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System Strength Study for Victoria: Modelling Report

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System Strength RIT-T
April 2025

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EXECUTIVE SUMMARY

The Australian Energy Market Operator (AEMO) Victorian Planning (AVP) commissioned Jacobs to conduct comprehensive market modelling in support of the System Strength Regulatory Investment Test for Transmission (RIT-T). This study's primary objective was to evaluate four portfolios of options for maintaining adequate system strength in Victoria's power grid as the energy landscape undergoes significant transformation, characterized by the withdrawal of synchronous coal-fired generation and the increasing penetration of inverter-based resources (IBR).

This report complements the Project Assessment Draft Report (PADR) published by AVP. It describes the assumptions, data sources, methodologies and outcomes of the market modelling underpinning the net present value calculation (NPV) developed in the PADR.

The study's assumptions were primarily based on the 2024 Integrated System Plan (ISP) ***Step Change*** scenario, providing a consistent and forward-looking framework for the analysis. All dollar values are presented in real 2023/24 terms.

Jacobs utilized PLEXOS, market modelling software, to simulate four distinct portfolios of options and a sensitivity case. A key aspect of the modelling approach was the development of detailed system strength constraints at key system strength nodes on the Victorian grid, encompassing both Minimum Fault Level (MFL) and Available Fault Level (AFL) requirements. These constraints were formulated iteratively through a collaborative effort between Jacobs and AVP, ensuring a robust representation of Victoria's system strength needs.

AVP developed four portfolios of options from the Reference Case, which is based on the energy-only dispatch of the AEMO's optimised Integrated System Plan (ISP) 2024 ***Step Change*** scenario. The portfolios were designed to include both network and non-network solutions to meet the system strength requirement in Victoria. They can be summarised as follows:

- **Option 1:** Existing generation plus committed and anticipated grid-forming (GFM) battery energy storage systems (BESS) and new synchronous condensers.
- **Option 2:** The same technology types as option portfolio 1 plus upgrading additional grid-following (GFL) BESS to be GFM.
- **Option 3:** The same technology types as option portfolio 2 plus a GFM BESS from the IBR forecasts.
- **Option 4:** The same technology types as option portfolio 3 with the exception of accelerated procurement of some new synchronous condensers.

The Base Case was defined as the 'do-nothing' counterfactual according to the Australian Energy Regulator's (AER) guidelines with the net market benefits of the portfolios of options evaluated relative to it. It is the Reference Case with the addition of system strength constraints – re-dispatching existing and committed generators to meet Victoria's system strength requirements.

Table 1 shows the gross market benefits for each of the four portfolios of options using a 7% commercial discount rate. Option 4 has the highest gross market benefits of $4.201 billion, which is $6 million more than Option 3, even though the latter is the preferred option according to the PADR due to its lower cost and therefore higher net market benefit. Key observations of the market benefits are as follows:

- All four options have positive gross market benefits, with the highest value benefit classes being avoided fuel costs and avoided emission costs.
- The four options share the same avoided involuntary load curtailment[1] (ILC) benefit because no ILC was recorded under the options, whereas the Base Case had ILC due to shortfalls in system strength provision. This occurs because the Base Case has no new solutions invested to meet the system strength requirement which is magnified under the exit of Victoria's coal-fired generation fleet.
- Elevated levels of both coal and natural gas are consumed under the Base Case relative to the option portfolios to meet the system strength requirement. This reflects the relative inefficiency of the incumbent generation fleet in meeting Victoria's system strength needs into the future, especially as Latrobe Valley plants begin withdrawing from the market.
- The key determinant with respect to gross market benefits is the avoided emissions category as this shows the highest variability from Option 1 to Option 4. Avoided fuel costs range by $13 million, avoided costs for non RIT-T proponents range by $4 million, but avoided emission costs showcase the largest range of $53 million. The difference in emission costs is mainly driven by variations in Latrobe Valley coal dispatch among the option portfolios. In particular, Options 3 and 4, which have the lowest emission outcomes, displace some of the Victorian coal generation in the later years by virtue of a GFM BESS that is absent in Options 1 and 2.
- Options 3 and 4 have the lowest installed number of synchronous condensers and the highest installed GFM BESS among the options, suggesting that more GFM BESS and less synchronous condensers leads to the optimal mix of system strength supply. This occurs because synchronous condensers have a VO&M cost and load demand cost that is in aggregate higher than that of GFM BESS. However, this conclusion can only be pushed so far as GFM BESS do not provide fault level contributions to the MFL, meaning that sufficient synchronous condensers must be part of the optimal mix for the adequate provision of MFL services.

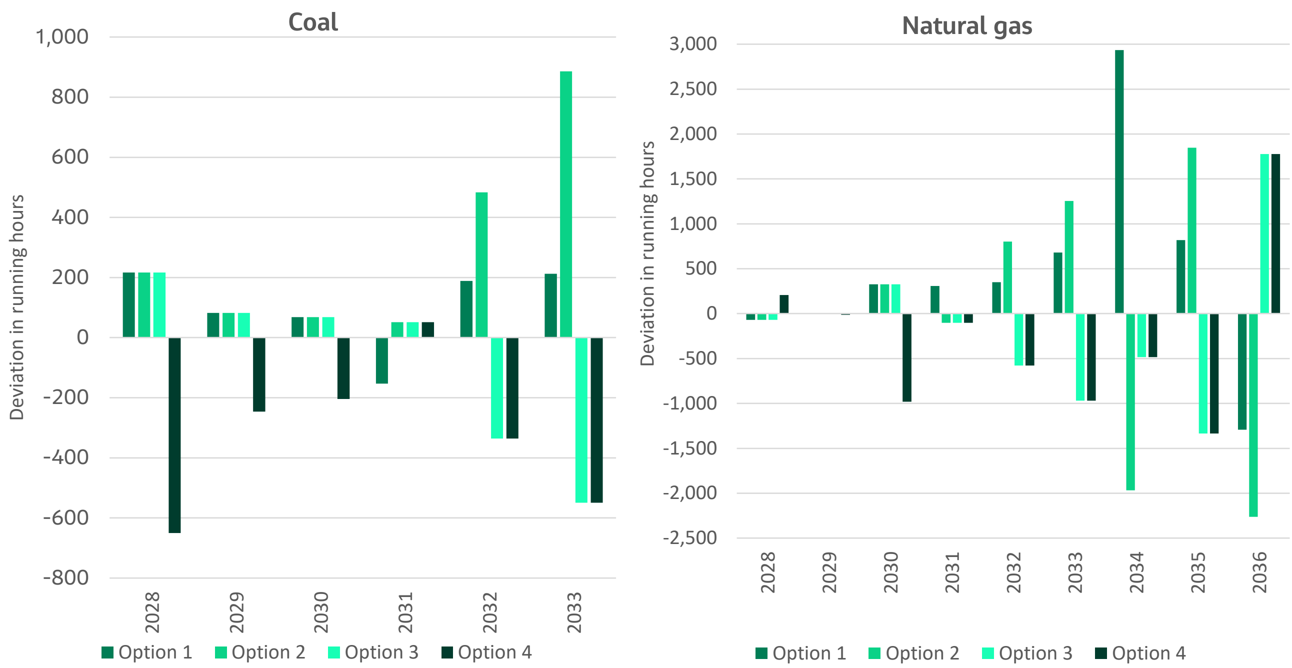
Table 1: Gross market benefits by category for all option portfolios, $million

	Option 1	Option 2	Option 3	Option 4
Avoided ILC costs	928	928	928	928
Avoided fuel costs	1,927	1,929	1,923	1,916
Avoided costs for non RIT-T proponents	121	122	123	125
Avoided emissions	1,199	1,178	1,221	1,231
Total	**4,176**	**4,158**	**4,195**	**4,201**

Given that gross market benefits are most sensitive to the cost of emissions, differences in the running hours of coal-fired generators, which are shown in Figure 1, best explain this outcome. This chart shows that in every year, apart from 2031, up till the withdrawal of coal in 2033, Option 4 has the lowest running hours of coal-fired generation among the options and this also translates into the lowest emissions.

1 This is also referred to as unserved energy (USE) in the PADR.

Figure 1: Deviation in running hours by option portfolio relative to average, coal and natural gas[2]



2 2026 and 2027 are excluded from the charts because all four option portfolios share the same results for these years.

IMPORTANT NOTE ABOUT THE REPORT

The sole purpose of this report and the associated services performed by Jacobs is to provide the Australian Energy Market Operator, Victorian Planning (the Client) a set of market modelling outputs that will be used to derive net market benefits in the PADR for each candidate portfolio of options for future supply of system strength services in Victoria. The services were provided in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

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CONTENTS

TABLES

FIGURES

ACRONYMS AND ABBREVIATIONS

Term	Definition
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFL	Available Fault Level
AVP	AEMO Victorian Planning
BESS	Battery energy storage system
CDP	Candidate development path
GFL	Grid-following
GFM	Grid-forming
GW	Gigawatts
GWh	Gigawatt-hours
IASR	Inputs Assumptions and Scenarios Report
IBR	Inverter-based resources
ILC	Involuntary load curtailment
ISP	Integrated System Plan
LHS	Left-hand side
MFL	Minimum Fault Level
NEM	National Electricity Market
NPV	Net present value
NSW	New South Wales
O&M	Operations and maintenance
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PSSE	Power System Simulation for Engineering
PV	Photo-voltaic
PVNSG	Photo-voltaic non-scheduled generation
REZ	Renewable Energy Zone
RFI	Request for information
RHS	Right-hand side
RIT-T	Regulatory investment test for transmission
SSN	System strength node
SSSP	System strength service provider
USE	Unserved energy
VRE	Variable renewable energy

1. INTRODUCTION

AVP is responsible for proactive provision of system strength services as the System Strength Service Provider (SSSP) for Victoria, to help manage power system stability and to facilitate efficient inverter-based resource (IBR) connections as set out in the 10-year forecast provided in the 2024 System Strength Report.

