INFRASTRUCTURE VICTORIA

IV128 Net Zero Emissions Scenario Analysis Stage 2

Study Report

DORiS

CONTACT DETAILS

CONTRACTOR

DORIS Engineering Australia Pty Ltd

Level 13, 191 Saint Georges Terrace
Perth, Western Australia, 6000
www.dorisgroup.com

Contractor's Contact:

Benoit LAMOUREUX
Managing Director

T +61 4 815 10 779
E benoit.lamoureux@dorisgroup.com

COMPANY

Infrastructure Victoria

Level 33, 140 William Street
Melbourne, 3000, Australia
www.infrastructurevictoria.com.au

Company's Contact

Nerys WEBSTER
Project Director

REVISION

Rev.	Date	Issued By	Checked By	Approved By	Reason for Revision
1	**22-OCT-21**	**A LOANE**	**B LAMOUREUX**	**E McNAMARA**	**Revised Final – Issued for Use**
0	15-OCT-21	A LOANE	B LAMOUREUX	E McNAMARA	Final – Issued for Use
A	26-SEP-21	A LOANE	B LAMOUREUX	B LAMOUREUX	Issued For Client Review

TABLE OF CONTENTS

Table of Tables

Table of Figures

1 EXECUTIVE SUMMARY

1.1 Context

Infrastructure Victoria (IV) has commissioned DORIS Engineering Australia to undertake a concept level analysis and generate technical data to support IV in provision of advice requested by the Treasurer of Victoria on the nature and timing of decisions regarding the gas transmission and distribution networks for Victoria in a future where:

- **Victoria's carbon emission reduction targets are achieved;**
- **Sufficient and suitable energy and chemical feedstocks are available** for domestic, commercial, and industrial use; and
- **An option is available for hydrogen and/or biomethane** to be part of the future energy mix.

The 2020-21 Victorian Budget included funding for Government to deliver a Gas Substitution Roadmap by the end of 2021, in support of net zero greenhouse gas emissions for the State by 2050.

Complementing the Gas Substitution Roadmap, IV's Advice will work backwards from 2050 to **understand the nature and timing of gas infrastructure-related decisions to maximise opportunities and minimise risks** associated with existing and committed gas infrastructure. This Advice will inform Government decision-making over the short, medium and long term.

Based on learnings taken from the prior *Net Zero Emission Scenario Analysis Study Report May 2021*, a Hybrid Scenario for reaching net zero emissions by 2050 was constructed and forms the basis of the analysis undertaken. One of the primary features of the Hybrid Scenario is that it maximises the re-use of existing energy infrastructure whilst providing a secure supply of low emissions energy during the transition. The Hybrid Scenario aims to minimise the need for constructing new gas and electricity transmission systems which have previously been shown to require very greatly increased levels of cost, for example the full Hydrogen Scenario (refer to Scenario D in the prior *Net Zero Emission Scenario Analysis Study Report May 2021*), or full variable renewable electrification.

1.2 Energy Demand Forecast

Energy consumption data from the Department of Industry, Science, Energy and Resources (DISER Table F) was used to estimate the total mean energy demand for Victoria in 2020 along with a breakdown identifying those areas relating to the study scope (electricity, energy gas & fuel for road vehicles). Notably excluded from the current study scope were agriculture, aviation and shipping. The 2020 mean energy demand data was then used as the basis for forecasting of mean energy demand to 2050.

In general, underlying energy demand was assumed to increase by 15% per decade with notable exceptions including:

- Fossil fuels (coal, natural gas, diesel & gasoline) which decline in accordance with Table 14 (Section 3.2). The decline profiles are notional and in line with those used in the prior

Net Zero Emission Scenario Analysis Study Report May 2021, with adjustments as necessary to suit the specific analysis case; and

- Renewable electricity to meet the demand of new energy centres including low emissions vehicles (Battery Electric Vehicles (BEVs) and Hydrogen Fuel Cell Vehicles (HFCVs)), green Hydrogen and green Ammonia.

Table 4 summarises overall annual mean energy demand for each analysis case relevant to the study scope (electricity, energy gas and fuel for road vehicles) and shows an increase from 732 PJ (2020) to 913 PJ (2050) representing overall growth of approximately 25%.

