in the lower demand scenarios (Cast Away and Groundhog Day).

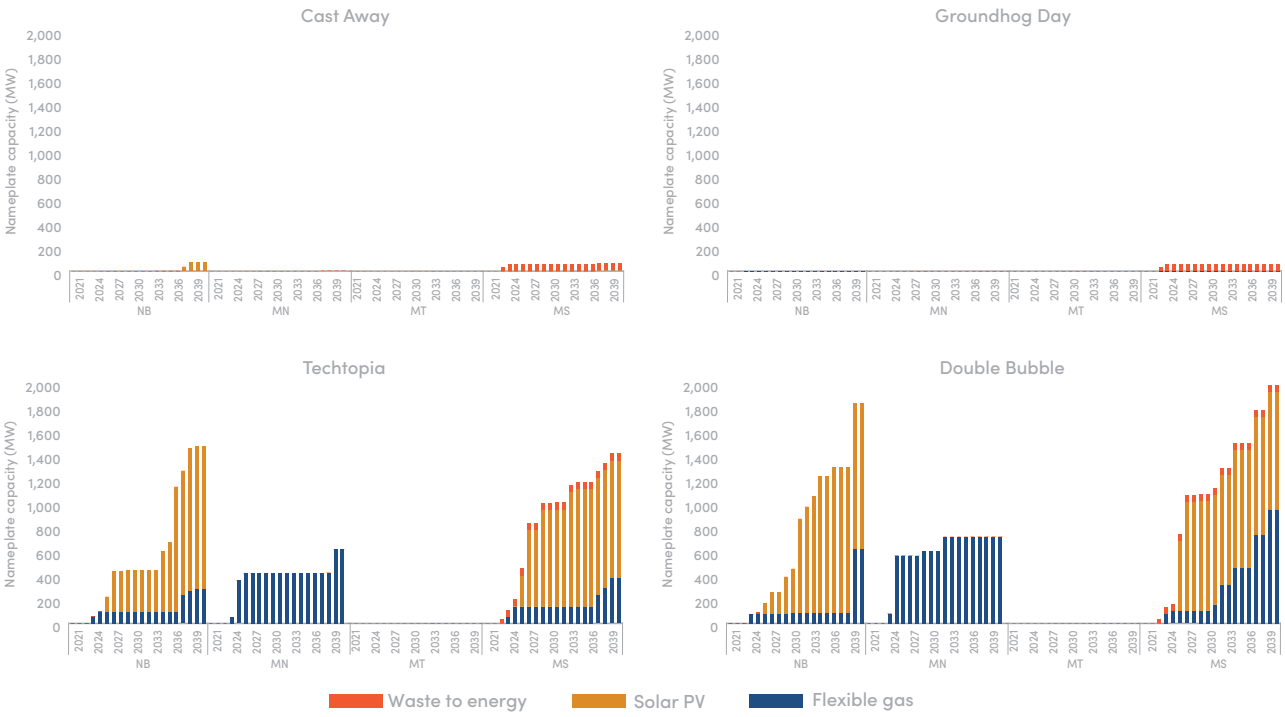


Figure 5.3: Generation capacity cumulative additions in Metro and Neerabup zones 2020 to 2040, excluding rooftop PV

The two higher demand scenarios see a significant amount of new large-scale generation being located in the Neerabup, Metro North and Metro South West zones. Under Techtopia, the rising demand and relatively slower uptake of rooftop PV compared to the other scenarios, results in a mix of large-scale solar being connected in Neerabup and Metro South West to take advantage of the network transfer capacity that exists between these zones, land availability and the large demand centre of the Perth metropolitan area. Demand levels in Techtopia require additional gas generation capacity, which the model includes close to existing 330 kV and 132 kV transmission lines alongside the Dampier to Bunbury Natural Gas Pipeline (DBNGP) in the Neerabup and Metro North zones.

The gas generation build in Double Bubble happens in similar locations to Techtopia but at a higher level due to the greater operational demand.

An assumption in the modelling is that the DBNGP can be constrained at times of peak electricity generation. The capital costs for contecting new gas generation in the WOSP model therefore include constructing additional lateral pipeline to the new gas generators, to allow for line packing sufficient gas to ride through the peak times. The amount of gas-fired generation capacity is restricted in the modelling to 2,000 MW.

Approximately 234 MW of OCGT generation is retired from the Neerabup zone in 2031, and a further 366 MW in 2037 due to the facilities reaching end of technical life. Under Techtopia this generation is replaced by large-scale solar in Neerabup, flexible gas generation in Metro North, and 4-hour duration storage in both zones as shown in Figure 5.4.

Under Double Bubble, additional flexible gas generation capacity is connected in 2039, when total SWIS demand is over 53,000 GWh p.a.

Following the gas-fired generation retirements in 2031 and 2037, under Cast Away, 213 MW of 4-hour duration battery storage is installed across all four zones in 2037. Under Groundhog Day, 219 MW of 4-hour storage is installed in 2031, 145 MW in 2035 and 283 MW in 2037.

Storage features strongly in the Metro and Neerabup zones under all scenarios. Under Cast Away there is an initial installation of 2-hour duration battery storage spread evenly across the Metro and Neerabup zones.

This shorter duration storage in the early years is predominantly to participate in the ESS markets and add some additional capacity to the system for peaks. As the capital cost of storage starts to fall, there is an increasing amount of 4-hour duration battery storage being installed evenly across these zones as it becomes cheaper, maximising the use of intermittent generation while avoiding network augmentation. (see Figure 5.4).

As mentioned above, some of this storage also contributes to replacing retiring gas peaking generation between 2030 and 2040.

Figure 5.4: Storage capacity cumulative additions Metro and Neerabup zones 2020 to 2040

5.1.2.3 Transmission network augmentations

No transmission augmentations are required to meet the levels of operational demand under Cast Away or Groundhog Day. Some augmentation would be required under Techtopia and Double Bubble.

Figure 5.5 shows the cumulative transmission network capacity additions required for the Metro, Metro North, Metro South West and Neerabup zones under Techtopia and Double Bubble between 2020 and 2040.

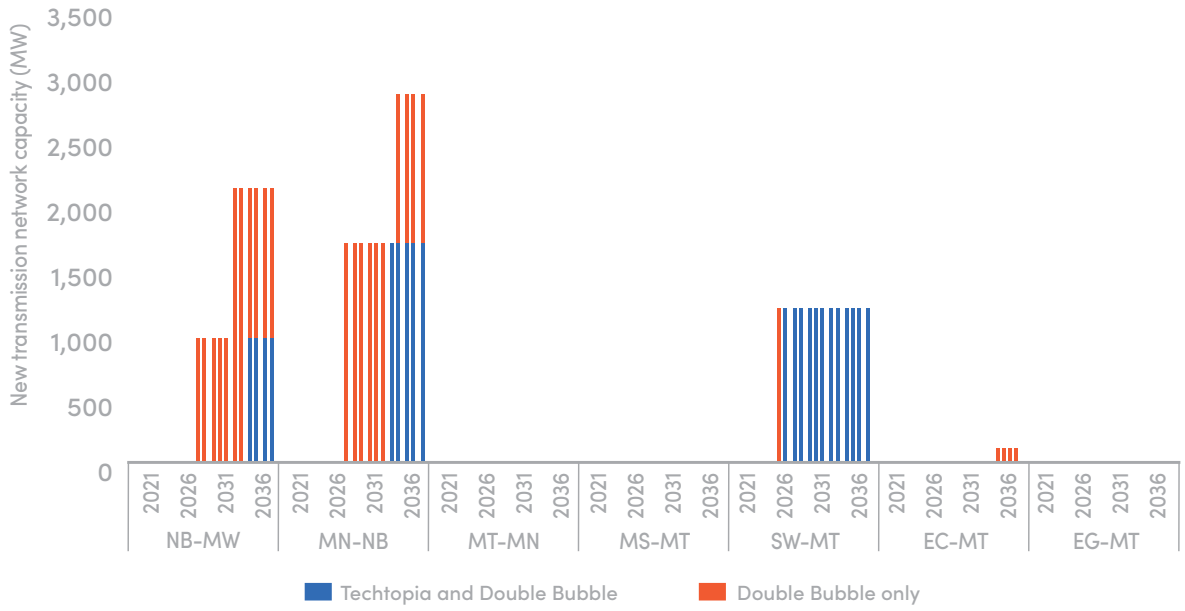


Figure 5.5: Cumulative new transmission network capacity under Techtopia and Double Bubble, Metro and Neerabup zones

Table 5.2 provides a summary of the augmentation requirements.

