Energy Transformation Taskforce

Whole of System Plan Appendix C

Modelling Outputs and Commentary

Energy Transformation Implementation Unit

October 2020

An appropriate citation for this paper is: Whole of System Plan Appendix C

Energy Transformation Taskforce

Level 1, 66 St Georges Terrace
Perth WA 6000
Locked Bag 11 Cloisters Square WA 6850

Main Switchboard: 08 6551 4600

www.energy.wa.gov.au

Enquiries about this report should be directed to:

Noel Ryan

Email: Noel.Ryan@energy.wa.gov.au

Modelling Outputs and Commentary

This appendix provides further detail on total system costs, Reserve Capacity Targets, total revenue, and the requirements and market costs for the provision of Essential System Services (ESS) produced as outputs from the modelling for the Whole of System Plan 2020 publication. It is intended to be read in conjunction with Appendices A and B.

Contents

1. Total System Costs

The Whole of System Plan (WOSP) modelling uses the calculation of total system costs to determine the lowest cost supply of network, generation and storage capacity mix to meet the four demand scenarios[1] within the requirements of the power system.

The total system cost is calculated as the net present cost (NPC) over the entire 20-year study period on the annual sum of capital expenditure (capex), operation and maintenance costs (fixed (FOM), variable (VOM) and fuel supply[2]) and Unserved Energy (USE).

The costs shown below represent:

- Undiscounted capex for generation, storage and transmission network augmentations, which is identified in the year it is incurred, not amortised over the life of the project;[3]
- Fuel, FOM and VOM, as they are incurred, for generation and storage; and
- Unserved energy.

This section details the costs in real June 2020 dollars that constitute the total system cost over the study period, based on the capacity mix for each demand scenario discussed in section 4 of the Whole of System Plan 2020.

1.1 Cast Away

Figure 1 shows the total costs expressed in June 2020 dollars on an annual basis for the lowest cost capacity mix described in the Whole Of System Plan 2020 Figure 4.3 Cast Away – cumulative capacity mix 2020 to 2040 and Figure 4.4 Cast Away – generation output by technology 2020 to 2040.

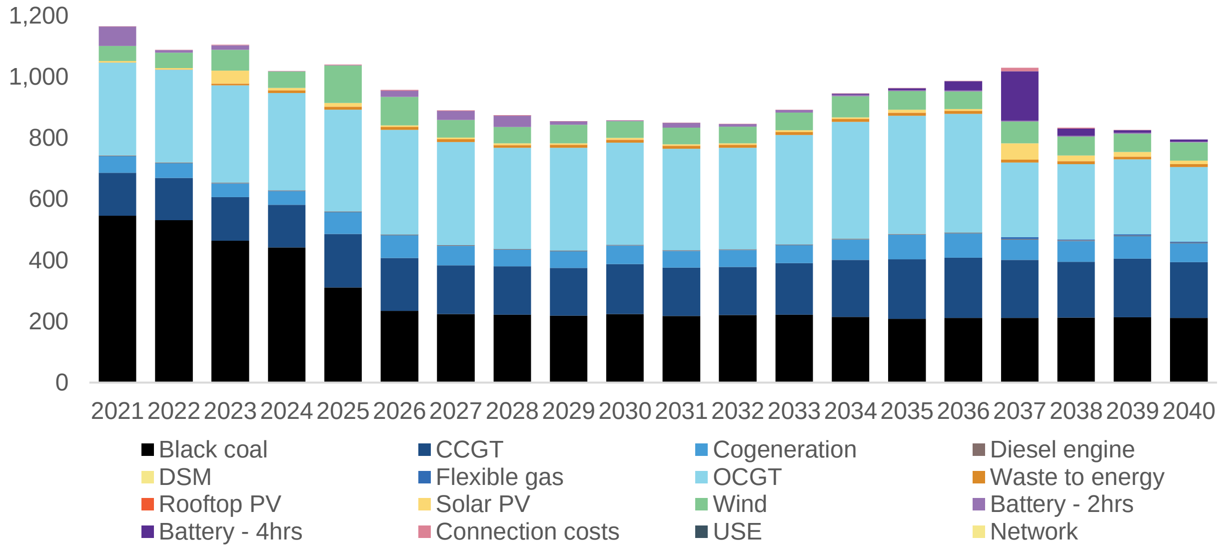

Figure 1 Cast Away total annual costs 2020 to 2040 ($ million real AUD)

[1] Detailed in section 2.3 of the Whole of System Plan 2020 publication.

[2] Fuel supply is the total of fuel cost and transport charge.

[3] While capex is amortised in the WOSP modelling, it is presented here as being incurred in the year it is expensed.

There is little new generation required to meet the expected operational demand in Cast Away so there is not much in the way of capex and as such the annual costs in Figure 1 fluctuate over time as a result of:

- increasing gas prices (based on the forecast GSOO base case prices);
- the different output of generators;
- the years' demand adjusted for rooftop PV generation and behind the meter battery storage and behind the meter-consumption;[4] and
- capex incurred by new entrant facilities, predominantly storage.

Fuel costs make up the largest portion of the costs in Cast Away as can be seen in Figure 2

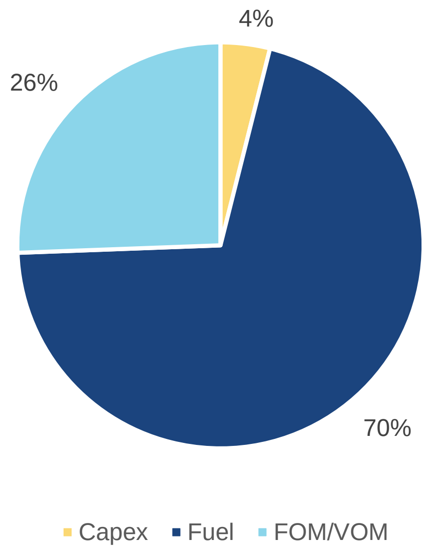

Figure 2 Cast Away total cost breakdown over 20 years

There is very little new storage or generation built in this demand scenario, so the effect of any new capital expenditure on increasing total system costs is minor, approximately 4% of total costs.

1.2 Groundhog Day

While the end-user demand is increasing over the study period by up to 50%, the operational demand in Groundhog Day remains flat, due to the high uptake of rooftop PV and behind the meter storage. Existing generation is sufficient to meet most of this demand, so a large portion of the costs are fuel related, with an upwards trend in costs due to the assumed increase in gas price[5] in the second half of the study period. With the end of technical life retirement of 600 MW of OCGT in 2031 and 2036 and the remaining flat operational load, there are additional capex costs for 880 MW of wind and 1,134 MW of 4-hour duration battery storage over the last nine years of the study period as replacement capacity enters the system.

[4] Each year will also be affected by the different weather reference year applied.

[5] GSOO fuel price assumption in Appendix B.

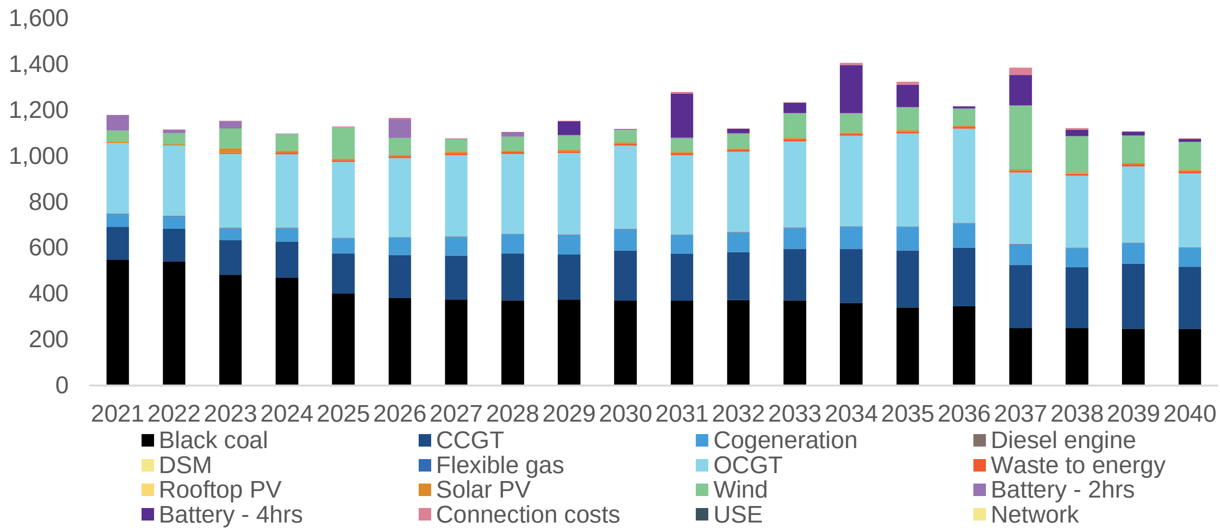

Figure 3 Groundhog Day total annual costs 2020 to 2040 ($ million real AUD)

What is not seen in Figure 3 is the downward pressure the uptake of Distributed Energy Resources (DER) exerts upon overall system costs. Traditionally, if end user demand increased then system costs would be expected to follow suit. However, with greater DER penetration a larger portion of electricity demand is being met by rooftop PV and behind the meter battery systems, meaning that increased end user demand doesn't necessarily translate to greater demand for electricity from the grid. The cost to the system of increased end user demand is therefore lower than in the past, when DER uptake was less prevalent. This effect is most pronounced in Groundhog Day, which has the highest DER uptake of the four scenarios, where annual system costs remain relatively flat despite a 50% increase in end user demand over the study period.

