

2025 Victorian
Transmission Plan
August 2025

Appendix D

Economic appraisal



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Acronyms

Term	Definition
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery energy storage systems
CBA	Cost benefit analysis
CGE	Computable general equilibrium
CIS	Capacity Investment Scheme
CPI	Consumer price index
DTF	Department of Treasury and Finance
EIRR	Economic internal rate of return
FTE	Full time equivalent
FY	Financial year
GDP	Gross domestic product
GRP	Gross regional product
GSP	Gross state product
GW	Gigawatt (one million kilowatts)
IA	Infrastructure Australia
IASR	Inputs, Assumptions and Scenarios
ISP	Integrated System Plan
LDES	Long duration energy storage
MWh	Megawatt hour (one thousand kilowatt hours)
NEM	National Electricity Market
NPV	Net present value
PHES	Pumped hydro energy storage
PTRM	Post-tax revenue model
RDP	Renewable Energy Zones Development Plan
REZ	Renewable energy zone
TWh	Terawatt hour (one billion kilowatt hours)
USE	Unserved energy
VCR	Value of Customer Reliability
VER	Value of emissions reduction
VNI	Victoria to New South Wales Interconnector
VTP	Victorian Transmission Plan
WRL	Western Renewables Link

Glossary

This glossary has been prepared as a quick guide to help readers understand terms used in this document. Words and phrases defined in the *National Electricity (Victoria) Act 2005* and other Victorian legislation have the meaning given to them in legislation.

Term	Definition
Augmentations	These are improvements or additions made to the existing electricity transmission network to increase its capacity, efficiency, or reliability. This can involve upgrading current infrastructure or building new components to handle increased demand or integrate new generation sources.
Candidate development pathway	A set of possible transmission projects and proposed timings to upgrade the Declared Shared Network, needed to accommodate the development of new generation and storage capacity in REZs.
Committed	Generation and storage projects are considered committed if they have reached a sufficiently advanced stage of planning and development. Projects have been considered committed for the purposes of energy market modelling in the VTP if they meet any of the following criteria: <ul style="list-style-type: none"> it was classified as Committed or In Commissioning by AEMO as at April 2025, or it is completed or in the construction phase as identified in AEMO Victorian Planning's Connections Portfolio list as at May 2025, or it was successful in CIS auction results released in or before December 2024, or it was successful in the VRET2 auction results.
Curtailment	A situation where energy generators are required to limit their energy supply into the market due to capacity limitations on the grid and corresponding market signals.
Declared Shared Network	The Victorian interconnected high-voltage power lines and shared terminal stations that transport large amounts of electricity from where it is generated to where it is needed across the state. It allows multiple electricity providers to share the infrastructure for transporting electricity. Sometimes wind and solar developments need to build their own private lines to connect their project to the shared network.
Integrated System Plan	An integrated 20-year plan for the efficient development of the National Electricity Market (NEM), prepared every 2 years by the Australian Energy Market Operator.
The optimal development pathway	The optimal mix of transmission projects needed to connect REZs with Victoria's Declared Shared Network over the next 15 years, taking into account economic cost-benefit and robustness analysis across different scenarios, as well as power system security and reliability. For the 2025 VTP, the optimal development pathway sets out proposed projects and sequencing over the next 15 years. Future VTPs will take a 25-year timeframe.
Renewable energy zone (REZ)	An area declared in a renewable energy zone Order where a REZ access scheme and special benefits arrangements will apply.
REZ access scheme	A scheme, under the proposed Victorian Access Regime, declared by the Minister for Energy and Resources which sets out arrangements governing network connections for new renewable generation and storage projects located in a REZ. These arrangements include access limits for each type of renewable generation, access fees, access conditions, and the process for allocating access.

Term	Definition
Robustness analysis	Robustness analysis is undertaken on all candidate development pathways to select the one that performs best (i.e., can adapt with minimal cost) across all scenarios. This approach, often called ‘least worst regrets’, is used to determine the optimal development pathway and seeks to minimise the risks of over- and under-investment.
Scenarios	Scenarios are a collection of assumptions that describe how the future may unfold. Scenario-based planning is useful in highly uncertain environments, and can help assess future risks, opportunities, and development needs in the energy industry.
Strategic land use assessment	An assessment that identifies suitable areas for siting infrastructure based on a range of social, cultural, technical, environmental, and economic factors.
Traditional Owner	A member of a Traditional Owner group, having the meaning set out in the <i>Traditional Owner Settlement Act 2010</i> . Traditional Owners have rights that must be upheld as laid out under the <i>Charter of Human Rights and Responsibilities Act 2006</i> , the <i>Traditional Owner Settlement Act 2010</i> , <i>Aboriginal Heritage Act 2006</i> and <i>Native Title Act 1993</i> (Cth).
Victorian Access Regime	The proposed set of new rules, to be defined under the <i>National Electricity (Victoria) Act 2005</i> , for how new generation projects can connect to the Declared Shared Network, both within and outside of REZs. Under the Victorian Access Regime, the Minister will declare REZ access schemes, and all new generation projects outside of REZs will be subject to a Grid Impact Assessment to reduce the risk of curtailment for REZ generators.
Victorian Transmission Investment Framework	A set of reforms being implemented to transmission planning in Victoria, including: a new transmission planning objective; a new planning process through the Victorian Transmission Plan; the Victorian Access Regime; new community and Traditional Owner benefit arrangements; and new approaches to procuring transmission infrastructure.
Victorian transmission plan	A document setting out an optimal set of transmission projects that address the planning and development needs over the following periods related to new major electricity transmission infrastructure to facilitate connection of renewable energy zones to the declared shared network: (a) 15 years for the first Victorian transmission plan; (b) 25 years for each subsequent Victorian transmission plan.

Appendix D: Economic appraisal

Appendix D: Economic appraisal – summary

This appendix details the comprehensive approach adopted to assess the economic costs and benefits of the candidate development pathways (CDPs) to help identify the optimal development pathway for the 2025 Victorian Transmission Plan (VTP). This analysis considers the feedback received on the draft VTP.

The appendix covers:

- the economic appraisal framework for the analysis of economic costs and benefits of the core development pathways
- overview of the core scenarios
- the cost benefit analysis including detailed overview of the core scenario costs and benefits methodology
- the economic evaluation results, including the robustness analysis.

D.1 Economic appraisal framework

D.1.1 Context

VicGrid is developing and implementing a new statewide approach for how renewable energy and transmission infrastructure is planned. This new approach includes delivering the VTP – a long-term strategic plan for renewable energy infrastructure and transmission development in Victoria.

The VTP economic appraisal framework expands on traditional engineering and cost focused transmission planning methodologies to incorporate broader economic, social and environmental considerations. The economic appraisal incorporates these considerations through:

- energy market modelling that reflects the renewable energy zone (REZ) development process and associated transmission planning considerations, through a range of constraints that incorporate strategic land use assessment (SLUA) outcomes, community feedback, regional development priorities and developer and generator interest across Victoria
- the consideration of social and environmental benefit categories within the cost benefit analysis (CBA), including avoiding greenhouse gas emissions, avoiding health costs and embodied emissions.

D.1.2 Overview

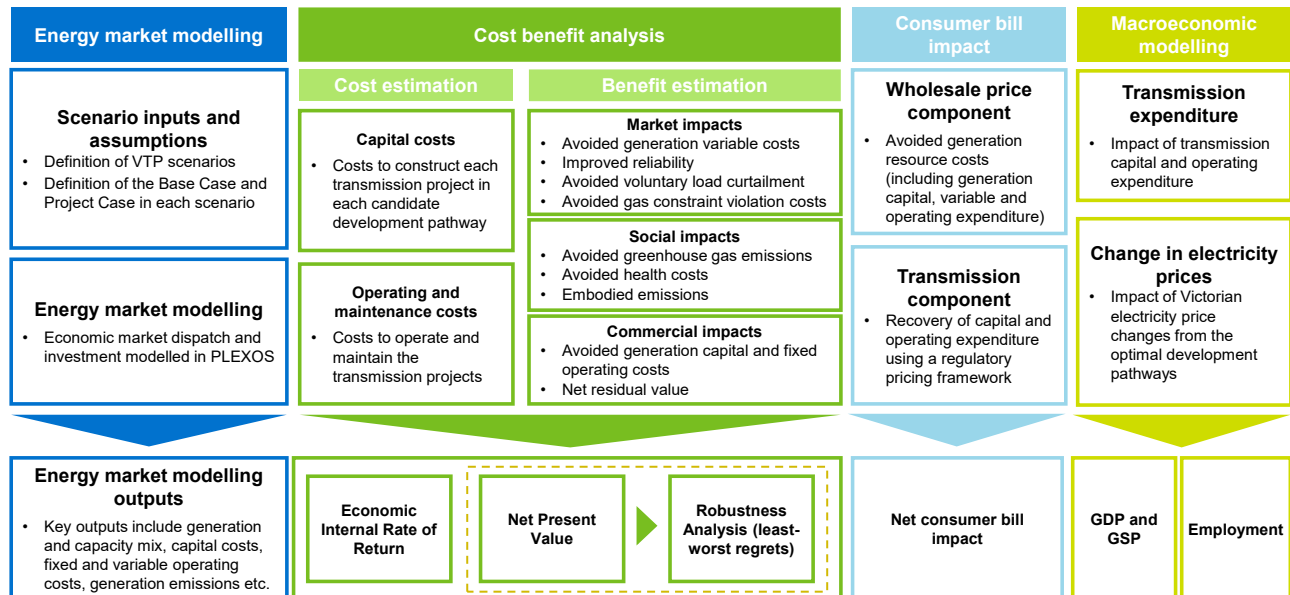
The economic appraisal compares the incremental impacts of a Project Case relative to a Base Case:

- **Base Case:** the Base Case represents a future without major transmission augmentations beyond those already committed to or anticipated under the ISP (meaning the VTP is excluded)
- **Project Case:** the Project Case includes the candidate development pathways developed for the VTP

See Section D.2.4 for a detailed definition of the VTP Base Case and Project Case. Further information on the VTP projects (including those delivered in the Base Case) is provided in Appendix A.

The approach and parameters used in this appraisal are derived from relevant guidelines and agreed assumptions and inputs from a range of stakeholders including VicGrid, the Victorian Department of Treasury and Finance (DTF) and Infrastructure Australia (IA). VicGrid has estimated project capital costs using industry benchmarks and data sources.¹ The economic appraisal framework is summarised in Figure D-1.

Figure D-1: VTP economic appraisal framework



The economic appraisal framework includes 4 components:

- Energy market modelling
- Cost benefit analysis
- Consumer bill impact assessment
- Macroeconomic modelling.

These are discussed in turn below.

D.1.2.1 Energy market modelling

Outputs of energy market modelling undertaken in the energy market modelling software, PLEXOS, are applied across the economic appraisal. For example, differences in generation and capacity mixes between the Base and Project Cases (and the resulting differences in costs) are core inputs to the CBA – facilitation of lower-cost renewable generation will be a primary benefit of the VTP. Differences in generation costs then form the basis for the consumer bill impact, itself a key input to the macroeconomic modelling. The approach to, and results of, VTP energy market modelling are detailed in Appendix B. PLEXOS outputs are reported in \$FY23. For the purposes of the economic appraisal, these have been escalated to \$FY25 values based on changes in the consumer price index (CPI).²

¹ Cost estimates are appropriate for use within the economic appraisal, which represents a comparative or relative analysis between the VTP and a counterfactual.

² The VTP economic appraisal was prepared in the first half of calendar year 2025. June quarter 2025 CPI was estimated assuming it is equal to March quarter CPI.

D.1.2.2 Cost benefit analysis

The CBA compares the system-wide costs and benefits of each candidate development pathway. Costs include capital and operating expenditures, while benefits fall into 3 broad categories:

- **Market impacts** – changes in the variable operating costs incurred to generate electricity, as well as reliability benefits, avoided voluntary load curtailment and avoided gas constraint violation costs
- **Social impacts** – benefits to society that result from decreased greenhouse gas emissions, a reduction in health expenditure and changes to embodied emissions
- **Commercial impacts** – avoided generation capital and operating costs and net residual value of infrastructure at the end of the appraisal period.

The methodologies used to analyse the economic costs and benefits are discussed further in Section D.3.2 and Section D.3.3, respectively.

The CBA also includes a robustness analysis to identify the most robust, or optimal, candidate development pathway. This analysis determines the level of 'regret' (or benefits foregone) for each candidate development pathway in each scenario, with the most robust pathway being the one with the least-worst regret across all scenarios. The robustness analysis methodology and results are detailed in Section D.3.6.

D.1.2.3 Consumer bill impact assessment

The VTP is expected to impact the wholesale and transmission components of consumer bills. The bill impacts are assessed over the period (2029 (commencement of the first VTP project) to 2050 (end of the market modelling period)). The consumer bill impacts of the VTP are shown in Section D.4.

D.1.2.4 Macroeconomic modelling

The macroeconomic modelling provides an understanding of the 'economy-wide' flow-on impacts of the economic/productivity enhancing benefits using a Computable General Equilibrium (CGE) model. The outputs of the CGE model are not cumulative to the economic benefits calculated in the CBA but provide a complementary view on the net economic contribution of the VTP. The macroeconomic impacts are detailed in Section D.5.

D.1.3 Key inputs and assumptions

The key inputs and assumptions used in the economic appraisal include:

- scenarios of future energy requirement – refer to Section 2.3 of the VTP for a description of the 3 scenarios used in the VTP economic appraisal for more detail
- capital costs – capital expenditure of the projects, excluding allowances for land acquisition, VicGrid and development/delivery partner, financing and risk
- operating and maintenance costs – all necessary recurrent costs to operate, maintain and renew transmission infrastructure delivered in each candidate development pathway. Costs are assumed to be 1 per cent of capital costs per annum
- energy market forecasts – outputs from the PLEXOS modelling for 2025 through to 2050,³ including the following variables, with annual values held constant from 2050 to the end of the appraisal period:
 - unserved energy
 - generation by fuel source
 - capacity by fuel source
 - wholesale electricity prices (volume-weighted and generation-weighted)
 - short run marginal costs
 - greenhouse gas emissions
 - generation capital expenditure and operating expenditure
 - consumption
 - gas consumption constraint violation costs
 - demand side participation costs and quantities
- unit rates – primarily based on the Australian Energy Market Operator's (AEMO) and the Australian Energy Regulator's (AER) documentation
- applicable evaluation parameters – key input parameters are summarised in Table D-1.

³ Refer to Appendix B for further detail regarding energy market modelling inputs and assumptions.

Table D-1: Key input parameters

Parameter	Value	Description
Discount rate, real	7% (central) 4%, 10% (sensitivity analysis)	Consistent with DTF ⁴ and IA ⁵ guidelines. Economic appraisal uses a discount rate to convert future costs and benefits into present values, that is the value of those costs and benefits in the present day.
Cost certainty	Class 5 estimate	Cost certainty reflects the confidence that a project will end up costing the expected final amount. Given the level of design information that will be available for the Final VTP, the cost certainty will align with the Class 5 costs estimates on the Association of Advancement of Cost Engineering's International Cost Estimate Classification System, which is broadly considered as a Strategic Estimate to -50% to +100% accuracy level.
Capital cost escalation rate (real)	0.7%-1.1%	DTF nominal escalation rates converted to real values. The real escalation rate reflects the price increase over time of a particular good or service, over and above general price changes (i.e. CPI).
Operational commencement	Financial year 2029	Operation of each individual VTP project is assumed to commence the year following its construction completion. Financial year 2029 is the first year in which a VTP project is operational.
Evaluation period	Financial year 2025 to financial year 2058. Includes 30 years of operations – FY2029-FY2058	As per IA and DTF guidance. The residual value of assets is included in the last year of evaluation to incorporate the benefits that will continue to be delivered by assets with economic lives that extend beyond the end of the evaluation period.
Price year	Financial year 2025	Most recent completed financial year.
Base year for discounting	Financial year 2025	To align with the price year.
Carbon price (central)	\$77/tCO ₂ -e (2025)- \$446/tCO ₂ (2050). Held constant thereafter (\$FY25).	Based on AER Value of Emissions (VER). Values escalated to \$FY25 at CPI in CBA. Financial year values are calculated by averaging the values of the corresponding calendar years (e.g., the financial year 2025 value is the average of the calendar year 2024 and 2025 values).
Cost of capital used in consumer bill impacts (real)	Generation – 7.0% Transmission – 1.5%	Cost of capital rates are used to discount future costs and revenues for generation and transmission businesses. These differ from the discount rate applied in the CBA to calculate present values for social costs and benefits. The generation rate is sourced from the AEMO 2023 inputs, assumptions and scenarios (IASR) workbook. The transmission rate is calculated from parameters in the most recent AusNet Post-Tax Revenue Model (PTRM).