Table 5.2: Summary of Metro and Neerabup potential transmission network augmentations

PROJECT	TRANSMISSION NETWORK AUGMENTATION REQUIREMENTS
South West – Metro Phase 1A	• Construct new single circuit 132 kV transmission line between Mandurah, Pinjarra and Alcoa Pinjarra substations
Metro North – Neerabup Phase 1	• New double circuit 330 kV transmission line between Northern Terminal and Neerabup Terminal • New Pinjar to Neerabup transmission line to link Northern Terminal to Pinjar
Metro North – Neerabup Phase 2	• Install second transformer in the 132 kV network in the Neerabup zone • Construct new circuit between Pinjar substation and Neerabup Terminal • Split the Wanneroo to Neerabup Terminal double circuit line into two circuits • De-mesh connection between Neerabup Terminal and Northern Terminal • Resupply substations at Joondalup and Henley Brook through two new circuits
Neerabup – Mid West Phase 1	• Regans and Moora substations will be increasingly used, and existing network assets at Eneabba will be reinforced • The second side of the 330 kV transmission line between Neerabup and Three Springs, which is currently operating at 132kV, will be converted to operate at 330 kV
Neerabup – Mid West Phase 2	• Construct a new double circuit 330 kV transmission line from Neerabup to the new Yandin Terminal
East Country – Metro Phase 1	• Construct 132 kV transmission line between Northam and Guildford • Expand Guildford and Northam Terminals

Figure 5.6: North Country and Mid West transmission network zones

5.2 North Country and Mid West

5.2.1 Current state

This section describes the electricity system infrastructure in the North Country and Mid West transmission network zones at 1 July 2020.

These two zones comprise key transmission infrastructure in Western Power's northern network area. Figure 5.6 shows an overview of the region, the location of large-scale generation, and the transmission network.

The region covered by the North Country and Mid West transmission network zones connects approximately 3.3% of the population of the SWIS. The region comprises small loads distributed over a large geographical area, however it also includes a number of larger mining loads.

The North Country zone runs from Three Springs to Kalbarri at the northern-most point of the SWIS.

The Mid West zone extends from Pinjar and Muchea in the south to Three Springs, and then inland approximately 150 km to service the northern Wheatbelt area of Western Australia.

There is a significant amount of existing generation in this region as there is good land availability and abundant wind and solar resources.

Warradarge Wind Farm. Source: Bright Energy Investments.

A list of the existing facilities and the associated capacity is provided in Table 5.3.

Table 5.3: Installed generation in the North Country and Mid West transmission network zones, by start date

FACILITY	FUEL	MODELLED CAPACITY (MW)	CAPACITY CREDITS (MW)	COMMISSION DATE
Walkaway Wind Farm	Wind	89.1	24.8	2005
Emu Downs Wind and Solar Farm	Wind	100.0[1]	30.1	2006
Kalbarri Wind Farm	Wind	1.6	0.3	2009
Greenough River Solar Farm	Solar	40.0	2.0	2012
Tesla Geraldton	Distillate	9.9	9.9	2012
Karakin Wind Farm	Wind	5.0	0.7	2013
West Hills Wind Farm	Wind	5.0	–	2013
Mumbida Wind Farm	Wind	55.0	10.0	2013
Ambrisolar	Solar	1.0	–	2018
Badgingarra Wind and Solar Farm	Wind	147.5[2]	35.6	2019
Beros Road Wind Farm	Wind	9.3	–	2019
Warradarge Wind Farm	Wind	180.0	36.1	2020
Yandin Wind Farm	Wind	214.2	40.9	2020
		857.5	**190.4**	

Notes:
(1) Includes 80 MW wind farm and 20 MW solar farm.
(2) Includes 130 MW wind farm and 17.5 MW solar farm.

5.2.2 Findings and observations

5.2.2.1 Operational demand

The primary assumptions that drive changes in demand in the North Country and Mid West transmission network regions continues to be population growth and economic activity. The two zones, however, have two different profiles in relation to:

- demand in the North Country is centred around Geraldton, and therefore reflects expectation of population growth under each of the scenarios; and
- demand in the Mid West is driven by large mining loads and agriculture, and therefore reflects expectations of economic activity, commodity prices and rainfall.

In the North Country zone, under Groundhog Day, Techtopia and Double Bubble end-user demand and operational demand increase significantly until 2028.

This reflects an assumed increase in population growth in the Geraldton area, which then flattens over the remainder of the study period. Rooftop PV increases under all scenarios, helping to meet local demand and placing downward pressure on operational demand.

The Mid West zone sees a significant reduction in end-user demand and operational demand by 2028 under Cast Away, Groundhog Day and Techtopia. This is largely driven by an expectation that there is a demographic shift away from the area due to rising temperatures. Demand under Double Bubble almost doubles over the first half of the study period as new mining loads connect to the network and are largely supplied by large-scale grid-connected generation from across the SWIS.

Figure 5.7 shows the assumed end-user demand and operational demand in the North Country and Mid West zones (combined) under each of the four modelling scenarios.

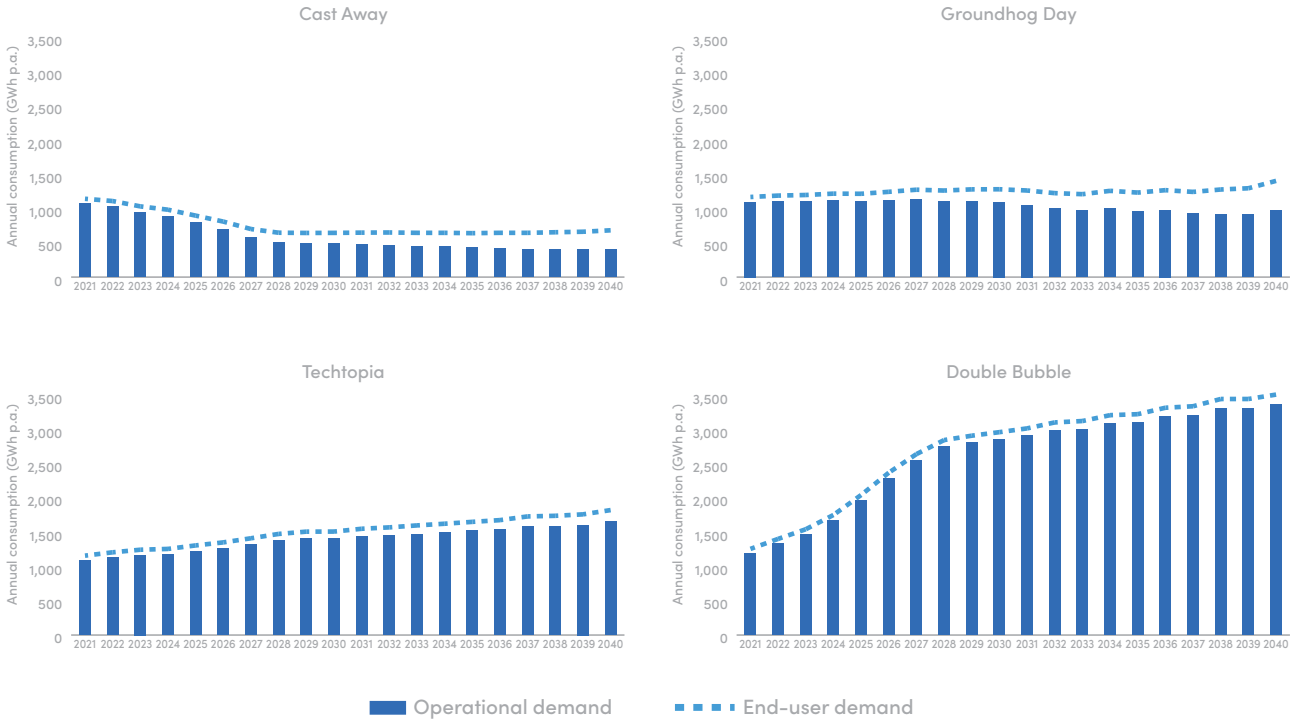


Figure 5.7: Operational and end-user demand, aggregated North Country and Mid West zone 2020 to 2040

5.2.2.2 **Capacity mix**

The overarching finding for new generation capacity in the lower demand scenarios is that only a limited amount of new capacity is connected in the region under the lowest cost to supply.

In the higher demand scenarios, it is anticipated that over the medium to longer term when additional operational demand emerges and consequent network augmentation is undertaken, the North Country and Mid West will be an attractive location for additional generation capacity.

Under the lower demand scenarios (Cast Away and Groundhog Day), no new generation is added in the first half of the study period, and only 81 MW and 116 MW respectively of new wind and large-scale solar connects by the end of the study period.

Under the higher demand scenarios (Techtopia and Double Bubble), the transmission network needs to be augmented to allow new generation capacity to connect in the North Country and Mid West zones. New entrant technologies are large-scale solar and wind as they are the lowest cost to supply.

Under both higher demand scenarios, a small amount of flexible gas generation capacity is added to the region. Under Techtopia, there is around 12 MW, and under Double Bubble there is around 70 MW. This is expected to help firm the largely intermittent generation in the region, providing localised system security and network reliability as more renewables are added. The increased intermittency is further addressed by the addition of storage capacity.