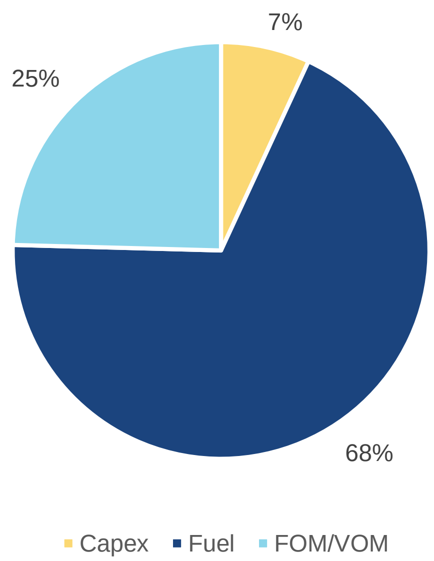

Figure 4 Groundhog Day total cost breakdown over 20 years

The additional capex incurred post end of life retirement of existing plants in Groundhog Day results in the capex proportion rising to 7%, compared to 4% in Cast Away, but the majority of system costs are still made up of fuel for the gas and coal-fired generation facilities.

1.3 Techtopia

Operational demand increases substantially under the Techtopia scenario, resulting in additional transmission network, generation and storage to be built in the SWIS to meet demand. Capex begins to be incurred in 2024 when there is construction of Wind, Solar, Flexible gas generation, 2-hour duration batteries and 4-hour duration batteries as well as the first addition of transmission network capacity between Muja and Eastern Goldfields.

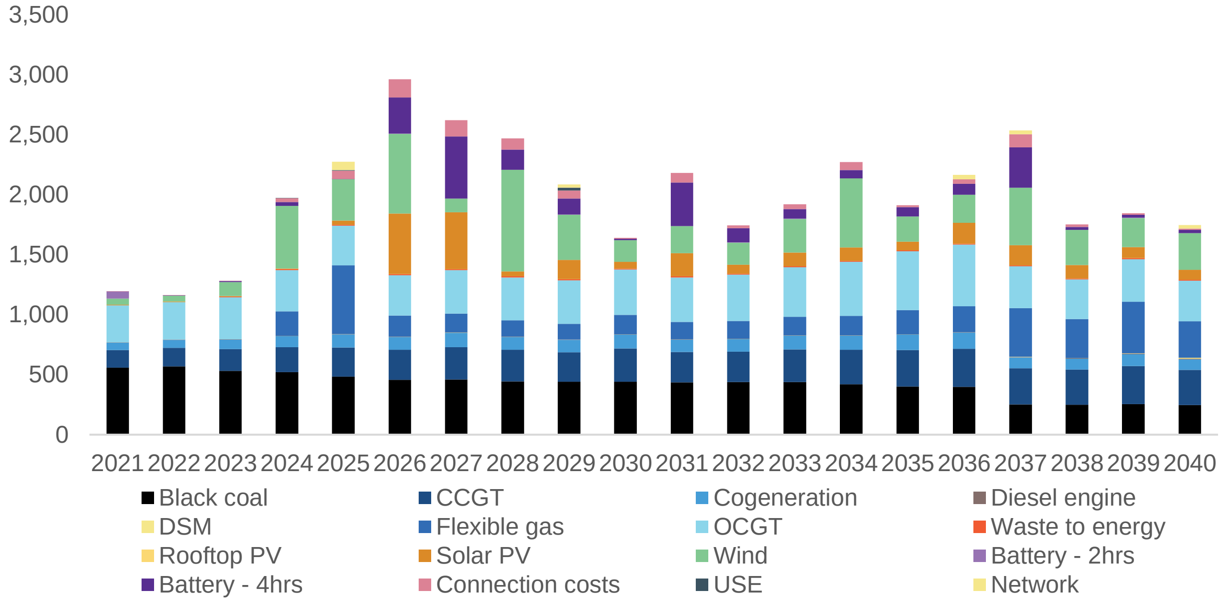

Figure 5 Techtopia total annual costs 2020 to 2040 ($ million real AUD)

Most of the capex is incurred from 2024-2030. This sets the system up with sufficient generation to meet the increasing demand in the second half of the study period. Consequently, costs decrease in the second decade and consist predominantly of fuel costs. Fuel is still the largest individual cost component but begins to account for a smaller portion of overall costs as renewable penetration increases.

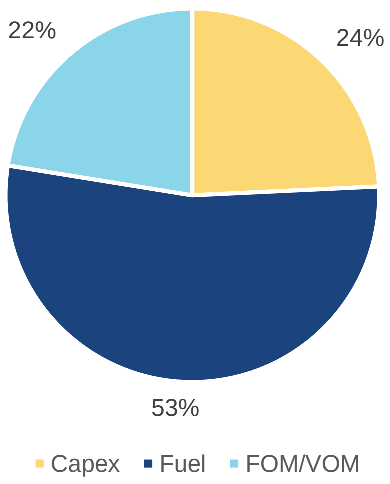

Figure 6 Techtopia total cost breakdown over 20 years

1.4 Double Bubble

Characterised by the largest increase in demand, Double Bubble sees the widest range and variation of new technology and the highest costs.

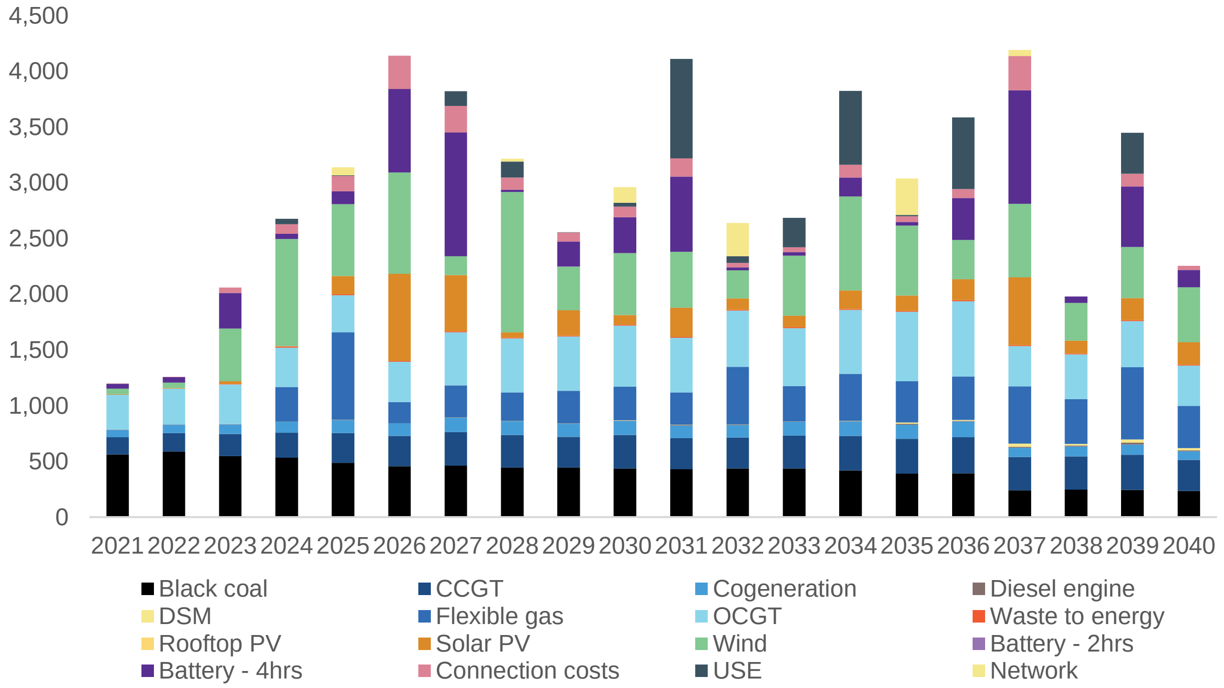

Figure 7 Double Bubble total annual costs 2020 to 2040 ($ million real AUD)

The cost breakdown in Double Bubble has the highest percentage of capex, compared to the other scenarios. While the new entrant renewables don't have a fuel cost, they do have an upfront capital cost which contributes significantly to overall system costs.