D.2 Scenarios assessed

D.2.1 Overview

This section describes the scenarios and candidate development pathways assessed in the economic appraisal. These inform the Base Cases and Project Cases used in the CBA.

D.2.2 Scenarios

Future demand for electricity in Victoria is uncertain. To account for this, 3 scenarios of future market conditions are considered as part of the economic appraisal, consistent with scenario 1, scenario 2 and scenario 3 as described in Section 2.3 of the VTP.

- Scenario 1 considers a potential future where the Victorian energy sector evolves in line with AEMO's national step change trends. The 2024 ISP describes this scenario as representing a transition pace that enables Australia's efforts to limit global temperature rise below 2°C, with consumer energy resources modelled to be a key contributor to the transition. Victoria's renewable energy targets, offshore wind targets and storage targets are met
- Scenario 2 considers a potential future where new energy-intensive industries are established in regional and central Victoria at scale, such as data centres, hydrogen production and green aluminium. Demand in this scenario is based on AEMO's national green energy export trends forecast, which models a rapid decarbonisation pathway and the development of low emission energy exports
- Scenario 3 considers a potential future where there may be delays of up to 1 year in delivering new energy infrastructure. There is reduced growth in coordinated consumer energy resources and to reflect broad challenges across the National Electricity Market (NEM), other NEM-Government policies and targets are generally delayed as well.

The scenarios weightings (Table D-2) are generally aligned to the likelihoods applied by AEMO in the 2024 ISP. These inform the robustness analysis, detailed in Section D.3.6, which is required in selecting the optimal development pathway.

The VTP scenarios do not represent VicGrid's view on how the energy transition will occur, nor are they an endorsement of one scenario over another. The development of scenarios for the VTP is important to facilitate planning and manage future risks and uncertainty. To support the analysis of robustness (least regrets), the scenarios have been designed to support a broad range of plausible future states and uncertainties.

Table D-2: Weighting of scenarios

Scenario	Scenario weighting
Scenario 1	43%
Scenario 2	15%
Scenario 3	42%

⁴ DTF (2013). *Economic Evaluation for Business Cases – Technical Guidelines*.

⁵ IA (2021). *Guide to economic appraisal – Technical guide of the Assessment Framework* (pg. 23).

D.2.3 Candidate development pathways

The candidate development pathways are proposed sequences of transmission upgrades over the period from 2025 to 2040. They have been designed to:

- facilitate the connection of the draft proposed renewable energy zones to the Declared Shared Network
- ensure transfer capacity across the transmission network to support generation and load
- ensure transmission network stability and security.

More detailed information about the candidate development pathways can be found in Appendix A.

Each scenario has a corresponding candidate development pathway (referred to as 'core candidate development pathways') specifically designed to address its needs. The CBA focuses on the 3 core candidate development pathways, and assesses each candidate development in each of the 3 scenarios (a total of 9 combinations) in the robustness analysis (illustrated in Figure D-2).

Robustness analysis reflects the uncertainty associated with scenario planning and ensures that the chosen pathway results in the least regret.⁶ See Section D.3.6 for further information on the robustness analysis.

Figure D-2: Overview of scenarios assessed in the CBA

	Scenario 1	Scenario 2	Scenario 3
Base Case	Scenario 1 Base Case	Scenario 2 Base Case	Scenario 3 Base Case
Candidate development pathway 1	CDP 1 Core	CDP 1 Scenario 2	CDP 1 Scenario 3
Candidate development pathway 2	CDP 2 Scenario 1	CDP 2 Core	CDP 2 Scenario 3
Candidate development pathway 3	CDP 3 Scenario 1	CDP 3 Scenario 2	CDP 3 Core

Core CDPs – Scenarios to be reported in detail throughout Appendix D.
 Other CDPs – Scenarios will be key inputs in the robustness analysis but will not be reported individually throughout Appendix D.

⁶ For each scenario, the robustness analysis identifies the candidate development pathway with the highest net present value of benefits. Proceeding with any other candidate development pathway within this scenario would therefore lead to foregone benefits. These foregone benefits reflect the 'regret' associated with each candidate development pathway in a particular scenario. Refer to Section 0 for further information on the robustness analysis.

D.2.4 Base Case and Project Case definition

The economic evaluation assesses and compares the incremental costs and benefits of the Project Case relative to a Base Case:

- **Base Case:** the Base Case represents a future without major transmission augmentations beyond those already committed to or anticipated under the ISP (meaning the VTP is excluded)
- **Project Case:** the Project Case includes the candidate development pathways developed for the VTP

D.2.4.1 Base Case

The Base Case represents a future without major transmission augmentation beyond those already committed to or anticipated under the ISP. The Base Case provides a counterfactual future (a hypothetical scenario) to compare the costs and benefits of the candidate development pathways against. Each scenario has a unique Base Case, reflecting the differences in demand and the timing of committed or anticipated transmission projects across the scenarios (as shown in Figure D-2). As a result, each Base Case will have a different generation and capacity mix.

D.2.4.2 Project Case

There are 7 transmission programs included in candidate development pathway 1 and 3, and 10 programs in candidate development pathway 2 – see Appendix A for the list of transmission projects the programs comprise of. These projects provide a systematic approach to unlocking further generation capacity in the Victorian electricity network and ensuring system stability.

The benefits that are quantified for the candidate development pathways are discussed in Section D.3.3.

D.3 Cost benefit analysis

D.3.1 Overview

As discussed above, the CBA focuses on the 3 core candidate development pathways, with additional robustness analysis undertaken to assess each candidate development pathway in each scenario. The CBA compares the capital and operating costs of each candidate development pathway to their anticipated benefits:

- **Market impacts** – changes in the variable operating costs incurred to generate electricity, as well as reliability benefits, avoided voluntary load curtailment and avoided gas constraint violation costs
- **Social impacts** – benefits to society that result from decreased greenhouse gas emissions, a reduction in health expenditure and changes to embodied emissions
- **Commercial impacts** – avoided generation capital and operating costs and net residual value of infrastructure at the end of the appraisal period.

D.3.2 Economic costs

D.3.2.1 Overview

DTF and IA guidelines note that only economic costs are to be included in an economic analysis. Economic costs include incremental costs relative to the Base Case necessary to implement each candidate development pathway, such as capital and recurrent costs but exclude all sunk costs and transfer payments.

Economic costs are expressed as real values (using a 2025 price base). A real value is a value that has been adjusted to remove the effects of general price level changes over time (i.e. CPI).

D.3.2.2 Capital costs

Capital costs reflect the capital expenditure of the projects, excluding allowances for land acquisition, VicGrid and development/delivery partner, financing, and risk. These exclusions are consistent with the Class 5 estimate level, however VicGrid has undertaken sensitivity analysis to consider the impact of increased costs on the cost-benefit analysis. The results of these sensitivity tests are presented in Section D.3.5

The capital costs are escalated using real escalation, which reflects real increases in costs over and above CPI.⁷ The cumulative real, escalated, undiscounted net capital expenditure of each candidate development pathway is:⁸

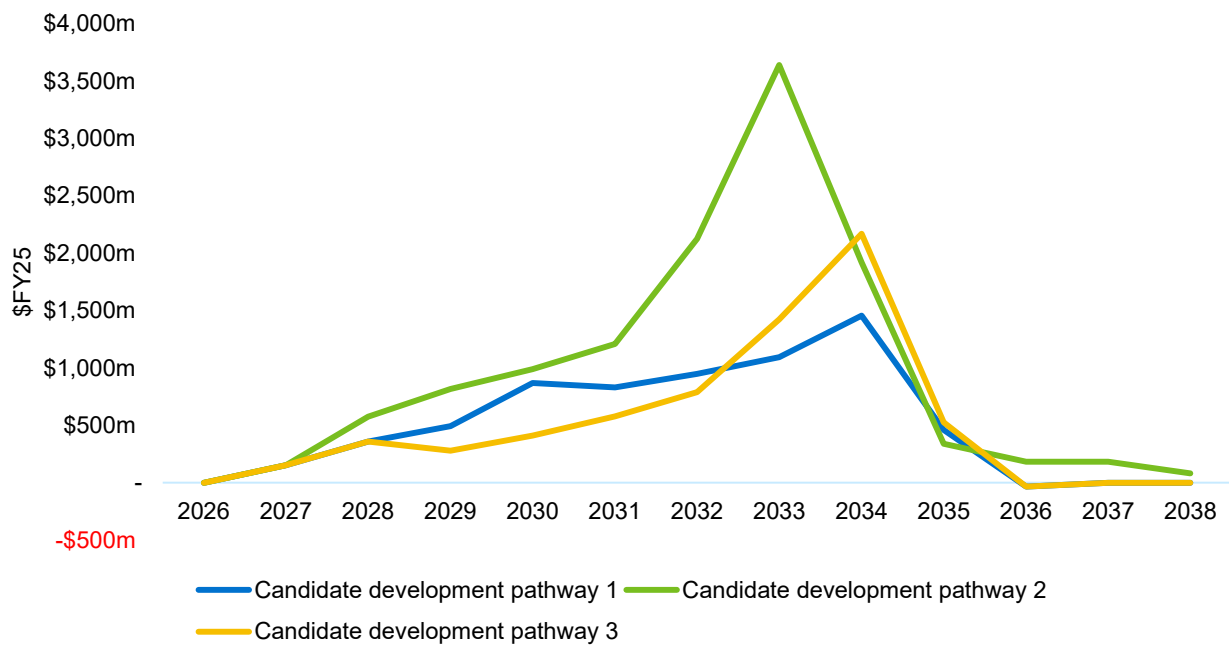
- Candidate development pathway 1: \$6,600m
- Candidate development pathway 2: \$12,200m
- Candidate development pathway 3: \$6,700m.

Figure D-3 shows the net capital expenditure by year for each core candidate development pathway. Negative values in the late 2030s represent a net cost saving compared to the base case. Figure D-4 shows the cumulative spend by year for each core candidate development pathway.

⁷ DTF (2024)

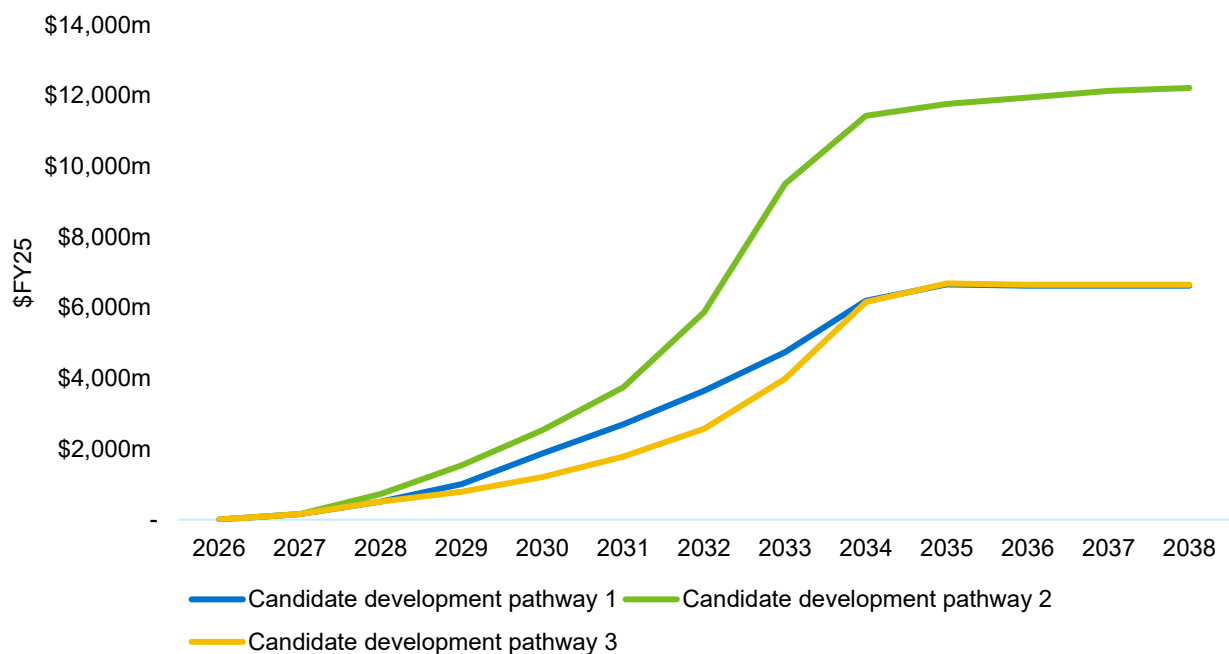
⁸ Construction of the transmission projects occurs between financial years 2026 and 2038

Figure D-3: Real, escalated, undiscounted net capital expenditure by year (\$FY25) for each core candidate development pathway



Source: VicGrid analysis

Figure D-4: Real, escalated, undiscounted cumulative net capital expenditure (\$FY25) for each core candidate development pathway



Source: VicGrid analysis

Base Case transmission capital expenditure

Some VTP projects are also expected to occur in the Base Case as they are critical to replace end-of-life assets or relate to offshore wind (which is assumed to occur in both the Base Case and Project Case). There are 8 such transmission projects, as shown in Table D-3. These are in addition to the baseline projects outlined in Appendix A:

- Renewable Energy Zone Development Plan (RDP) stage 1 projects
- Marinus Link stages 1 and 2
- Victoria to New South Wales Interconnector (VNI) West
- Western Renewables Link (WRL)
- Gippsland offshore wind transmission stage 1.

The appraisal includes the capital and operating expenditures of the projects outlined in Table D-3 in the Base Case and Project Cases:

- Where there is no difference in project timing between the Base and Project Cases, the costs balance out and there is no net cost increase in the Project Case
- Where there is a difference in timing, the appraisal quantifies the net difference in present value costs between the Base and Project Cases.

These projects are defined in Appendix A. The net difference between Base and Project Case capital expenditure is presented in Section D.3.2.4. Additionally, sensitivity analysis is presented in Section D.3.5 in which the total costs of projects that occur in the Base and Project Cases are not netted-out (as in the core analysis).

Table D-3: VTP projects included in the Base and Project Cases

Transmission project	Reason for inclusion	Capital cost in Base Case (Real \$ FY25, undiscounted)
VTP Projects delivered at the same time in the Project Case compared to the Base Case		
Install a second Gippsland 500 kV double circuit radial line and tie-in loop – Woodside to Driffield section	Offshore wind is developed in both the Base Case and Project Case. Transmission projects that enable the delivery of offshore wind are therefore included in both the Base Case and Project Case.	\$790m
Install a second Gippsland 500 kV double circuit radial line and tie-in loop – Woodside to Giffard section		\$400m
Increase the rating of the Portland to Heywood 500 kV double circuit lines		\$10m
Replace the H1 and H2 South Morang 330/220 kV transformers	The South Morang transformer will reach end of life in 2030 and will need to be replaced.	\$70m
VTP Projects delivered earlier in the Project Case compared to the Base Case		
Install a second 500/220 kV transformer at Cranbourne and tie in the existing Hazelwood to Rowville 500 kV (No.3) circuit at Cranbourne	These 2 projects together will help to relieve projected unserved energy (USE) in Melbourne's east as identified by Eastern Victoria Grid Reinforcement	\$90m

Transmission project	Reason for inclusion	Capital cost in Base Case (Real \$ FY25, undiscounted)
Undertake load management works on the Rowville to Templestowe to Thomastown 220 kV circuit, and Rowville to Ringwood to Thomastown 220 kV circuit	Project Specification Consultation Report.	\$40m
Switch the existing Geelong to Keilor circuits at Deer Park (No.1 and No.3)	These 2 projects together will help to relieve projected USE in Melbourne's west as identified by the Western Metropolitan Melbourne Reinforcement Project Specification Consultation Report.	\$50m
Rebuild the 3 existing circuits from Deer Park to Keilor with new high-capacity double circuit lines		\$250m

D.3.2.3 Fixed operating and maintenance costs

Fixed operating and maintenance costs includes all the necessary costs relating to operating, maintenance and periodical renewal of the candidate development pathway projects. Like the capital costs, only the net difference between the Project and Base Case is assessed in the CBA.