New storage is added under all scenarios in the North Country as part of the lowest cost capacity mix. There are two drivers of connecting new storage facilities:

- the potential for storage facilities to participate in the ESS market;[58] and
- the ability to maximise the utilisation of existing assets and intermittent generation output.

In the lower demand scenarios the majority of storage connected is 2-hour duration battery storage in the first half of the study period, with some 4-hour duration batteries being added as the cost of the technology comes down later in the study period.

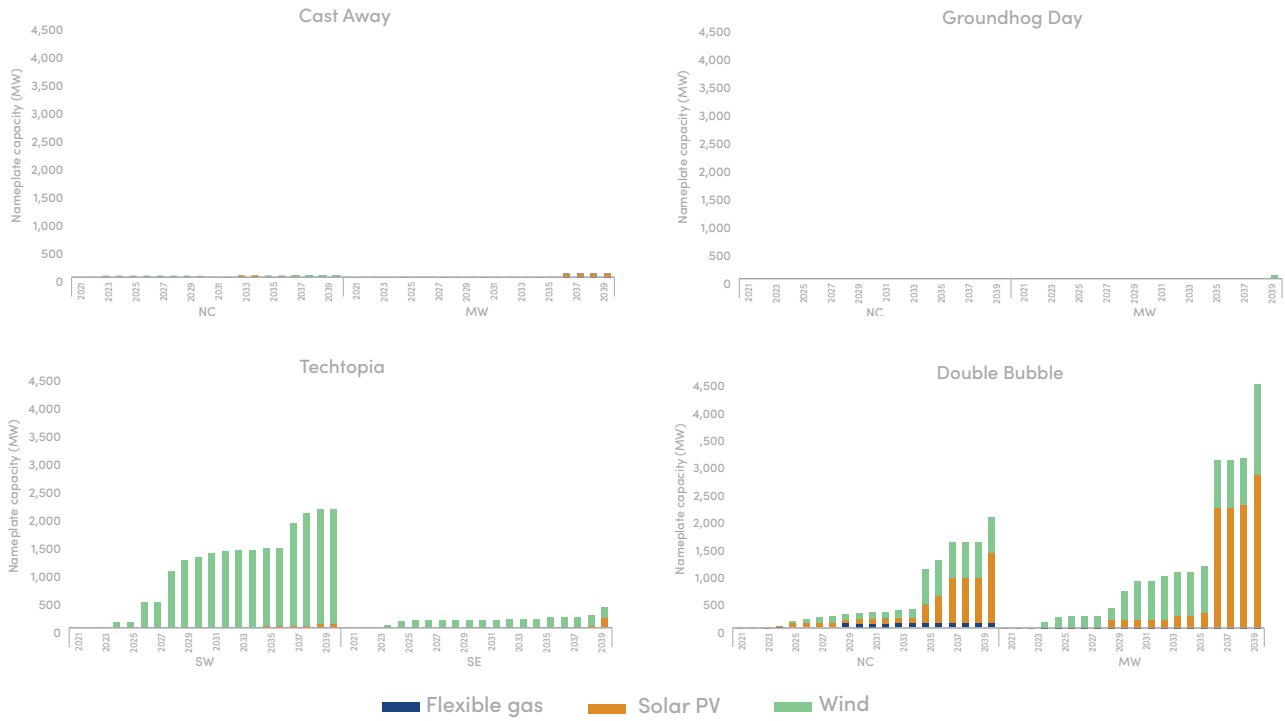


Figure 5.8: Generation capacity cumulative additions in North Country and Mid West zones 2020 to 2040, excluding rooftop PV

58 This is a common driver for connecting storage in all transmission network zones.

Under the higher demand scenarios, new storage comprises 4-hour duration battery storage in the later years of the study period as the price of storage comes down and the requirement for ESS increases.

As previously highlighted, particularly under Double Bubble, the additional storage capacity will help firm the largely intermittent generation in the region, and maximise the utilisation of network assets.

Figure 5.9 shows the additional storage modelled in the North Country and Mid West transmission network zones over the study period.

Figure 5.9: Storage capacity cumulative additions North Country and Mid West zone 2020 to 2040

5.2.2.3 Transmission network augmentations

No transmission augmentations are required to meet operational demand under the lower demand scenarios. Some augmentation would be required under Techtopia and Double Bubble.

Figure 5.10 shows the cumulative transmission network capacity additions required for the North Country and Mid West zones under Techtopia and Double Bubble between 2020 and 2040.

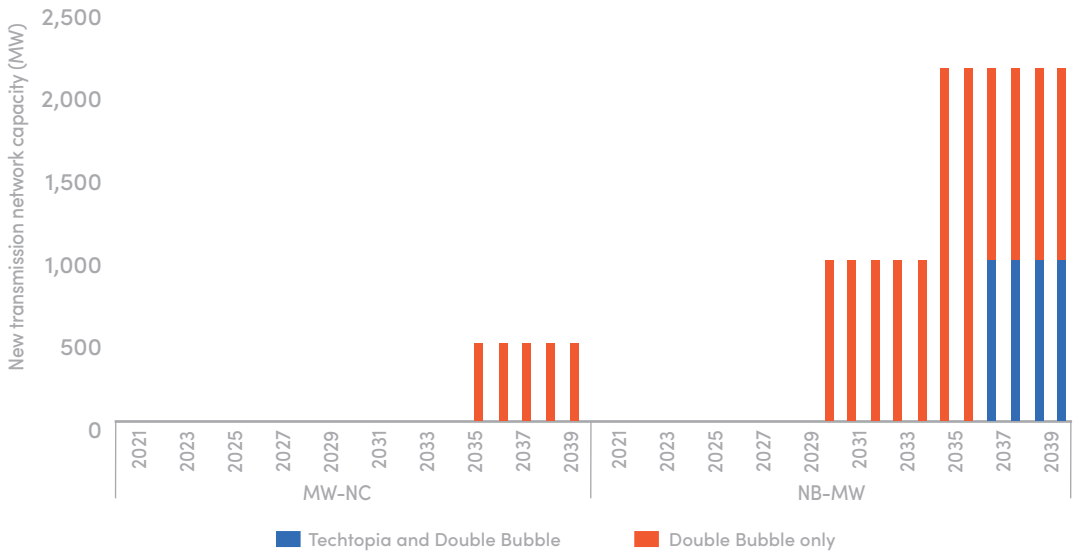


Figure 5.10: Cumulative new transmission network capacity under Techtopia and Double Bubble, North Country and Mid West zones

Table 5.4 provides a summary of the augmentation requirements.

Table 5.4: Summary of North Country and Mid West potential transmission network augmentations

PROJECT	TRANSMISSION NETWORK AUGMENTATION REQUIREMENTS
Neerabup – Mid West Phase 1	• The second side of the 330 kV transmission line between Neerabup and Three Springs, currently operation at 132 kV will be converted to operate at 330 kV • De-mesh and reinforce the 132 kV network • Implement dynamic line rating technology
Neerabup – Mid West Phase 2	• Construct a new 330 kV double circuit transmission line from Neerabup to Yandin
Mid West – North Country Phase 1 + Phase 2	• Construct a new 132 kV double circuit transmission line between Three Springs and Geraldton • Establish a new 132 kV terminal substation at Three Springs • Install a reactive compensation scheme