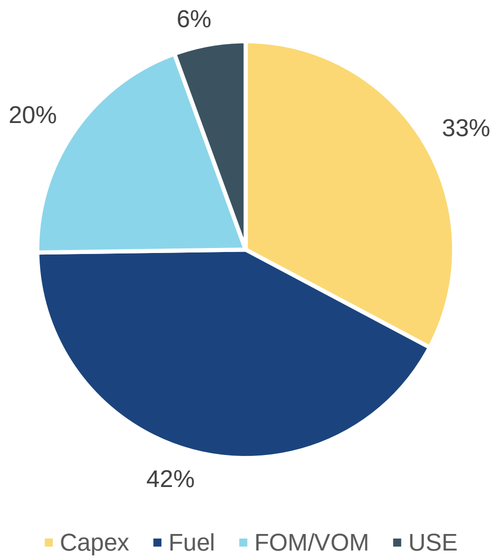

Figure 8 Double Bubble total cost breakdown over 20 years

A notable difference between Double Bubble and the other scenarios is that there's significant unserved energy (USE) in the lowest cost mix. This USE only occurs in the Eastern Goldfields transmission network zone and is a result of the power transfer limits to the Eastern Goldfields region and build limits on the amount of local generation that can be connected. The Eastern Goldfields transmission network augmentation only increases the transfer limit to 500 MW, after which a new transmission line would need to be built. The cost of this new line is large enough that it costs the system less to allow for relatively high quantities of USE, rather than incurring the cost of the new line. This does not necessarily reflect what would actually be allowed to happen in such a high demand scenario: it is simply a consequence of the resource planning model being designed to solve for the lowest cost solution.

Annual system costs for the 4 demand scenarios, comprising: total capital expenditure (generation, storage and network), fuel supply costs, fixed and variable operating and maintenance costs, the cost of unserved energy and the cost of ESS are reported in Appendix B.

2. Reserve Capacity Target

AEMO sets the Reserve Capacity Target[6] (RCT) annually in the Wholesale Electricity Market (WEM). The RCT is AEMO's estimate of the total amount of generation and Demand Side Management (DSM) capacity required in the SWIS. The calculation of the RCT considers the annual 10% probability of exceedance (POE) forecast of electricity demand, a reserve margin, Frequency Regulation requirements and an intermittent load allowance.

The RCT sets the number of Capacity Credits to be procured in each capacity year and is an input into the Reserve Capacity Price calculation which is based on administered pricing formulas. The parameters in these formulas have been modified as part of recent reforms.

As part of the WOSP, an estimate of the RCT has been developed based on the 10% POE peak demand forecast provided in each of the four scenarios. A Frequency Regulation requirement and intermittent load allowance has been assumed for each scenario. The Frequency Regulation requirement is based on the outcomes of the intermittent generation build in the resource planning model and the assumption around the uptake of DER for that scenario.

Figure 9 charts the RCT outcomes for the four WOSP demand scenarios on an annual basis.

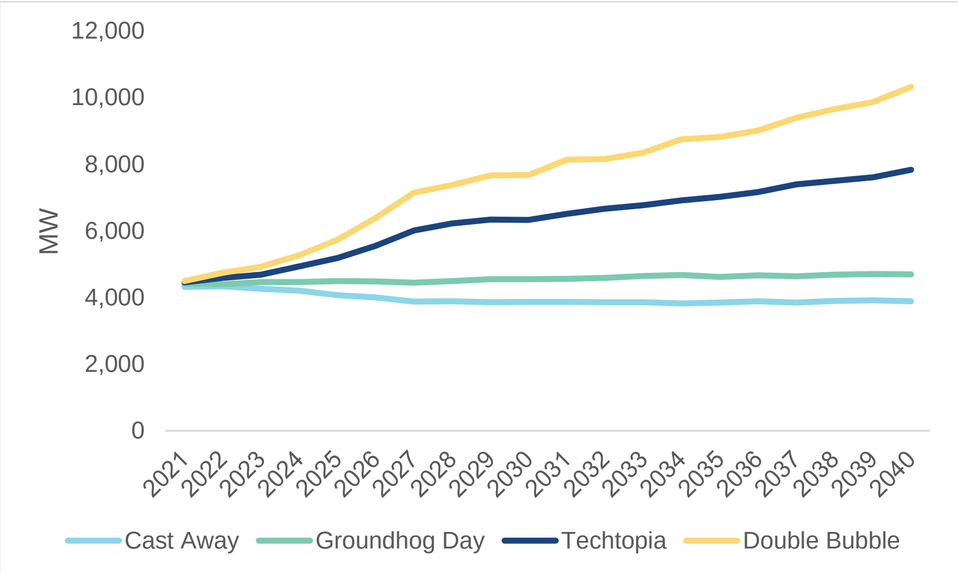

Figure 9 Reserve Capacity Targets 2020 - 2040

The mix of facilities chosen by the model to meet these targets is discussed in Chapter 4 of the Whole of System Plan 2020 (SWIS wide findings).

---

[6] https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism.

3. Total revenue

Figure 10, Figure 11, Figure 12 and Figure 13 illustrate the proportion of revenue estimated in the Wholesale Electricity Market (WEM) for each of the four revenue streams available to generation and storage facilities under the new WEM arrangements.

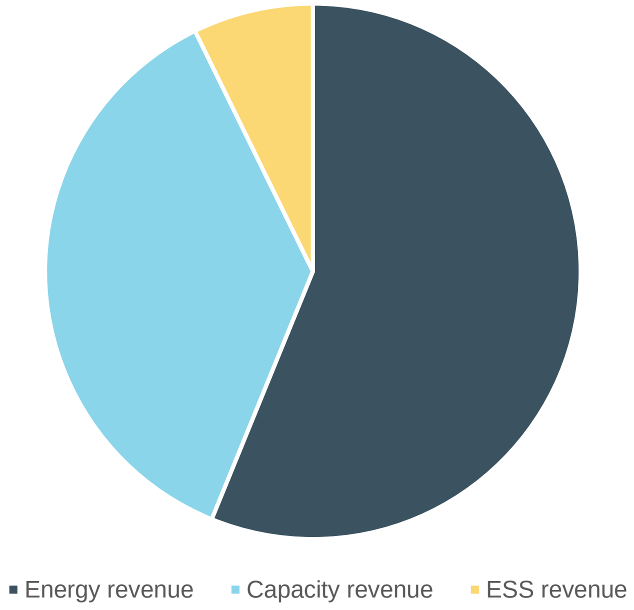

Figure 10 Cast Away WEM Revenue over 20 years

In the Cast Away and Groundhog Day scenarios, where rooftop PV uptake is higher and operational demand flat or decreasing, the ESS and Capacity revenues are proportionally relatively high due to the lower revenues available from the energy market and increasing ESS requirements.

ESS market costs are discussed in more detail for the different services, and technologies that provide them, in the following section.

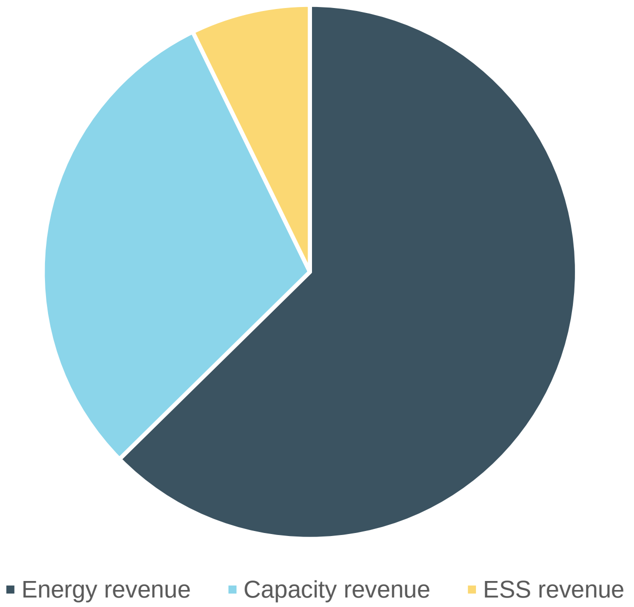

Figure 11 Groundhog Day WEM Revenue over 20 years

Under Techtopia and Double Bubble, where operational demand is higher, energy revenue makes up a higher proportion of the overall estimated revenue.