1.3 Hybrid Scenario

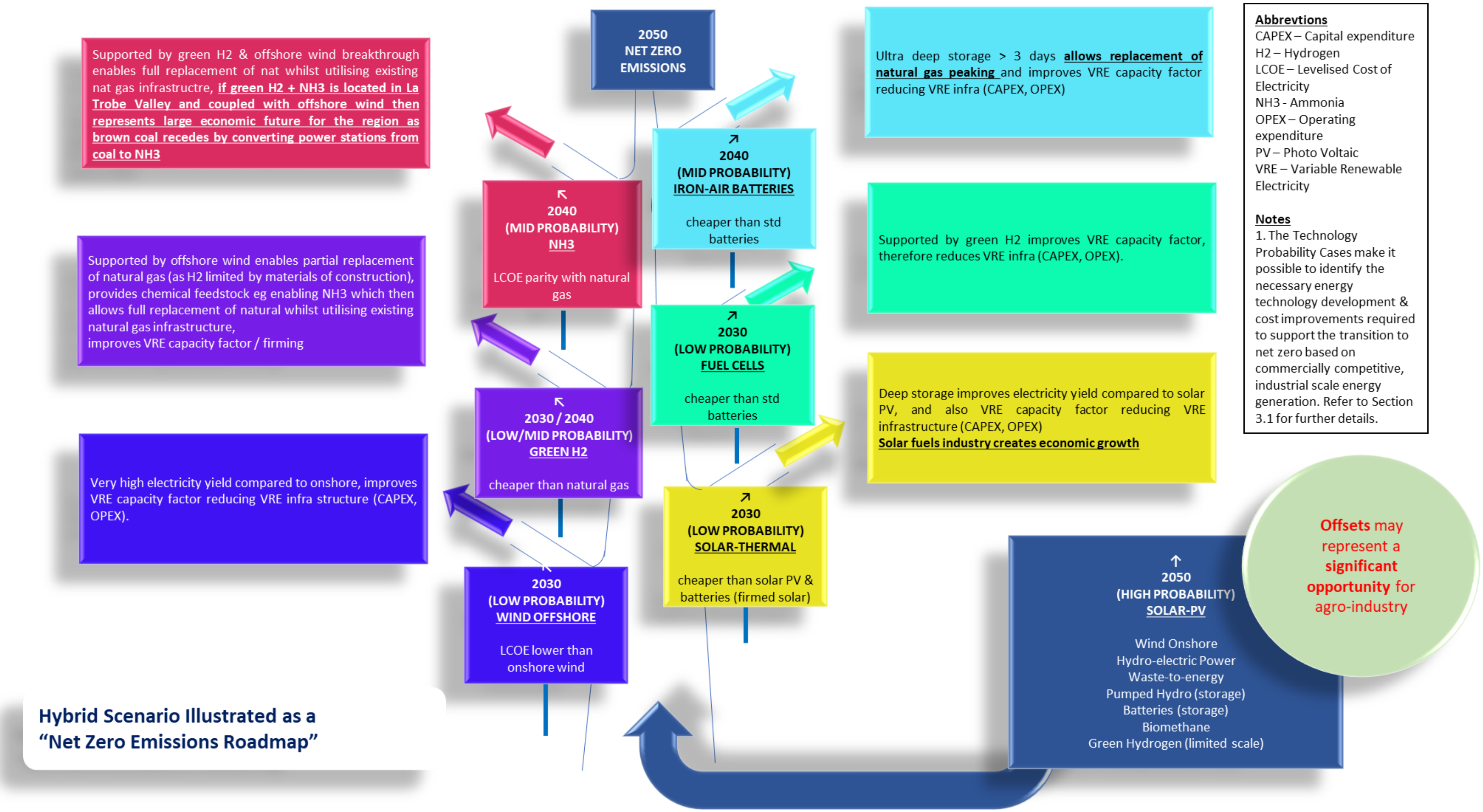
The Hybrid Scenario represents a set of potential routes to achieving net zero emissions by 2050, dependent upon the probability of breakthroughs in the performance and cost competitiveness of low emissions energy technologies. The breakthroughs were defined as a set of technology probability cases which, when combined, represent a Hybrid Scenario Roadmap for reaching net zero emissions by 2050 (see Figure 1).

Construction of the Hybrid Scenario was based on:

- Filling the demand / supply gap with new, low emissions energy technologies whilst maximising the use of existing energy infrastructure.
- Combining the most attractive attributes of Scenarios A, B and C analysed in the prior Net Zero Emission Scenario Analysis Study Report May 2021 to provide the best energy mix during the transition and flexibility to adopt new technologies that may reach a commercially competitive status in the future. By inference this also provides mitigation for any singular energy technology that does not achieve a breakthrough.
- Maximising the amount of power generation produced from bioenergy. This allows a greater proportion of energy from decentralised, localised, small scale generation, with potential for fewer large-scale infrastructure investments.
- Considering the level of both “virtual power plant” (aggregated, small scale electrical storage systems) and “behind the meter” energy storage that is connected to provide a stable, manageable network.
- Increasing the proportion of natural gas in the early phases of the transition to delay the uptake of biomethane in order to provide sufficient time to put in place the necessary supply chain infrastructure and flatten the capital expenditure schedule.
- Investigating the role of green Hydrogen in the transition by analysing various proportions in the energy mix.
- Removing blue Hydrogen from the mix in line with the forecast decline in natural gas production rates. Any inclusion of blue Hydrogen would be marginal based on the levels of natural gas forecast for 2050.
- Incorporating offshore wind given its proximity to the existing electrical generation and transmission infrastructure of the Latrobe Valley.

Figure 1: Hybrid Scenario Roadmap for Achieving Net Zero Carbon Emissions by 2050

(In this diagram only the technology breakthroughs are identified for each Technology Probability Case in order to highlight the timing and technologies assumed in the Study. A full definition of the Technology Probability Cases is provided in 3.1)



1.4 Analysis Cases

The methodology adopted for the current study is consistent with analysis undertaken by the International Energy Agency (IEA), “Net Zero by 2050 - A Roadmap for the Global Energy Sector”, 2021 where it is recognized that, in 2050, a substantial proportion of emissions reduction will come from technologies that are currently at the demonstration or prototype stage of development. The Hybrid Scenario requires that new, low emissions energy generation technologies fill the demand / supply gap with affordable, secure energy at scale whilst also generating low, zero or even negative levels of carbon emissions per unit of energy. For these conditions to be met, it will be necessary for breakthroughs to occur at key points in the future in the performance and cost competitiveness of current & emerging low emissions energy technologies in both generation and storage, for energy gas and electricity.

One example of the need for breakthroughs in low emissions energy technology is green Hydrogen which does not currently deliver affordable energy at scale, with its current status being described as follows by *CSIRO’s “Low Emissions Technology Roadmap (Technical Report), 2017):*

- Commercially available but high cost.
- Currently only used for niche applications; and
- Requiring further R&D to bring down costs.

Drawing on in-house expertise in combination with credible references including CSIRO’s Global – Local & Learning & Modelling (GALLM), a series of notional Technology Probability Cases were constructed for the purpose of investigating various energy transition pathways as a function of technology type and timing of introduction.