Operating and maintenance costs are estimated at 1 per cent per annum of the total capital cost. This is considered an appropriate figure for operating costs for transmission line works and is consistent with the approach within the AEMO ISP.⁹

D.3.2.4 Cost summary

The incremental costs incurred to deliver each candidate development pathway are outlined in Table D-4.

Table D-4: Economic costs of each core candidate development pathway (real, discounted, \$FY25)

Cost item	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Project Case			
Capital costs	\$5,300m	\$8,700m	\$5,100m
Operating costs	\$550m	\$900m	\$550m
Base Case			
Capital costs	\$1,100m	\$1,100m	\$1,100m
Operating costs	\$100m	\$100m	\$100m
Net costs			
Capital costs	\$4,200m	\$7,600m	\$4,050m
Operating costs	\$450m	\$800m	\$450m

Note: Totals may not add due to rounding

⁹ AEMO 2023 Transmission Expansion Options Report

D.3.3 Economic benefits

This section discusses the benefits to be delivered by the candidate development pathways. The economic benefits are summarised into 3 broad categories:

- **Market impacts** – changes in the variable operating costs incurred to generate electricity, as well as reliability benefits, avoided voluntary load curtailment and avoided gas constraint violation costs
- **Social impacts** – benefits to society that result from decreased greenhouse gas emissions, a reduction in health expenditure and changes to embodied emissions
- **Commercial impacts** – avoided generation capital and operating costs and net residual value of infrastructure at the end of the appraisal period.

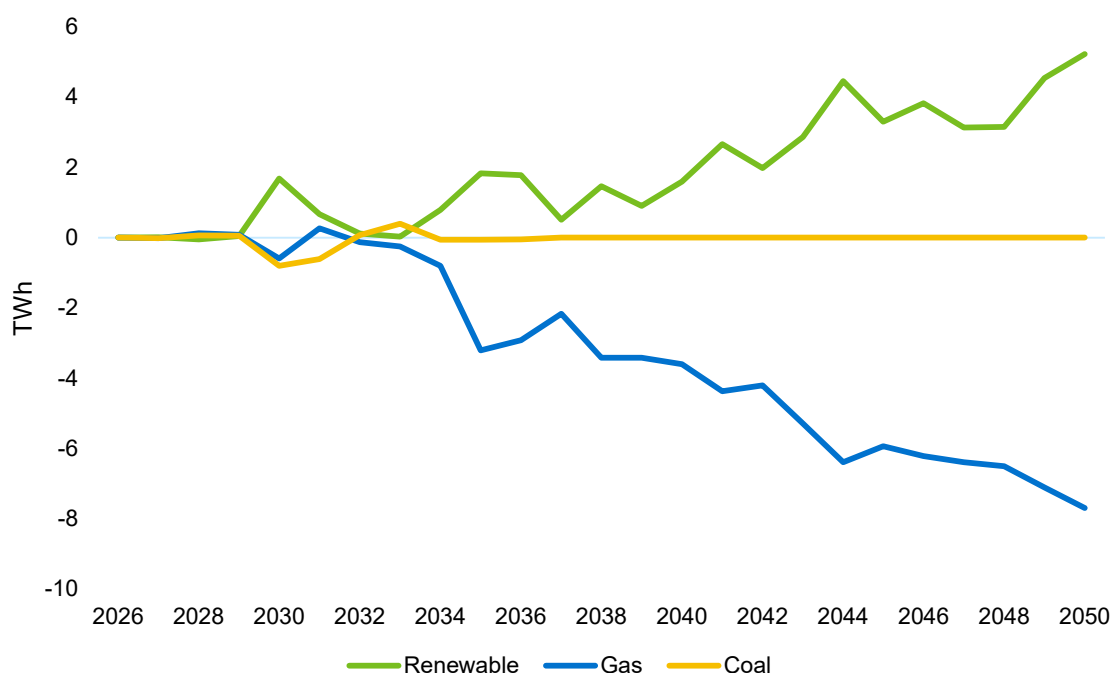
D.3.3.1 Market impacts

Avoided generation variable costs

The variable costs of electricity generation are calculated by multiplying annual generation by the short run marginal cost for each fuel type (informed by AEMO ISP assumptions)¹⁰ – a function of the variable operating and maintenance cost, the heat rate and the fuel cost. The short run marginal cost of renewable energy sources, including solar, battery storage, offshore wind and onshore wind is zero. Coal and gas-powered generation have higher short run marginal costs.

Figure D-5, Figure D-6, Figure D-7 show the change in renewable, gas and coal generation between the Project Case and Base Case for core candidate development pathways 1, 2 and 3 respectively. For all 3 pathways, the increase in renewable generation leads to a net reduction in coal and gas-powered generation. This decreases total generation variable cost benefits in all 3 candidate development pathways.

Figure D-5: Change in renewable, coal and gas generation from Base Case to Project Case – candidate development pathway 1



¹⁰ AEMO (2024). 2023 – 24 inputs, assumptions and scenarios.

Figure D-6: Change in renewable, coal and gas generation from Base Case to Project Case – candidate development pathway 2

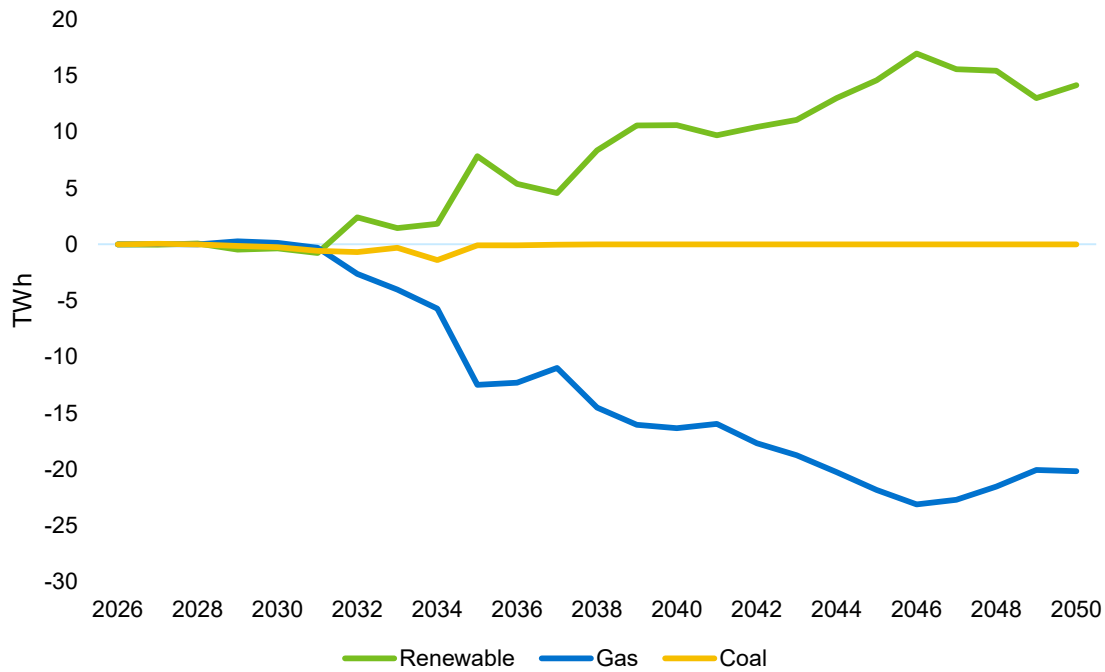
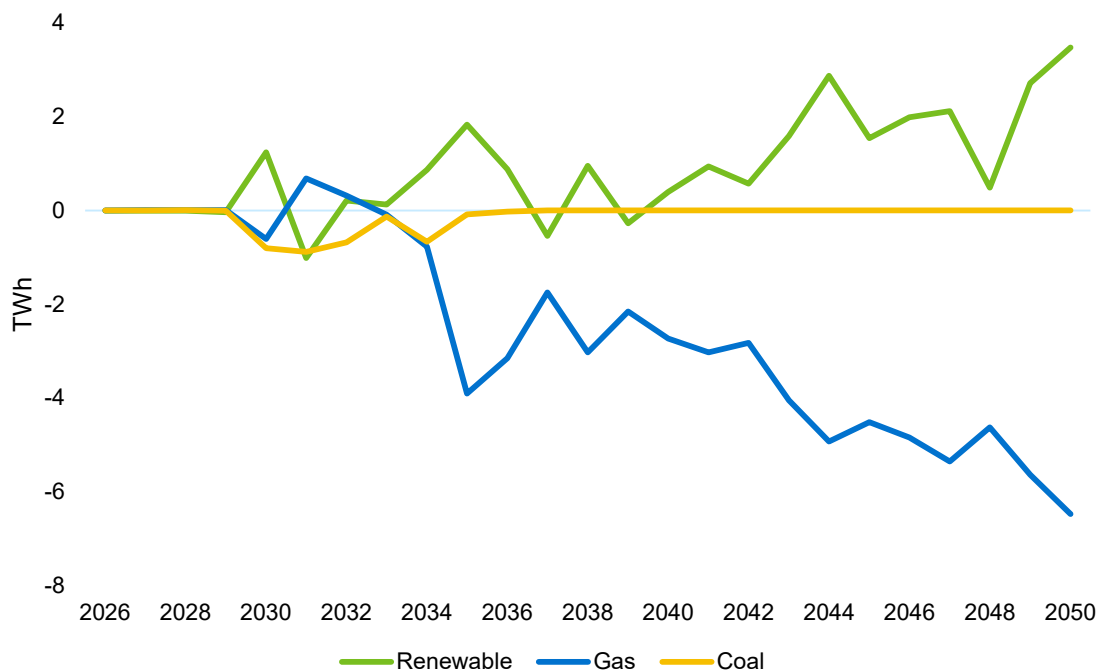


Figure D-7: Change in renewable, coal and gas generation from Base Case to Project Case – candidate development pathway 3



The present value reduction in variable generation costs for each core candidate development pathway is presented in Table D-5.

Table D-5: Value of reduced variable costs of electricity generation, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided generation variable costs	\$5,300m	\$19,300m	\$4,300m

Improved reliability

An electricity system is reliable when the system has enough generation and network capacity to produce and transport electricity to meet customer demand.

For the purpose of reporting against reliability standards, the key measure of energy reliability is USE, which is the amount of customer demand that cannot be supplied within a region due to a shortage of generation, demand-side participation, or interconnector capacity.¹¹

Forecasts of USE are primarily based on PLEXOS modelling. No USE is forecast in either the Base Case or Project Case for any CDP in any scenario from 2026-2050.

While the PLEXOS modelling aims to identify how transmission augmentation can increase efficiency, it does not model how this might reduce limitations on the transmission network more generally or the increased reliability of supply to customers in high growth areas. These are additional to the benefits of more efficient connection of renewable generation.

A subset of the candidate development pathway projects is expected to improve reliability of supply in high growth areas:

- **Eastern Victoria reinforcement program:** Significant involuntary load shedding is expected to occur in the Base Case due to demand growth on the eastern metropolitan Melbourne network.¹² This is intended to be addressed through the Eastern Victoria Grid reinforcement program in both the Base and Project Cases (see Table D-3). Delivery of the program will be brought forward from 2035 in the Base Case to 2030 in the Project Case, meaning that the VTP captures the benefits of reducing USE earlier.
- **Western Victoria reinforcement program:** There is also expected to be significant USE on the western metropolitan Melbourne network and in Western Victoria under the Base Case.¹³ This is planned to be addressed through the Western Victoria reinforcement program, which commences in 2033 in the Base Case in all scenarios. There is no difference in timing between the Base and Project Case for this project in candidate development pathway 1, so no net benefit captured in the analysis. The project is brought forward 1 year in candidate development pathway 2, and delayed 1 year in candidate development pathway 3.

¹¹ Australian Energy Market Commission (2019). *Definition of unserved energy*

¹² AEMO (2024). *Eastern Victoria Grid Reinforcement, Figure 4*

¹³ AEMO (2024). *Western Metropolitan Melbourne Reinforcement, Figure 8*

The benefit of reducing USE is monetised using state-specific values of customer reliability (VCR). The following VCR are applied in the CBA (these have been escalated from September 2024 values to \$FY25 at CPI):¹⁴

- Victoria – \$36.5/kWh
- Tasmania – \$19.4/kWh
- New South Wales – \$31.6/kWh
- Queensland – \$26.3/kWh
- South Australia – \$34.0/kWh.

The present value of energy reliability benefits for each core candidate development pathway is presented in Table D-6.

Table D-6: Improved energy reliability benefit, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Improved reliability based on PLEXOS modelling	-	-	-
Additional improved reliability based on AEMO reports	\$400m	\$400m	\$400m
Total improved energy reliability	\$400m	\$400m	\$400m

Avoided voluntary load curtailment

Delivery of the VTP is anticipated to reduce voluntary load curtailment. This reduction has been valued by multiplying the change in voluntary load curtailment between the Base and Project Cases by the assumed willingness to pay for electricity that is not voluntarily curtailed (approximately \$300–600/MWh over the period 2025–2050).¹⁵

The present value of avoided voluntary load curtailment for each core candidate development pathway is presented in Table D-7.

Table D-7: Avoided voluntary load curtailment, core candidate development pathways (real, discounted, \$FY25)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided voluntary load curtailment	\$16m	\$5m	\$12m

¹⁴ AER (2024). *Values of customer reliability Final report on VCR values, Table 20*

¹⁵ PLEXOS modelling outputs

Avoided gas constraint violation costs

If demand for gas-powered generation exceeds the available supply of gas each year, additional costs are assumed to be incurred to switch from gas to more expensive liquid fuels such as diesel. This benefit category reflects the reduction in these costs in the Project Case compared to the Base Case, due to the decreased demand for gas-powered generation following delivery of the VTP. The assumed availability of gas varies over time and is based on AEMO analysis gas market modelling as adopted in the 2024 ISP Step Change model.

The assumed total gas capacity allowances are:¹⁶

- Scenario 1: 3.6 GW
- Scenario 2: 4.4 GW
- Scenario 3: 3.6 GW.

Gas constraints are exceeded in the scenario 1 and 3 Base Cases. The introduction of additional renewable generation in candidate development pathways 1 and 3 reduces the number of times the gas constraint is exceeded in the Project Case, resulting in avoided gas constraint violation costs.

The constraint is not exceeded in the scenario 2 Base Case, given the greater assumed availability of gas. There are therefore no avoided gas constraint violation costs in this scenario.

The present value of avoided gas constraint violation costs benefits for each core candidate development pathway is presented in Table D-8.