AVP engaged Jacobs to undertake market modelling to facilitate the ranking of portfolios of options in the PADR. This succeeds the Project Specification Report (PSCR), which was published in July 2023, as part of the RIT-T framework.

Jacobs conducted the electricity market modelling under AEMO's 2024 ISP ***Step Change*** scenario for an assessment period of 11 years. Jacobs assisted in the development of a system strength constraints methodology, formulated individually for each option. AVP then assessed the dispatch from each option in the Power System Simulation for Engineering (PSSE) package to confirm the system strength requirement was met. Based on the results of the modelling, AEMO then calculated the net market benefit to facilitate the calculation of the net present value (NPV) to rank the portfolios of options.

This report documents Jacobs' inputs and methodologies in the market modelling of network and non-network solutions to maintain adequate system strength in Victoria. An overview of the market benefit for each option concludes this report and elaborates on the NPV calculation presented in the central AVP PADR document.

Jacobs has adopted most of the assumptions from the 2024 ISP ***Step Change*** scenario, including the ISP's Optimal Development Path (CDP14). Much of the data forming these assumptions is sourced from the 2023 Inputs Assumptions and Scenarios Report (IASR), in line with the AER's RIT-T guidelines. The development of system strength constraints for Victoria specific to this study has been a collaborative effort between AVP and Jacobs.

The market modelling performed by Jacobs has enabled the calculation of a range of classes of market benefits for the options that were evaluated. Benefits were considered across the entire National Electricity Market (NEM) and include:

- Changes in fuel consumption.
- Changes in greenhouse gas emissions.
- Changes in costs for other parties in the NEM.
- Changes in involuntary load curtailment.

The remainder of this report is structured as follows:

- Section 2 describes the methodology used to conduct the market modelling.
- Section 3 describes the input assumptions, including the structure and sources of inputs for the market model.
- Section 4 describes the structure of the system strength constraints.
- Section 5 details the market modelling outcomes.
- Section 6 concludes the document.

2. METHOD

The energy transition underway in Australia will see the progressive withdrawal of synchronous coal-fired generation capacity and increasing penetration of IBR. A consequence of this is reduced levels of system strength that were readily available as a by-product of energy produced by rotating machines synchronised with the electricity grid. AVP is responsible for ensuring the ongoing provision of adequate levels of system strength to maintain grid stability in Victoria. As part of this System Strength RIT-T, AVP will procure system strength services through the contracting of new and/or existing system strength solutions such as synchronous condensers, GFM BESS and/or contracting with incumbent synchronous generators.

Jacobs in collaboration with AVP have developed a modelling framework to co-optimise Victoria's future system strength requirements along with energy dispatch. AVP has developed four portfolios of options designed to meet Victoria's future system strength requirements at least cost. Jacobs has used PLEXOS (developed by Energy Exemplar) to perform market modelling for each of these options to assess whether the system strength requirement is met and to facilitate the calculation of market benefits for each option relative to a counterfactual do-nothing case ('Base Case').

This section of the report describes the modelling framework. Section 2.1 provides an overview of the framework and section 2.2 describes the calculation of the market benefits.

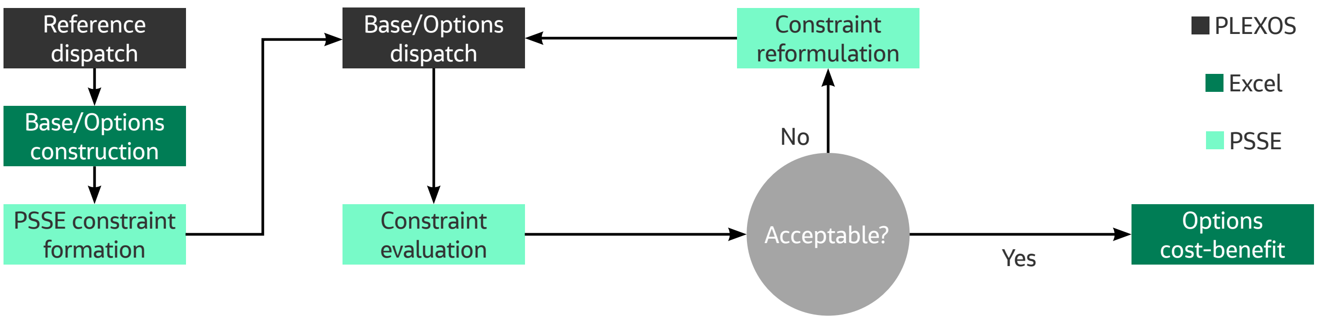
2.1. OVERVIEW

The modelling tasks carried out in this RIT-T study were as follows:

- Simulation of the Reference Case, based on the 2024 ISP ***Step Change*** scenario.
- Development of option portfolios.
- Formulation of system strength constraints in PLEXOS by using PSSE assessment of fault levels.
- Simulation of the Base Case (the Reference Case with the addition of system strength constraints) as the counterfactual.
- Modelling of options in PLEXOS with the inclusion of system strength constraints.
- Assessment of options dispatch in PSSE.
- Calculation of gross market benefits based on options dispatch.

Figure 2 presents a process chart outlining how the modelling of the Base Case and option portfolios was carried out.

Figure 2: Process diagram for Base and Options modelling



2.1.1. REFERENCE CASE

The Reference Case was based on the 2024 ISP ***Step Change*** scenario, considered to be the optimal dispatch scenario for the NEM. Unit commitment constraints as per the IASR were applied to develop optimal energy-only dispatch representing realistic bidding assumptions while maintaining short-run marginal cost dispatch. An overview of the assumptions for the Reference Case is presented further in Section 3, Table 2.

2.1.2. BASE CASE

Under the Base Case, the Victorian synchronous generators were dispatched to meet the system strength requirement in each trading interval but where no new solutions were constructed to meet the system strength requirement. It is equivalent to the Reference Case, with the addition of system strength constraints.

This case serves as the do-nothing counterfactual case, as per the AER's RIT-T guidelines[3], and the market benefits of the four option portfolios have been ranked relative to this case.

2.1.3. DEVELOPMENT OF LEAST-COST SYSTEM STRENGTH PORTFOLIO OF OPTIONS

AVP used the Reference Case simulated by Jacobs as the input into the development of the portfolio of options. This process is detailed further in the PADR. The general process is as follows:

- For each trading interval calculate the shortfall in system strength requirements at each system strength node using the dispatch from the Reference Case. This was carried out for both the minimum fault level and the available fault level[4].
- In years where system strength requirements are not met, identify the least cost solution to supply that shortfall, primarily considering additional operation of incumbent Victorian synchronous generators and existing synchronous condensers, new synchronous condensers and/or GFM BESS based on a least cost approach.

2.1.4. DEVELOPMENT OF SYSTEM STRENGTH CONSTRAINTS

Unique system strength constraint sets had to be constructed for each option to effectively assess the market benefit of each portfolio of options. System strength constraints were formulated separately for both MFL and AFL[5]. The method underpinning the system strength constraints formulation is detailed further in Section 4.

At a high level each synchronous unit had a coefficient which was used to represent its fault level contribution, with units sitting on the left-hand side (LHS) of the constraint representing controllable units. Synchronous generation units have a positive contribution to meeting the system strength requirement whilst asynchronous sources require system strength remediation.

Due to the non-linear nature of system strength constraints, we formulated constraints that varied on an interval level.

3 AER - RIT-T application guideline (marked up) - 21 November 2024.pdf
4 This is also referred to as the efficient fault level.
5 Further detailed in Section 4, where the methodology for developing the system strength constraints is also outlined.

For each interval, a correction factor was calculated based on the delta between the total fault level of all synchronous generation online and the individual sum product of synchronous units and their respective coefficient. This correction factor was then netted off from the requirement and as such the right-hand side (RHS) of the constraint equation was 'corrected' for.

The input into PLEXOS was an individual file per generating unit containing the coefficients and RHS values which varied by interval.

The market model dispatch for each option was assessed in PSSE for each time interval to determine if the requirement was met.

2.1.5. EVALUATING BENEFITS OF OPTION PORTFOLIOS

Jacobs modelled each option in the market model, with the outcomes used to calculate the gross market benefit. These were then compared to the counterfactual and were used as an input into the net present value calculation (along with the capital and operating costs provided by AVP).

In addition to the evaluation of the four option portfolios, we also conducted a sensitivity for the preferred option where it was assumed that all offshore wind capacity would be self-remediating. This in effect means that the demand for system strength services for the sensitivity is lower than that of the corresponding option case.

2.2. CALCULATION OF MARKET BENEFITS

The guidelines for the RIT-T require that all options are assessed against a counterfactual ('Base' scenario).

Gross market benefits were calculated for the four option portfolios as well as the sensitivity relative to the Base Case for all benefit classes that were examined.