The analysis cases along with the specific technologies selected were not intended to:

- Define the future energy mix, but rather guide the timing and identify the focus for support to energy technology development programs;
- Represent unique solutions. The key criterion regarding technology selection was to ensure breakthroughs are identified across the entire energy supply chain including generation and storage (both gas and electricity). The specific technologies identified for breakthrough in the current study, along with the timing, are not unique and can be changed for other technologies within the same technology category to achieve another feasible net zero solution. For example, the Iron-air battery technology identified for breakthrough in the Mid Probability Technology Case could be replaced by another emerging long duration electrical storage technology, resulting in another feasible net zero solution generated.

- Specify a particular type of greenhouse gas offset. Where individual cases and sensitivities utilize greenhouse gas offsets deliver net zero emissions in 2050, it has been assumed that agro-forestry offsets, specifically soil farming, provides the source of those offsets. This should be seen as illustrative only and does not representative of the only greenhouse offset solution. In this study offsets have only been used to balance the emissions projections in each analysis case and ensure the delivery of net zero emissions by 2050.

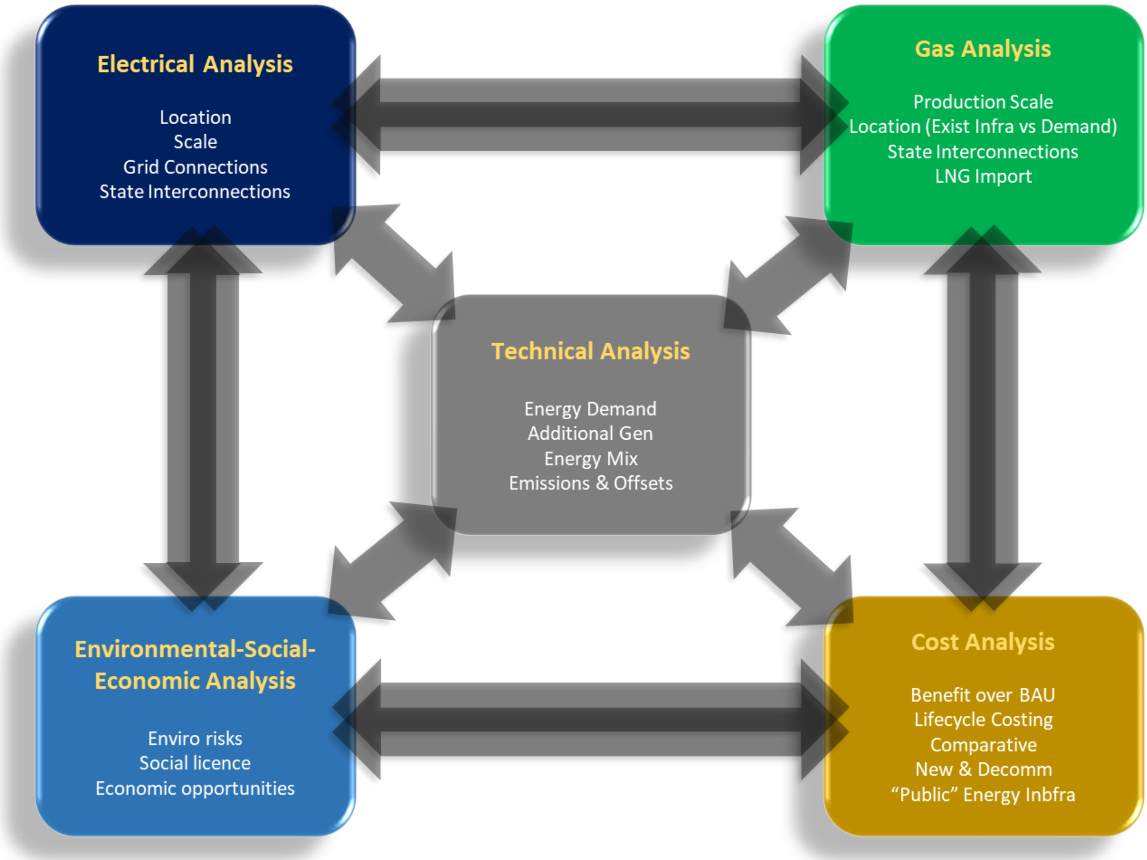
Table 1: Analysis Cases with Summary of Technology Breakthroughs

Analysis Case	Description	Technology Breakthrough Timing	Primary Breakthrough Technologies	Secondary Breakthrough Technologies
High Probability Technology	Utilises low emissions technologies, primarily solar PV and wind, that are currently capable of delivering commercially competitive energy at an industrial scale.	Not Applicable	Current energy technology	Green Hydrogen (energy gas generation)
Mid Probability Technology	Utilises primarily green Ammonia (NH3) to replace natural gas entirely and allows electrical generation and transmission infrastructure in the Latrobe Valley to be utilized beyond 2050.	2040	Green Ammonia (energy gas, electrical generation)	Iron-air batteries (electrical storage)
Low Probability Technology	Utilises primarily solar thermal and molten salt deep duration storage to provide an enhanced level of high quality electrical power, with the potential to reduce firming infrastructure.	2030	Solar thermal & molten salt (electrical generation & storage)	Offshore wind, fuel cells, green Hydrogen (electrical generation, electrical storage, energy gas generation)
Sensitivity 1 “Accelerated Net Zero”	Investigate the potential of achieving net zero significantly earlier than 2050, along with an understanding of the associated cost implication. Sensitivity Case 1 was constructed by combining the technology breakthroughs of both the Low and Mid Probability Technology Cases.	2030 / 40	Green Ammonia, solar thermal & molten salt (energy gas, electrical generation, electrical storage)	Iron-air batteries, offshore wind, fuel cells (electrical generation, electrical storage)
Sensitivity 2 “Reduced Ammonia”	A sensitivity of the Mid Probability Technology Case, with the objective of calibrating Ammonia demand to identified supply prospects e.g. Western Green Energy Hub (WA).	2040	Green Ammonia (energy gas, electrical generation)	Iron-air batteries (electrical storage)
Sensitivity 3 “Energy Efficiency”	Investigate the influence of energy efficiency on the transition cost benefit. The High Probability Technology Case was modified by adjusting the energy efficiency level for both gas and electricity from 5% to 20% improvement per decade.	Not Applicable	Current energy technology	Green Hydrogen (energy gas generation)
Sensitivity 4 “Maximum Green Hydrogen”	Investigate how a high proportion of green hydrogen in the energy mix would affect transition cost, emissions and use of existing energy infrastructure. Combined with the Low Probability Technology case (limited green Hydrogen) it provides a more complete understanding of the role of green Hydrogen in the transition representing another “mid-point” Hydrogen case between the two extreme cases analysed in the prior Net Zero Emission Scenario Analysis Study Report May 2021: Scenario A (full electrification, with no Hydrogen); and Scenario D (full Hydrogen (brown)).	2030	Green Hydrogen (energy gas generation)	Solar thermal, molten salt, offshore wind & fuel cells (electrical generation & storage)