Table D-8: Avoided gas constraint violation costs, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided gas constraint violation costs	\$600m	-	\$450m

¹⁶AEMO 2024 Integrated System Plan (ISP)

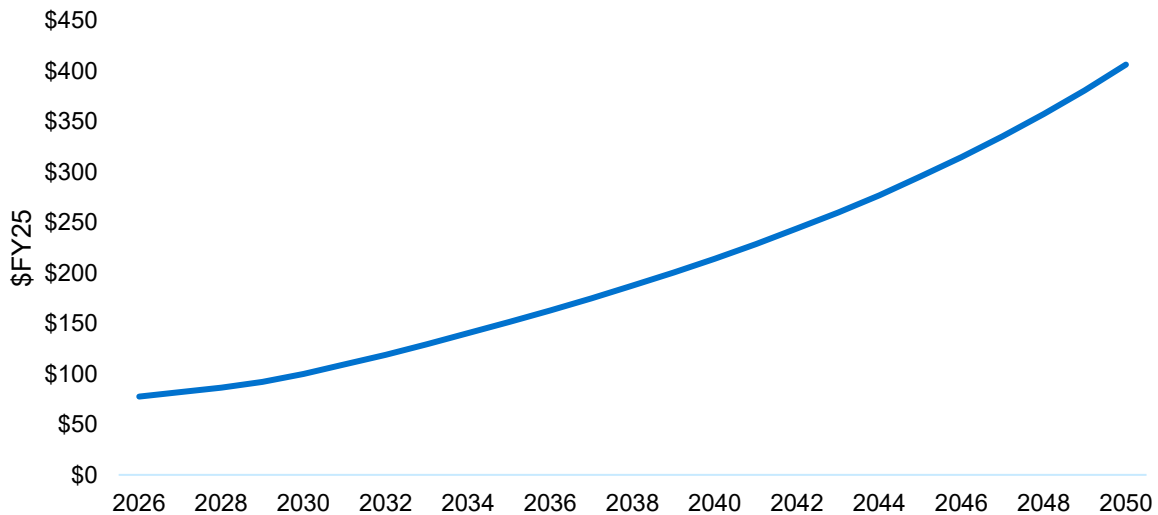
D.3.3.2 Social impacts

Avoided greenhouse gas emissions

The candidate development pathways are intended to facilitate the energy transition by enabling renewable electricity generation and the abatement of greenhouse gas emissions. As shown in Figure D-5, Figure D-6 and Figure D-7, there is a reduction in the generation of fossil fuels in all 3 candidate development pathways against their respective Base Cases. The cumulative emissions avoided in each core candidate development pathway are shown in Figure D-9.

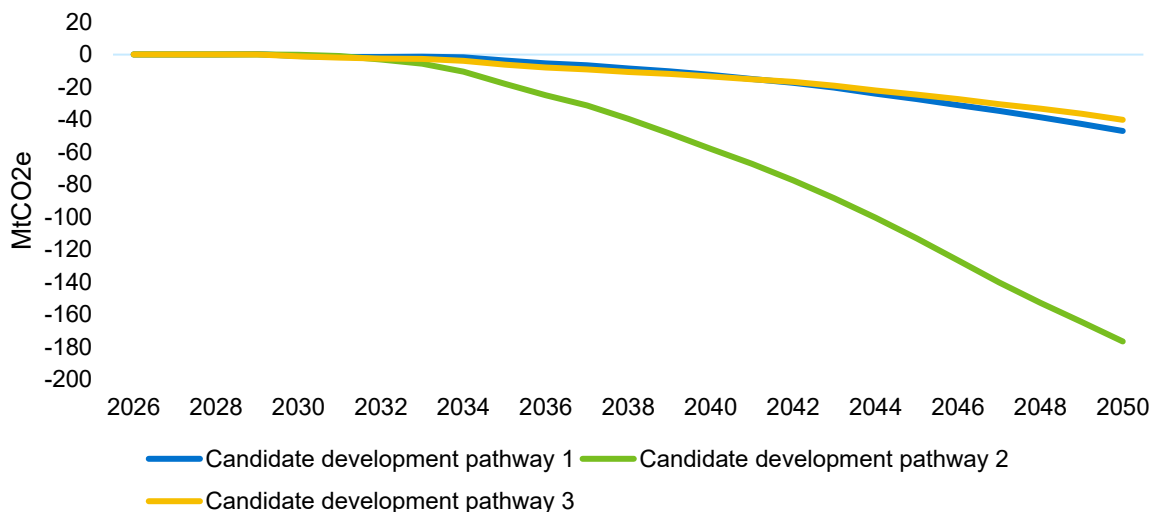
The CBA applies AER values of emissions reduction (Figure D-8) to the total emissions abated, illustrated in Figure D-9. The value per tonne of greenhouse gases emitted increases over time until 2050 and is held constant thereafter. The AER publishes values on a calendar year basis. For the purposes of the CBA, financial year values are calculated by averaging the values of the corresponding calendar years (e.g., the financial year 2025 value is the average of the calendar year 2024 and 2025 values). These have been escalated from \$FY23 values to \$FY25 at CPI).

Figure D-8: Value of greenhouse gas emissions, \$/tCO₂-e (\$FY25)



Source: AER (2024), *Valuing emissions reduction*, Table 1, Australian Bureau of Statistics (ABS) CPI

Figure D-9: Cumulative greenhouse gas emissions avoided, candidate development pathways 1, 2 and 3



The present value of decreased generation emissions for each core candidate development pathway is presented in Table D-9.

Table D-9: Value of decreased generation emissions, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Value of decreased generation emissions	\$6,050m	\$20,150m	\$5,100m

Avoided health costs

The combustion of fossil fuels emits primary air pollutants that negatively impact air quality, the environment and human health.

Secondary pollutants, such as ozone, are formed through reactions between certain pollutants in the atmosphere. Exposure to common air pollutants like sulphur dioxide, nitrogen oxides and fine particulate matter is linked to various health issues, including respiratory and cardiovascular conditions and premature mortality. These costs are over and above the cost of carbon emissions.

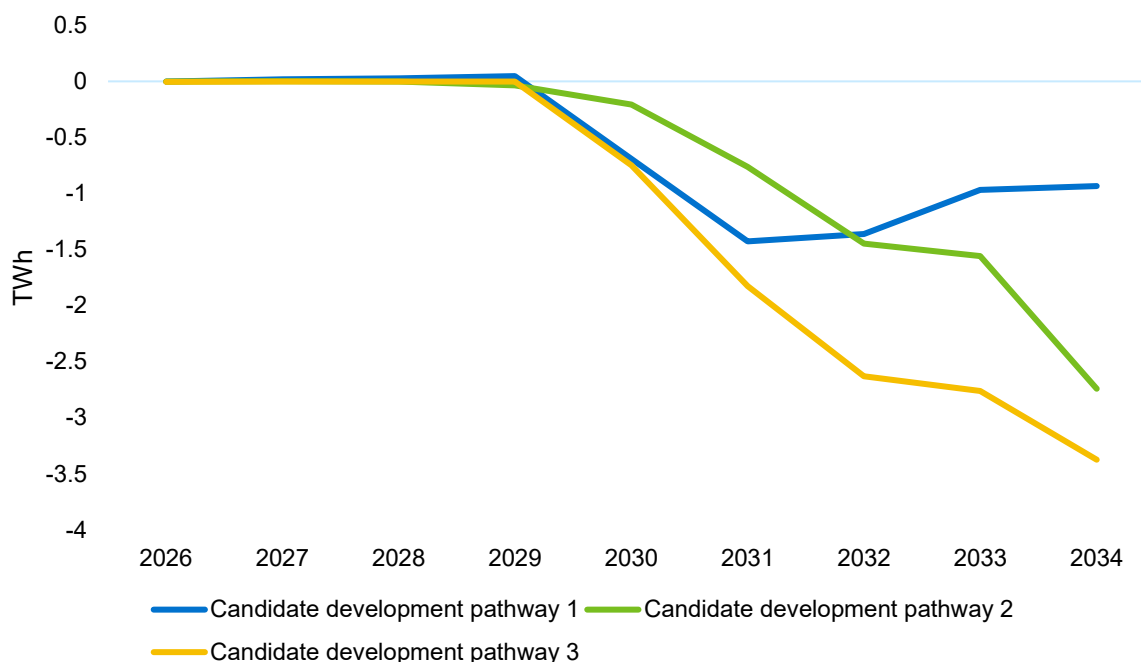
In a 2018 working paper, the Department of Energy, Environment and Climate Action (then the Department of Environment, Land, Water and Planning (DELWP)) estimated the damage costs of electricity generation at the Loy Yang A and Loy Yang B power stations to be \$18.85 and \$16.86/MWh (\$FY18) respectively.¹⁷ The average damage costs of the 2 power stations escalated to \$FY25 is \$22.4/MWh.¹⁸ This damage cost parameter is applied to the incremental difference in coal generation to compute the avoided health costs associated with a reduction in brown coal use across Victoria (no brown coal generation is forecast elsewhere across the NEM).

The cumulative reduction in brown coal generation between the Base Case and Project Case for each core candidate development pathway between 2026 and 2034 (no brown coal use is projected after 2034) is illustrated in Figure D-10.

¹⁷ DELWP (2018) Estimating the health costs of air pollution in Victoria

¹⁸ The other remaining coal power station in Victoria, Yallourn is expected to retire by 2028, and is therefore not included in the calculations

Figure D-10: Cumulative brown coal generation avoided, candidate development pathway 1, 2 and 3



The present value of avoided health costs for each core candidate development pathway is presented in Table D-10.

Table D-10: Avoided health costs, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided health costs	-	\$50m	\$50m

Embodied emissions

Greenhouse gases will be emitted during the construction of transmission and generation infrastructure in the Base and Project Cases. These are referred to as embodied emissions and are estimated by applying the Australian Government calculation methodologies and parameter values.¹⁹

Construction emissions are estimated by multiplying the Australian Government benchmarks for materials share of capital expenditure and carbon emissions per dollar of expenditure. The materials share used in this analysis is 23 per cent.²⁰ Embodied emissions are monetised using the same VER as illustrated in Figure D-8.

¹⁹ Infrastructure and transport ministers (2024). Embodied Carbon Measurement for Infrastructure. Accessed online at [Embodied Carbon Measurement for Infrastructure Technical Guidance](#)

²⁰ Infrastructure and transport ministers (2024). Embodied Carbon Measurement for Infrastructure. Accessed online at [Embodied Carbon Measurement for Infrastructure Technical Guidance](#). As there was not a materials share available for Transmission Line: Double Circuit, a figure of 23% was used, which represents the average across all infrastructure types.

Figure D-11 and Figure D-12 show the cumulative net embodied emissions generated in the Project Case of each core candidate development pathway for transmission and generation infrastructure respectively. While each core candidate development pathway is expected to create emissions from the construction of transmission infrastructure, this will be offset by a reduction in generation embodied emissions. The reduced generation embodied emissions fully offset the additional transmission embodied emissions in core candidate development pathway 3, though only partially in core candidate pathways 1 and 2.

Figure D-11: Net cumulative transmission embodied emissions, candidate development pathway 1, 2 and 3

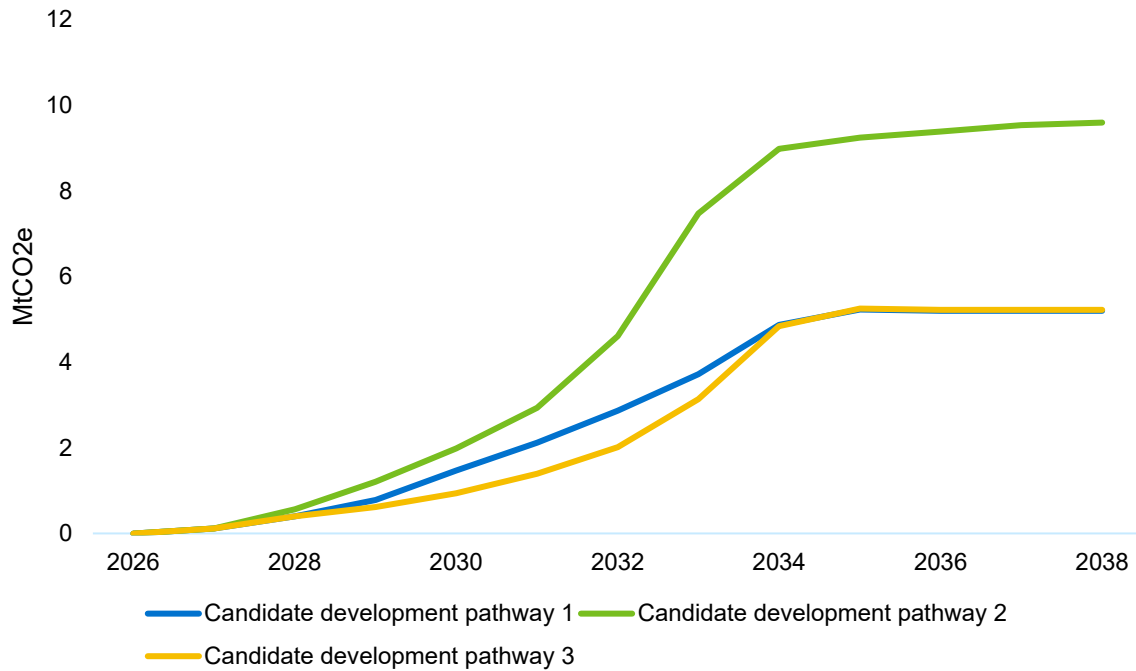
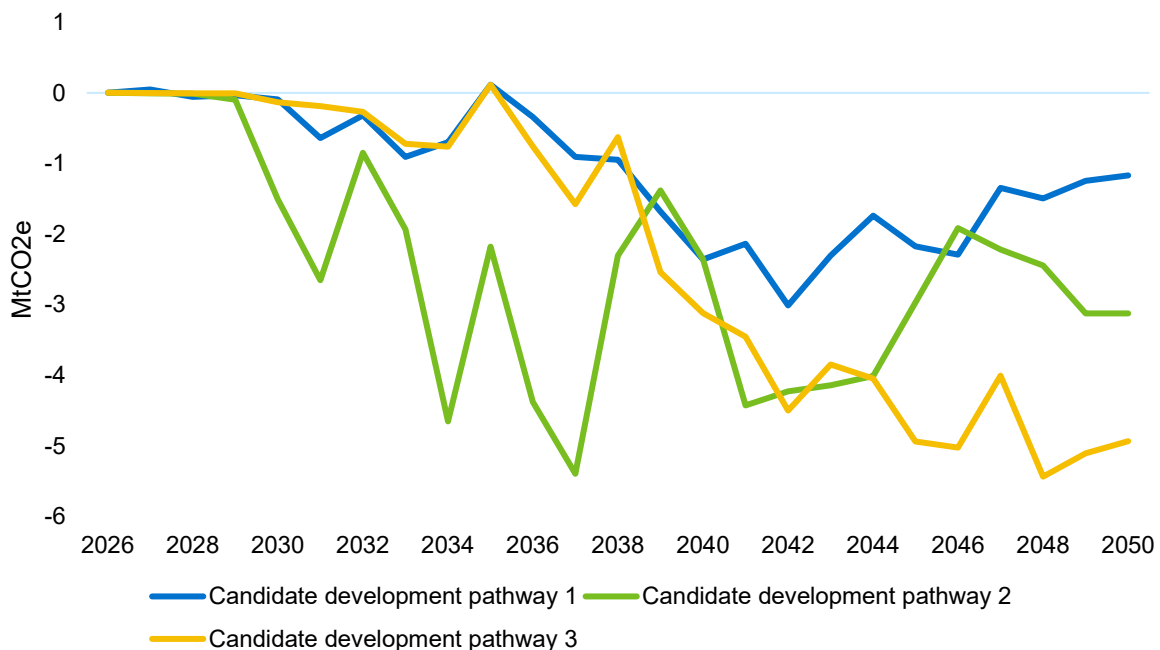


Figure D-12: Net cumulative generation embodied emissions, candidate development pathway 1, 2 and 3



The present value of net embodied emission benefits for each core candidate development pathway is illustrated in Table D-11.

Table D-11: Embodied emission benefits, core candidate development pathway (real, discounted, \$FY25. Rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Transmission embodied emission benefits	-\$400m	-\$750m	-\$400m
Generation embodied emission benefits	\$100m	\$250m	\$400m
Total embodied emission benefits	-\$300m	-\$500m	-

D.3.3.3 Commercial impacts

Avoided generation capital expenditure

The candidate development pathways enable the construction of additional renewable generation in more suitable locations, displacing fossil fuel and other forms of renewable generation in less optimal locations. As a result, some capital expenditure that would otherwise have been incurred in the Base Case to increase generation capacity will be avoided in the Project Case.