The following market benefit classes were material in this RIT-T:

- Changes in fuel consumption.
- Changes in greenhouse gas emissions.
- Changes in costs for other parties in the NEM.
- Changes in ILC.

Benefit classes that were deemed to be immaterial in the analysis include competition benefits, option value, changes in the cost of frequency control ancillary services, change in the cost of unrelated transmission investments, changes in voluntary load curtailment and changes in transmission losses.

3. ASSUMPTIONS

The following section discusses the assumptions and data sources used for this report.

At the commencement of this project the ISP 2024 and IASR 2023 were the most recent available data sources from AEMO[6].

Jacobs' approach in modelling the counterfactual and option portfolios was to use the ***Step Change*** scenario under the ISP 2024 framework, where the NEM is represented as a 12-node system. The model included Renewable Energy Zone (REZ) limits and the optimised ISP transmission augmentations, to represent transmission flow limits between the NEM sub-regions. The timing of interconnector expansions corresponded to that of the Optimal Development Path (ODP). The CDP 14 generation capacity expansion plan was adopted, as this is the least-cost plan that meets the government policy targets and supplies future demand growth at least cost given the retirement schedule of the NEM's coal-fired generation fleet.

The 2024 ISP model ***Step Change*** scenario based on the CDP14 generator expansion plan was used as the basis for this RIT-T, as per section 3.4 of the AER's guidelines[7]. Given the objectives of this study and more recent market developments, there were some slight deviations from the ISP 2024 that are detailed in Table 2.

Table 2: Input and assumptions

Assumption	Parameter	Setting
Policy	Commonwealth emissions policy	ISP 2024 ***Step Change***, including: ▪ 43% emission reduction on 2005 levels by 2030 ▪ 82% electricity supplied by variable renewable energy (VRE)
	Victoria	▪ ISP 2024 ***Step Change***, including: ▪ 65% minimum VRE state-wide generation by 2030 growing to 95% by 2035. ▪ 2.6 GW storage by 2030, 6.3 GW by 2035. ▪ Offshore wind targets of 2 GW by 2032, 4GW by 2035.
	Queensland	▪ ISP 2024 ***Step Change***: ▪ 50% of underlying demand supplied by VRE by 2030, 70% by 2032 and 80% by 2035
	New South Wales (NSW)	ISP 2024 ***Step Change***: ▪ NSW Energy Infrastructure Roadmap targeting equivalent of 12 GW new VRE capacity and 2GW/16GWh long-duration storage by 2030 ▪ NSW 50% emissions reduction by 2030 and 70% by 2035
	South Australia	ISP 2024 ***Step Change***: ▪ 50% emission reduction target by 2030.
	Tasmania	ISP 2024 ***Step Change***: ▪ Renewable energy target of 150% of 2020 levels by 2030.
Demand	Demand growth	ISP 2024 ***Step Change***; modelled as rolling references years as per ISP 2024 ***Step Change*** sequence
	Electric vehicle growth	ISP 2024 ***Step Change***
	Rooftop PV and PVNSG	ISP 2024 ***Step Change***; solar profiles modelled as rolling references years as per ISP 2024 ***Step Change*** sequence
	Embedded storage	ISP 2024 ***Step Change***

6 The IASR Draft 2025 was released during the course of the modelling phase, at which point key modelling assumptions had already been locked in.
7 AER - RIT-T application guideline (marked up) - 21 November 2024.pdf

Assumption	Parameter	Setting
Fuel prices	Gas prices	ISP 2024 ***Step Change***
	Coal prices	ISP 2024 ***Step Change***
	Green Hydrogen prices	ISP 2024 ***Step Change***
Generator parameters	Outage rates	ISP 2024 ***Step Change***; treatment of coal plant forced outages are further described in Section 3.1
	O&M costs	ISP 2024 ***Step Change***
	Retirements	ISP 2024 ***Step Change*** except Eraring retirement deferred to August 2027[8]
	Minimum stable level	AVP RFI responses
	Min up/down times	IASR 2023
	Ramp up/down times	IASR 2023
	VRE profiles	Rolling reference years as per 2024 ISP ***Step Change*** scenario
	Hydro profiles	2024 ISP ***Step Change*** scenario
	Start costs of coal plant	Jacobs' assumptions
Project timing	Snowy 2.0	December 2028 as per Generation Information page Oct 2024
	Transmission	As per ISP 2024 Optimal Development Plan for ***Step Change*** scenario
	Generation	CDP 14 as the per ISP 2024 - determined to be the least-cost candidate path The only exception is the inclusion of Goorambat East solar farm in Victoria as an anticipated generator
	REZ augmentations	As per CDP 14 from ISP 2024

3.1. TREATMENT OF OUTAGES

Generator outages, both planned and unplanned, were approached as per Table 2. Planned outages were optimised by PLEXOS such that capacity reserves would be levelized across the year, which in practice means that maintenance mainly occurs over the shoulder seasons. Unplanned outages, both full and partial, were generated randomly by PLEXOS (using the same seed[9]) according to the assumed outage rate for each generator, except for:

- Full unplanned outages of Victorian coal-fired generators.
- Full unplanned outages of GFM BESS.

Shortfalls in the system strength requirement in Victoria are particularly sensitive to coincident outages of Victorian coal-fired generating units. As such, they were an exogenous input so that coincident outages matched the statistical average of the outage probability distribution. This approach meant that up to three simultaneous coal-fired unit outages in Victoria were modelled based on the assumed outage rates.

Full unplanned outages for GFM BESS were treated differently in the model because they were represented as two distinct objects:

- One to conduct energy arbitrage, as per usual BESS operations.
- The other to contribute to the system strength constraints, to represent operation as a synchronous machine.

The most pragmatic approach for ensuring outages were applied consistently to these representations of the GFM BESS was to generate outages exogenously to PLEXOS and link both objects to the same outage sequence.

8 As per the announcement of the agreement between Origin Energy and the New South Wales government released on 23 May 2024.
9 This is done to replicate the same outage sequence across all modelled cases, thereby eliminating variations in costs due to different outage sequences.

3.2. SYSTEM STRENGTH SOLUTION ASSUMPTIONS

There were six system strength building blocks that were part of the four option portfolios considered in the modelling. These are described below in Table 3.

Table 3: System strength solutions

Name of option class	Description	Contribution to MFL	Contribution to AFL
New synchronous condensers	These are new builds with the primary function of providing system strength services in Victoria.	Yes	Yes
Committed synchronous condensers	These are synchronous condensers that have reached financial close and are either in service already or are in the process of construction. They are tied to specific generation projects in the NEM, but their location also makes them suitable for AVP to contract with for the provision of system strength services that will benefit the broader Victorian transmission system.	Yes	Yes
New GFM BESS	These are future BESS projects in Victoria that will be commissioned as GFM BESS and contracted with to provide system strength services. All future BESS are assumed to be GFM, in that they have zero system strength demand, but only the GFM BESS that are assumed contracted to provide system strength are included in the system strength constraint equations.	No	Yes
Converting committed BESS to GFM capability	These are BESS projects initially built with GFL capability but will be upgraded to GFM capability as more system strength services in Victoria are required with the progressive withdrawal of coal-fired generating units.	No	Yes
Incumbent synchronous generators with/without synchronous condenser capability	This category includes all of the synchronous generation fleet in Victoria. These generators will be used to “top up” system strength supply at times of low system strength. Some incumbent generators are able to operate in synchronous condenser mode without operating in the energy market.	Yes	Yes

The four final option portfolios and the assumed timing of new synchronous condensers by year are shown in Table 4. The year indicates the commencement of the contract with AVP and in all cases contracting with these assets spans the duration of the modelling horizon. In addition to the synchronous condensers, the option portfolios include a mix of GFM BESS, the timing of which is presented in Figure 4.

The option portfolios comprise the following key differences:

- Option 1 is primarily focussed on supply of system strength through the procurement of new synchronous condensers.
- Options 2, 3 and 4 optimise supply of system strength through the procurement of a combination of synchronous condensers and GFM BESS.
- Options 2 and 3 are identical up until 2031.
- Option 4 is identical to Option 3 with the following exceptions:
  - the first Hazelwood synchronous condenser is brought forward from 2029 into 2028.
  - the third Hazelwood synchronous condenser is brought forward from 2031 into 2029.

Table 4: Option portfolios – composition and timing of synchronous condensers (cumulative)

Year	Option 1	Option 2	Option 3	Option 4
2026	Red Cliffs SSN[10] SC (existing)	as per Option 1	as per Option 1	as per Option 1
2027		as per Option 1	as per Option 1	as per Option 1
2028		as per Option 1	as per Option 1	Hazelwood SSN SC
2029	Hazelwood SSN SC x 2	as per Option 1	as per Option 1	Hazelwood SSN SC x 2
2030		as per Option 1	as per Option 1	
2031	Giffard SC	Hazelwood SSN SC	as per Option 2	
2032	Giffard SC			as per Option 3
2033	Bulgana SC			as per Option 3
2034	Hazelwood SSN SC Giffard SC	Hazelwood SSN SC Giffard SC	Hazelwood SSN SC	as per Option 3
2035	Kerang SC		Giffard SC	as per Option 3
2036	Giffard SC	Giffard SC		as per Option 3

Asset-specific assumptions Table 5 shows the capacity and cost assumptions underlying the modelled synchronous condensers. The Ararat synchronous condenser does not have any associated costs for the purpose of the RIT-T assessment as it is a committed synchronous condenser and is common to all modelling cases. The variable costs for all other synchronous condensers are derived from AVP's PSCR RFI proponent responses.