1.5 General Method

In recognition of the large array of "un-knowns" and limited "knowns" as well as the brief analysis time-frame available, a heuristic approach was adopted, and combined with an iterative solution methodology. A "first pass" analysis is undertaken using DORIS' proprietary Net Zero Analysis Tool providing an estimate of energy mix which is then input to other analysis centres to develop more refined data which is subsequently fed back into the Net Zero Analysis Tool. A solution is reached when the input and output from all analysis models is consistent.

Figure 2: Specific Analysis Centres used to Define the Hybrid Scenario

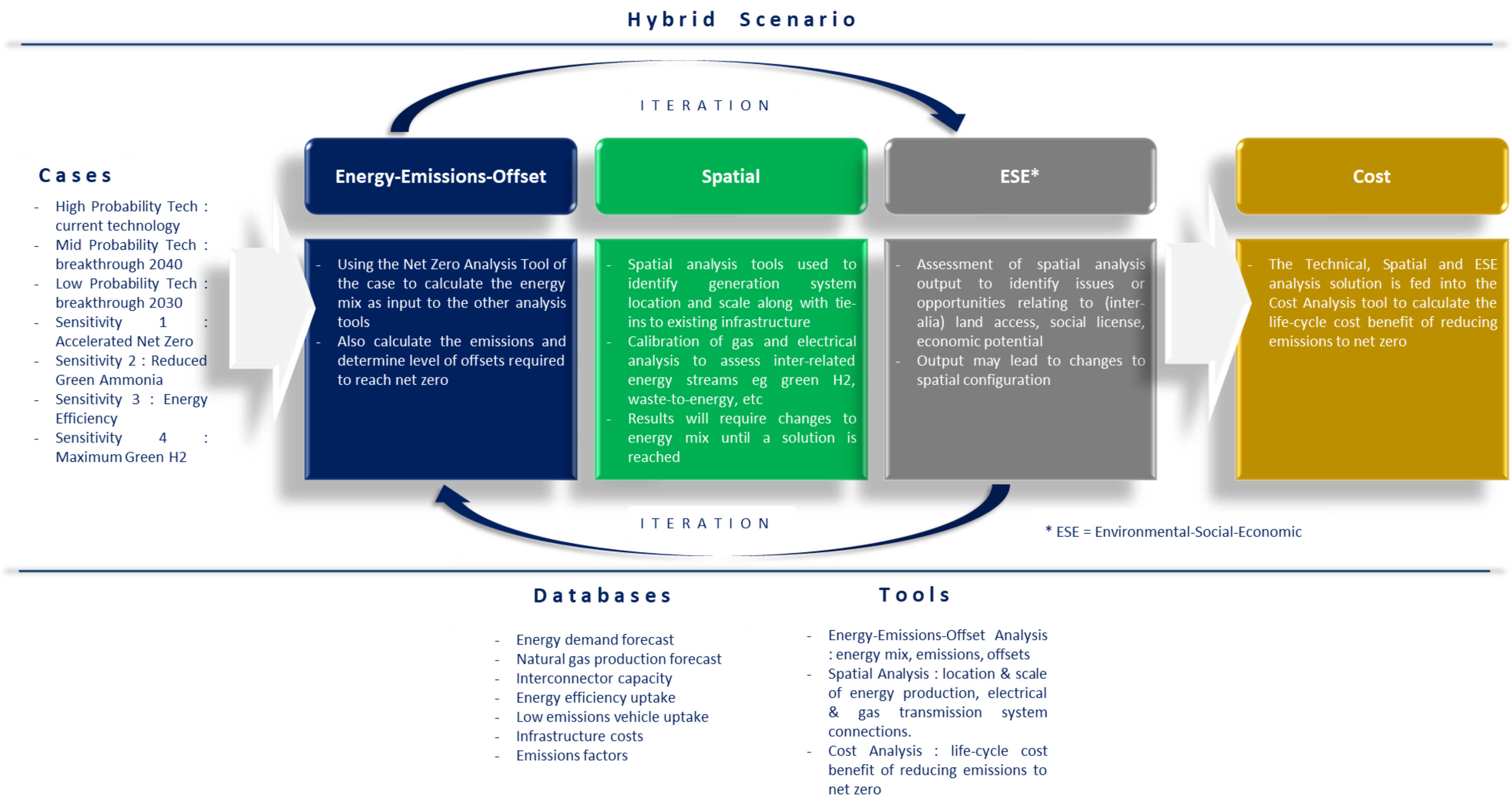


In line with the heuristic approach utilised for the current study, the modelling undertaken identifies a single, non-unique solution based on selection of a specific set of variables and constraints. The numerous analysis centres required to achieve an overall solution (energy-emissions-offsets-spatial-environmental-social-cost) were found to generate complex inter-connections between variables and constraints requiring several iterations to reach a balanced solution. Minor inconsistencies in data output / input between the analysis centres can be amplified by a ripple effect as each analysis centre interacts with the others, and whilst the resultant deviations are observed to be within the order of magnitude level of modelling accuracy adopted for the current study it may limit conclusions that can be drawn from subtle trends and minor deviations between cases.