Figure D-13, Figure D-14 and Figure D-15 show the net change in capacity for gas, battery energy storage system (BESS), solar, onshore wind, pumped hydro energy storage (PHES, >24) and long duration energy storage (LDES) and for candidate development pathways 1, 2 and 3 respectively. Although there is higher onshore wind capacity in all core candidate development pathways compared to the Base Case, there is a bigger offset in the construction of all other forms of generation, driving a net reduction in total generation capital expenditure. This results in avoided generation capital expenditure benefits.

Avoided capital expenditure is calculated by multiplying the annual change in installed generation capacity by the generation capital expenditure (for each fuel type) using capital cost projections (per kW of generation capacity avoided) for the different generation sources.²¹

²¹ VTP PLEXOS energy market modelling

Figure D-13: Change in total capacity from Base Case to Project Case for core candidate development pathway 1

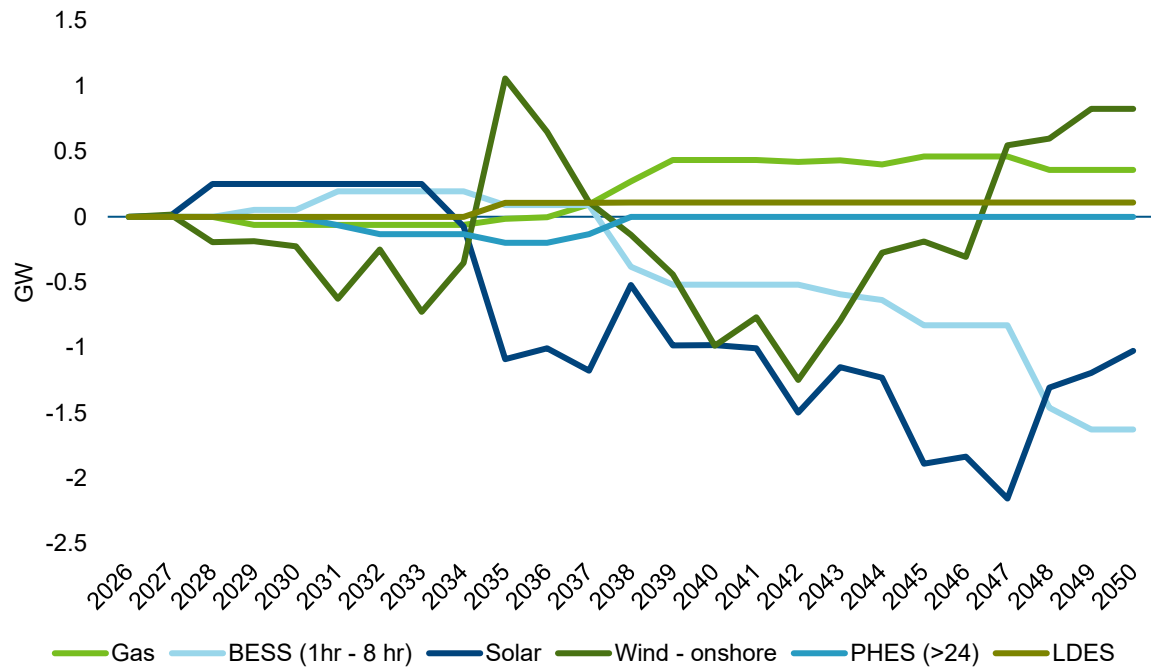


Figure D-14: Change in total capacity from Base Case to Project Case for core candidate development pathway 2

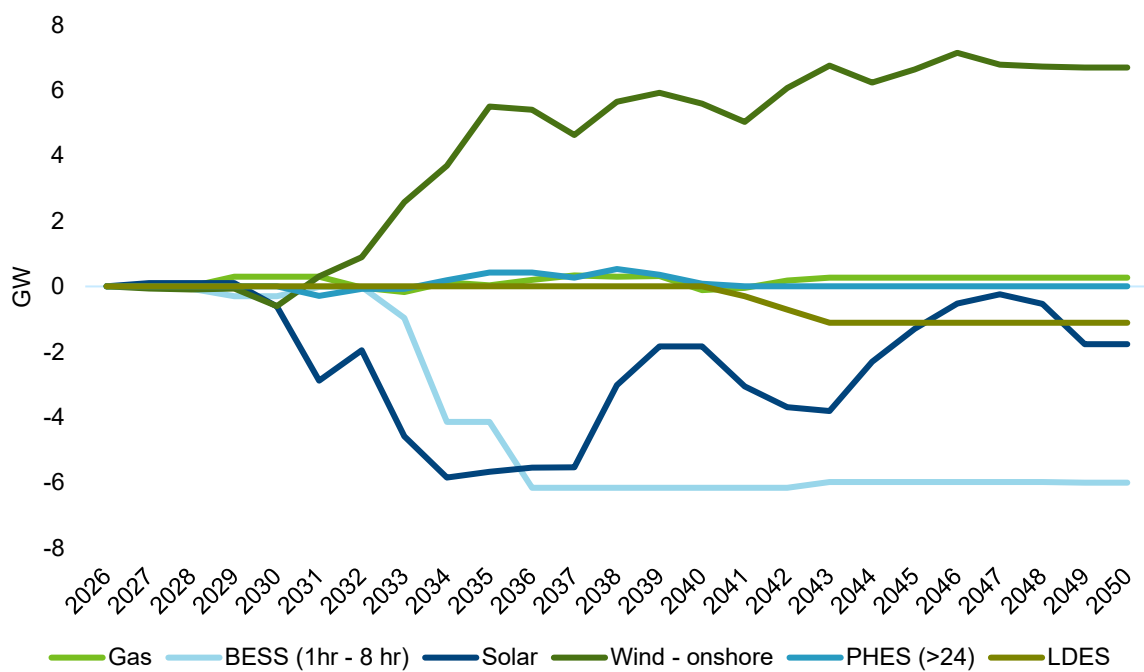
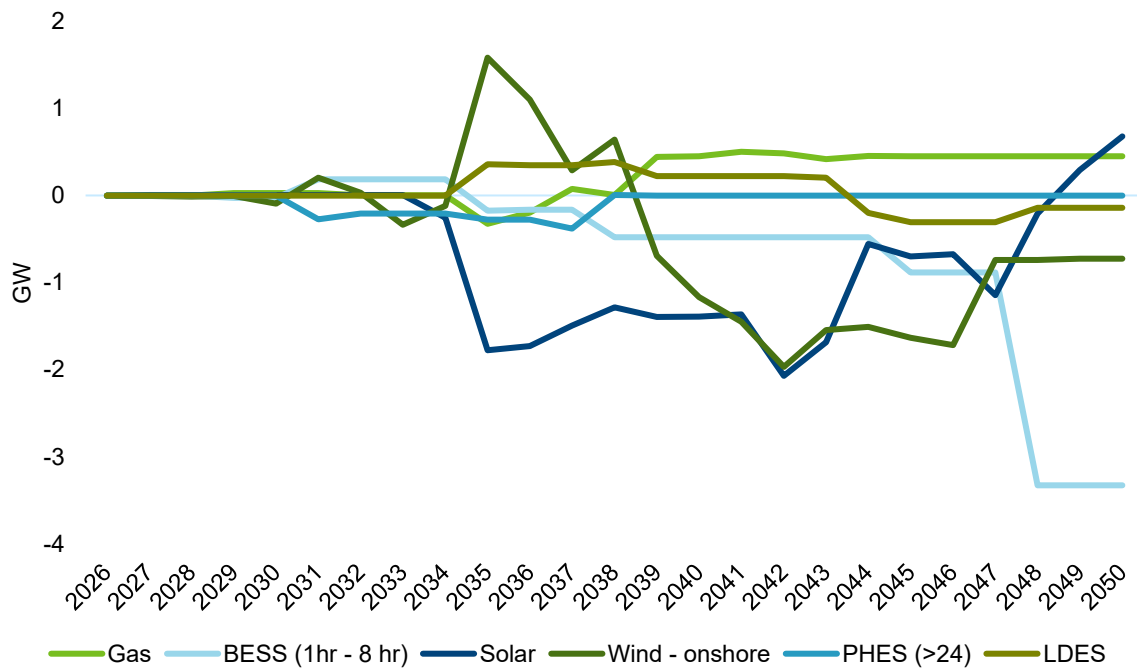


Figure D-15: Change in total capacity from Base Case to Project Case for core candidate development pathway 3



The present value of avoided generation capital expenditure for each core candidate development pathway is presented in Table D-12.

Table D-12: Avoided generation capital expenditure, core candidate development pathway (real, discounted, \$FY25, rounded to nearest \$50m)

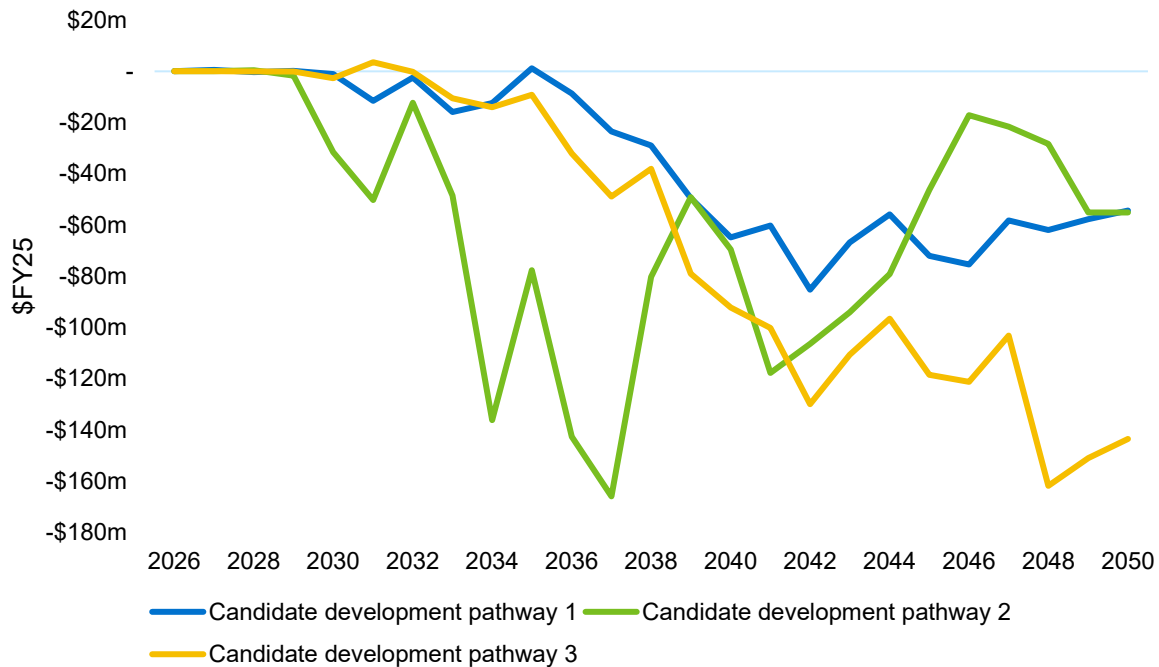
Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided generation capital expenditure	\$1,450m	\$3,800m	\$3,450m

Avoided generation operating and maintenance expenditure

The change in generation mix from the Base Case to the Project Case also leads to a reduction in operating and maintenance expenditure. Only fixed operating and maintenance costs are considered in this benefit category, with changes in variable operating costs considered as part of the market impacts.

Fixed operating and maintenance expenditure is calculated based on the unit costs and capacity mixes of each candidate development pathway. As there is a net reduction in generation capacity in all 3 core candidate development pathways, there is also a resulting decrease in fixed operating and maintenance expenditure. Figure D-16 presents the net reduction in annual fixed operating and maintenance expenditure for each core candidate development pathway.

Figure D-16: Change in annual operating and maintenance expenditure from Base Case to Project Case for the core candidate development pathways (undiscounted, \$FY25)



The present value of avoided generation operating and maintenance expenditure for each core candidate development pathway is presented in Table D-13.

Table D-13: Avoided generation operating and maintenance costs, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Avoided generation operating and maintenance costs	\$300m	\$650m	\$600m

Net residual asset value

The appraisal period includes 30 years of operations to align with IA and DTF guidance. Notwithstanding this, the investment in other generation and transmission infrastructure required in both the Base Case and Project Case may have an economic life beyond the end of the appraisal period. The residual value is an estimate of the economic benefit of the transmission and generation infrastructure from the end of the appraisal period to the end of the economic life of the asset. Table D-14 shows the asset lives for transmission and generation infrastructure.

Table D-14: Assumed asset useful life (years)²²

Benefit	Asset life
Transmission infrastructure	50
Open cycle gas turbine	40
Large scale photovoltaic solar	30
BESS (1–8 hours storage)	20
Wind – onshore	30
Wind – offshore	30
PHES	50
LDES	50

The value of assets at the end of the evaluation period (excluding decommissioning or disposal costs) is discounted to present values. Each of the core candidate development pathways' net residual value is summarised in Table D-15. The net residual asset value is positive in all greater build out of transmission infrastructure compared to candidate development pathways 1 and 3.

Across all scenarios, less generation infrastructure is constructed in the Project Case compared to the Base Case in total over the period 2025-2050. However, in core candidate development pathways 1 and 2, more wind capacity is constructed in the Project Case compared to the Base Case which retains much of its value by the end of the appraisal period. This results in a positive net residual asset value for generation assets. In core candidate pathway 3 however, less wind capacity is constructed in the Project Case compared to the Base Case, and the net residual asset value for generation assets is negative.

The higher net residual asset value of transmission assets in core candidate development pathway 2 reflects the greater build out of transmission infrastructure compared to candidate development pathways 1 and 3.

Table D-15: Net residual asset value, core candidate development pathways (real, discounted, \$FY25, rounded to nearest \$50m)

Benefit	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Transmission residual value	\$350m	\$650m	\$350m
Generation residual value	\$100m	\$100m	-\$200m
Total residual value	\$450m	\$750m	\$200m

Note: Totals may not sum due to rounding

²² AEMO 2024 ISP inputs and assumptions workbook, Lead time and project life worksheet; AER (2023) Final decision, Transgrid transmission determination, Attachment 4 – Regulatory depreciation.

D.3.3.4 Alignment of benefit categories to the AEMO ISP

The VTP economic appraisal approach is consistent with DTF, IA and AER CBA guidance. As shown in Table D-16, the appraisal considers all benefit categories included within the AEMO ISP. It also includes select additional benefit categories to reflect expected social and environmental impacts of the candidate development pathways.

Table D-16: Alignment of benefit categories to the AEMO ISP

VTP benefit category	ISP benefit category / description	Consistency with ISP
Avoided generation variable costs	Fuel cost savings	✓
	Variable operating and maintenance cost savings	✓
Improved reliability	Involuntary load shedding reductions	✓
Avoided voluntary curtailment	Changes in voluntary load curtailment (demand side participation)	✓
Avoided emissions	Emissions reduction benefits	✓
Avoided health costs	Reflects additional health benefits associated with the reduction of coal-fired generation	+
Avoided generation capital costs	Generator and storage capital deferral	✓
Avoided generation fixed operating costs	Fixed operating and maintenance cost savings	✓
Net residual value	A number of assets have economic life beyond the appraisal period. This is reflected through the residual asset value. Capital costs are amortised in the ISP.	+
Embodied emissions	Reflects the net embodied emissions associated with the construction of transmission and generation infrastructure in the Base and Project Cases	+
<div> <div>✓</div> <div>Benefit category included in the AEMO ISAP</div> </div> <div> <div>+</div> <div>Additional benefit category not included in the AEMO ISP</div> </div>		

D.3.4 Core results

The CBA assesses the core candidate development pathways against the following economic indicators:

- Net Present Value (NPV) - gives an indication of the magnitude of the net benefit to society, calculated by taking the difference between the present value of the total incremental benefits and the present value of the total incremental costs. A positive NPV indicates that an investment is desirable to society as a whole.
- Economic Internal Rate of Return (EIRR) – the discount rate that makes the NPV of a pathway equal to zero by equating the present value of benefits to the present value of costs. The EIRR is used to determine whether a project should proceed through comparison to an appropriate discount rate.