Table 5: Assumptions for the modelled synchronous condensers

	Max capacity (MVA)	Forced outage rate (%)
Ararat	250	2.5
Red Cliffs SSN SC (existing)	190	2.5
Other	250	2.5

10 System strength node

4. SYSTEM STRENGTH REPRESENTATION

This section describes the system strength constraints used in the market modelling.

4.1. SYSTEM STRENGTH CONSTRAINTS

AVP formulated two classes of system strength constraints for the Victorian network:

- Minimum fault level (MFL): required to meet minimum fault level requirements as specified in the 2024 System Strength Report at each of the five system strength nodes.
- Available fault level (AFL): to meet the efficient level requirement, sufficient to accommodate the IBR forecast, at each of the five system strength nodes. AFL constraints were also included at key future IBR connections points to help more efficient placement of future efficient level solutions.

These constraints were formulated for the nodes specified in Table 6.

Table 6: List of modelled system strength constraints

MFL nodes	AFL nodes
Dederang 330kV	Dederang 330kV
Hazelwood 500kV	Hazelwood 500kV
Moorabool 220kV	Moorabool 220kV
Red Cliffs 220kV	Red Cliffs 220kV
Thomastown 220kV	Thomastown 220kV
	Bulgana 500kV
	Giffard 500kV
	Kerang 500kV

4.2. MINIMUM FAULT LEVEL CONSTRAINTS

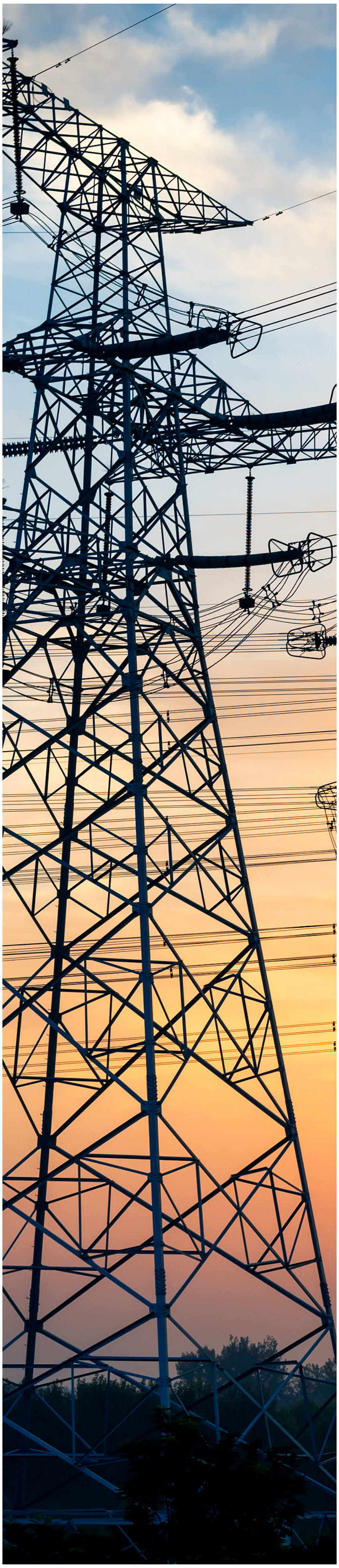
MFL constraints were formulated for each dispatch interval, comprised of the following components:

- Fault level contribution from each synchronous machine
- Interstate contribution
- Delta correction
- Safety margin
- Offset for critical planned outages[11]

Fault level coefficients for each synchronous generator combination was provided by AVP at each system strength node. They were calculated in PSSE assuming the dispatch included solutions identified in the option portfolio development step, under two conditions:

- A synchronous machine dispatched in a trading interval has its fault level contribution calculated directly. In this case, the machine combination was 'switched out' in PSSE and then the respective fault level recorded.
- A synchronous machine not dispatched in a trading interval had its fault level contribution calculated by 'switching in' the unit in PSSE, with the respective fault level recorded.

11 This was assessed in PSSE, and for each year in the assessment horizon it was determined that there was no material impact on each option portfolio, and so the offset is effectively zero. Additionally, this was only modelled for MFL constraints because AVP's interpretation of the NER is that IBR curtailment is acceptable in meeting the efficient level requirement, particularly under planned outage conditions.



The interstate contribution was calculated through PSSE and represents the fault level contribution available from interstate sources such as the Project EnergyConnect (PEC) synchronous condensers, and as further described in the PADR.

The delta correction is used, as the name suggests, to 'correct' for the non-linearity of the fault level calculation. It is derived as the difference between the total fault level of all online synchronous machines and the individual sum product of unit status and each individual synchronous machine's fault level. For a given system strength node, it is calculated as follows:

$$\mathrm{Delta}_t = \mathrm{FL}_{t,\mathrm{PSSE}} - \sum_g c_{g,t} s_{g,t} - \mathrm{IS}_t \quad \text{eq. (1)}$$

where:

t is the trading interval;

$FL_{t,PSSE}$ is the total fault level as calculated in PSSE in time interval t;

g is the set of Victorian synchronous generators providing system strength services;

$c_{g,t}$ is the fault level contribution of synchronous generator g in time interval t;

$s_{g,t}$ is the status (i.e. on or off represented as 1 or 0 respectively) of synchronous generator g in time interval t; and

IS_t is the interstate fault level contribution in time interval t.

The minimum fault level requirement for each of the five modelled MFL constraints was constant across the modelling horizon and is shown in Table 7. A safety margin, or confidence level, of 5% of the minimum fault level requirement was introduced.

Table 7: Minimum fault level requirements for each system strength node

System strength node	Minimum fault level requirement (MVA)	Safety margin (MVA)
Dederang 330kV	3500	175
Hazelwood 500kV	7700	385
Moorabool 220kV	4600	230
Red Cliffs 220kV	1786	90
Thomastown 220kV	4700	235

The full formulation of the minimum fault level constraints is as follows:

$$\sum_g c_{g,t} s_{g,t} \geq \mathrm{MFL} + \mathrm{SM} - \mathrm{Delta}_t - \mathrm{IS}_t \quad \text{eq. (2)}$$

Where:

g, $c_{g,t,}$, $s_{g,t,}$ $Delta_t$ and IS_t are as defined in equation (1);

MFL is the minimum fault level for the node, which is invariant over time and as shown in Table 7; and

SM is the safety margin.

The only variable co-optimised by PLEXOS during the simulation phase is $s_{g,t}$ which is the online status of each synchronous machine in Victoria.

4.3. AVAILABLE FAULT LEVEL CONSTRAINTS

AFL constraints were formulated separately for each dispatch interval. They are comprised of the following components:

- Fault level contribution from each synchronous generator
- Contingency offset embedded into the requirement
- Interstate contribution
- IBR contribution
- Delta correction
- Safety margin

Most of the components are identical to those described for the MFL constraints in the previous section. Here, we document only the components that are specific to the formulation of the AFL constraints.

The IBR component is a negative contribution to the available fault levels at each system strength node since they represent sources which demand system strength.

The full formulation of the AFL constraints was as follows:

$$\sum_g c_{g,t} s_{g,t} \geq \mathrm{AFL} + \mathrm{SM} - \mathrm{Delta}_t - \mathrm{IS}_t + \sum_i a_{i,t} \quad \text{eq. (3)}$$

where,

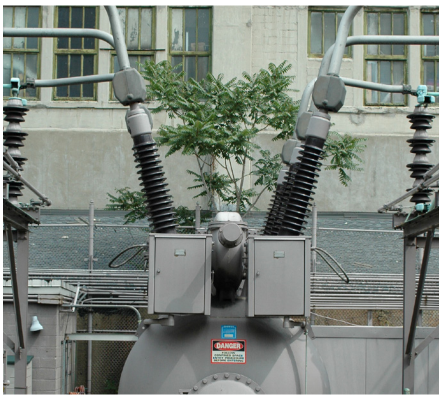
g, $c_{g,t,}$, $s_{g,t,}$ $Delta_t$ and IS_t are as defined in equation (1);

SM is as defined in equation (2), and key IBR connection point AFL constraints had the same value applied as their nearest fault level node;

AFL is the n-1 fault level requirement which accounts for the largest contingency loss at a node;

i is the set of IBR in Victoria; and

$a_{i,t}$ is the increase in the required AFL due to IBR *i* in time interval *t*.



5. MARKET MODELLING OUTCOMES

5.1. OPTIONS AND SENSITIVITY

5.1.1. OPTIONS

The four option portfolios include a combination of new-build synchronous condensers and GFM BESS required to meet Victoria's system strength requirements. The synchronous condenser build out is illustrated in Figure 3, with Option 1 having the greatest build out of synchronous condensers built.