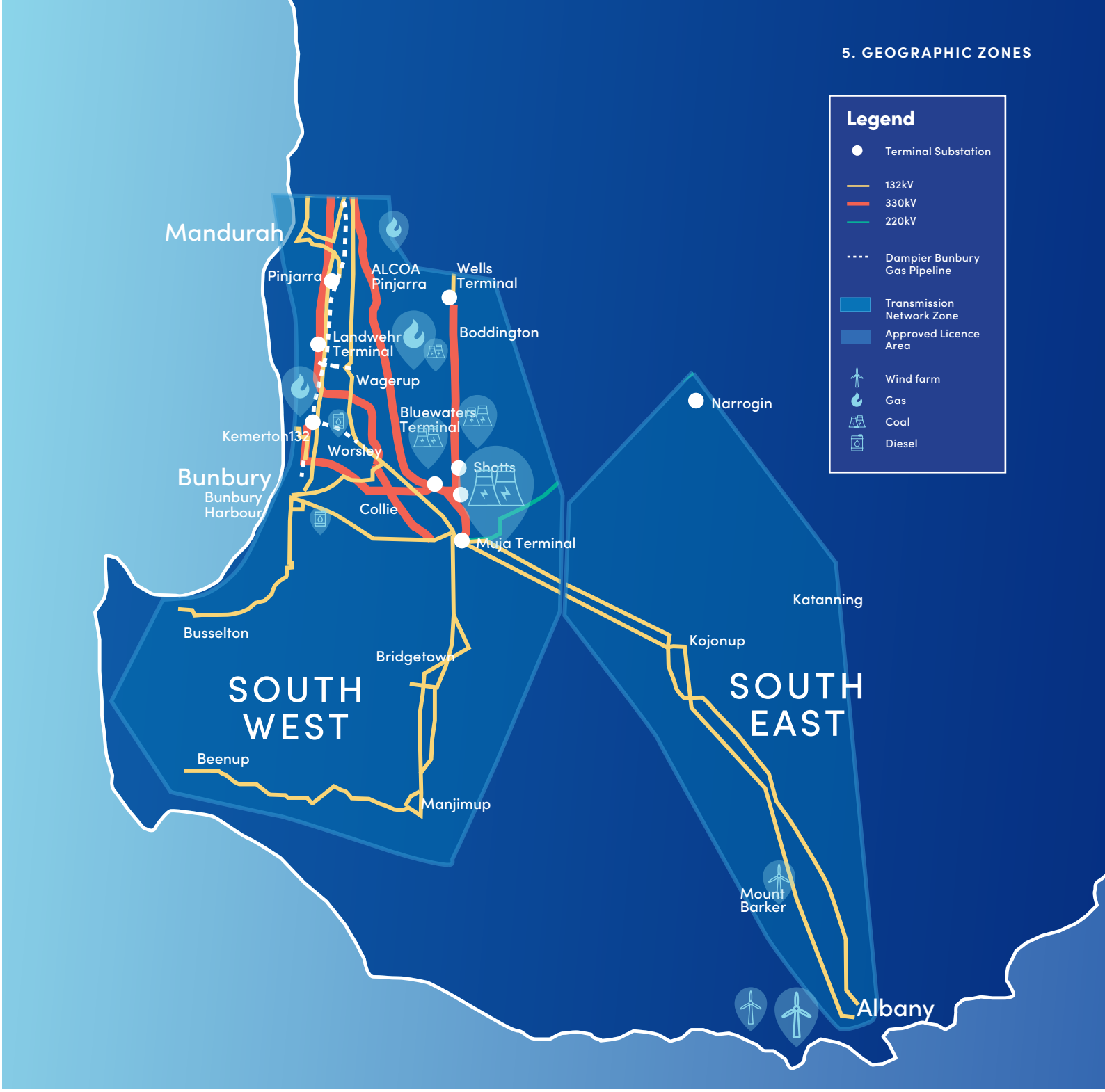


Figure 5.11: South West and South East transmission network zones

5.3 South West and South East

5.3.1 Current state

This section describes the electricity system infrastructure in the South West and South East transmission network zones at 1 July 2020.

Figure 5.11 shows an overview of the region, the location of large-scale generation capacity, and the transmission network.

The region covered by the South West and South East transmission network zones is the second most populous area of the SWIS (after the metropolitan area). It comprises approximately 18% of the population of the SWIS and includes residential, large industrial and commercial demand centres.

The South West zone includes all of the coal-fired generation facilities in the SWIS (1,569 MW) and several large gas generation facilities (1,027 MW).

Some wind generation capacity (40 MW) is connected in the South East zone, principally on the coast. There is presently no installed wind generation capacity in the South West zone.

A list of the existing facilities and the associated capacity is provided in Table 5.5.

Table 5.5: Installed generation in the South West and South East transmission network zones, by start date

FACILITY	FUEL	MODELLED CAPACITY (MW)	CAPACITY CREDITS (MW)	COMMISSION DATE
Muja 5	Coal	195.8	195.0	1981
Muja 6	Coal	195.8	193.0	1981
Alcoa Wagerup[1]	Gas	26.0	26.0	1985
Muja 7	Coal	212.6	211.0	1986
Muja 8	Coal	212.6	211.0	1986
Collie G1	Coal	318.3	317.2	1999
Albany Wind Farm	Wind	21.6	6.6	2001
Alinta Pinjarra 1	Gas	143.0	135.0	2005
Kemerton 1	Dual (Gas / Distillate)	155.0	155.0	2005
Kemerton 2	Dual (Gas / Distillate)	155.0	155.0	2005
Alinta Pinjarra 2	Gas	143.0	135.5	2006
Alinta Wagerup Gas Turbine 1	Dual (Gas / Distillate)	195.2	196.0	2007
Alinta Wagerup Gas Turbine 2	Dual (Gas / Distillate)	210.0	196.0	2007
Bluewaters 1	Coal	217.0	217.0	2008
Bluewaters 2	Coal	217.0	217.0	2009
Mount Barker Wind Farm	Wind	2.4	0.7	2010
Tesla Picton	Distillate	9.9	9.9	2011
Grasmere Wind Farm	Wind	13.8	4.5	2012
Tesla Kemerton	Distillate	9.9	9.9	2012
Denmark Wind Farm	Wind	1.4	0.5	2013
		2,655.3	**2591.8**	

Note:
(1) Mostly behind-the-meter supply, with small amount of export to the SWIS.

Alinta Wagerup Gas Turbine. Source: Alinta Energy.

There is a significant amount of transmission infrastructure connecting this region to the rest of the system. The South West transmission network zone is connected to the main metropolitan load area via a strong 330 kV transmission network. There is also a 220 kV single circuit connection from Muja to the Mid East and Eastern Goldfields zones.

5.3.2 Findings and observations

5.3.2.1 Operational demand

In this region, an important assumption is that population growth occurs as a result of a population migration from the north and metropolitan areas of the SWIS due to urban sprawl and greater economic opportunity. Any significant economic growth in the region is assumed to be a result of an uplift in the local energy metals industries (specifically lithium and nickel), which would drive significant end-user demand in the Techtopia and Double Bubble scenarios.

Figure 5.12 shows the assumed end-user demand and operational demand in the South West and South East transmission network zones (combined) under each of the four modelling scenarios.

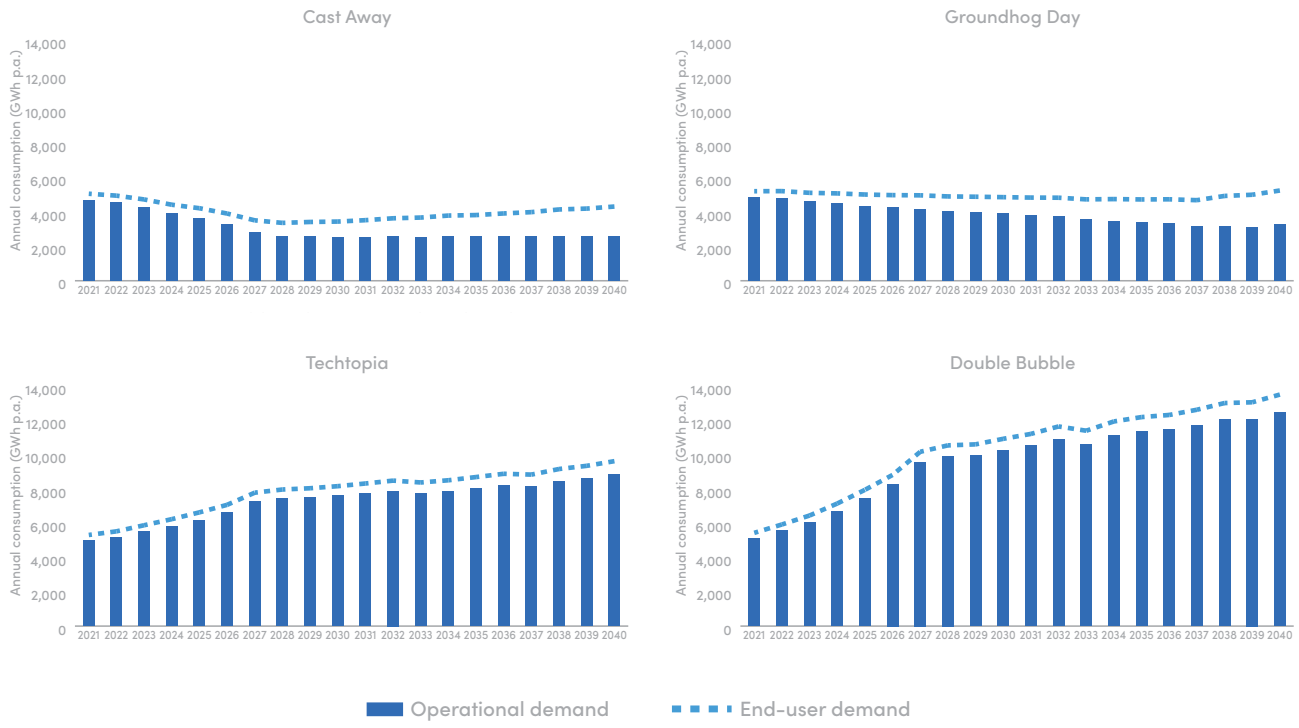


Figure 5.12: Operational and end-user demand, aggregated South East and South West zones 2020 to 2040

In Cast Away and Groundhog Day, end-user demand is assumed to be relatively flat. The initial end-user demand decreases in Cast Away are attributed to the muted economic climate assumed in the Cast Away scenario generally, and relatively slow population growth. In both these scenarios operational demand declines over the study period.