The economic evaluation results (applying a 7 per cent discount rate) for the core candidate development pathways are presented in Table D-17. Candidate development pathways 1, 2 and 3 are estimated to generate an NPV of \$9,600m, \$36,200m and \$10,050m respectively (\$FY25).

The NPVs in the core candidate development pathways is driven by a significant reduction in gas generation across all pathways. This decreases generation variable costs and reduces emissions. The core candidate development pathways also provide substantial uplift to transfer capacities across the transmission network leading to less generation (and storage) capacity being required in the Project Case. This drives significant generation capital expenditure and operating and maintenance expenditure savings.

A notable difference between candidate development pathways 1 and 3 lies in the commercial benefits. In Scenario 3, a one-year delay in constructing transmission infrastructure in the Base Case and less consumer energy resources necessitates significantly more BESS in the Base Case (see Section D.3.3.3). As such, the difference in generation capacity between the Project Case and Base Case is greater in candidate development pathway 3 compared to candidate development pathway 1.

The results for core candidate development pathway 2 are significantly higher than those of the other 2 core development pathways, primarily because the savings in gas generation and generation capital expenditure between the Project Case and Base Case are substantially greater in scenario 2. While the additional programs associated with core candidate development pathway 2 do incur higher costs, the total benefits delivered far outweigh these extra expenses, resulting in a significantly higher NPV compared to the other core development pathways.

Table D-17: Economic evaluation results, core candidate development pathways (7 per cent discount rate, \$FY25, rounded to nearest \$50m)

Item	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Benefits			
Market impacts			
Avoided generation variable costs	\$5,300m	\$19,300m	\$4,300m
Improved reliability	\$400m	\$400m	\$400m
Avoided demand side participation costs	-	-	-
Avoided gas constraint violation costs	\$600m	-	\$450m
Social impacts			
Avoided emissions	\$6,050m	\$20,150m	\$5,100m
Avoided health costs	-	\$50m	\$50m
Net embodied emissions	-\$300m	-\$500m	-
Commercial impacts			
Avoided generation capital expenditure	\$1,450m	\$3,800m	\$3,450m
Avoided generation fixed operating costs	\$300m	\$650m	\$600m
Net residual asset value	\$450m	\$750m	\$200m
Total benefits	\$14,250m	\$44,600m	\$14,550m
Costs²³			
Capital expenditure	\$4,200m	\$7,600m	\$4,050m
Operating expenditure	\$450m	\$800m	\$450m
Total costs	\$4,650m	\$8,400m	\$4,500m
Economic indicators			
Net Present Value	\$9,600m	\$36,200m	\$10,050m
Economic Internal Rate of Return	19%	41%	22%

²³ The economic costs reflect the incremental difference between the Project Case and the Base Case, as discussed in Section D.3.2.2

D.3.5 Sensitivity analysis

Sensitivity analysis acknowledges and accounts for a degree of uncertainty surrounding the transmission projects. It tests the impact on overall economic appraisal results of changes to key variables. Sensitivity analysis was undertaken to test the impact of changing key parameter values on the overall economic merit of the candidate development pathways, including:

- Discount rates of 4 per cent and 10 per cent
- Higher cost estimates of +/- 30 per cent, +100 and +200 per cent
- Applying IA emissions values
- Including the costs of base case projects in the evaluation, rather than netting them out.

The NPV and incremental change from the core results are shown for each sensitivity test are presented in Table D-18.

The results of the sensitivity analysis align with the results of the core analysis – the core candidate development pathways are robust to changes in all of the key assumptions and parameter values. The results of all sensitivity analyses are as expected:

- The economic rationale for the candidate development pathways increases with a lower discount rate (as the present value of future benefits is discounted less) and decreases with a higher discount rate (as the present value of future benefits is discounted more). Given that the benefits of most infrastructure-related projects are realised after the costs are incurred, they are generally more sensitive to the discount rate applied
- Applying higher costs reduces the NPV but still results in positive NPVs for all core development pathways. The lowest increase in costs required to roughly offset the net benefits of any core development pathway is 200 per cent for candidate development pathway 1. Higher cost increases are required to offset the benefits of core development pathways 1 and 3
- Applying the IA social cost of carbon (an average of \$40/tCO₂-e higher than the AER values between 2025 and 2050) increases the NPVs of the candidate development pathways, as all 3 projects have a positive impact on emissions
- Including the costs of Base Case projects in core candidate development pathways (rather than netting them out) increases the net costs of each. Despite this, the NPVs are still positive.

Table D-18: Economic sensitivity evaluation results (NPV, \$FY25, rounded to nearest \$50m)²⁴

Sensitivity test	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Core results	\$9,600m	\$36,200m	\$10,050m
4% discount rate	\$20,250m (+\$10,650m)	\$68,150m (+\$31,950m)	\$19,950m (+\$9,900m)
10% discount rate	\$4,550m (-\$5,050m)	\$20,100m (-\$16,100m)	\$5,100m (-\$4,950m)
-30% costs	\$11,000m (+\$1,400m)	\$38,750m (+\$2,550m)	\$11,350m (+\$1,300m)
+30% costs	\$8,200m (-\$1,400m)	\$33,600m (-\$2,600m)	\$8,650m (-\$1,400m)
+100% costs	\$4,950m (-\$4,650m)	\$27,750m (-\$8,450m)	\$5,450m (-\$4,600m)
+200% costs	\$150m (-\$9,450m)	\$19,150m (-\$17,050m)	\$900m (-\$9,150m)
IA central carbon pricing guidance	\$9,850m (+\$250m)	\$38,250m (+\$2,050m)	\$10,450m (+\$400m)
Include Base Case project costs (rather than net them out)	\$8,300m (-\$1,300m)	\$34,850m (-\$1,350m)	\$8,750m (-\$1,300m)

D.3.6 Robustness analysis

Robustness analysis (or least-regrets analysis) is used to determine the optimal development pathway. The optimal development pathway is the one that is most robust across scenarios.

For each scenario, the robustness analysis identifies the candidate development pathway with the highest NPV. Proceeding with any other candidate development pathway within this scenario would therefore lead to foregone net benefits. These foregone benefits reflect the 'regret' associated with each candidate development pathway in a particular scenario.

The robustness analysis involves 3 steps:

- **Step 1:** Calculate the NPV for each candidate development pathway and scenario combination
- **Step 2:** Determine the 'regret' or net benefits foregone for each candidate development pathway
- **Step 3:** Weight the level of regret by the scenario weightings to calculate the 'weighted regret' for each candidate development pathway.

These steps are summarised below.

²⁴ The changes from the core results are shown in brackets.

Step 1: Calculate the NPV for each candidate development pathway

The NPV for each candidate development pathway under each scenario has been quantified through the economic evaluation reported in Section D.3.4. These results are summarised below in Table D-19.

Table D-19: NPV for each candidate development pathway

Candidate development pathway	Scenario 1	Scenario 2	Scenario 3
Candidate development pathway 1	\$9,600m	\$39,300m	\$9,950m
Candidate development pathway 2	\$6,000m	\$36,200m	\$6,450m
Candidate development pathway 3	\$9,450m	\$38,850m	\$10,050m

Step 2: Determine the 'regret' for each candidate development pathway

To calculate the regret for each candidate development pathway, the highest NPV for each scenario is identified. Then, for each scenario, each of the 3 NPVs are subtracted from this highest NPV.²⁵ This results in a zero value for the highest NPV and positive values (regret) for the other NPVs. This process provides the range of regret for each candidate development pathway. The regret results are shown in Table D-20.

Table D-20: Computation of 'regret' metric

Candidate development pathway	Scenario 1	Scenario 2	Scenario 3
Candidate development pathway 1	-	-	\$100m
Candidate development pathway 2	\$3,600m	\$3,100m	\$3,600m
Candidate development pathway 3	\$150m	\$450m	-

²⁵ Example: For scenario 1, candidate development pathway 1 has the highest NPV. The calculation of the regret for candidate development 2 in scenario 1 is $\$9,600\text{m} - \$6,000\text{m} = \$3,600\text{m}$

Step 3: Weighted regret of each candidate development pathway

The scenario weightings reflect the likelihood that each scenario will occur (refer to Table D-2). The regrets outlined above are multiplied by the corresponding scenario weightings, and the highest or 'worst' value is identified for each candidate development pathway.²⁶ The optimal development pathway is the pathway with the lowest 'worst regret' value.

Table D-21 shows that candidate development pathway 1 has the lowest weighted regret and is therefore considered the optimal development pathway. Further economic analysis was undertaken for the optimal development pathway to show the consumer bill impact (Section D.4) and the macroeconomic impact (Section D.5).

Table D-21: Computation of 'weighted regret'

Candidate development pathway	Scenario 1	Scenario 2	Scenario 3	Worst regret	Ranking (lowest to highest regret)
Weighting	43.0%	15.0%	42.0%		
Candidate development pathway 1	-	-	\$42m	\$42m	1
Candidate development pathway 2	\$1,548m	\$465m	\$1,512m	\$1,548m	3
Candidate development pathway 3	\$65m	\$68m	-	\$68m	2

²⁶ Example: The calculation of the weighted regret for scenario 1, candidate development pathway 2, is $\$3,600\text{m} \times 43\% = \$1,548\text{m}$

D.4 Consumer bill impact assessment

D.4.1 Overview

The VTP is anticipated to impact the wholesale and transmission components of consumers' electricity bills. It is anticipated to decrease wholesale electricity prices (by facilitating greater renewable generation), though the costs to construct and operate the additional transmission infrastructure are anticipated to increase the transmission network component.

These differences are measured relative to the Base Case and reflect the impact of delivering the VTP, rather than changes in electricity prices over time.

Bill impacts were assessed for the optimal development pathway and averaged over the long term (2029–2050). Calculation of the consumer bill impacts draws on the same generation and transmission cost changes as were evaluated in the CBA.

D.4.2 Wholesale component

The wholesale price impact is estimated using a resource cost calculation approach. It is calculated by comparing the difference in generation costs between the Base Case and the optimal development pathway, including changes in Victorian:²⁷

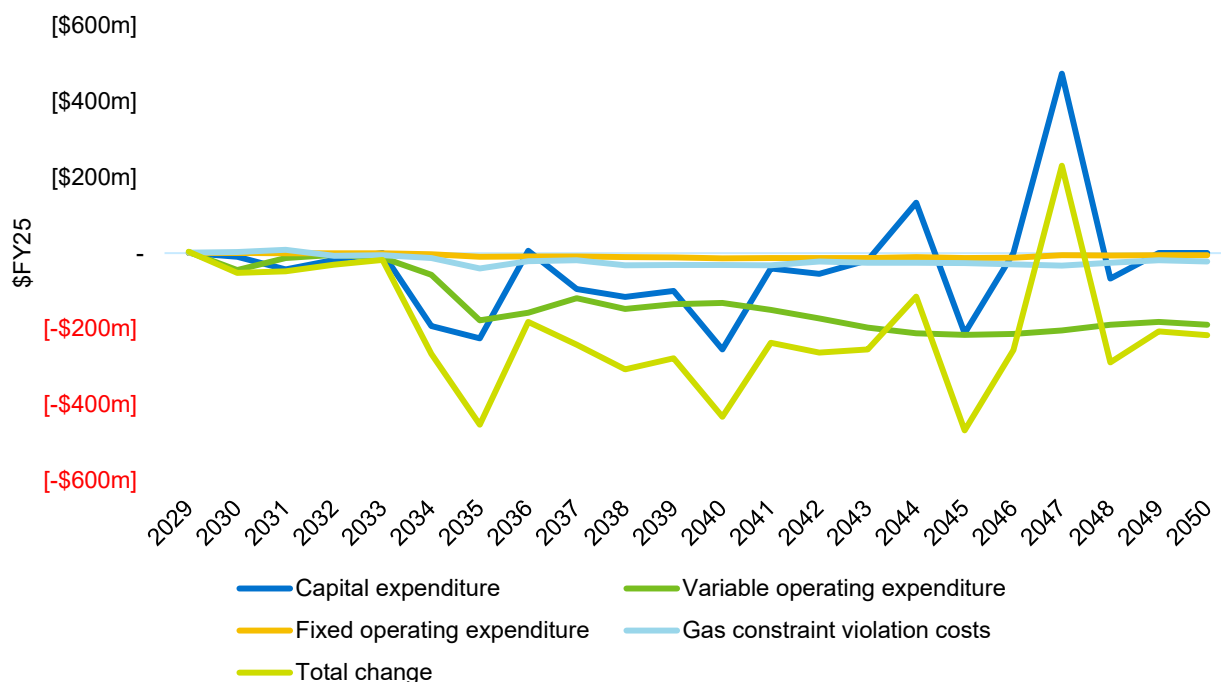
- generation capital expenditure
- generation variable operating expenditure
- generation fixed operating expenditure
- gas constraint violation costs.

Annual differences in resource costs in Victoria are discounted to a present value, then divided by the present value of Victorian consumption to reveal the change in generation costs per MWh. This is assumed to be passed through to consumers through changes in wholesale prices.

Figure D-17 shows the change in Victorian generation resource costs in the optimal development pathway. As discussed in Section D.3.3, the optimal candidate pathway avoids capital expenditure, fixed and variable operating expenditure and gas constraint violation costs. These avoided costs are assumed to be passed through to consumers as lower wholesale prices.

²⁷ The wholesale component considers only the listed items and not the all the benefit categories quantified in the CBA.

Figure D-17: Change in Victorian resource cost profile from the Base Case to the Project Case for candidate development pathway 1, discounted (\$FY25)



The average reduction in generation costs (and therefore the wholesale component of consumer bills) in the optimal development pathway is \$8.5 (discounted \$FY25) per MWh, equivalent to an annual saving of \$33.8 per household and \$84.6 per small business.

D.4.3 Transmission component

The transmission price impact is determined using a high-level regulatory pricing approach. The additional annual revenue required by Victorian transmission businesses to construct and operate the optimal development pathway over the period 2029–2050 is calculated, including the following components:

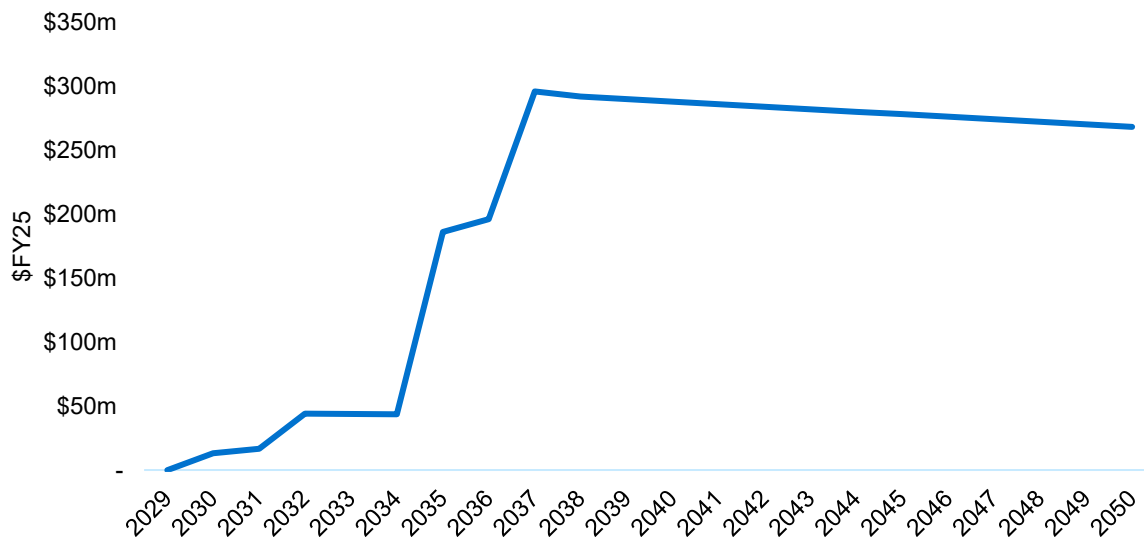
- **Return on capital:** The return on capital in each year is a function of the opening asset balance and the weighted average cost of capital (estimated to average 1.5 per cent real over the period).²⁸
- **Return of capital:** The return of capital is calculated using a straight-line depreciation method, and is a function of the capital expenditure per transmission project and the assumed useful life.
- **Operating expenditure:** Annual operating expenditure is a function of the capital expenditure per transmission project and the annual operating expenditure.
- **Tax allowance:** This represents the portion of revenue allowed to be recovered by a regulated entity to cover the cost of corporate tax.