Figure 3: Synchronous condenser build by option portfolio

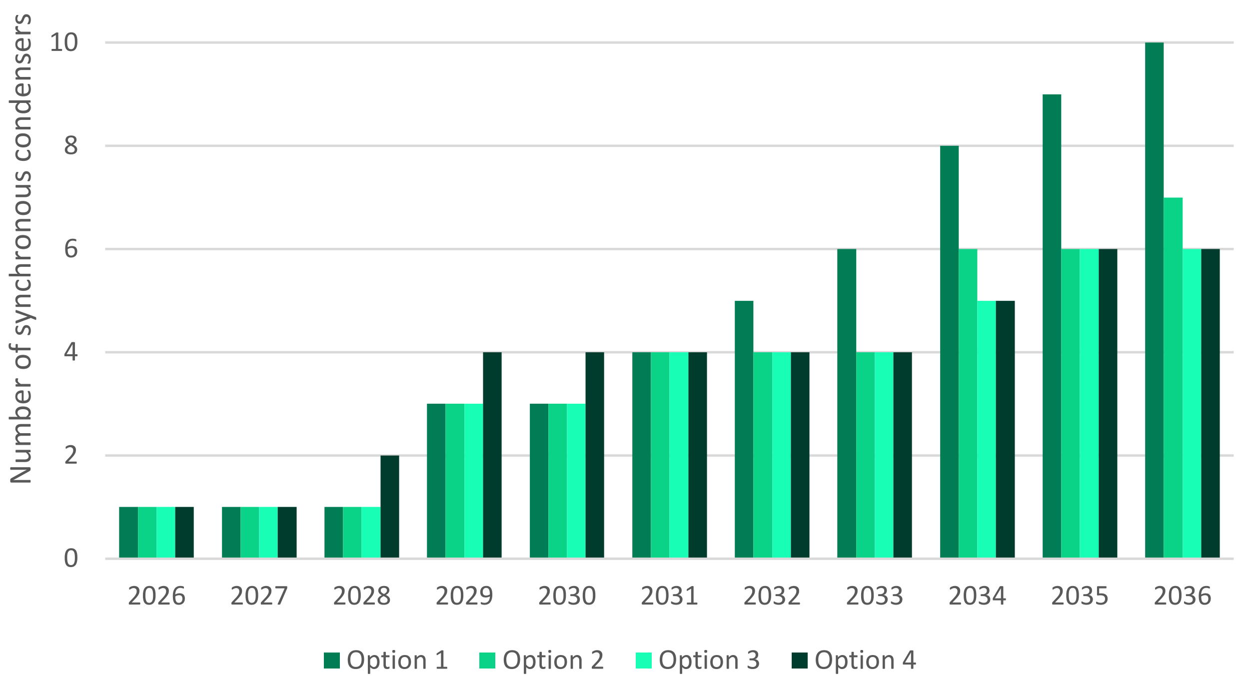
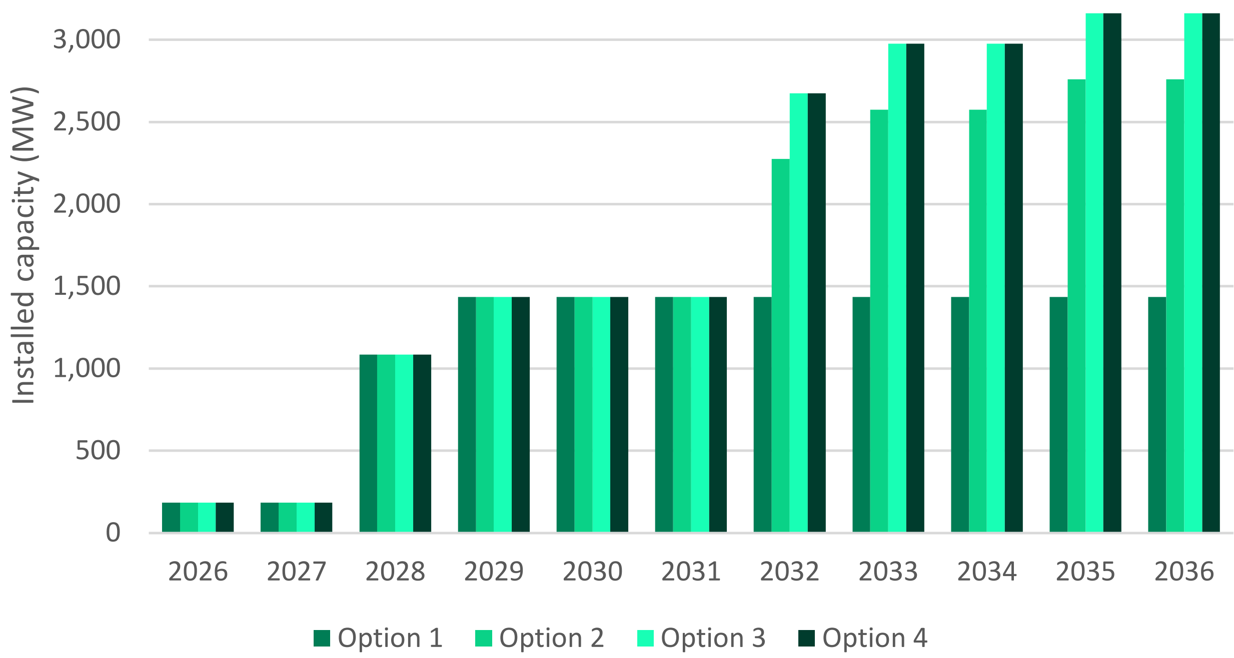


Figure 4 shows the GFM BESS build out by option portfolio, which also includes GFMs that have been upgraded from GFL BESS as well as new builds. Option 1, which has the highest build of new synchronous condensers has the lowest build of GFM BESS with the installed capacity remaining constant from 2029 onwards. In contrast, Options 3 and 4, which have the lowest new synchronous condensers have the highest installed GFM BESS capacity from 2032 onwards. Synchronous condenser and GFM BESS builds for Option 2 lie in between the extreme cases.

Figure 4: GFM BESS installed capacity by option portfolio

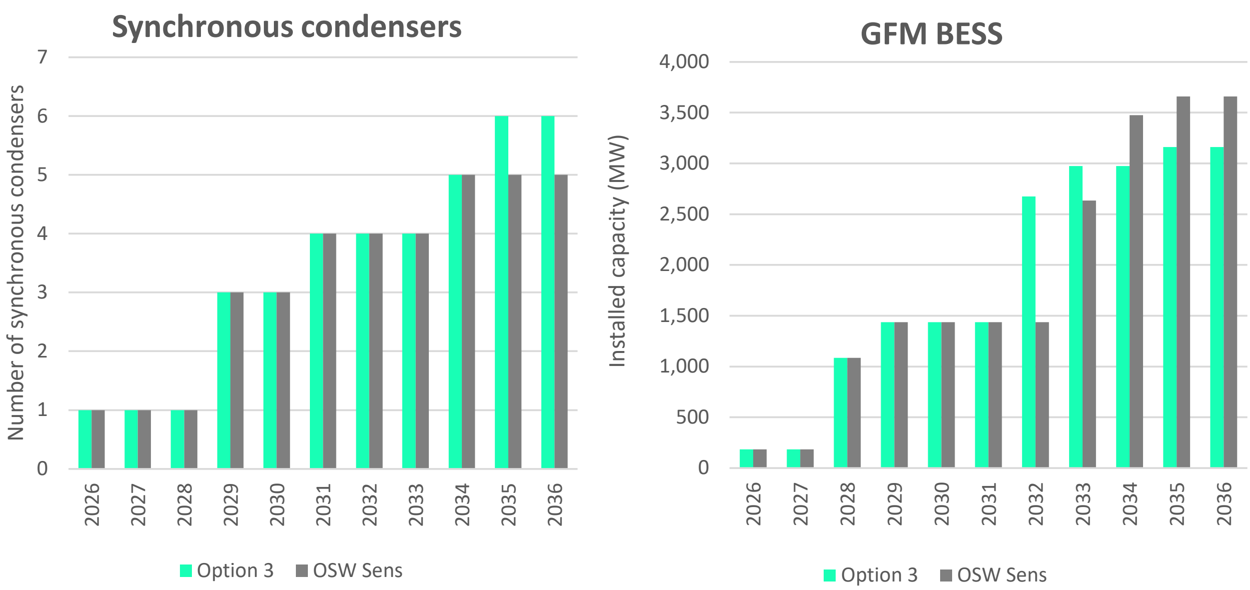


5.1.2. SENSITIVITY

The premise behind the offshore wind (OSW) sensitivity is that all offshore wind IBR built in Victoria is self-remediating and as such, the efficient level system strength requirement for Victoria was significantly reduced in the latter half of the assessment period. This sensitivity was only modelled for the preferred option portfolio, being Option 3. Under this sensitivity the system strength constraints for the Giffard offshore wind terminal were not modelled as it was assumed that system strength services for all wind connecting to these system strength nodes would not need to be procured centrally.

Figure 5 shows the comparison of synchronous condenser build and GFM BESS build for the OSW sensitivity to that of Option 3. With respect to synchronous condensers, the only difference between the two cases is one Giffard synchronous condenser that is built for Option 3 but is not required for the sensitivity. For GFM BESS, 500 MW more capacity is eventually built for the sensitivity from 2034 onwards, but the ramp up of the GFM BESS build out is delayed compared to Option 3.

Figure 5: Synchronous condenser build and GFM BESS build, Option 3 and OSW sensitivity



5.2. MARKET MODELLING OUTCOMES

This section presents the high-level outcomes of the market modelling for the options relative to the counterfactual, which is the Base Case.