The input assumption driving the decline in operational demand is the DER uptake. In Figure 5.12, the gap between end-user demand and operational demand is driven by the level of DER (primarily rooftop PV) assumed in each scenario. Under Cast Away and Groundhog Day, rooftop PV uptake is assumed to be high, which pushes out the requirement for additional capacity to be supplied via the network, driving down operational demand.

Under Techtopia and Double Bubble, DER uptake is assumed to be lower.

Albany Wind Farm. Source: Synergy.

5.3.2.2 **Capacity mix**

The overarching finding for the South West and South East zones is that network capacity is available for new large-scale generation to connect to the transmission network to meet SWIS-wide operational demand.

In particular, the model selects wind capacity as the lowest cost form of new large-scale generation to be connected in the region, predominantly in the South West zone (see Figure 5.13).

Figure 5.13: Generation capacity cumulative additions in South West and South East zones 2020 to 2040, excluding rooftop PV

The WOSP modelling selects the capacity mix that forms the lowest cost to supply electricity across the whole of the SWIS. The algorithm within the resource planning model is designed to identify the lowest cost to securely supply the entire power system, which means that the driver for connecting new generation or storage capacity is demand right across the SWIS, not solely demand in the specific transmission network zone.

This region is strongly connected to the Metro and Neerabup region demand centres and has capacity to facilitate increased transfer levels. It also has an abundance of renewable resource, hence why the model chooses to connect new generation in the South West.

The resource planning model selects wind as the lowest cost form of new large-scale generation capacity in the region. This is because wind capacity is relatively inexpensive to install and is a more diverse resource than solar. Having more generating facilities in areas of the SWIS where there is currently little or no wind capacity will enable more wind energy to be captured to meet demand. This increases the overall system ability to match wind energy with load profile and allows wind capacity overall to be more competitive.

Under Techtopia and Double Bubble, between 2,063 MW and 2,450 MW of wind generation capacity is installed in the South West zone by the end of the study period. This is simply due to the fact there is sufficient SWIS-wide demand to merit new large-scale generation capacity.

While large-scale capacity other than wind could be installed, alternatives such as gas and large-scale solar are less co-optimised options for the region. Gas is more expensive predominantly because of fuel and fuel transport costs. There is currently a limited gas supply in the region. The modelling has assumed that installing gas in the South West zone would require an additional cost to reinforce gas pipeline infrastructure into the area.

Large-scale solar is a less economic option than wind in the south of the SWIS for two reasons. First, the prevalence of rooftop PV in the region displaces the generation profile of large-scale solar. This is because rooftop PV simply reduces demand for grid served energy. Second, the likelihood of cloud cover tends to be greater in the south of the State, which reduces the capacity factor.

The two lower demand scenarios (Cast Away and Groundhog Day) see little or no additional large-scale generation required in the South East or South West zones. This is due to the rooftop PV meeting a larger portion of end-user demand which displaces other forms of generation.

The South West zone contains all of the coal-fired generation in the SWIS. In both Cast Away and Groundhog Day, operational demand is declining over the study period, with end-user demand increasingly being met by rooftop PV generation. Baseload coal-fired facilities do not have the required flexibility to adjust to these conditions which increases their cost to run, and consequently impacts the economics of coal-fired generation.

Under the low demand scenarios (Cast Away and Groundhog Day) this leads to additional exit (on economic grounds) of between 132 MW and 500 MW of coal-fired generation capacity as it no longer features in the lowest cost to supply mix from 2026.

There is relatively little storage located in the region, compared to other regions.

Under Double Bubble, the majority of the storage installed in the South East transmission network zone is used to maximise utilisation of the network and delay the need to undertake transmission network augmentation. Figure 5.14 shows the additional storage installed in the South West and South East transmission network zones over the study period.

Figure 5.14: Storage capacity cumulative additions South West and South East zones 2020 to 2040

5.3.2.3 Transmission network augmentations

No transmission augmentations are required to meet operational demand under Cast Away or Groundhog Day. Some augmentation would be required under Techtopia and Double Bubble.

Figure 5.15 shows the cumulative transmission network capacity additions required for the South West and South East zones under Techtopia and Double Bubble between 2020 and 2040.

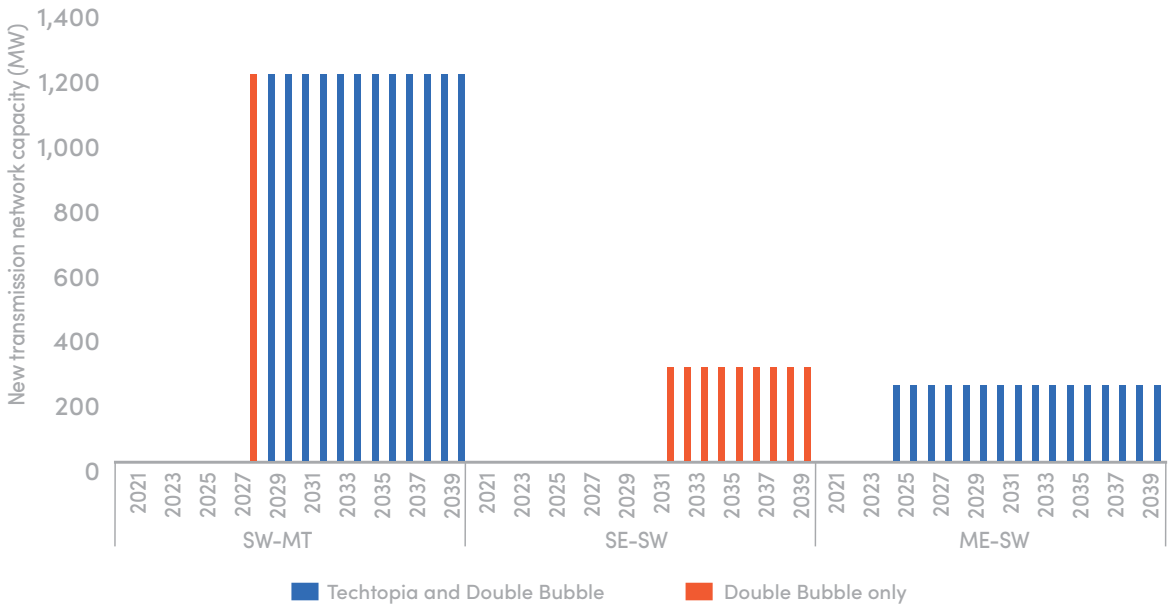


Figure 5.15: Cumulative new transmission network capacity under Techtopia and Double Bubble, South West and South East zones

Table 5.6 provides a summary of the augmentation requirements.

Table 5.6: Summary of South East and South West potential transmission network augmentations

PROJECT	TRANSMISSION NETWORK AUGMENTATION REQUIREMENTS
South West – Metro Phase 1A	• Construct new single circuit 132 kV transmission line between Mandurah, Pinjarra and Alcoa Pinjarra substations
South East – South West Phase 1 + Phase 2	• Construct new 132 kV transmission lines between Muja Terminal and Kojonup, Mount Barker and Albany substations

Figure 5.16: East Country and Mid East transmission network zone

5.4 East Country and Mid East

5.4.1 Current state

This section describes the electricity system infrastructure in the East Country and Mid East transmission network zones at 1 July 2020.

These two zones comprise key transmission infrastructure in Western Power's eastern network area. Figure 5.6 shows an overview of the region, the location of large-scale generation capacity, and the transmission network.

Merredin Solar Farm. Source: Risen Energy.

The region covered by the East Country and Mid East transmission network zones service the Wheatbelt area east of Perth and covers approximately 2% of the population of the SWIS. It has highly dispersed population centres and low local demand growth rates, with a mix of agricultural, smaller mining, industrial and commercial customers.

The East Country zone is connected in the west through the 132 kV transmission network to Northern Terminal in the Metro North zone and Guildford in the Metro zone.

In addition to servicing local demand requirements, the Mid East zone provides a critical transmission link to the neighbouring Eastern Goldfields area from the generation areas in the South West zone.

The East Country and Mid East zones have high land availability and high quality solar resources, which is why the majority of solar farms are connected here, including the state's largest solar facility, the new 100 MW Merredin Solar Farm. A list of the existing facilities and the associated capacity is provided in Table 5.7.

Table 5.7: Installed generation in the East Country and Mid East transmission network zones, by start date

FACILITY	FUEL	MODELLED CAPACITY (MW)	CAPACITY CREDITS (MW)	COMMISSION DATE
Collgar Wind Farm	Wind	206.0	18.9	2011
Merredin Gas Turbine	Distillate	92.6	82.0	2011
Tesla Northam	Distillate	9.9	9.9	2012
Northam Solar Farm	Solar	9.8	3.7	2018
Merredin Solar Farm	Solar	100.0	29.3	2020
		418.3	**143.8**	

Merredin Solar Substation. Source: Western Power.