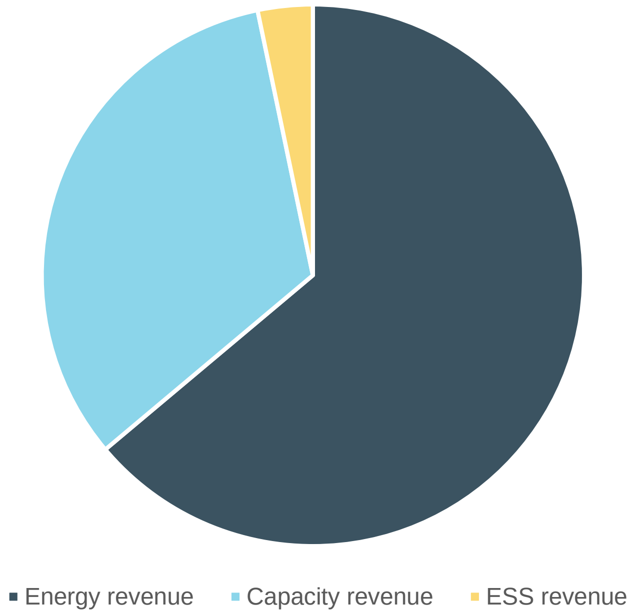

Figure 12 Techtopia WEM Revenue over 20 years

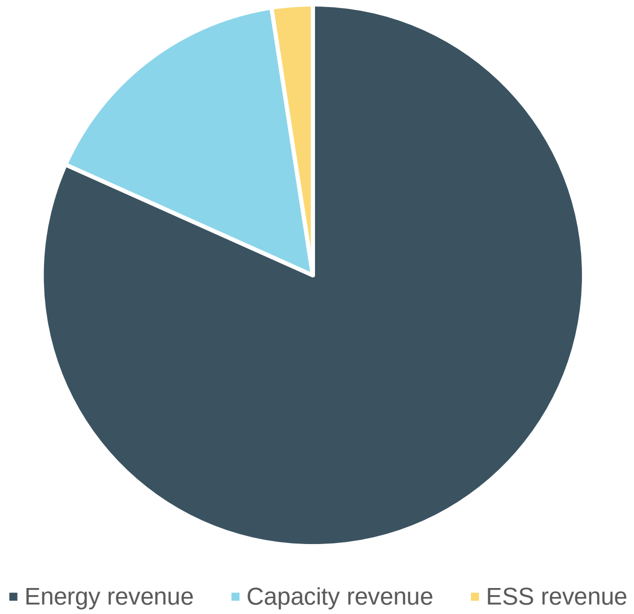

Figure 13 Double Bubble WEM Revenue over 20 years

4. Essential System Services

4.1 ESS requirements

The WOSP considers how ESS requirements may impact total system costs, generation dispatch and the required generation capacity mix over the study period. The following ESS have been factored into the WOSP market models:

- Frequency Regulation Raise (currently referred to as Load Following Ancillary Services (LFAS) up)
- Frequency Regulation Lower (currently referred to as LFAS down)
- Contingency Reserve Raise (currently referred to as spinning reserve)
- Contingency Reserve Lower (currently referred to as load rejection reserve).

4.1.1 Frequency Regulation requirement

The Frequency Regulation requirement in each of the scenarios is influenced by the rooftop PV uptake for that scenario and the prevailing generation mix outcomes.

The resource planning model considers the effect that new entrant wind and solar capacity has on the Frequency Regulation requirement as well as the cost to provide this additional service when optimising what generation technology to build and when to build it.

The growth in the Frequency Regulation requirement for each scenario is calculated based on the approach described in Table 1

Variable	Impact on frequency regulation requirement
Rooftop PV capacity	Each MW of additional rooftop PV capacity is assumed to increase the Frequency Regulation requirement by 0.04 MW during the period between 05:30 and 19:30.
Installed wind capacity	Each MW of additional wind capacity installed in the North Country, Mid West and Neerabup nodes is assumed to increase the Frequency Regulation requirement by 0.03 MW for all periods. For all other nodes, each MW of additional capacity installed increases the Frequency Regulation requirement by 0.018 MW for all periods.
Installed large-scale solar capacity	Each MW of additional solar capacity installed at any node increases the frequency regulation requirement by 0.05 during the period between 05:30 and 19:30.

Table 1 Variables that impact the Frequency Regulation requirement in each scenario

Figure 14 and Figure 15 summarise the Frequency Regulation requirements for the day-time and night-time period in each WOSP scenario on an annual basis based on the outputs of the resource planning model.

The daytime Frequency Regulation requirement is expected to increase in each of the WOSP scenarios. The increase in the requirement is primarily driven by the impact of additional rooftop PV capacity in the SWIS and the impact of the fluctuating output on daytime operational load variability. Variability also occurs in the Double Bubble and Techtopia scenarios due to significant growth in large-scale wind and solar generation capacity, the increased variability occurs on the supply side. Differences between the forecast and actual output of wind and solar facilities cause increased supply-side variability, which can disturb the supply-demand balance from period to period.[7] This increases the requirement to manage the natural variances in the power system's supply-demand balance from period to period.

The Frequency Regulation requirement during the night is forecast to remain flat in the Cast Away and Groundhog Day scenarios. In the Double Bubble and Techtopia scenarios, material amounts of wind capacity are added to the system, which increases supply-side variability during the night. This drives the need for higher Frequency Regulation requirements during the night-time periods.