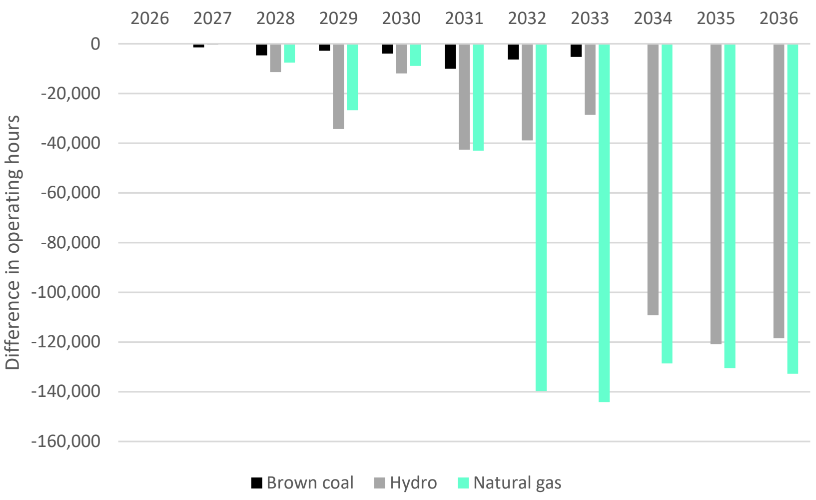
5.2.1. OPTION 1 – EXISTING GENERATION PLUS COMMITTED/ ANTICIPATED GFM BESS AND NEW SYNCHRONOUS CONDENSERS

Figure 6 shows the delta in aggregate operating hours between Option 1 and the counterfactual. To put this chart in context, the decreases in the operating frequency of coal, hydro and natural gas plants are 11.2%, 63% and 94.9% respectively.

The difference in operating hours is lowest in 2026 and increases through to 2031 as more coal-fired capacity progressively exits the market.

The largest differences in operating hours occur post-2032. The lack of new system strength solutions in the Base Case means that Victorian natural gas plants need to ramp up production to meet the system strength requirement. Under Option 1, the new synchronous condensers and GFM BESS are able to provide the required system strength services at lower cost, obviating the need for higher levels of gas plant operation. The difference in operating hours for hydro plants is most accentuated from 2034 onwards after the withdrawal of all coal-fired capacity in Victoria.

Figure 6: Aggregate Victorian operating hours relative to counterfactual, Option 1



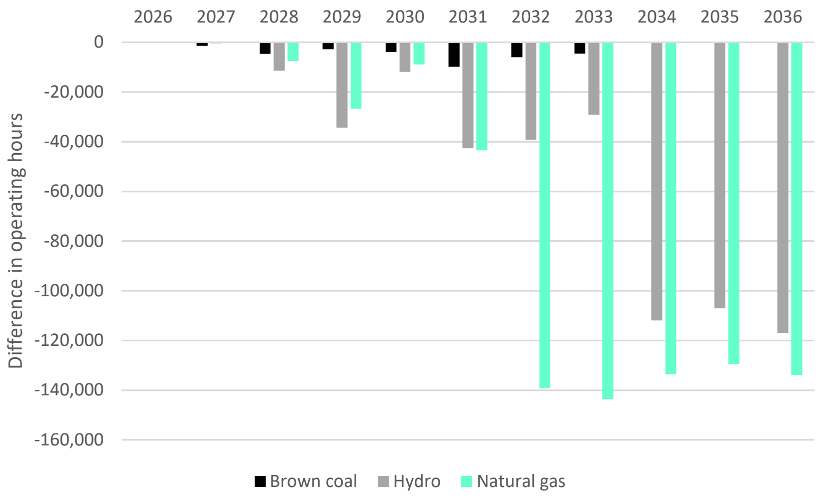
5.2.2. OPTION 2 – THE SAME TECHNOLOGY TYPES AS OPTION PORTFOLIO 1 PLUS UPGRADING ADDITIONAL GFL BESS TO BE GFM

Figure 7 shows the difference in aggregate operating hours of synchronous generation between Option 2 and the counterfactual. Values until 2030 are identical to those of Option 1 as both options share the same expansion plan. Post 2030 the trends present in Option 2 relative to the Base Case are very similar to those in Option 1 and the same is also true for Options 3 and 4. This commonality among the solution options highlights the importance of the new-build GFM BESS and synchronous condensers in meeting the system strength requirement and greatly reduces surplus dispatch from the existing generators.

Post 2030 more GFM BESS are commissioned for Option 2 and less synchronous condensers are commissioned relative to Option 1. Under Option 2 coal, hydro and natural gas plants have 10.9%, 62% and 95.3% reductions in operating hours respectively, relative to the counterfactual. The aggregate reduction in operating hours for coal and hydro is lower than Option 1 but higher for natural gas.

Coal and hydro operating hours increase relative to Option 1, in 2032-2033 and 2035, respectively. It is difficult to discern changes in coal operating hours by comparing Figure 6 to Figure 7. A more direct comparison where these changes are observable is presented in Figure 13 in Appendix A.

Figure 7: Aggregate Victorian operating hours relative to counterfactual, Option 2

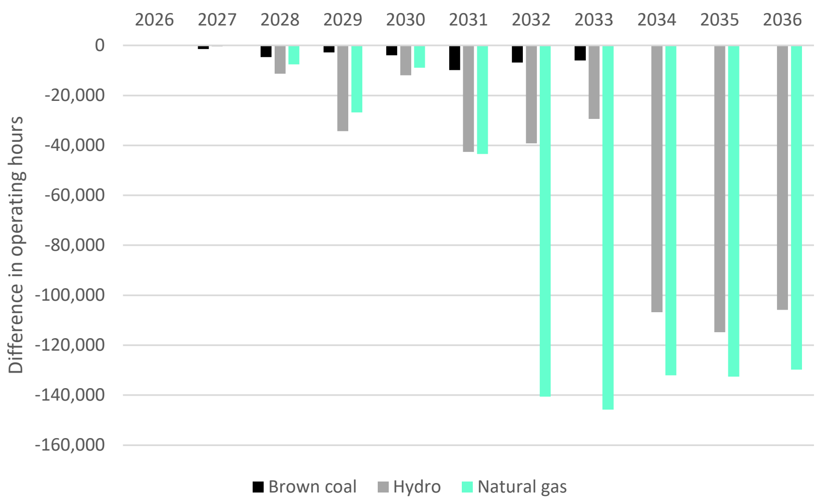


5.2.3. OPTION 3 – THE SAME TECHNOLOGY TYPES AS OPTION PORTFOLIO 2 PLUS A GFM BESS FROM THE IBR FORECASTS

Figure 8 shows the delta in aggregate operating hours for Option 3 relative to the counterfactual. Results are identical to Option 2 until 2031 as both options use the same expansion plan until this point in time. Under Option 3 coal, hydro and natural gas plants have 11.5%, 61% and 95.4% decrease in operating hours respectively, relative to the counterfactual. It has the largest decrease in coal and natural gas operating hours relative to Options 1 and 2 and the lowest decrease in operating hours for hydro across the assessment horizon.

Overall Option 3 has less operating hours for the incumbent synchronous generation fleet as it includes an additional GFM BESS at the Hazelwood system strength node (absent in Options 1 and 2), which displaces some of the coal and gas generation relative to Option 2. Hydro operating hours are elevated in 2034 and 2036 relative to the preceding option portfolios.

Figure 8: Aggregate Victorian operating hours relative to counterfactual, Option 3



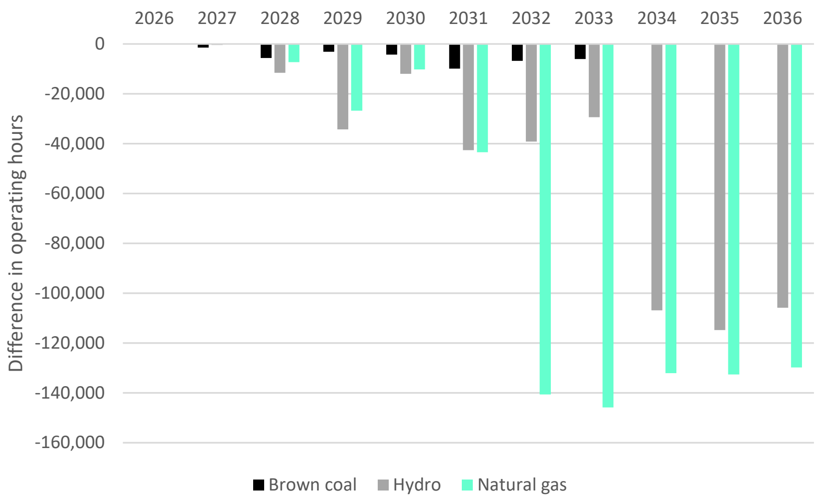
5.2.4. OPTION 4 – THE SAME TECHNOLOGY TYPES AS OPTION PORTFOLIO 3, EXCEPT WITH ACCELERATED PROCUREMENT OF SYNCHRONOUS CONDENSERS

Figure 9 shows the difference in aggregate operating hours for Option 4 relative to the counterfactual. Results are identical to Option 3 for all years apart from 2028, 2029 and 2030 when two of the Hazelwood synchronous condensers are brought forward. Under Option 4 coal, hydro and natural gas plants have an 11.9%, 61% and 95.6% decrease in operating hours respectively, relative to the counterfactual. It has the largest decrease in coal and natural gas operating hours relative to all preceding options and similar decrease in operating hours for hydro as Option

3. The significance of this becomes apparent in the evaluation of gross market benefits (see section 5.4), specifically under the emissions category.