5.4.2 Findings and observations

5.4.2.1 Operational demand

In the East Country and Mid East transmission network zones, under the lower demand scenarios (Cast Away and Groundhog Day) end-user demand and operational demand decrease through to 2027. Even in the higher demand scenarios, demand remains relatively flat to 2027.

As with all zones, population and economic growth drive end-user demand and economic growth. The impact of these factors on demand in the East Country and Mid East zones is lower than other regions, as there are relatively few people in the area and the agricultural industry is typically less energy intensive than mining and manufacturing loads.

Figure 5.17 shows the assumed end-user demand and operational demand in the East Country and Mid East zones (combined) under each of the four modelling scenarios.

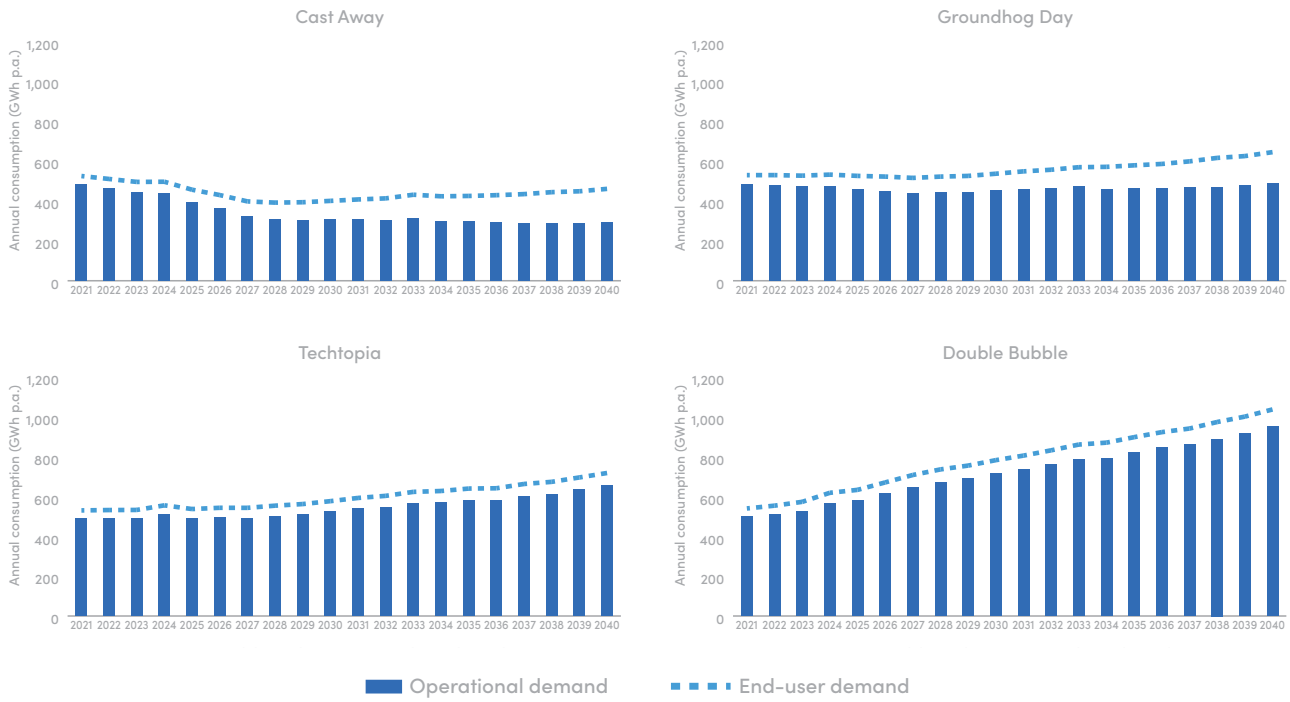


Figure 5.17: Operational and end-user demand, aggregated East Country and Mid East zones 2020 to 2040

5.4.2.2 **Capacity mix**

The overarching finding in the East Country and Mid East transmission network zones is that limited additional generation capacity is required in all scenarios before 2026. Later in the study period, additional solar and wind is selected by the model to meet SWIS-wide operational demand as part of the lowest cost to supply (see Figure 5.18).

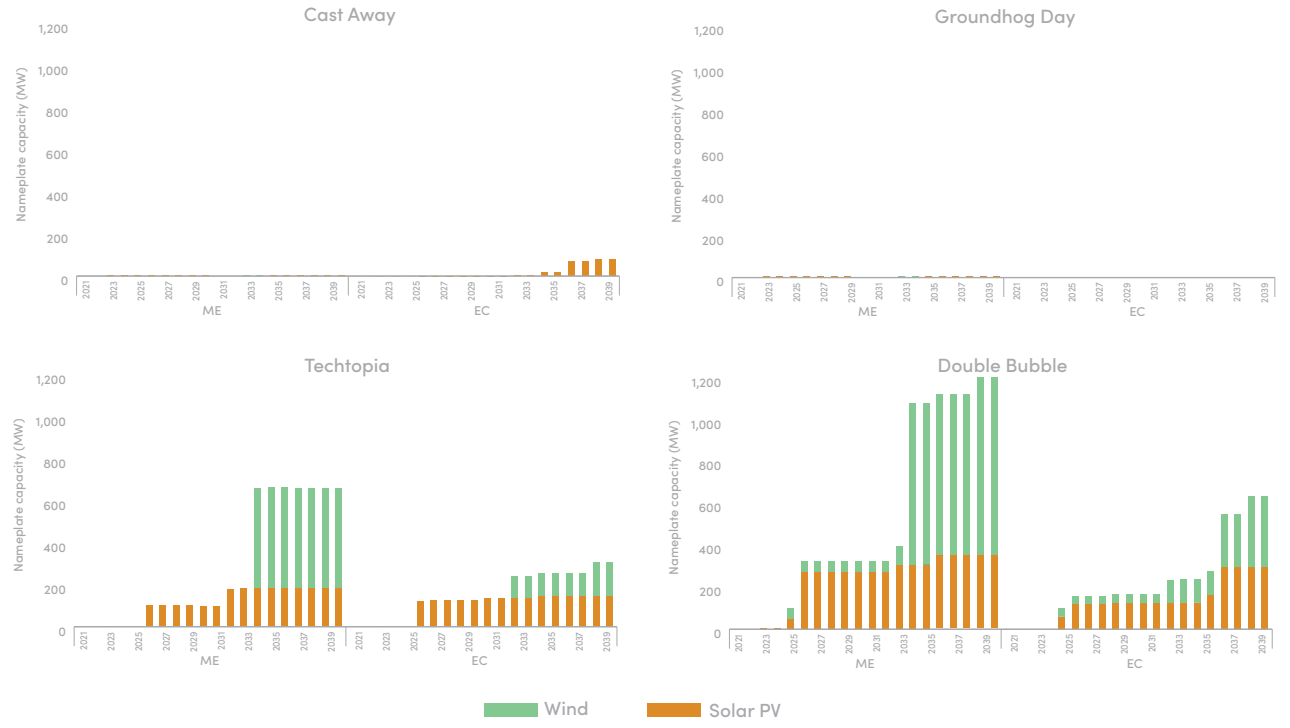


Figure 5.18: Generation capacity cumulative additions East Country and Mid East zones 2020 to 2040

Under the two lower demand scenarios, minimal new capacity is added over the study period. Under Cast Away, around 80 MW of large-scale solar PV is connected from 2035 to meet local demand. Under Groundhog Day, no new generation capacity is added.

Under the higher demand scenarios large-scale solar is chosen as the least cost generation source in the eastern region of the SWIS. This is because it matches the load in the region and the capacity factor for solar in the Mid East and East Country zones is relatively high. A further 645 MW to 1,099 MW of additional wind capacity is also connected from 2033 to meet SWIS-wide demand.

While no new generation capacity is added in the two zones before the mid-2030s under Cast Away and Groundhog Day, around 10 MW of 2-hour duration batteries are connected at the start of the study period as part of the lowest cost to supply. This reflects the potential for storage facilities to be geographically diverse across the SWIS, provide SWIS-wide ESS, and help maximise utilisation of intermittent generation and network.

Under Cast Away and Groundhog Day, around 100 MW of 4-hour duration battery storage connects in the Mid East zone. A further 90 MW connects in the East Country zone under Groundhog Day as these longer duration batteries become cheaper.

Under both the higher demand scenarios, relatively few batteries are required in the East Country and Mid East zones over the first decade of the study period. This is because under these scenarios a network augmentation is conducted in 2025 to increase the transfer limit between the Eastern Goldfields and the rest of the SWIS. The network augmentation is sufficient to accommodate an increase in local demand and generation capacity, therefore there is less need for storage.

Under Techtopia, 44 MW of larger batteries are installed by 2033 in the East Country zone only. Under Double Bubble, around 80 MW of larger batteries are installed in each zone by the end of the study period as battery storage costs fall.