The analysis relied on an extensive set of reference data bases which were compiled from input data covering energy demand forecast, natural gas production forecast, interconnector capacity, energy efficiency uptake, low emissions vehicle uptake, infrastructure costs and emissions factors, as illustrated in Figure 3 (overleaf). Input data references are provided in Section 2.6.

The analysis cases presented in this study were developed with the objective of delivering the required emissions abatement across the industry sectors covered by the study scope using low emissions technologies. The absolute emissions results of several analysis cases were found to exceed net zero by 2050, overshooting by 2 or 3 million tonnes CO2e per year, and in these cases greenhouse gas offsets were utilised to deliver net zero by 2050. The degree to which greenhouse gas offsets were required to achieve net zero emissions by 2050 was not intended to be material and likely falls within the accuracy bounds of the analysis.

Figure 3: General Method for the Net Zero Emissions Scenario Analysis



1.6 Key Results

1.6.1 Energy Mix

The generalised energy mix is summarised in Table 4 (overleaf), with detailed breakdowns provided in the main body of the report.

1.6.2 Cost of Achieving Net Zero

The costs (capital operating and decommissioning) for each scenario were compiled and compared to a “Control Scenario” resulting in a “comparative net cost” allowing a comparison between analysis cases and identification of which case may have the potential to represent the lowest cost compared with the others. The main reason for doing this was the uncertainty in providing total costs. A positive value was considered a net cost benefit for the analysis case compared to the Control Scenario, whilst a negative value (red) was considered a net cost increase.

The costs should not be considered an absolute value but for comparison purposes only to assess whether there is a net cost advantage or disadvantage between the cases.

The cost of carbon abatement was the total of the annualised net present costs for each scenario divided by the emissions abated between 2020 and 2050 providing a comparative $/tonne value.

Table 2 shows the estimate of comparative net costs for each analysis case, where the lower the value the greater is the benefit of the case, the higher the value the greater the cost of the case.

The High Probability Technology Case represents the least cost of the primary analysis cases and is therefore (comparatively) the lowest cost transition case compared to the Mid and Low Probability Technology cases.

Sensitivity Case 3 “Energy Efficiency”, based on the High Probability Technology case was found to be the least cost of all the analysis cases.

The Mid Probability Technology and Sensitivity Case 2 “Reduced Ammonia” have a higher net cost due to the early retirement of coal fired generation replaced with new generation costs mostly related to green hydrogen / ammonia.

The Low Probability Technology Case has a higher net cost compared to the High Probability Technology Case mostly due to the higher cost of solar thermal and offshore wind.

Sensitivity Case 1 “Accelerated Net Zero” has a higher net cost compared to all the scenarios due to the higher costs of solar thermal, offshore wind plus the early retirement of coal fired generation replaced with new generation costs related to green hydrogen / ammonia.

The comparative cost of abatement follows a similar pattern to the comparative net costs of the analysis cases as the emissions abatement (net zero) is the same in each case.

Table 2: Comparative Cost Analysis Results

Analysis Case	Estimated Comparative Net Cost ($M)	Estimated Comparative Cost of Abatement ($/tonne CO_{2e})
High Probability	-1,587	89
Mid Probability	-3,563	112
Low Probability	-1,896	93
Sensitivity Case 1 “Accelerated Net Zero”	-5,280	132
Sensitivity Case 2 “Reduced Ammonia”	-2,679	102
Sensitivity Case 3 “Energy Efficiency”	-482	76
Sensitivity Case 4 “Maximum Green Hydrogen”	-2,792	103

1.6.3 Potential Jobs Creation

Table 3 summarises the relative employment impacts of each case studied. The values represent an estimate of the number of full-time equivalent positions involved in operating the energy supply infrastructure for each analysis case, rationalised against the High Probability Technology Case to provide a focus on comparing the jobs potential between the various cases.

Table 3: Estimated Permanent Jobs in 2050 (Operations Phase)

"On-Site" (Operations & Maintenance) & "Off-Site" (logistics & supply, accounting, admin & support, engineering design & modification, etc)

Analysis Case	Jobs Index (Rationalised to High Probability Case)
High Probability	1.0
Mid Probability	2.3
Low Probability	2.3
Sensitivity 1 "Accelerated Net Zero"	2.6
Sensitivity 2 "Reduced Ammonia"	2.0
Sensitivitiy 3 "Energy Efficiency"	1.1
Sensitivitiy 4 "Maximum Green H2"	1.4

Table 4: Generalised Energy Mix (Mean Demand)

Analysis Case	Energy Gas (PJ)								Electricity (PJ)								Road Vehicles (PJ, Note 3)				Total (PJ)	Approximate Split Energy Gas / Elec
	Natural Gas				Low Emissions Gas (Note 1)				Coal & Natural Gas				Low Emissions Elec. (Note 2)				Gasoline & Diesel					
	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050	2050	2050
High Probability	209	171	128	50	0	34	49	82	149	93	44	0	57	356	545	781	318	214	96	0	913	15 / 85
Mid Probability	209	171	0	0	0	33	141	262	149	93	0	0	57	355	624	651	318	214	97	0	914	30 / 70
Low Probability	209	121	80	20	0	33	50	81	149	97	45	0	57	395	589	812	318	222	99	0	914	10 / 90
Sensitivity 1 “Accelerated Net Zero”	209	174	0	0	0	33	125	203	149	95	0	0	57	346	638	712	318	218	99	0	914	20 / 80
Sensitivity 2 “Reduced Ammonia”	209	171	22	22	0	33	118	181	149	93	0	0	57	355	625	710	318	214	97	0	914	20 / 80
Sensitivity 3 “Energy Efficiency”	209	162	118	47	0	31	42	67	149	96	45	0	57	331	488	678	318	203	87	0	792	15 / 85
Sensitivity 4 “Maximum Green H2”	209	117	66	15	0	49	128	201	149	93	37	0	57	396	553	698	318	212	80	0	914	25 / 75