Differences between Option 3 and 4 derived from the comparison of Figure 8 to Figure 9 are too subtle to discern. This is further discussed in Appendix A where more direct comparisons are made.

Figure 9: Aggregate Victorian operating hours relative to counterfactual, Option 4

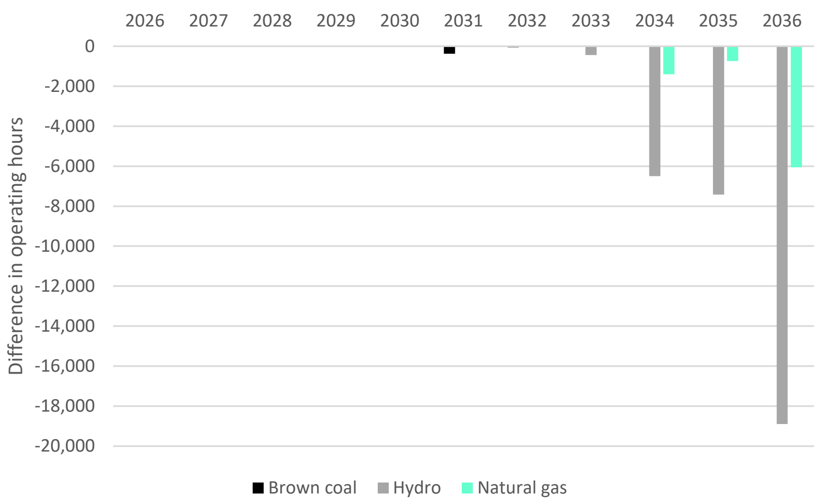


5.3. OFFSHORE WIND SENSITIVITY

Figure 10 shows the difference in aggregate operating hours for the OSW sensitivity relative to Option 3. Under this sensitivity coal, hydro and natural gas plants have 0.1%, 8.5% and 17.3% less operating hours respectively relative to Option 3. The decrease in operating hours across all three categories translates into higher gross market benefits due to lower fuel consumption and lower emissions.

The reason for lower operating hours lies in the assumption that offshore wind will be self-remediating with respect to system strength services, which in practical terms means that AFL constraints are not modelled for the Giffard terminal station. Excluding these additional constraints effectively lowers the system strength requirement and this directly translates into lower operating hours for the incumbent Victorian synchronous plant.

Figure 10: Aggregate Victorian operating hours relative to Option 3, OSW sensitivity



5.4. GROSS MARKET BENEFITS

Figure 11 shows the total gross market benefits (real 2023-24 dollars) for each of the option portfolios, which have been calculated using a 7% discount rate. Option 4 has the highest gross market benefit of $4.201 billion, followed closely by Option 3 at $4.195 billion, where the latter is the preferred option as assessed in the PADR due to its lower cost and therefore overall higher net market benefit (see PADR).

The difference between Option 4 and Option 3 is $6 million and the largest difference is between Option 4 and Option 2, which is $43 million.

Figure 11: Gross market benefits for all option portfolios

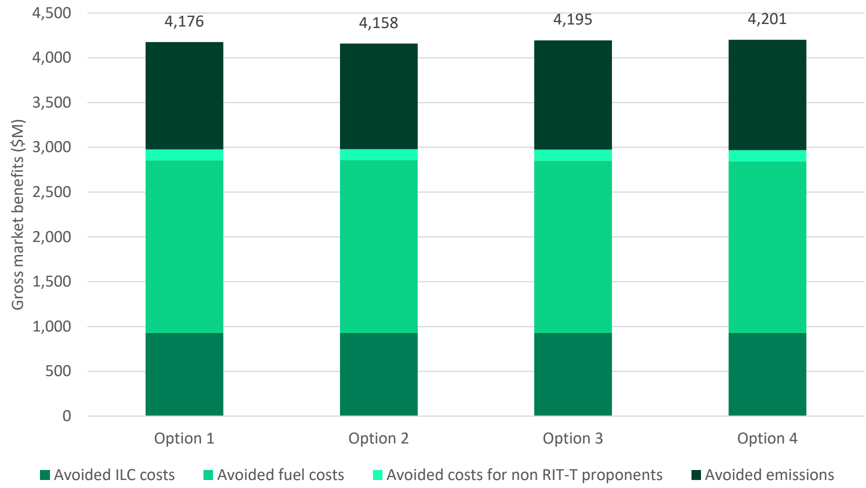


Table 8 shows the breakdown in gross market benefits by benefit class. The key results and insights are as follows:

- Gross market benefits are positive under all categories relative to the Base Case where system strength was supplied by the incumbent synchronous generation fleet. This reflects the importance of procuring system strength services.
- Avoided ILC benefits are identical for all options. This occurs because there is no ILC observed for the option portfolios but a significant amount of ILC is incurred under the counterfactual due to the expected load shedding required to maintain a stable and secure network after all coal generators exit the market. As a result, each option portfolio accrues the same benefit for this category.
- The key determinant with respect to gross market benefits is the avoided emissions category as this shows the highest variability between Option 1 to Option 4. Avoided fuel costs vary by $13 million from lowest to highest, avoided costs for non RIT-T proponents vary by $4 million, but avoided emission costs vary by $53 million. The difference in avoided emission costs is mainly driven by variations in Latrobe Valley coal dispatch among the option portfolios. In particular, Options 3 and 4, which have the lowest emission outcomes, displace some of the Victorian coal generation in the later years by virtue of a GFM BESS that is absent in Options 1 and 2.
- The avoided emissions outcomes across the options are closely related to the increase in operating hours of the Victorian coal plants. Option 2, which has the lowest benefit, shows a 10.9% decrease relative to the counterfactual, whereas Option 4, which has the highest benefit, has a decrease of 11.9%.
- Interestingly, Option 4 has the least benefit in avoided fuel costs among the option portfolios but at the same time has the least running hours for natural gas plants in Victoria. Examining the fuel costs confirms that Victorian gas plants run at a higher capacity factor for Option 4 but operate for shorter periods of time.
- The gross market benefits for Options 1, 2, 3 and 4 are similar with $43 million difference between the highest and lowest benefits over the 11-year modelling horizon.
- Options 3 and 4, which include the lowest number of synchronous condensers and the highest GFM BESS capacity yield the two highest gross market benefits. This occurs because synchronous condensers have a VO&M cost and load demand cost that is in aggregate higher than that of GFM BESS. In addition, GFM BESS are already present in the Base Case and contracting with them does not change their VO&M and other costs.

Table 8: Gross market benefits by category for all option portfolios, $ million

	Option 1	Option 2	Option 3	Option 4
Avoided ILC costs	928	928	928	928
Avoided fuel costs	1,927	1,929	1,923	1,916
Avoided costs for non RIT-T proponents	121	122	123	125
Avoided emissions	1,199	1,178	1,221	1,231
Total	**4,176**	**4,158**	**4,195**	**4,201**

5.5. GROSS MARKET BENEFITS OSW SENSITIVITY

Figure 12 and Table 9 show the comparison of the gross market benefits for the OSW sensitivity compared to Option 3, the option that the sensitivity is based on. Gross market benefits are higher under the OSW sensitivity because demand for system strength is lower than that of Option 3. As a result, coal-fired generation has 0.1% less operating hours relative to Option 3. However, the largest impact is in the reduction of natural gas operating hours, where the sensitivity has 17.3% less operating hours compared to Option 3. This translates into lower fuel costs and also lower emission costs, which are the two categories in which most of the benefits are accrued for the OSW sensitivity relative to Option 3.

The other factor contributing to the increase in gross market benefits for the sensitivity is the relativity of synchronous condenser build and GFM build relative to Option 3. By 2036 the OSW sensitivity has one less synchronous condenser than Option 3 and 500 MW more GFM BESS. This continues the pattern that we discerned in comparing the option portfolios. Namely, the optimal mix for system strength is portfolios with lower numbers of synchronous condensers and higher GFM BESS capacity, due to the lower marginal cost of GFM BESS. Having said that, we note this pattern does have a lower limit because GFM BESS cannot supply MFL constraints, which means that the optimal mix cannot fall below the minimum number of synchronous condensers required to satisfy MFL requirements.

Figure 12: Delta in gross market benefits of OSW sensitivity compared to Option 3

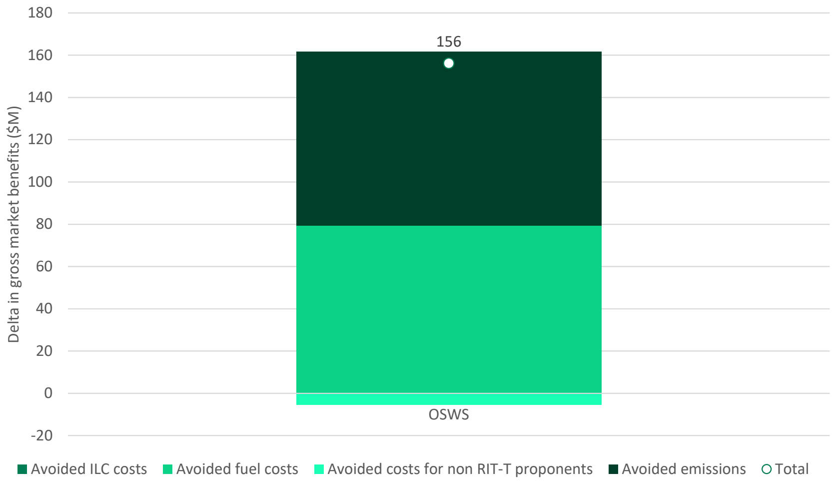


Table 9: Gross market benefits of OSW sensitivity relative to option 3, $ million

	Delta
Avoided ILC costs	0
Avoided fuel costs	79
Avoided costs for non RIT-T proponents	-5
Avoided emissions	82
Total	**156**

6. CONCLUSIONS

The detailed market modelling study conducted by Jacobs in conjunction with AVP has shown that modelling system strength requirements for Victoria is complex and requires successive iterations between PSSE load flow analysis and the PLEXOS market model. The best approach for this modelling was to represent Victoria's system strength requirement as a set of linear constraint equations for each 30-minute trading interval.