Figure 5.19 shows the additional storage installed in the East Country and Mid East transmission network zones over the study period.

Figure 5.19: Storage capacity cumulative additions East Country and Mid East zones 2020 to 2040

5.4.2.3 Transmission network augmentations

No transmission augmentations are required to meet operational demand under Cast Away or Groundhog Day. Some augmentation would be required under Techtopia and Double Bubble.

Figure 5.20 shows the cumulative transmission network capacity additions required for the East Country and Mid East zones under Techtopia and Double Bubble between 2020 and 2040.

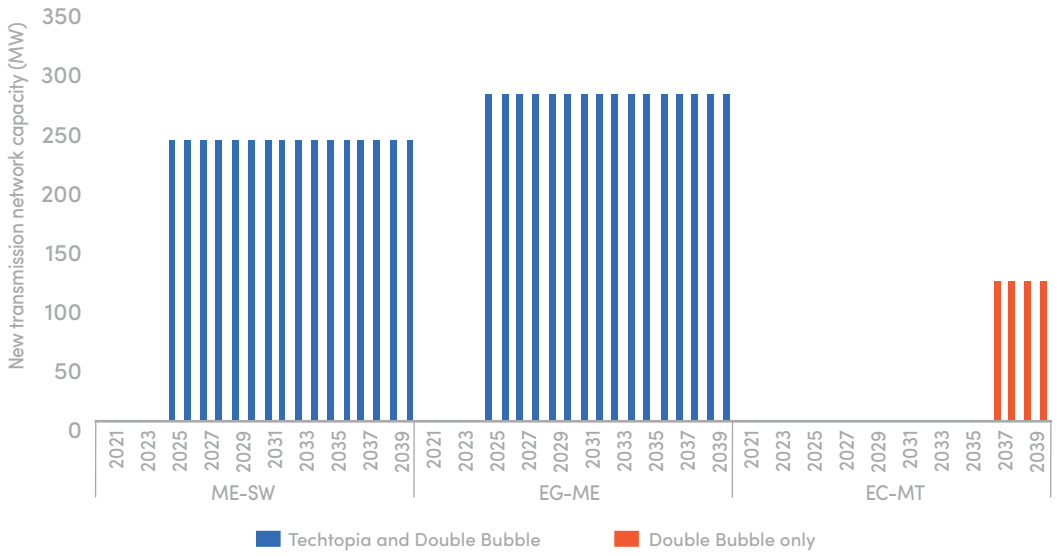


Figure 5.20: Cumulative new transmission network capacity under Techtopia and Double Bubble, Mid East and East Country zones

Table 5.8 provides a summary of the augmentation requirements.

Table 5.8: Summary of East Country and Mid East potential transmission network augmentations

PROJECT	TRANSMISSION NETWORK AUGMENTATION REQUIREMENTS
Mid East – South West and Mid East – Eastern Goldfields Phase 1	• Install wide area monitoring protection and control system • Install 330/220 kV transformer at Muja • Install 220/132 kV transformer at West Kalgoorlie • Install dynamic reactive capability at Merredin, Narrogin South and Kalgoorlie
East Country – Metro MT Phase 1	• Construct 132 kV transmission line between Northam and Guildford • Expand Guildford and Northam Terminals

Figure 5.21: Eastern Goldfields transmission network zone

5.5 Eastern Goldfields

5.5.1 Current state

This section describes the electricity system infrastructure in the Eastern Goldfields transmission network zone at 1 July 2020.

This zone is the eastern-most part of the network and connects to the Mid East zone at Southern Cross in the west. Figure 5.21 shows an overview of the region, the location of large-scale generation capacity, and the transmission network.

The Eastern Goldfields transmission network zone is centred around the Kalgoorlie and Boulder townships, and supplies local residential and large mining loads. It provides energy to around 1.5% of the population of the SWIS.

Growth in this region typically relates to large mining loads. The inherent volatility in response to global market forces and commodity prices makes demand in the area difficult to forecast over long periods.

Parkeston Power Station. Source: TransAlta, photographed by Geoff Collins.

Demand in the region is typically greater than the local generation and requires power transfer via a long 220 kV single line from the South West network zone via the Mid East transmission network zone.

Stability is the limiting factor and constrains the transfer into this region, also limiting the opportunities for connection of new generation. A substantial amount of demand from large mining customers in the area is currently met by behind-the-meter generation.

There are two generators in the Eastern Goldfields zone that provide energy into the network; Parkeston and Southern Cross. However, the bulk of the Southern Cross facility's installed capacity is used to supply the BHP Nickel West operation. The two existing facilities and their associated capacity is provided in Table 5.9.

Table 5.9: Installed generation in the Eastern Goldfields transmission network zone, by start date

FACILITY	FUEL	MODELLED CAPACITY (MW)	CAPACITY CREDITS (MW)	COMMISSION DATE
Parkeston	Dual (Gas / Distillate)	68.0	59.4	1996
Southern Cross Power Station	Gas	23.0	20.0	1996
		91.0	**79.4**	

Note:

(1) Southern Cross only has a declared sent out capacity (DSOC) of approximately 30 MW, with the remainder used to power BHP Nickel West.

5.5.2 Findings and observations

5.5.2.1 Operational demand

The primary assumption that drives changes in demand in the Eastern Goldfields transmission network zone is variation in economic activity. In the Goldfields, almost all economic activity relates to mining precious metals, predominantly gold. Where the gold price is assumed to be high (or increasing), population growth and economic activity in the region increases and as such end-user demand grows.

Figure 5.22 shows the assumed end-user demand and operational demand in the Eastern Goldfields under each of the four modelling scenarios.

Under Techtopia and Double Bubble the gold price is assumed to remain sufficiently high over the study period to trigger high production output and further mining exploration. This in turn leads to high end-user demand over the period.

Unlike the other transmission network zones, the Eastern Goldfields is less impacted by rooftop PV uptake due to the relatively small residential population in the region. As a result, the gap between end-user demand and operational demand is smaller, with almost all electricity being supplied via the network.

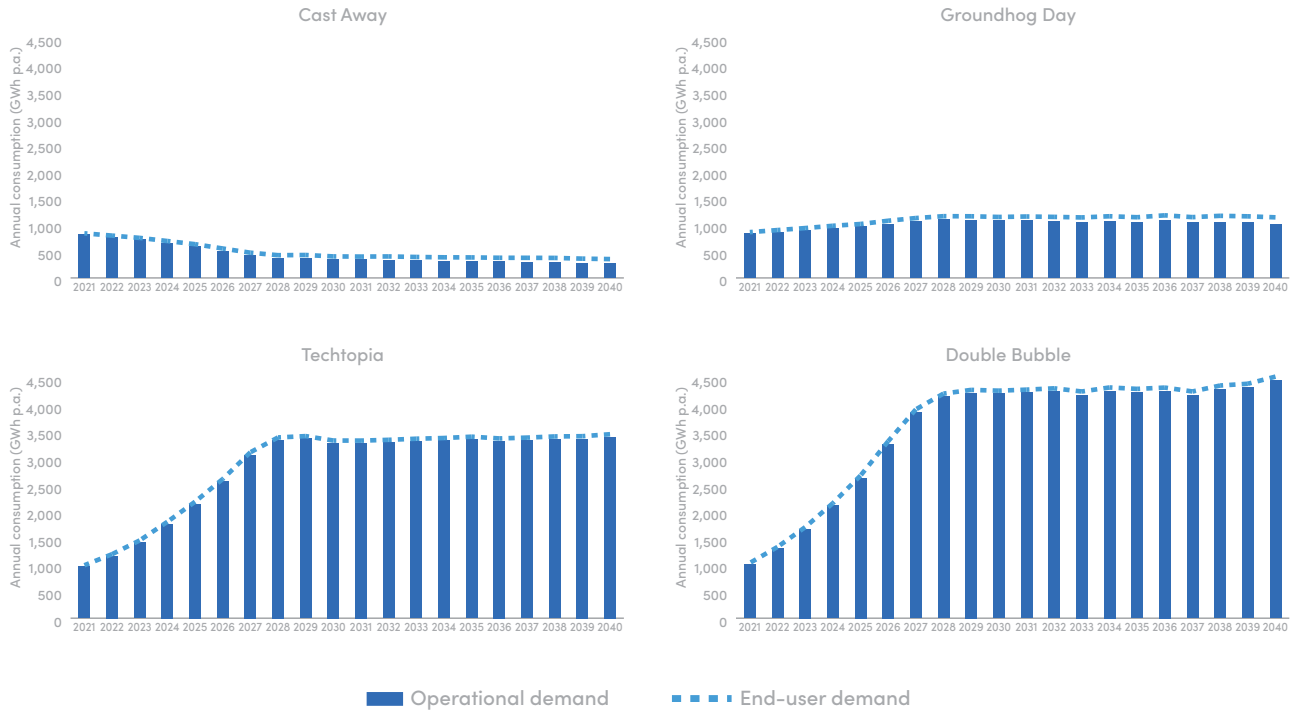


Figure 5.22: Operational and end-user demand, aggregated Eastern Goldfields zone 2020 to 2040

5.5.2.2 **Capacity mix**

The ability to connect new generation capacity in the Eastern Goldfields in limited unless the network is augmented. Further, due to the limited additional gas supply in the region (the Goldfields Gas Pipeline currently being fully utilised), wind and large-scale solar are the primary forms of new large-scale generation capacity for the Eastern Goldfields zone (see Figure 5.23).