Notes

1. Low emissions gas includes green Hydrogen, green Ammonia, and biomethane.
2. Low emissions electricity includes NH3, hydropower, solar PV (large scale + non-sched + BTM), solar thermal, wind (onshore + offshore), bioenergy, fuel cells, (storage) - pumped hydro, (storage) - batteries (incl. standard + VPP + BTM + iron-air).
3. Fuel for low emissions vehicles included in Energy Gas and Electricity. Refer Section 3.7 for road vehicle fuel data.

1.6.4 Emissions and Time to Net Zero

Table 5 (overleaf) documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions results for the various analysis cases relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which cover additional emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline & diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profiles for each analysis case is that a margin exists in the interim target to cover out of scope emissions, which was estimated to be:

- 2025 interim emissions target: up to 20 Million Te CO_2-e to cover out of scope emissions (depending on the analysis case); and
- 2030 interim emissions target: up to 14 Million Te CO_2-e to cover out of scope emissions (depending on the analysis case).

Figure 4 shows the estimated annual greenhouse gas emissions at five yearly intervals for each of the analysis cases indicating that for the High Probability Technology Case, Low Probability Technology Case, Sensitivity Case 3 “Energy Efficiency”, and Sensitivity Case 4 “Maximum Green Hydrogen” there is a relatively linear decline in emissions to 2050. The Mid Probability Technology Case, Sensitivity Case 1 “Accelerated Net Zero” and Sensitivity Case 2 “Reduced Ammonia” also show as linear decline in emissions out to 2035 before an accelerated reduction in emissions prior to 2040. Note the data in Figure 4 does not indicate the effect of offsets in 2050 reducing the residual emissions from technologies modelled to achieve net zero in 2050.

Figure 4: Analysis Cases – Greenhouse Gas Emissions Profile

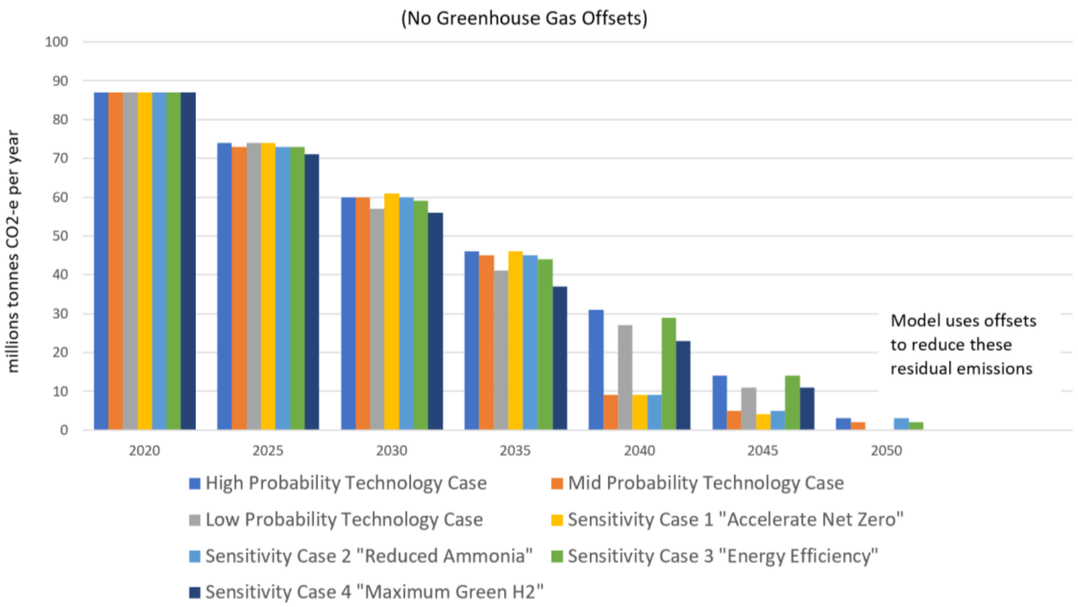


Table 5: Interim Emissions Targets and Estimated Absolute Emissions

Analysis Case	Total Emissions per Year (NOTE 1) (Mill Te CO_2-e)												
	2005	2020	2025	2005 to 2025 % Reduction	2030	2005 to 2030 % Reduction	2035	2005 to 2035 % Reduction	2040	2005 to 2040 % Reduction	2045	2005 to 2045 % Reduction	2050 (NOTE 2)
High Prob	128	87	74	-42%	61	-52%	47	-63%	33	-74%	17	-87%	3
Mid Prob	128	87	74	-42%	61	-52%	46	-64%	10	-92%	7	-95%	3
Low Prob	128	87	74	-42%	57	-55%	41	-68%	27	-79%	11	-91%	-2
Sensitivity 1 "Accelerated Net Zero"	128	87	74	-42%	61	-52%	46	-64%	9	-93%	4	-97%	-1
Sensitivity 2 "Reduced Ammonia"	128	87	74	-42%	61	-52%	46	-64%	11	-91%	7	-95%	3
Sensitivity 3 "Energy Efficiency"	128	87	74	-42%	60	-53%	46	-64%	31	-76%	16	-88%	3
Sensitivity 4 "Maximum Green H2"	128	87	72	-44%	56	-56%	37	-71%	23	-82%	11	-91%	0
Interim Targets			**86-92**	**28-33%**	**64-70**	**45-50%**							