Using this approach with market modelling assumptions based on the 2024 ISP ***Step Change*** scenario, we were able to calculate the gross market benefits for four option portfolios and an offshore wind sensitivity relative to the counterfactual scenario. The option portfolios were comprised of existing and new synchronous condensers and GFM BESS. The incumbent synchronous generators in the Victorian fleet played an important role in the early years before the new options could come online, which then transformed into a "top up" role, especially as the Victorian brown coal fleet progressively exited the market.

The modelling showed that Option 4 yields the maximum amount of gross market benefits and is separated from Option 3 by only $6 million, where Option 3 is the preferred option in the PADR due to its lower cost and therefore higher net market benefit. The key difference between these options is earlier entry for two of the synchronous condensers located at the Hazelwood substation. Options 3 and 4 have the most installed GFM BESS capacity and the least number of synchronous condensers. The modelling suggests the optimal strategy is to minimise the build of synchronous condensers while still building enough to meet MFL requirements and to supplement these with GFM BESS capacity to supply AFL requirements. This outcome is tied to the higher marginal cost of synchronous condensers relative to GFM BESS.

Fuel cost savings and emission cost savings were the main sources of benefit in this study. Options 1, 2, 3 and 4 do not contain any ILC, meaning that this benefit is identical among these options. The key differentiator between the options was shown to be the market benefit from reduction in emissions.

Appendix A. Portfolio of Options results comparison

The large amount of gas-fired generation consumed under the Base case somewhat masks the significance in the relativities of operating hours for the options cases. In this appendix we present a more direct comparison of the option portfolio results by showing the difference of each option portfolio relative to Option 3, the preferred option with the highest net market benefit. This is shown in Figure 13 for coal-fired generation and Figure 14 for hydro generation and natural gas.

Option 2 has the highest coal-fired operating hours and is followed by Option 1. Most of the additional running hours for both of these options are incurred in 2032 and 2033. The key driver for this outcome is an additional GFM BESS that is part of Option 3 and 4 (see Figure 4). This BESS, which is located to the east of Melbourne, displaces coal-fired generation in 2032 and 2033 as it is able to contribute to meeting the AFL requirement for a number of system strength nodes at lower cost than coal-fired generation. This has a relatively large impact on emission benefits, due to the high emission production factors of the coal-fired generation but a small impact on fuel costs benefits, due to the low cost of brown coal.

Option 4, which only differs from Option 3 between 2028 to 2030, has lower operating hours of coal-fired generation in each of these years. This is due to the accelerated procurement of a Hazelwood SSN synchronous condenser in 2028 and 2029 relative to Option 3. The additional synchronous condenser displaces coal-fired generation, resulting in more emission benefits relative to Option 3 and explains why Option 4 ranks first in gross market benefits.

Hydro running hours are not as decisive in understanding market benefits as coal running hours because hydro dispatch has zero marginal cost for the purpose of this modelling, so spreading hydro dispatch over more hours does not actually increase its cost. However, this implies spreading hydro dispatch over more operating hours by generating at lower output levels is a more efficient outcome from the perspective of system strength costs. Figure 14 shows that Options 3 and 4 have the most hydro operating hours since Option 1 has materially less hydro operating hours from 2034 onwards. This implies hydro is used more efficiently under Options 3 and 4 from the perspective of system strength supply and these options also have the highest gross market benefits.

Figure 14 shows that Option 4 has the least running hours of Victorian natural gas, with Options 1 and 2 having more running hours than Option 3. These outcomes broadly align with the gross market benefit rankings of the options, in that Options 3 and 4 have less Victorian gas usage than Options 1 and 2.

Figure 13: Difference in running hours compared to Option 3, coal-fired generation[12]

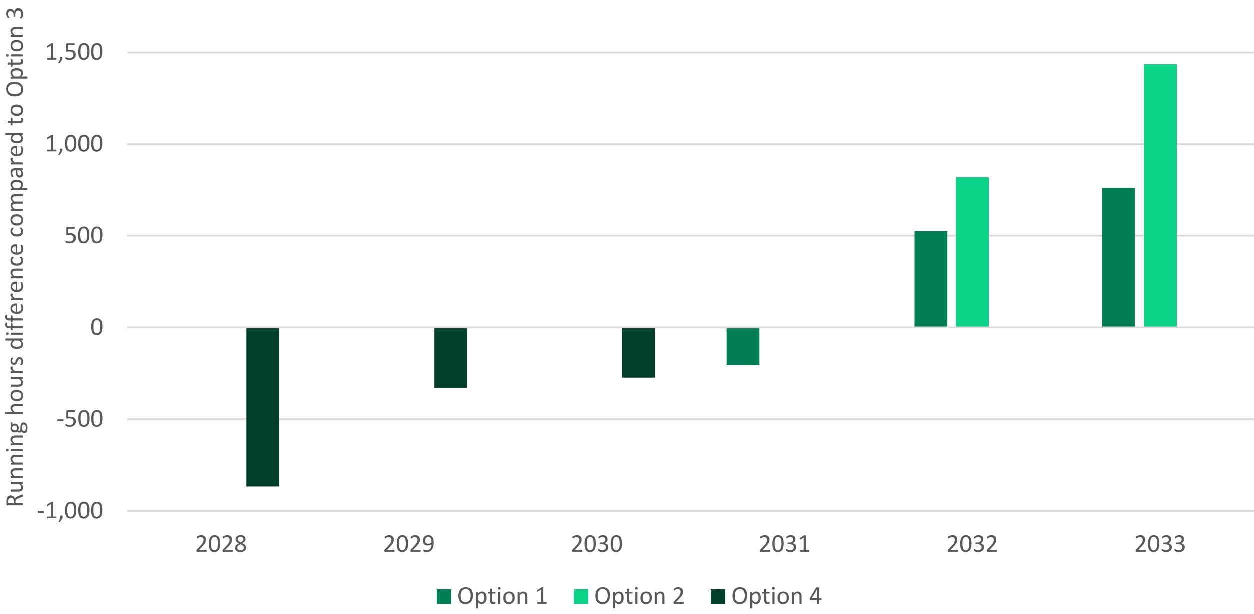
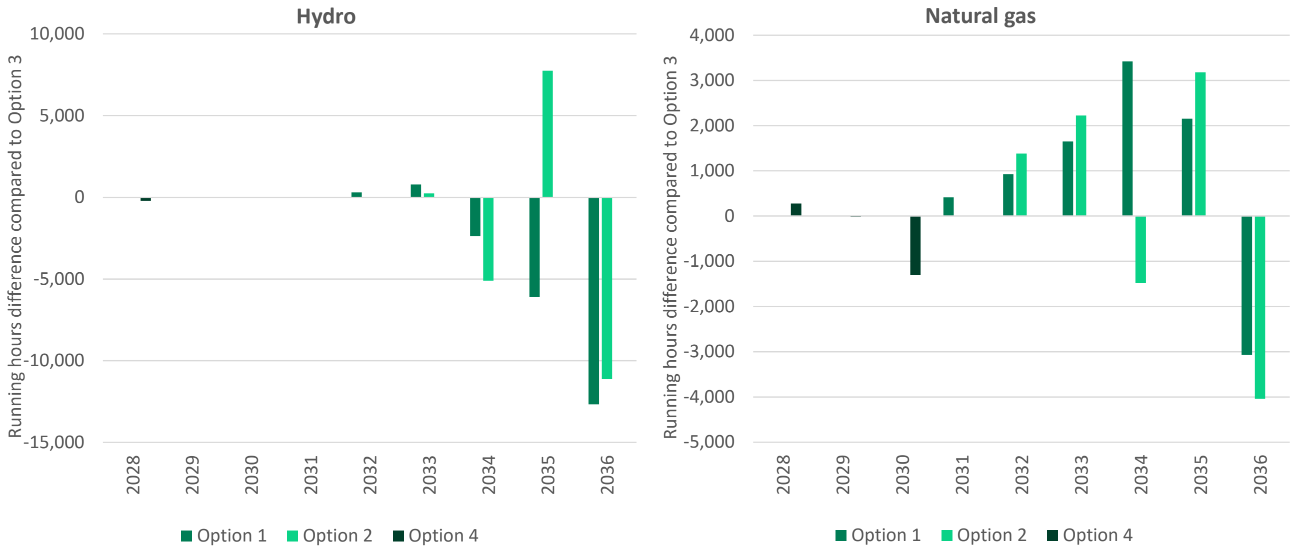


Figure 14: Difference in running hours compared to Option 3, hydro and natural gas



12 2026 and 2027 have been removed from both charts because outcomes are identical in those years across the four option portfolios.

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