Figure 5.23: Generation capacity cumulative additions in Eastern Goldfields zones 2020 to 2040, excluding rooftop PV

Under Groundhog Day and Cast Away, operational demand remains flat or decreases, which means there is little requirement for new generation capacity in the region, particularly during the first decade of the study period. When selecting new capacity, the model selects the lowest cost form of generation and places it in a part of the SWIS where there is sufficient network capacity and fuel supply. In most instances wind and large-scale solar are the most cost-efficient forms of new generation, therefore these two renewable forms of capacity will typically be selected by the model first.

However, due to the stability/strength of the network between the South West and Eastern Goldfields zones, the amount of new renewable generation that can be connected in the Eastern Goldfields has been limited to 200 MW in the modelling.

Under Techtopia and Double Bubble, wind and large-scale solar uptake is greater due to the high operational demand in each scenario. Operational demand in the Eastern Goldfields zone reaches upwards of 2,500 GWh p.a., more than triple current levels, by the mid-2020s under the higher demand scenarios.

Figure 5.24 shows the additional storage modelled in the Eastern Goldfields transmission network zones over the study period.

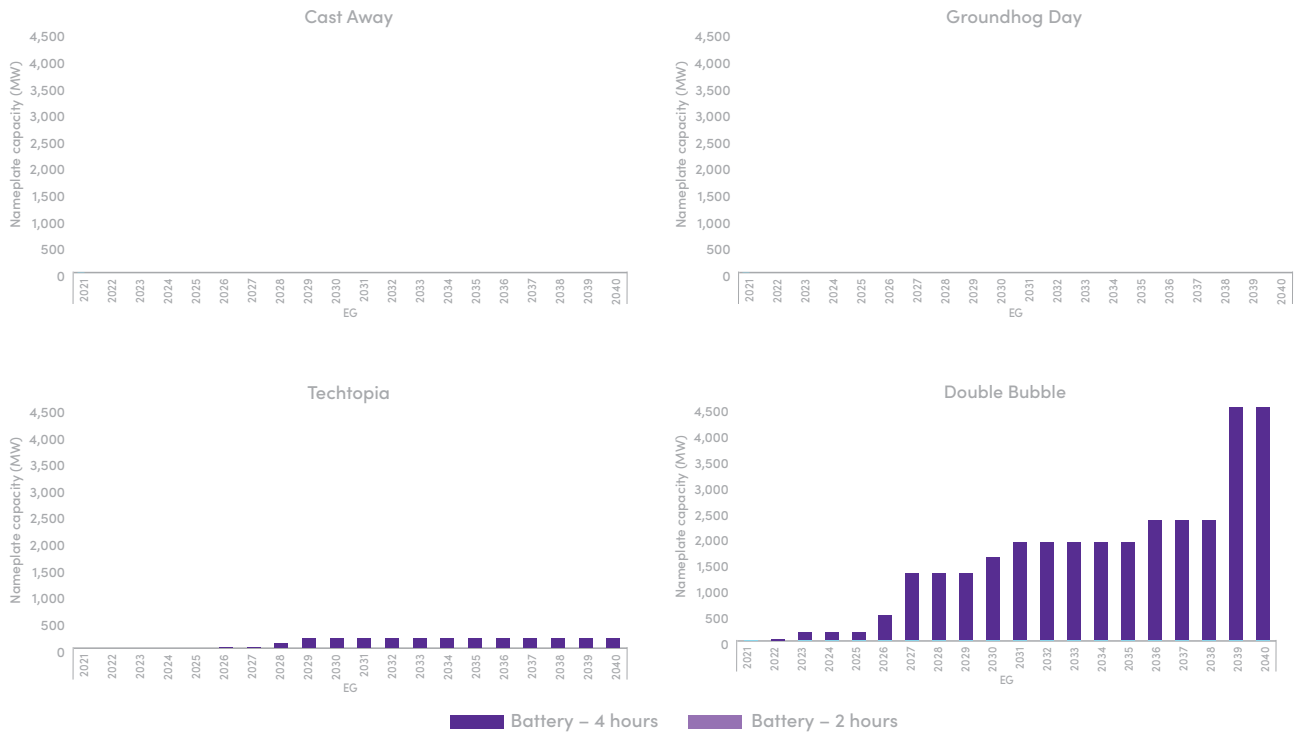


Figure 5.24: Storage capacity cumulative additions Eastern Goldfields zone 2020 to 2040

No new storage capacity is selected by the model for the Eastern Goldfields zone under the lower demand scenarios. This is because there is sufficient generation and transfer capacity to meet demand.

Under Techtopia there is a requirement for a small amount of storage to form part of the capacity mix in 2029, when local demand has reached 3,400 GWh p.a. This storage capacity is required to maximise the utilisation of network and intermittent generation.

The high uptake of storage capacity in Double Bubble is due to the large growth in demand quickly outstripping the network transfer capacity between the East County and Eastern Goldfields zones. The lowest cost solution is to build storage rather than a new transmission connection.

A network augmentation is delivered by the model in 2025 to increase the transfer capacity to the region (see section 5.5.2.3). However, the steep demand profile means storage is required to support the connection of additional large-scale generation capacity. The model selects battery storage solutions as part of the lowest cost mix post 2028. The Eastern Goldfields would experience some USE in the Double Bubble scenario, however this remains a lower cost option than building additional transfer capacity.

5.5.2.3 Transmission network augmentations

No transmission augmentations are required to meet operational demand under Cast Away or Groundhog Day. Some augmentation would be required under Techtopia and Double Bubble.

Figure 5.25 shows the cumulative transmission network capacity additions required for the Eastern Goldfields zone under Techtopia and Double Bubble between 2020 and 2040. The Mid East – South West and Eastern Goldfields – Mid East augmentations, although shown as separate in this section, form one project designed to increase the transfer capacity of the 220 kV circuit which connects the three zones and is predominantly used to provide transfer of energy to the Eastern Goldfields.

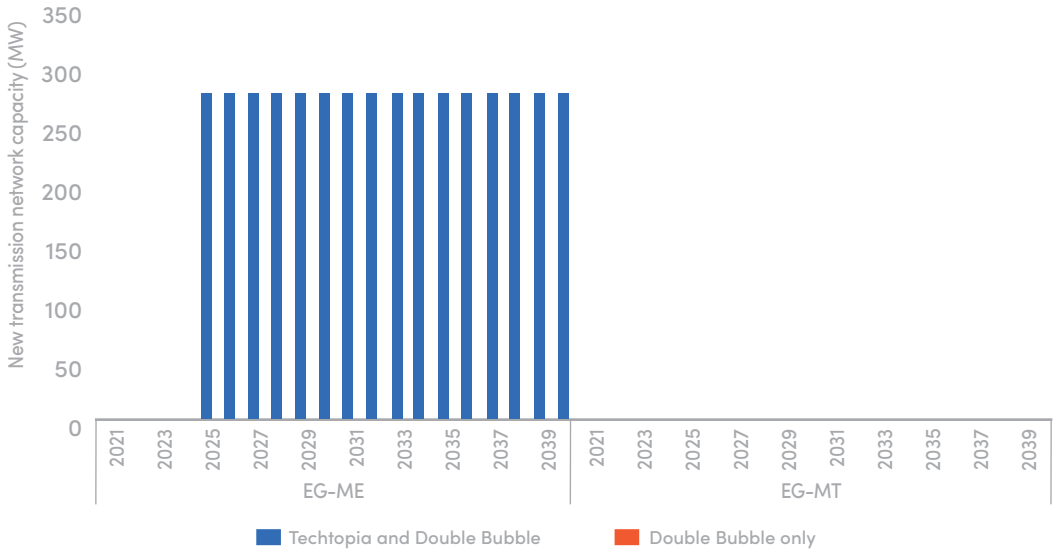


Figure 5.25: Cumulative new transmission network capacity under Techtopia and Double Bubble, Eastern Goldfields zone

Table 5.10 provides a summary of the augmentation requirements.

Table 5.10: Summary of Eastern Goldfields potential transmission network augmentations

PROJECT	TRANSMISSION NETWORK AUGMENTATION REQUIREMENTS
Mid East – South West and Mid East – Eastern Goldfields Phase 1	• Install wide area monitoring protection and control system • Install 330/220 kV transformer at Muja • Install 220/132 kV transformer at West Kalgoorlie • Install dynamic reactive capability at Merredin, Narrogin South and Kalgoorlie

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