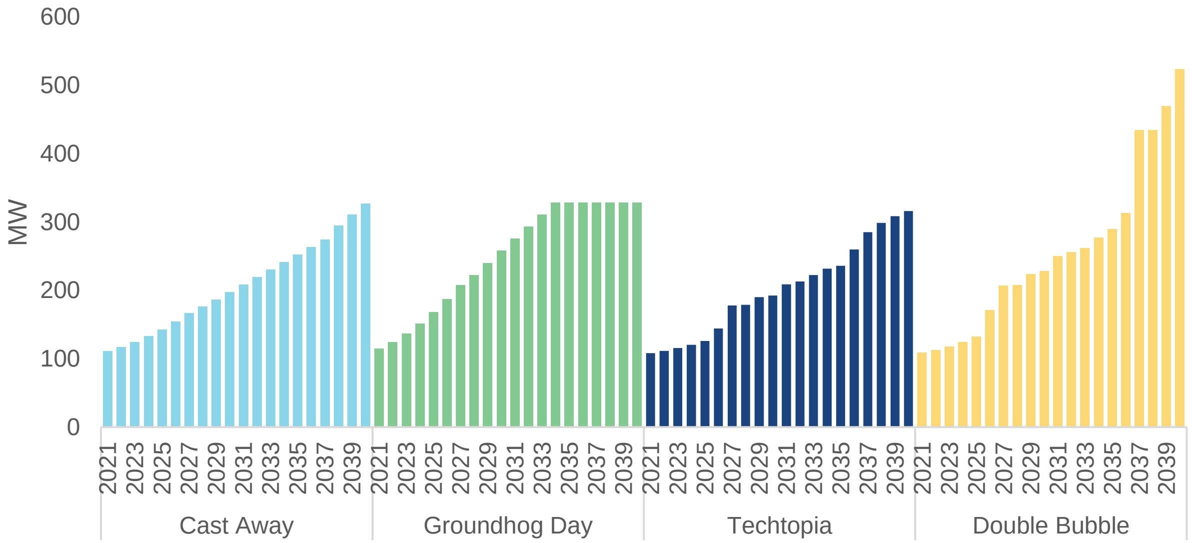

Figure 14 Frequency Regulation requirement for period from 5:30am to 7:30pm

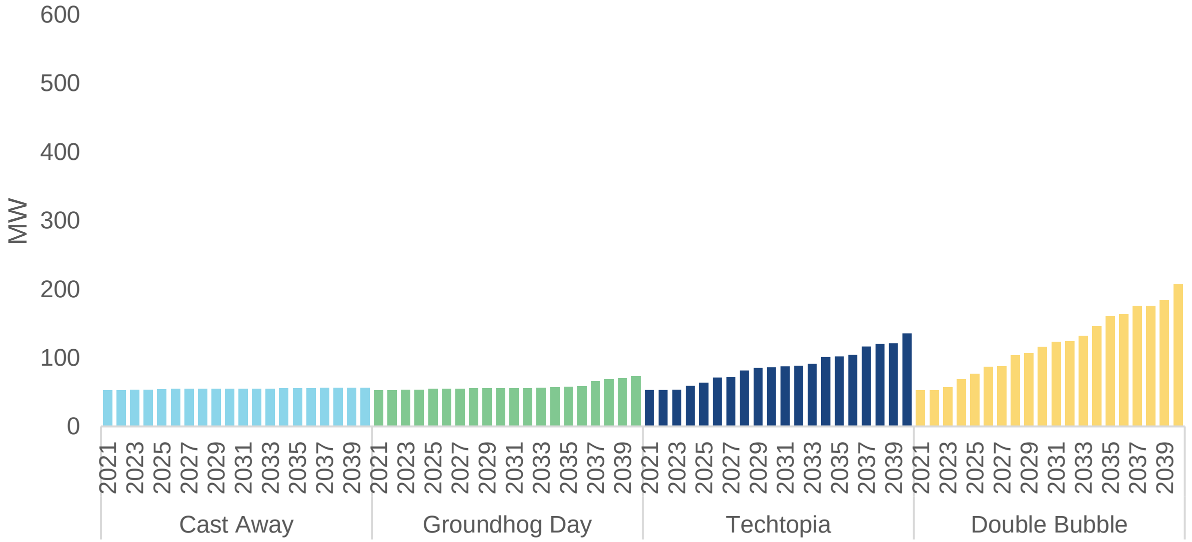

Figure 15 Frequency Regulation requirement for period from 7:30pm to 5:30am

[7] Although the model has perfect foresight of demand, the Frequency Regulation requirement is calculated on the basis of the quantity required to account for the variability between forecasts and actual output in a real-world system without perfect foresight of demand

4.1.2 Contingency Reserve Raise requirement

The resource planning model implements dispatch constraints to ensure that generators are available to provide primary frequency response (PFR) in the event of a sudden loss of supply. Generators capable of providing PFR are dispatched at an operating level below their available capacity to ensure there is sufficient headroom to increase supply and system frequency in response to a sudden loss of supply.

The PFR requirement on the power system is modelled as a function of the maximum contingency size, the system load and system interruptible loads[8] and applied to each modelling interval. The Contingency Reserve Raise service is then procured to meet the system PFR requirement.

The WOSP model also includes consideration of an approximated system inertia value and a PFR performance factor for each technology type.[9] A bare minimum PFR requirement has also been set based on 70% of the maximum contingency size to assist with secondary frequency control and bringing the system frequency back to 50Hz.

Contingency Reserve Raise requirement

Figure 16 summarises the average annual Contingency Reserve Raise requirement for each scenario. It provides the PFR requirement that would be required to be met, on average across the year, in the Contingency Reserve Raise market under each scenario. A portion of this requirement is provided by System Interruptible Load (SIL).

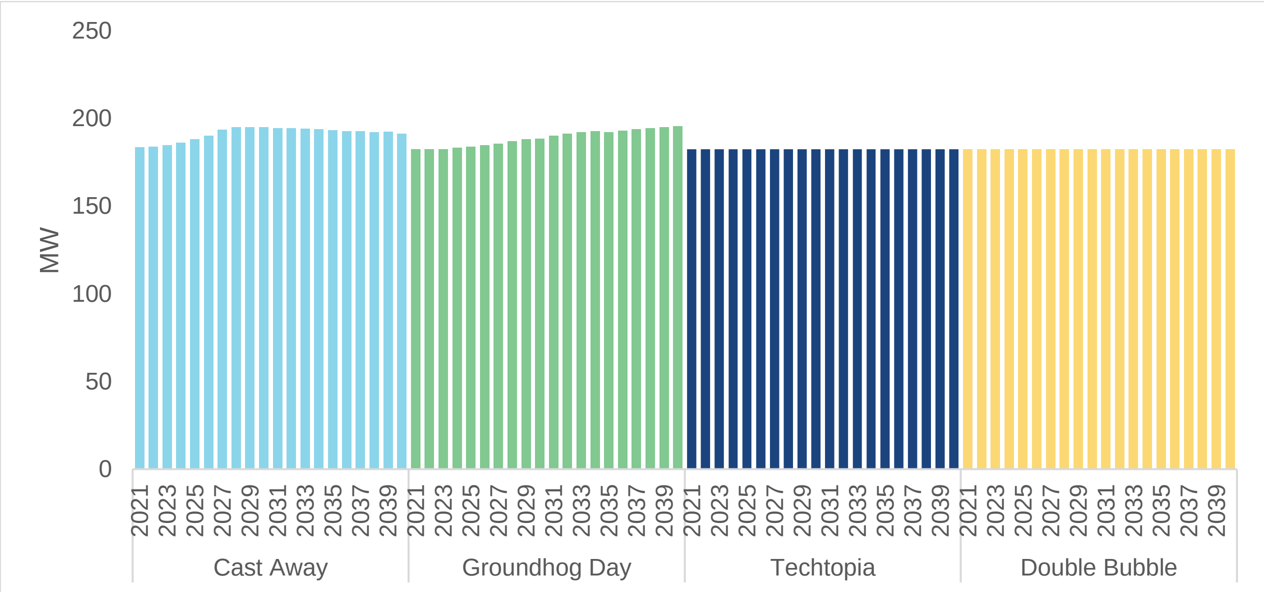

Figure 16 Annual average Contingency Reserve Raise requirement

[8] There is currently 63 MW of system interruptible load (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 that less SIL would be required 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.

[9] The performance factor provides a notional value on 'fast' PFR verses 'standard' PFR in meeting the requirement. Different values of kPFR are applied to different technologies. For example, a battery providing "fast" frequency response will be provided a kPFR of 1, whereas a thermal generator providing a "standard" response may receive a kPFR of 1.5. The inverse of the kPFR is then used as a coefficient in the constraint equation for different technology types.

The annual average PFR required in the Contingency Reserve Raise market is forecast to remain relatively flat in each of the WOSP scenarios, as it is largely dependent on the size of the maximum contingency on the system, and this maximum contingency size does not materially increase over the modelling period.

In the scenarios with lower system demand, Cast Away and Groundhog Day, there was a slight increase in the PFR requirement as the PFR available from system load decreased over the study period.

Conversely, in scenarios with significant demand growth, Techtopia and Double Bubble, the amount of PFR available from system load increased, decreasing the need for PFR from the Contingency Reserve Raise market. In these scenarios, over time the PFR requirement equated to 70% of the largest contingency, the minimum requirement allowed in the model.

4.1.3 Contingency Reserve Lower requirement

The Contingency Reserve Lower requirement is set by the largest load contingency minus a load relief factor.[10] The resource planning model implements a dispatch constraint on generation facilities capable of providing the Contingency Reserve Lower service, ensuring that the minimum requirement is procured for each dispatch interval. Operational constraints are imposed in the modelling to ensure a facility is dispatched sufficiently above its minimum load.

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 assumed to be independent of the generation and network investment build.

Figure 17 summarises the Contingency Reserve Lower requirement that would be required to be met, on average across the year, under each scenario.