NOTE 1*: Emissions in current study scope: electricity, energy gas, and road vehicles, which is a component only of the scope used for Victorian Government reported emissions.*

NOTE 2*: For positive emissions in 2050, offsets are required to achieve net zero position (refer relevant Energy-Emissions-Offset section for results). A negative emissions result in 2050 indicates net zero can be achieved prior to 2050.*

1.6.5 Gas Infrastructure Upgrades

Table 6 provides summary details of the additional gas transmission pipelines for each case. For the High, Mid and Low Probability Technology Cases new transmission lines are planned to move biomethane produced in the west and north west of the state to centres of demand.

Table 6: Estimated Extent of Additional Gas Transmission Pipelines

(4,694 kms installed transmission pipelines)

Analysis Case	2030	2040	2050
High Probability	0 km	360 in 2035	0
Mid Probability	0 km	360 in 2035	0
Low Probability	0 km	360 in 2035	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	0	0
Sensitivity Case 3	0	0	0
Sensitivity Case 4	0	0	0

Table 7 shows a summary of the decommissioning of existing gas transmission pipelines. This can occur when local production of biomethane and/or hydrogen is able to meet local demand. In Sensitivity Case 4, the majority of the high pressure gas transmission system can be decommissioned as green hydrogen is produced locally to meet most of the demand.

Table 7: Estimated Extent of Decommissioning of Existing Gas Transmission Pipelines

(4,694 kms installed transmission pipelines)

Analysis Case	**2030**	**2040**	**2050**
High Probability	0 km	0	850
Mid Probability	0 km	1700	0
Low Probability	0 km	1700	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	1200	700
Sensitivity Case 3	0	1200	0
Sensitivity Case 4	0	2000	4000

Table 8 shows an estimate of the extent of decommissioning of existing gas distribution pipelines. A detailed analysis has not been undertaken, so this an initial estimate only.

Table 8: Estimated Extent of Decommissioning of Existing Gas Distribution Pipelines

(34,016 kms total installed infrastructure for the 3 fully regulated network suppliers)

Analysis Case	2030	2040	2050
High Probability	0	0	2500
Mid Probability	0	4000	0
Low Probability	0	8000	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	0	0
Sensitivity Case 3	0	0	0
Sensitivity Case 4	0	0	0

<u>Gas Infrastructure Specific to the Mid Probability Technology Case</u>

Table 9 shows the changes required to accommodate 100% hydrogen in the distribution network and 100% ammonia in the transmission network for each case.

Table 9: Impacts for Hydrogen and Ammonia Transport

Analysis Case	Impacts to Accommodate Hydrogen	Impacts to Accommodate Ammonia
High Probability	No impact as overall flow is less	Not Applicable
Mid Probability	Distribution network upgrades to handle 100% hydrogen required by 2030.	Transmission network compatibility with liquid ammonia transport required by 2030.
Low Probability	No impact as overall flow is less	Not Applicable

1.6.6 Electrical Infrastructure Upgrades

Data in Table 10 defines the extent of new or upgraded electrical infrastructure required for each analysis case over and above existing and committed electrical infrastructure. The values are presented as a "relative index" calculated as follows:

$$\textbf{Relative Electrical Generation Infrastructure Index}_{\textbf{Scenario High}} = \frac{A}{B}$$

With:

A = **Electrical Generation Infrastructure Capacity of period 20XX Estimate (MW)** **Scenario High**

B = **Electrical Generation Infrastructure Capacity (MW) of period 2025 Estimate** **Scenario with Lowest Level of Electrical Infrastructure**

All analysis cases start in 2025 with the same amount of additional electrical capacity and for this reason the 2020-2025 period is always considered to have the lowest level of electrical infrastructure with a relative electrical index of 1.

In 2030, all scenarios are similar with respect to additional electrical infrastructure, but between 2035 and 2050 some deviations occur, and a large difference is observed between the High Probability Technology Case with the highest index of 3.3 and the Mid Probability Technology Case with the lowest index of 2.1.

A decrease is present in the Mid Probability Technology Case, Sensitivity 1 "Accelerated Net Zero" and Sensitivity 2 "Reduced Ammonia" between 2045 and 2050 corresponds to all the cases with the use of green ammonia. Between 2045 and 2050, decommissioning of several gas and coal electricity generation infrastructure facilities is observed (all the remaining production assets). It means that if a case has almost reached its 2050 demand in 2045 without gas and coal production, in the 2045-2050 period, there will be more decommissioning in the generation infrastructure than commissioned generation infrastructure.

An analogous approach has been taken to calculating the values for electrical storage infrastructure upgrades presented in Table 11.