The annual revenue requirement is estimated over the period 2029–2050 and discounted to a present value. The discount rate used for transmission price impacts is based on the estimated weighted average cost of capital. Figure D-18 shows the change in annual required revenue (\$FY25) over that period. The required revenue increases 2029–2037 as transmission expenditure for the VTP increases, then declines as assets depreciate.

²⁸ Estimated based on parameters outlined in *AER – AusNet Services transmission 2022–27 PTRM – 2025–26 Return on debt update – March 2025*

The total present value transmission revenue requirement is converted to a per MWh basis to align with the wholesale component. Delivery of the optimal development pathway is anticipated to increase the transmission component of consumer bills by approximately \$3.4/MWh (\$FY25), equivalent to an annual increase of \$13.7 per household and \$34.3 per small business.

Figure D-18: Change in annual revenue requirement between Base and Project Case, 2029-2050 (\$FY25)



D.4.4 Net consumer bill impact

The net consumer bill impact is shown in Table D-22. The optimal development pathway is estimated to reduce consumer bills by \$5.0 per MWh compared to the Base Case, equivalent to an annual reduction of \$20.1 per household and \$50.3 per small business.

Table D-22: Net consumer bill impact, average change between Base Case and optimal development pathway (\$FY25)

Component	Average change between Base Case and optimal development pathway	Average change in household annual electricity bills	Average change in small business annual electricity bills
Wholesale component	-\$8.5 / MWh	-\$33.8	-\$84.6
Transmission component	\$3.4 / MWh	\$13.7	\$34.3
Net consumer bill impact	-\$5.0 / MWh	-\$20.1	-\$50.3

D.4.4.1 Sensitivity analysis

The analysis above uses the cost of capital parameters from the most recent version of AusNet's PTRM to calculate annual revenue requirements. Given that cost of capital rates are currently at historically low levels, a sensitivity analysis was conducted to determine the required increase in the transmission cost of capital to offset reductions in the wholesale bill component. The real post-tax cost of capital would need to be maintained at more than 10% (more than 6 times its current level) throughout the period for the increase in the transmission component to exceed the decrease in the wholesale component.

D.5 Macroeconomic modelling

D.5.1 Overview

The macroeconomic modelling focuses on the economic and labour market effects of the VTP, including those that arise through supply chain linkages and price-induced behavioural changes. The analysis is conducted using KPMG-SD, a dynamic regional Computable General Equilibrium (CGE) model of the Australian economy. KPMG-SD captures interactions between industries and regions and behavioural responses to relative price changes emanating from constraints on the supply of primary factors of production and on budget balances.²⁹ The CGE modelling was performed on the optimal development pathway (candidate development pathway 1) as identified in D.3.6.

A summary of key inputs and results of the optimal development pathway is provided in Table D-23. An additional \$6.6bn is invested in Victorian's transmission sector compared to the Base Case. The energy market modelling showed that as a result of this investment, the average retail price of electricity is \$5.0 per MWh lower in the Project Case compared to the Base Case between FY 2029³⁰ and 2050.

CGE modelling outputs indicate that, relative to the Base Case, Victoria's Gross State Product (GSP) will be \$6.0bn higher, and Australia's Gross Domestic Product (GDP) will be \$4.7bn higher, in present value terms (30 June 2025, \$FY25).

Over the same period, employment is projected to be approximately 1,590 full-time equivalent (FTE) workers per year higher in Victoria and 887 FTE workers per year higher in Australia compared to the Base Case. The positive impacts on Victoria's GSP are primarily driven by the optimal delivery pathway's ability to deliver solar and wind energy more efficiently, supplying power to users at lower costs with fewer generation assets.

Table D-23: Summary of macroeconomic modelling inputs and outputs (\$FY25)

VTP inputs overview	Victoria	Australia
Capital expenditure additional to base-case	\$6.6bn	
Average retail electricity price change compared to base-case	-\$5.0 / MWh	
VTP macroeconomic impacts overview (2025-26 to 2049-50)		
GSP/GDP (present value, 7% discount rate)	\$6.0bn	\$4.7bn
FTE jobs (average number of workers per year)	1,590	887

AEMO's most recent transmission cost database updated adjusted with additional VicGrid analysis; VTP PLEXOS energy market modelling; KPMG-SD modelling results

²⁹ KPMG-SD takes a 'bottom-up' approach to multi-regional modelling. The regional economies are integrated through interregional flows of goods and services, factors of production and the explicit representation of population and labour supply.

³⁰ The first year in which a VTP project is operational

D.5.2 The macroeconomic (KPMG-SD) model

A special-purpose version of KPMG-SD has been used to quantify and analyse the economy-wide impacts of the optimal development pathway. For this study, a regional aggregation is used that explicitly captures the areas in which the projects will be located as well as other regions in Victoria and the rest of Australia. The regional disaggregation used for the modelling is set out in Table D-24, which also shows the concordance between the regions and the Statistical Area classifications used by the ABS.

Table D-24: Concordance between modelled regions and ABS Statistical Area classifications

Modelled regions	Corresponding ABS regions
Greater Melbourne	Greater Capital City Statistical Area (GCCSA)
Southwest Victoria	Geelong: Statistical Area Level 4 (SA4) Ballarat: Statistical Area Level 4 (SA4) Warrnambool and Southwest: Statistical Area Level 4 (SA4)
Bendigo Shepparton	Bendigo: Statistical Area Level 4 (SA4) Shepparton: Statistical Area Level 4 (SA4)
Hume	Hume: Statistical Area Level 4 (SA4)
Latrobe Gippsland	Latrobe-Gippsland: Statistical Area Level 4 (SA4)
Grampians	Grampians: Statistical Area Level 3 (SA3)
Mildura	Mildura: Statistical Area Level 3 (SA3)
Murray River Swan Hill	Murray River-Swan Hill: Statistical Area Level 3 (SA3)
Rest of Australia	All other Australian regions

D.5.3 Macroeconomic simulation design

The economic impact analysis makes use of 2 sets of simulation results from KPMG-SD:

- **Base Case scenario** - the Base Case represents an estimate of the size and structure of the economy will evolve without future transmission augmentations beyond those already committed to or anticipated under the ISP
- **Project Case scenario** - is an estimate of how the size and structure of the economy will evolve if the optimal development pathway is constructed and operated as planned.

The Base Case and Project Case are assessed at the regional level of Victoria. The development of the Base Case representation of these regional economies occurs in 2 stages. First, an initial database is generated to reflect the best estimate of the size and structure of these economies in FY 2024, using updated historical data published by the ABS, such as input-output tables and state and national accounts.³¹

³¹ The ABS publishes input-output tables at the national level only. The 'bottom-up' approach to multi-regional modelling adopted in KPMG-SD requires us to generate integrated input-output databases for each of the regions separately identified in the model. The approach that we take to generating regional input-output data is based on that documented in <https://www.copsmodels.com/ftp/workpaper/g-219.pdf>. In summary, the national input-output data published by the ABS is disaggregated using supplementary information including, but not limited to: census data; state national accounts and other state-level data disaggregated by industry or commodity; labour market data contained in the labour force survey; regional population/household/dwelling data; Australian Harmonized Export Commodity Classification merchandise data; small region labour market data; detailed government accounts; and distance metrics.

The second stage is forward-looking, where forecasts for key macroeconomic variables are imposed. KPMG-SD is then used to generate annual projections for all variables in the model, extending from FY 2025 to 2050.

The Project Case scenario includes shocks that reflect the optimal development pathway capital expenditure and the subsequent implications for Victorian retail electricity prices. Technical change parameters for the power generation and transmissions sectors move accordingly to facilitate the price changes.

The total, direct and indirect economic impacts of the optimal development pathway are characterised by differences in the values of economic variables (Gross Regional Product (GRP), GSP, GDP and FTE) in the Project Case scenario relative to the Base Case scenario.

D.5.4 Key macroeconomic modelling assumptions

To simulate the Project Case scenario in the KPMG-SD model, assumptions about key variables defining the expected economic environment over the simulation horizon are necessary. These assumptions, which are primarily related to supply-side settings, such as budget and labour market constraints, are not specific to the VTP:

- At the national level, the supply of labour is highly restricted, with the working-age population fixed at its Base Case levels. While the participation rate can adjust to real wage movements, such responses are minimal. A trade-off between real wages and the natural rate of unemployment is imposed at the national level, with real wages gradually adjusting to drive the unemployment rate towards its natural rate. Regional real wage differences are progressively eliminated through labour movements, leading to regional unemployment rates to converge towards the national natural rate over time
- The Federal government budget-balance-to-GDP ratio is assumed to remain unchanged from its Base Case values. Similarly, the Victorian government budget-balance-to-GSP ratio is assumed to remain unchanged from its Base Case values
- Household consumption is assumed to adjust over time to ensure that the current account deficit as a share of GDP stabilises in the long run
- Consumer preferences and technical change parameters, except those for the power generation and distribution sectors, are held fixed at Base Case values

D.5.5 Project parameters

The capital expenditure profile used on the economy-wide modelling is outlined in Section D.3.2. An additional \$6.6bn in capital expenditure is projected compared to the Base Case.

The electricity price differential between the Project Case and Base Case was derived from energy market modelling inputs for electricity price changes in Victoria. The optimal development pathway alleviates transmission bottlenecks for renewable energy generated in remote areas, enabling cost savings in the wholesale power price of \$8.5 per MWh by reducing the need for additional sector investment. This benefit is partly offset by an increase of \$3.4 per MWh in the transmission component of electricity bills. Overall, this results in a net decrease of \$5.0 per MWh in the electricity price in the Project Case compared to the Base Case. This decrease in electricity prices is modelled as an increase in the efficiency of the electricity sector, requiring less capital and other inputs per unit of electricity output.

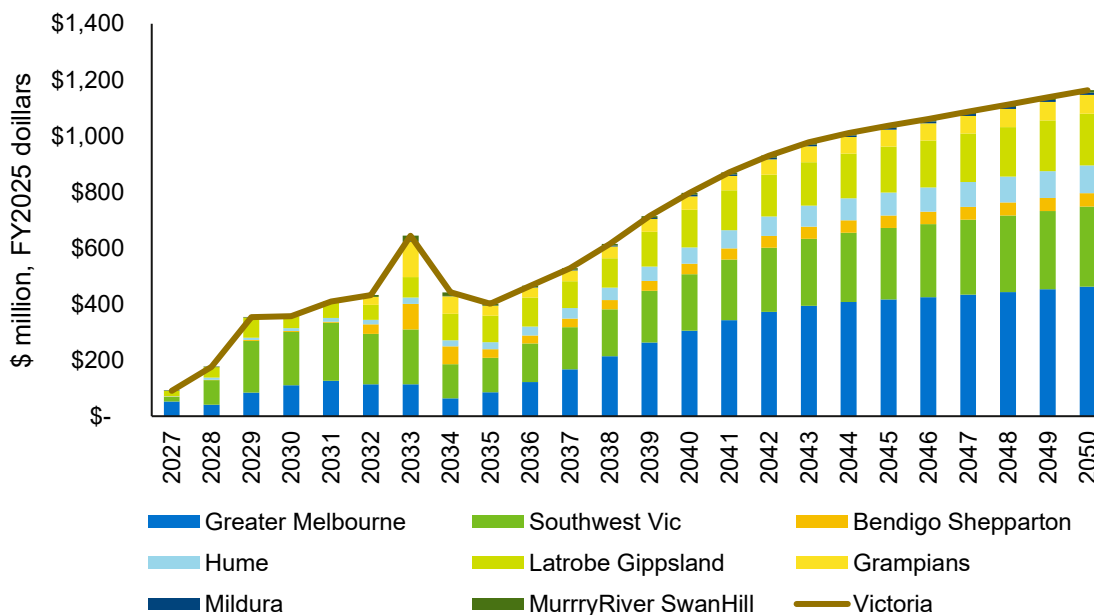
D.5.6 Macroeconomic modelling results

The KPMG-SD results reported in this section are estimates of the direct and indirect economic impacts of the candidate development pathway. The impacts are analysed both for Victoria only and the whole of Australia.

Figure D-19 illustrates the incremental impacts on GRP across Victoria's regions. Total Victorian GSP is consistently higher in the Project Case compared to the Base Case, with a cumulative uplift of \$6.0bn in present value terms. Fluctuations in GSP impacts during the construction phase mainly reflect variations in investment levels in the power transmission and distribution sector. Beyond the construction phase period, the positive GRP impacts continue to grow, driven by the sustained reductions in electricity prices. In absolute terms, Greater Melbourne sees the largest gains, reflecting that it is the biggest consumer of electricity among Victoria's regions. Southwest Victoria, Latrobe Gippsland, Bendigo, Shepparton, and Hume all record a net higher GRP between the Project Case and the Base Case.

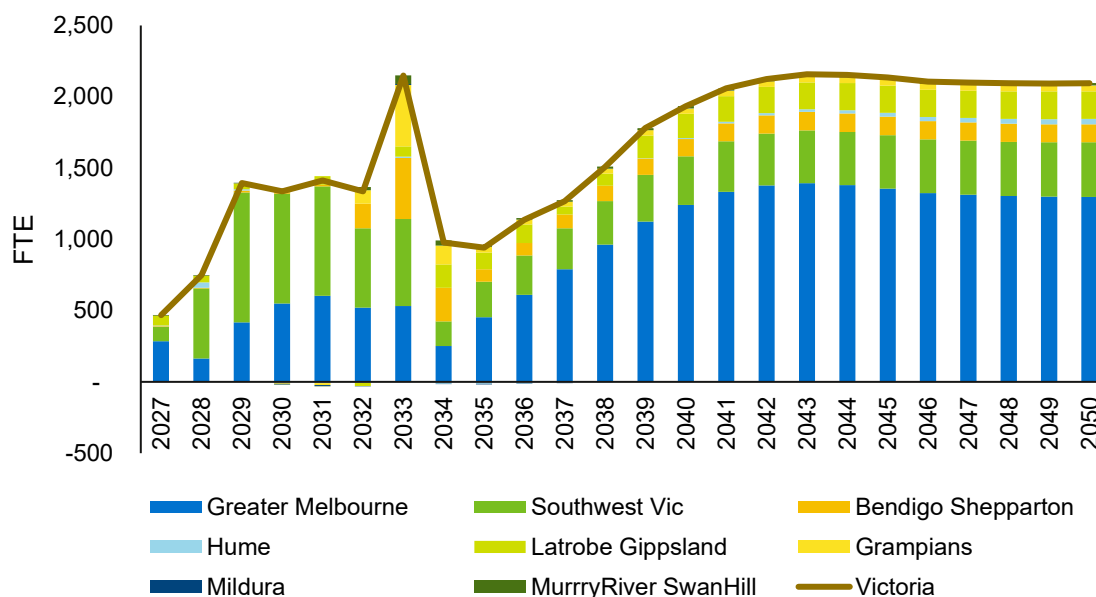
The employment impacts for the Victorian regions are shown in Figure D-20. While the construction phase is active, the uplift in FTE jobs is greatest in Southwest Victoria followed by Greater Melbourne, reflecting the size of the transmission investment made in these regions. The employment uplift in the construction phase is transitory, reflecting the temporary uplift in investment activity. Following the construction phase, the uplift in employment is ongoing, resulting from the positive impact of permanently lower electricity prices. On average 1,590 additional FTE jobs are created by the optimal development pathway over the simulation horizon.