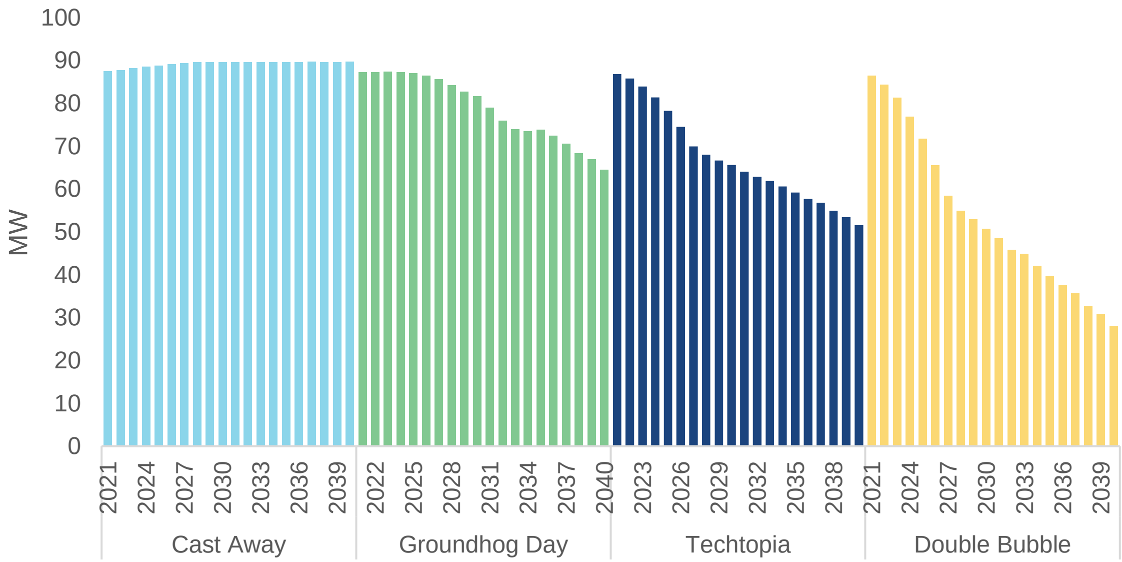

Figure 17 Annual average Contingency Reserve Lower requirement

The annual average Contingency Reserve Lower requirement is calculated similarly to the current practice in the WEM today. That is, the requirement is set by the largest load contingency and then allows for a portion of load relief that is available from power system load. As such, the

[10] 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'

Contingency Reserve Lower 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.

Over time, this requirement is forecast to decrease in scenarios with increasing power system 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 the lowest demand scenario, the load relief available from the power system is forecast to decrease to the point where the Contingency Reserve Lower requirement increases to the maximum of 90 MW.

4.2 ESS market costs

The same four ESS markets that are modelled in the resource planning model are included in the dispatch model. The dispatch model co-optimises the dispatch of energy and ESS markets, and calculates 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 takes the ESS requirements derived from the resource planning model for use as inputs. These values set a demand for each service to be met by market participants that are assumed to be able to participate.

For each market participant eligible to participate, an offer curve is produced for each facility in the four markets. The offer curve for each facility is based on a combination of short run marginal cost (SRMC) and opportunity costs, consistent with the set of data inputs and assumptions used for that facility in the resource planning model.[11] Offer profiles for each facility in each market are constructed based on 'trapezium offer profiles', which ensure that the sum of a facility's dispatch totals in the ESS and energy markets does not exceed its total capacity, as used in the National Electricity Market (NEM).[12]

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

Figure 18, Figure 19, Figure 20 and Figure 21 show the total ESS costs, which is also the revenue pool available to providers of these services, across the four WOSP scenarios.

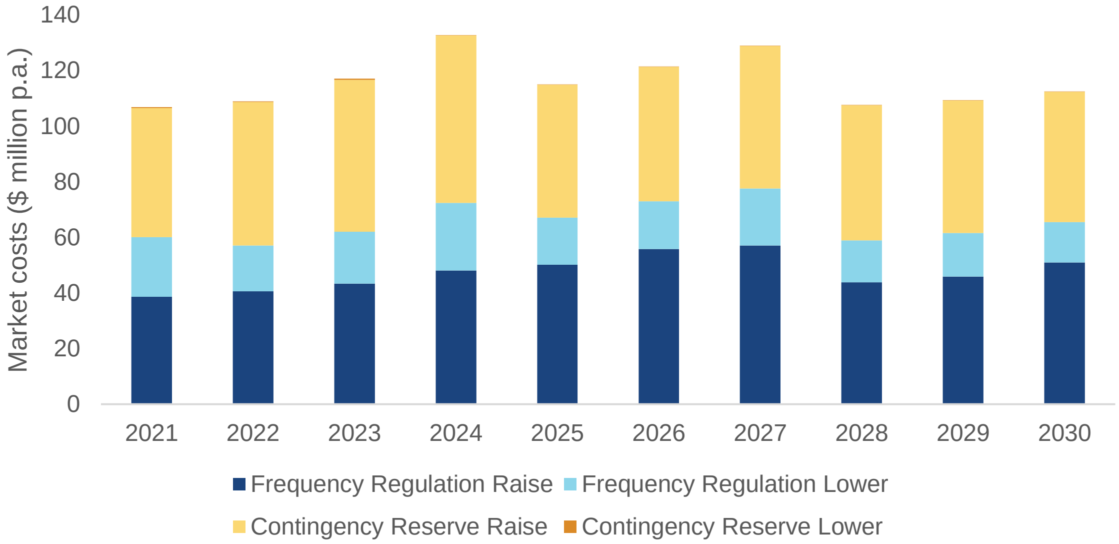

Figure 18 Total ESS market costs Cast Away

[11] Opportunity costs are being considered in the dispatch modelling. See section 3.2.2 of the Energy Transformation Taskforce – 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

[12] Guide to Ancillary Services in the National Electricity Market - https://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf

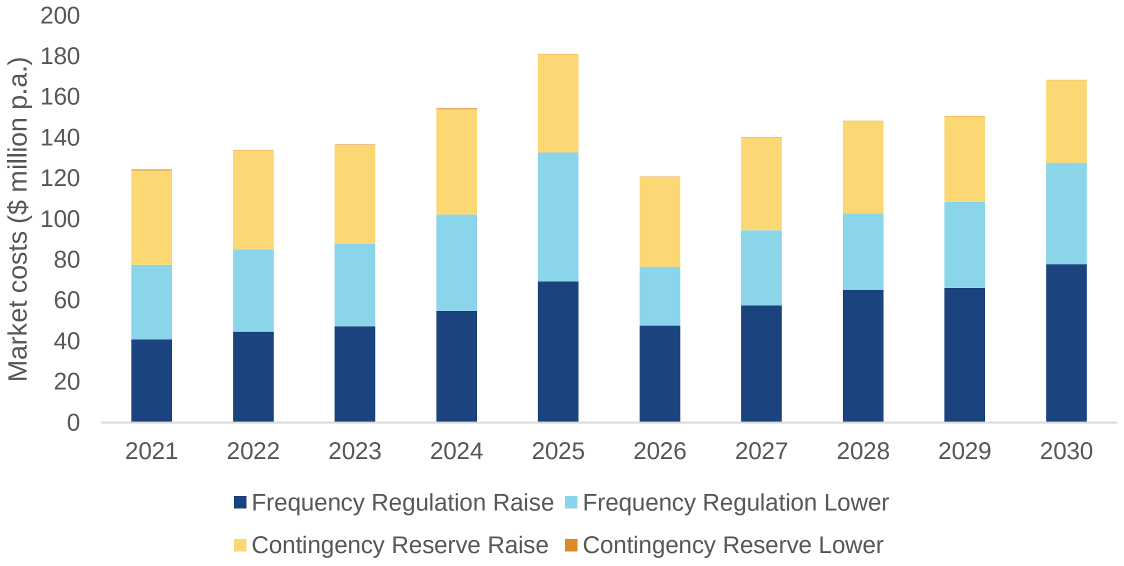

Figure 19 Total ESS market costs Groundhog Day

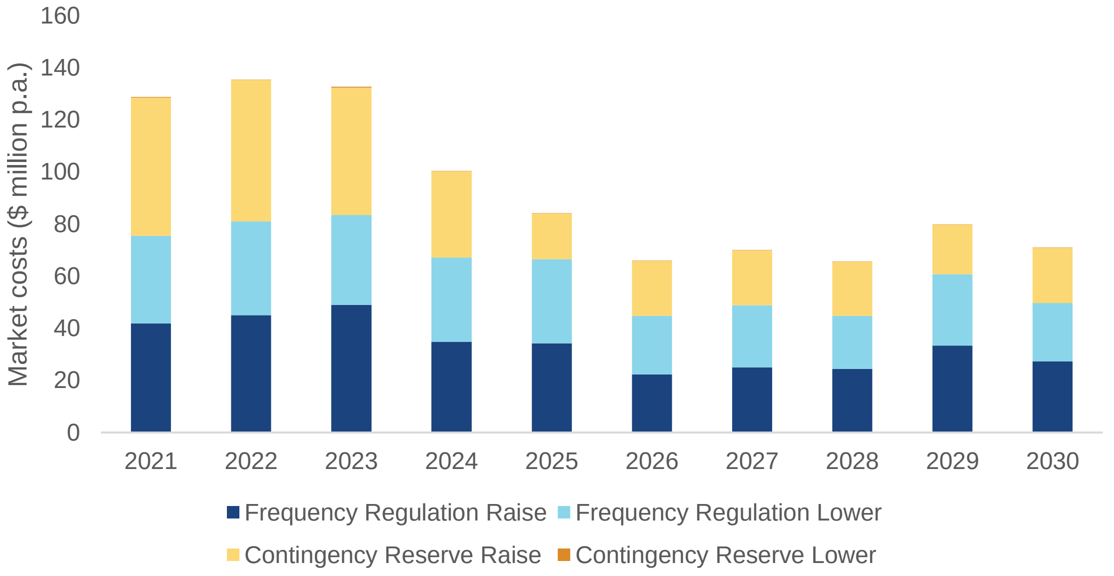

Figure 20 Total ESS market costs Techtopia

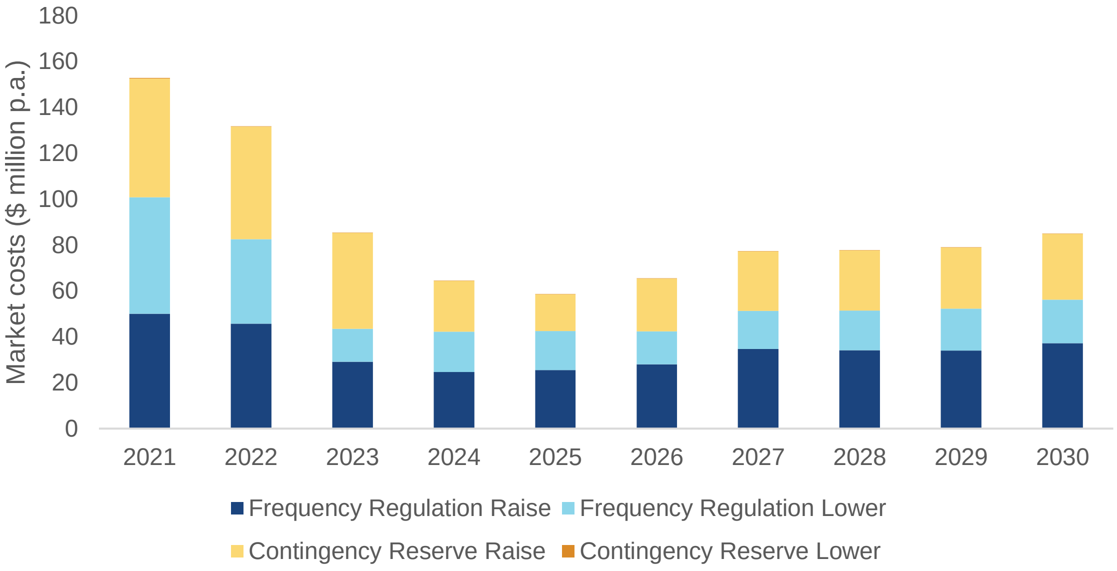

Figure 21 Total ESS market costs Double Bubble

4.2.1 Contingency Reserve Raise market costs

The outcomes of the Contingency Reserve Raise market are driven by a complex mix of interactions between energy market outcomes and the co-optimisation of energy and ESS. The Contingency Reserve Raise service requires a generator to withhold its capacity from the energy market to provide the service. A generator withholding capacity from the energy market foregoes potential revenue from energy sales. The revenue from the Contingency Reserve Raise market therefore needs to be enough to warrant this withholding of capacity.

To account for this interaction, offer curves are derived for participating facilities based on the calculation of each facility's SRMC and forecast energy prices. These are derived on a time of day basis for each year.

Figure 22 summarises the Contingency Reserve Raise market costs for the period up to 2030 in each of the WOSP scenarios.

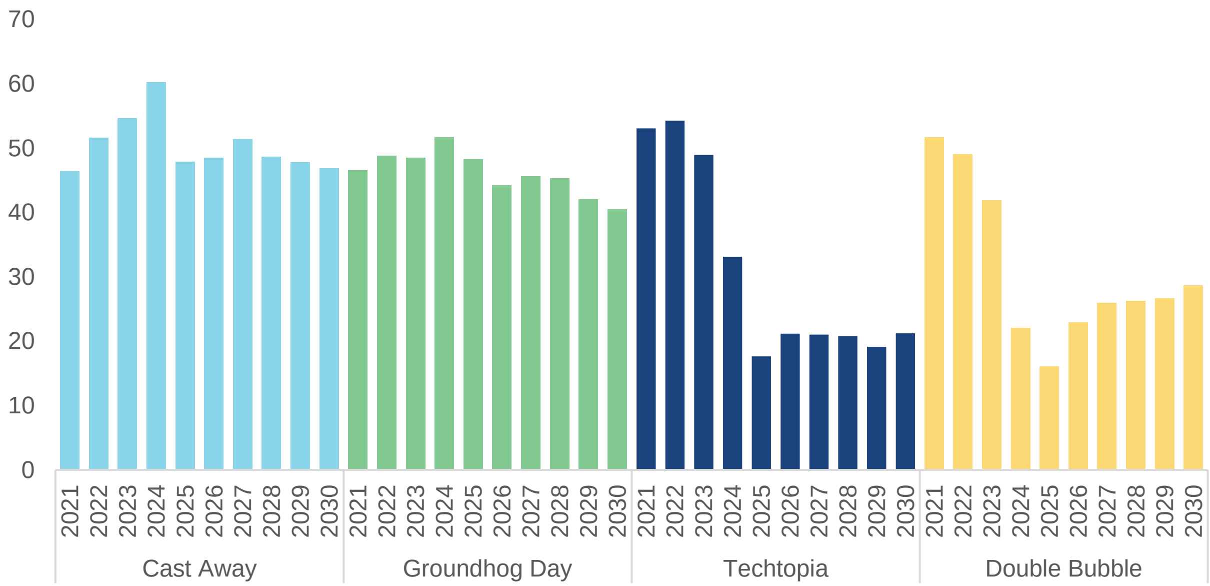

Figure 22 Annual Contingency Reserve Raise market costs ($ million real AUD)

The total market cost for the Contingency Reserve Raise service is expected to decrease around the mid-2020s in the scenarios where coal-fired generation withdraws from the market (Cast Away and Groundhog Day). The marginal provider of the Contingency Reserve Raise service during this period is typically a gas facility with a higher SRMC than the average energy price, so the facility bids into the market at the difference between its SRMC and the energy price to recover its running costs. As energy prices increase following the withdrawal of coal-fired generation, the difference between the marginal provider's SRMC and the energy price decreases, leading them to bid into the Contingency Reserve Raise market at a lower price. Increased participation of battery storage also puts downwards pressure on prices from the late 2020s.

Figure 23 shows the average quantity of Contingency Reserve Raise provided by technology type for the Cast Away and Groundhog Day scenarios.

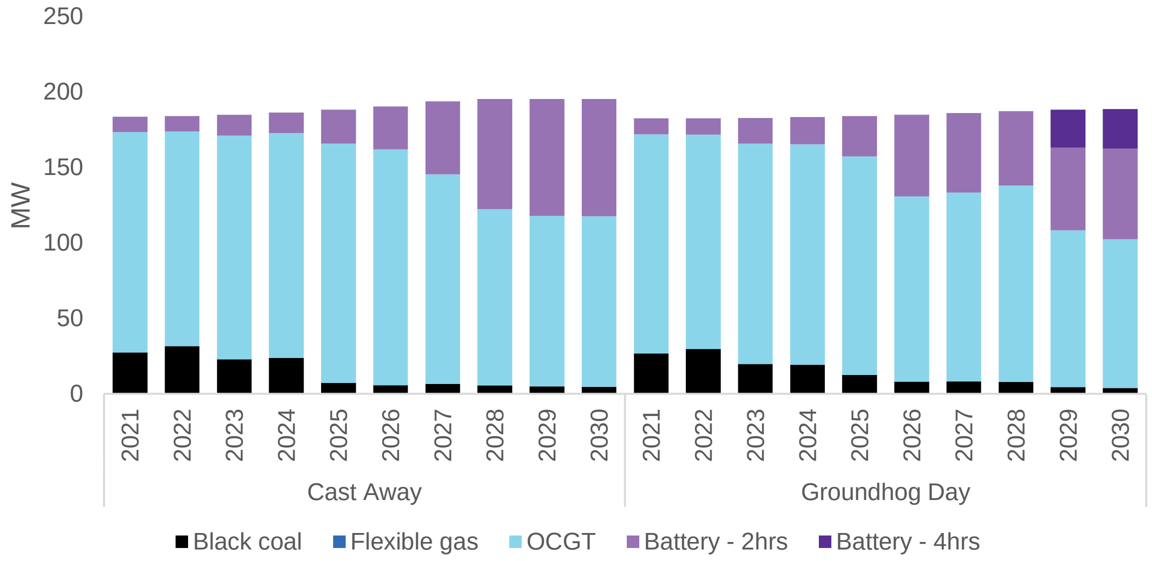

Figure 23 Average annual quantity of Contingency Reserve Raise provided by technology type (Cast Away/Groundhog Day)

In the Double Bubble and Techtopia scenarios, the reduction in the total cost of the Contingency Reserve Raise market is primarily driven by increased participation from new entrants leading to greater competition for the service. Whilst the annual average PFR requirement across all WOSP scenarios is quite similar, the higher demand scenarios have significantly more new entrant supply capacity as part of the least cost mix. Many more gas and battery storage facilities enter the market during the mid-2020's to cater for increased demand while the average PFR requirement remains relatively flat. These facilities are able to provide the service cheaper than existing gas facilities and place downward pressure on the overall cost of the service.