Figure D-19: GRP impacts in Victoria



Source: KPMG-SD modelling results

Figure D-20: Regional employment impacts (FTE jobs) in Victoria

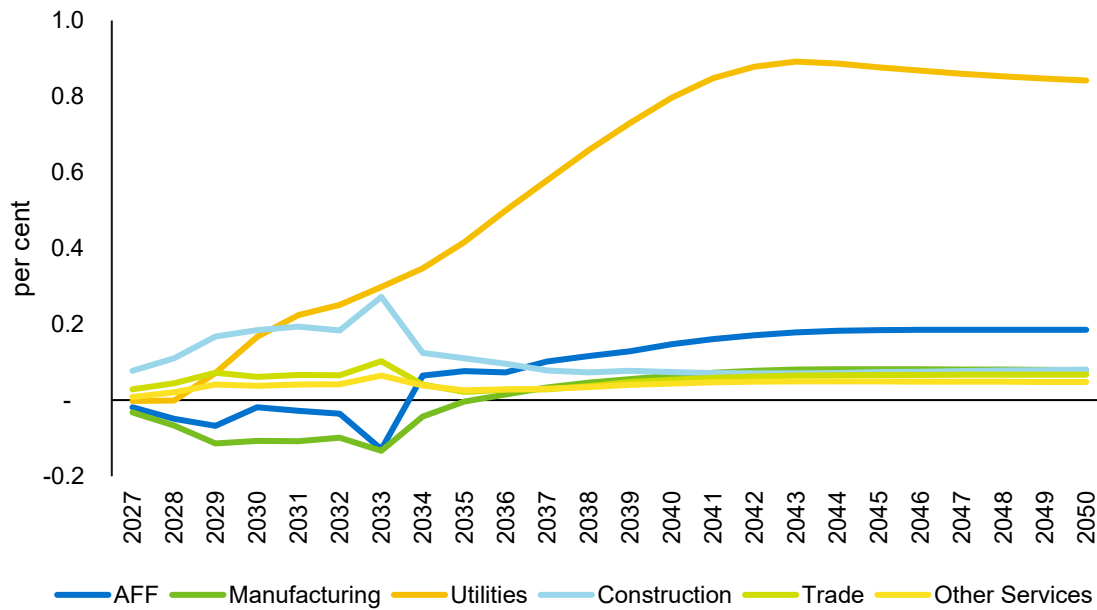


Source: KPMG-SD modelling results

Figure D-21 and Figure D-22 show the Project's estimated impacts on sectoral value added and employment for the Victorian regions respectively. The results are presented as percentage deviations of variables in the Project Case relative to the Base Case. The Utilities sector records the largest proportional uplift in value added. For instance, over the decade ending FY 2050, the Utilities sector is expected to generate on average 0.9 percent more value added per annum in the Project Case than in the Base Case. This result is driven by lower power prices, which stimulate additional demand for electricity.

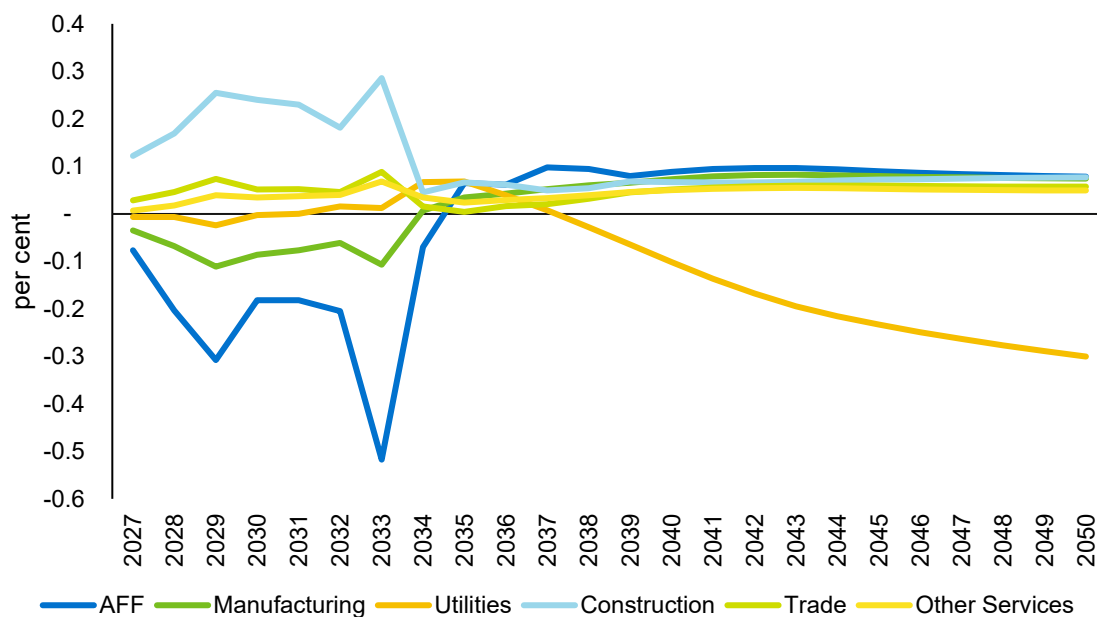
The improvement in the productivity of the electricity generation sector means that in the Project Case, it can produce the same amount of output with fewer inputs than in the Base Case. This is reflected in the employment results for the Utilities sector, which needs less labour in the Project Case. In the longer term, the Manufacturing and Agriculture, Forestry, and Fishing sectors record the largest proportional uplifts in employment. Lower power prices enhance the competitiveness of these sectors against interstate and international competitors, resulting in an increase in both value added and employment. During the construction phase, there is some crowding out which is reflected in the employment profile of the trade-exposed Manufacturing and Agriculture, Forestry, and Fishing sectors.

Figure D-21: Industry value added impacts in Victoria: percentage deviations from the Base-case



Source: KPMG-SD modelling results

Figure D-22: Industry employment (FTE jobs) impacts in Victoria: percentage deviations from the Base-case



Source: KPMG-SD modelling results

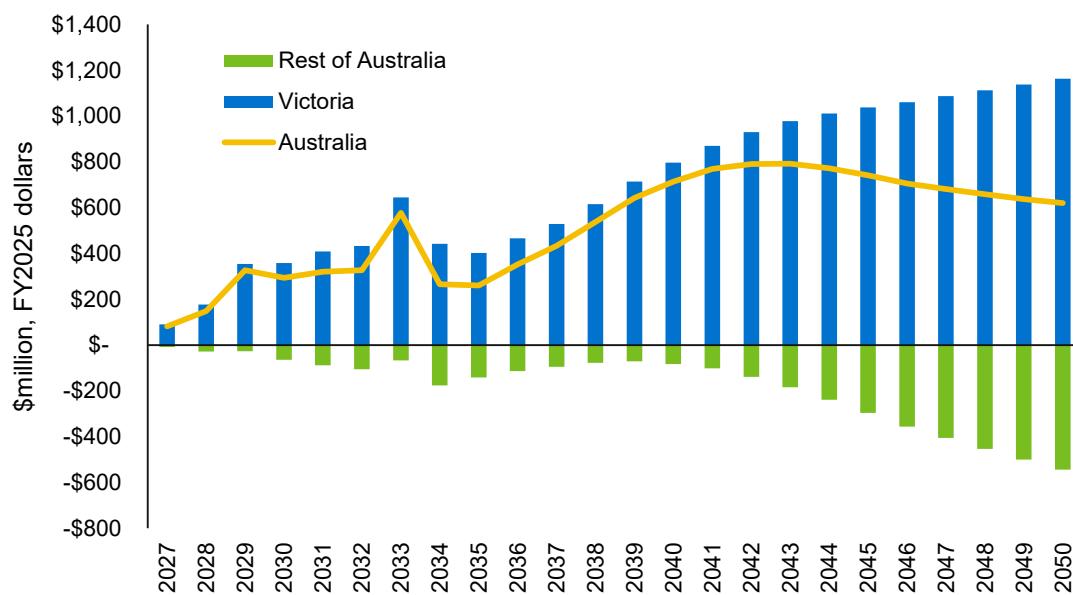
At the national level, GDP and total FTE are higher in the Project Case relative to the Base Case. In present value terms, compared to the Base Case, the optimal development pathway results in a national GDP uplift of \$4.7bn and an average increase of 887 additional FTE workers per year.

Victoria's competitive advantage from lower electricity prices leads to higher demand for labour and goods and services within the state. This increased demand drives up real wages and costs, causing some crowding out of activity in the rest of Australia. Higher real wages attract resources to Victoria from the rest of

the country. With the national supply of labour fixed at its Base Case value, the increased demand for labour pushes up real wages and temporarily reduces the unemployment rate below its equilibrium level. However, as the labour supply remains fixed, national employment eventually returns to its Base Case values. Despite this, Victoria benefits from a permanently higher share of national employment due to the efficiencies gained from lower electricity prices.

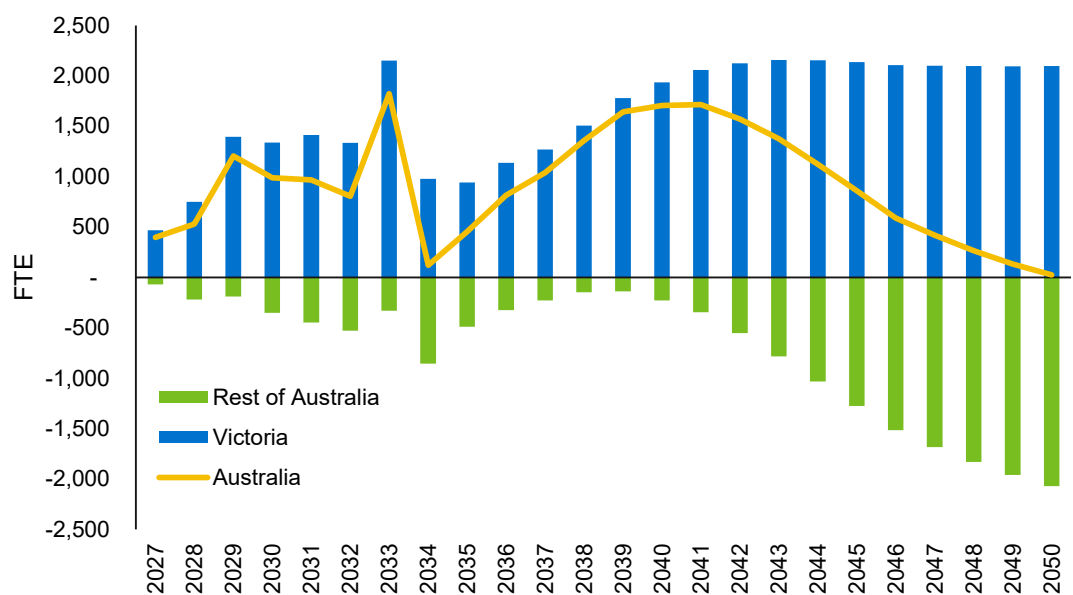
Figure D-24 illustrates that by the end of the simulation period, national employment is nearly unchanged compared to the Base Case, with increased employment in Victoria offsetting the decrease in the rest of Australia. While the GSP for the rest of Australia contracts in line with reduced employment, Figure D-23 shows that this is more than compensated by the increase in Victoria's GSP.

Figure D-23: GSP and GDP impacts



Source: KPMG-SD modelling results

Figure D-24: Employment (FTE jobs) impacts on Victoria, Rest of Australia, and Australia



Source: KPMG-SD modelling results

D.6 Results summary

This section summarises the results of the VTP economic appraisal, including the CBA, consumer bill impacts and macroeconomic results.

The VTP is anticipated to benefit the economy across each of these measures. The optimal development pathway is anticipated to provide \$9,600m in net benefits to the NEM. This primarily reflects the avoided costs of greenhouse gas emissions (\$6,050m) and avoided generation expenditure (totalling \$7,050m across fixed and variable capital and operating costs).

This reduction in generation costs is assumed to be passed through to consumers through lower wholesale prices. The optimal development pathway is estimated to reduce the wholesale component of consumer bills by \$8.5/MWh, equivalent to annual savings of \$33.8 for households and \$84.6 for small businesses. These savings are offset to some degree by the additional costs to construct and maintain the transmission infrastructure (\$3.4/MWh), with net annual reductions in consumer bills ranging from \$20.1 for households to \$50.3 for small businesses.

Delivery of the optimal development pathway also provides broader impacts to the Victorian and national economies. Construction of the transmission infrastructure provides a direct stimulus to the economy, while reductions in consumer bills generate additional economic activity. In total, the optimal development pathway is anticipated to increase Victorian economic output by a present value of \$6.0bn over the period to 2050, and increase Victorian employment by 1,590 FTE jobs per year.

CBA results (including robustness analysis), consumer bill impacts and the macroeconomic impacts of the optimal development pathway are summarised in Sections D.6.1, D.6.2 and D.6.3, respectively.

D.6.1 CBA results

Table D-25 shows the headline results of the core candidate development pathways at a 7 per cent discount rate. Candidate development pathways 1, 2 and 3 are estimated to generate an NPV of \$9,600m, \$36,200m and \$10,050m respectively (\$FY25). These results are robust to changes in key assumptions and parameter values.

Table D-25: Headline evaluation results, core candidate development pathways (7 per cent discount rate, \$FY25, rounded to nearest \$50m)

Item	Candidate development pathway 1	Candidate development pathway 2	Candidate development pathway 3
Total benefits	\$14,250m	\$44,600m	\$14,550m
Total costs	\$4,650m	\$8,400m	\$4,500m
Economic indicators			
Net Present Value	\$9,600m	\$36,200m	\$10,050m
Economic Internal Rate of Return	19%	41%	22%

Table D-26 shows the weighted regret for each candidate development pathway. Candidate development pathway 1 has the lowest weighted regret (\$42m) and is considered the optimal development pathway.

Table D-26: Computation of 'weighted regret'

Candidate development pathway	Scenario 1	Scenario 2	Scenario 3	Worst regret	Ranking (lowest to highest regret)
Weighting	43.0%	15.0%	42.0%		
Candidate development pathway 1	-	-	\$42m	\$42m	1
Candidate development pathway 2	\$1,548m	\$465m	\$1,512m	\$1,548m	3
Candidate development pathway 3	\$65m	\$68m	-	\$68m	2

D.6.2 Consumer bill impacts

The net consumer bill impact is shown in Table D-27. The estimated net consumer bill impact of the optimal development pathway is a reduction of \$5.0 per MWh compared to the Base Case.

Table D-27: Net consumer bill impact, average change between Base Case and optimal development pathway, discounted, \$FY25

Component	Average change between Base Case and optimal development pathway	Average change in household annual electricity bills	Average change in small business annual electricity bills
Wholesale component	-\$8.5 / MWh	-\$33.8	-\$84.6
Transmission component	\$3.4 / MWh	\$13.7	\$34.3
Net consumer bill impact	-\$5.0 / MWh	-\$20.1	-\$50.3

D.6.3 Macroeconomic impacts

A summary of key inputs and results of the optimal development pathway is provided in Table D-28. The optimal development pathway leads to an additional \$6.6bn being invested in Victorian's transmission sector compared to the Base Case. The investment and resulting reduction of \$5.0 per MWh in electricity prices leads to a \$6.0bn increase in the present value of Victoria's GSP and \$4.7bn increase in Australian GDP over the period to 2050. Over the same period, employment is projected to grow by 1,590 and 887 FTE workers on average per year higher in Victoria and Australia respectively.

Table D-28: Summary of macroeconomic modelling inputs and outputs (\$FY25)

VTP inputs overview	Victoria	Australia
Capital expenditure additional to base-case	\$6.6bn	
Average retail electricity price change compared to base-case	-\$5.0 / MWh	
VTP macroeconomic impacts overview (2025-26 to 2049-50)		
GSP/GDP (present value, 7% discount rate)	\$6.0bn	\$4.7bn
FTE jobs (average number of workers per year)	1,590	887

Source: VicGrid analysis; VTP PLEXOS energy market modelling; KPMG-SD modelling results

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