Figure 24 provides a summary of the average quantity of Contingency Reserve Raise provided by technology type for Double Bubble and Techtopia.

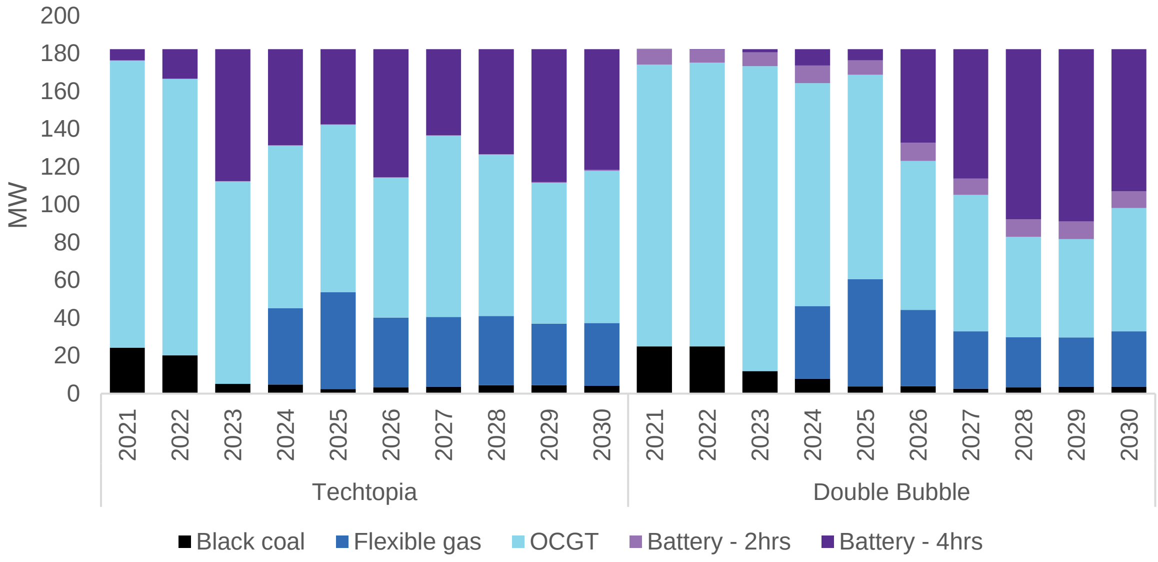

Figure 24 Average annual quantity of Contingency Reserve Raise provided by technology type (Double Bubble/Techtopia)

4.2.2 Contingency Reserve Lower market costs

The annual market value for the Contingency Reserve Lower service was observed to be consistently lower than $1 million in each year across the study period for all scenarios. The low market costs are driven by a comparatively low requirement compared to the large number of participants that are able to provide this service. In the Double Bubble scenario, the average annual requirement reduces by 40% by the end of the study period.

An important input assumption is that new entrant wind and solar facilities can participate in the Contingency Reserve Lower market, which is a departure from current market arrangements. Currently, this service is supplied from a select number of thermal generation facilities.

The new market arrangement facilitates additional market competition. With additional competition, it is forecast that the costs associated with this service will decrease and trend towards the marginal cost of keeping the lower cost providers on and enabled. Wind and solar facilities are assumed to offer into this market at the marginal cost of keeping them on and enabled (subject to their own resource availability) which places downwards pressure on overall market costs right from the beginning of the study period.

4.2.3 Frequency Regulation market costs

Synergy gas facilities as well as independent power producers that currently participate in the Frequency Regulation market are assumed to remain active in the future market. New entrant large-scale batteries also participate in the future market and are modelled to shadow bid the lowest-cost frequency regulation provider. New entrant flexible gas facilities are also assumed to participate in the market and are modelled with a lower SRMC than existing providers that currently participate in the market.

Figure 25 provides a summary of the total Frequency Regulation costs (both Raise and Lower) modelled across each WOSP scenario.

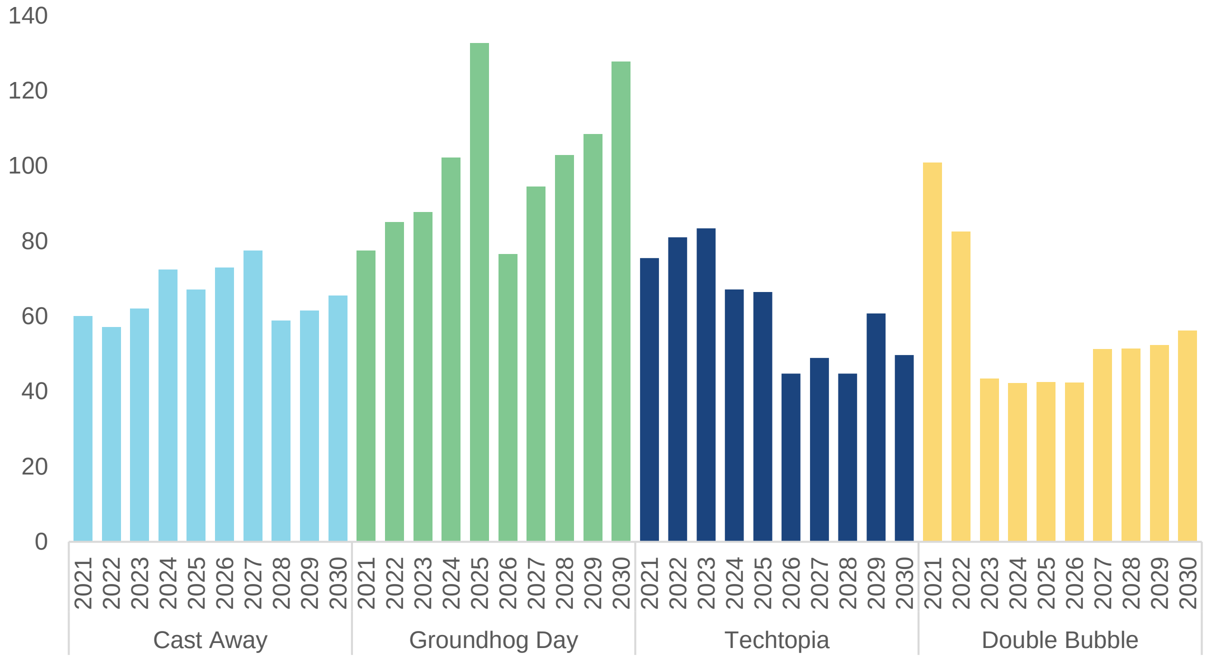

Figure 25 Annual Frequency Regulation Raise/Lower market costs ($ million real AUD)

In Cast Away and Groundhog Day, the total costs associated with these services is forecast to increase until the mid to late 2020s due to large growth in the day-time Frequency Regulation requirement. The day-time requirement is forecast to double by the late 2020s to around 200 MW, primarily due to the high uptake of rooftop PV in both scenarios. Gas facilities account for a substantial portion of the Frequency Regulation providers, and consequently the costs associated with the Frequency Regulation markets are also driven in part by gas price variations. Both scenarios also show a step-change decrease in market costs due to new entrant battery capacity being installed by the mid to late 2020s.

In Techtopia and Double Bubble, Frequency Regulation market costs are forecast to decrease by the mid 2020s as a result of new entrant flexible gas capacity with a lower SRMC than existing providers. These new entrant facilities displace existing facilities as the marginal facility setting the clearing price in the Frequency Regulation markets. From the mid 2020s, a substantial increase in SWIS wind and solar capacity drives growth in the Frequency Regulation requirement until the end of the study. Combined with increasing gas prices, this places upwards pressure on market costs.