Table 10: Relative Extent of Upgrades to Electrical Generation Infrastructure

Analysis Case	2025	2030	2035	2040	2045	2050
High Probability	1.0	1.5	2.0	2.3	2.7	3.3
Mid Probability	1.0	1.5	1.8	2.2	2.2	2.1
Low Probability	1.0	1.5	1.8	1.9	2.1	2.6
Sensitivity 1 “Accelerated Net Zero”	1.0	1.5	1.8	2.1	2.4	2.3
Sensitivity 2 “Reduced Ammonia”	1.0	1.5	2.0	2.2	2.6	2.5
Sensitivity 3 “Energy Efficiency”	1.0	1.5	1.8	1.9	2.2	2.8
Sensitivity 4 “Maximum Green H2”	1.0	1.2	1.8	2.1	2.4	2.5

Table 11: Relative Extent of Upgrades to Electrical Storage Infrastructure

Analysis Case	2025	2030	2035	2040	2045	2050
High Probability	2	7	11	16	21	29
Mid Probability	2	7	10	13	15	19
Low Probability	2	11	15	19	23	33
Sensitivity 1 “Accelerated Net Zero”	2	6	9	16	19	23
Sensitivity 2 “Reduced Ammonia”	2	7	11	12	13	23
Sensitivity 3 “Energy Efficiency”	1	6	9	12	15	22
Sensitivity 4 “Maximum Green H2”	2	5	5	5	5	12

1.6.7 Electrical Storage by Type

Table 12: Electrical Storage by Type for each Analysis Case

Analysis Case	Iron-Air Batteries (PJ)				Pumped Hydro (PJ)				Standard batteries "large scale" (Li-ion, flow, etc) (PJ)				"Virtual Power Plant" (aggregated small-scale batteries) (PJ)				"Behind the meter" non-aggregated small-scale batteries (dis-connected from grid) (PJ)				Molten Salt (PJ)				Total (PJ)
	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040*	2050	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050	2050
High Probability	0	0	0	0	0	2	3	4	0	56	97	152	0	3	7	16	1	6	14	25	0	0	0	0	**193**
Mid Probability	0	0	4	12	0	2	3	3	0	56	79	67	0	3	8	9	1	6	17	17	0	0	0	0	**108**
Low Probability	0	0	0	0	0	3	3	4	0	28	44	77	0	3	5	10	1	8	15	21	0	33	57	78	**190**
Sensitivity 1 “Accelerated Net Zero”	0	0	17	36	0	3	3	3	0	27	34	31	0	3	7	10	1	6	16	20	0	20	47	48	**148**
Sensitivity 2 “Reduced Ammonia”	0	0	24	48	0	2	3	3	0	56	77	71	0	3	7	10	1	6	16	20	0	0	0	0	**152**
Sensitivity 3 “Energy Efficiency”	0	0	0	0	0	3	3	4	0	49	83	125	0	3	7	16	1	6	14	26	0	0	0	0	**171**
Sensitivity 4 “Maximum Green H2”	0	0	0	0	0	2	3	3	0	34	35	44	0	1	3	5	1	7	12	16	0	20	26	30	**95**

**In some cases 2040 marks the point where de-commissioning of standard battery facilities exceeds the rate of installation of new ones and a result of the uptake of alternative storage technologies.*

1.6.8 Key Risks & Opportunities

Table 13: Key Risks & Opportunities

Analysis Case	Key Risks	Key Benefits
All	Cost of additional infrastructure, compared with any analysis case that does not achieve net zero, and impact on future energy prices	Reduction of emissions and achieving net zero by 2050 whilst meeting energy demand
High Probability	Continued supply of natural gas, including imports into Victoria and new local production Reliance on carbon offsets to achieve net zero	Existing proven technology, utilisation of existing gas infrastructure
Mid Probability	Breakthrough in green hydrogen supply cost and cost competitive sourcing of large quantities of ammonia. Security of supply for ammonia Commercialisation of new ammonia fired power plants (gas turbines) Commercialisation of ammonia to hydrogen for energy gas distribution Commercialisation of iron-air battery technology Reliance on carbon offsets to achieve net zero	Proven technologies Gas turbines fuelled by ammonia provide peaking power Reduced capital expenditure due to use of existing electricity and gas infrastructure Continued use of existing gas transmission and distribution infrastructure whilst minimising upgrade requirements Improved safety and electricity system cost reduction Opportunity for conversion of existing coal fired power plants to ammonia to reduce transition cost
Low Probability	Breakthrough in solar thermal power generation cost Cost effective offshore wind	Proven technology, reduced land area for solar power generation, grid firming storage from molten salt Proven technology, reduced land area for wind power generation No reliance on offsets to achieve net zero Opportunity for solar fuels industry based on solar thermal temperature levels
Mid & Low Probability	One or more of the new technologies may not become technically proven and/or	The net zero outcome does not rely on these specific technologies alone, nor the assumed timings. Other combinations of technologies and

Analysis Case	Key Risks	Key Benefits
	commercially competitive within the timeframes.	implementation dates are possible e.g. novel battery technologies, compressed air storage, ammonia fuel cells and direct solar-to-hydrogen (photo electrocatalysis)
Sensitivity 1 "Accelerated Net Zero"	Generally as per Mid and Low Probability Technology Cases	Generally as per Mid and Low Probability Technology Cases No reliance on offsets to achieve net zero
Sensitivity 2 "Reduced Ammonia"	As per Mid Probability Technology Case for ammonia supply and power generation Commercial operation of gas transmission and distribution infrastructure under reduced loads Additional electricity supply compared with Mid Probability Technology Case requires additional electrical infrastructure Reliance on carbon offsets to achieve net zero	Reduced risk of sourcing smaller quantities of ammonia compared with Mid Probability Technology Case
Sensitivity 3 "Energy Efficiency"	As per High Probability Technology Case Achieving the optimal cost-benefit balance from energy efficiency measures Reliance on carbon offsets to achieve net zero	Reduced energy demand leading to reduced infrastructure requirements and reduced requirements of carbon offsets
Sensitivity 4 "Maximum Green H2"	As per Low Probability Technology Case	No reliance on offsets to achieve net zero

1.7 Major Conclusions

The energy supply implications of the transition to net zero carbon emissions by 2050 for energy consumers (residential, commercial and industrial) include:

Cost - either directly, or indirectly

Change – energy type, appliances, generation, vehicles, demand management, energy efficiency (near term)

This analysis found that while there are a range of environmental and social impacts associated with the scale of development envisaged, these are manageable using existing and established processes. Particular care is required to maintain community support, particularly with local stakeholders given the scale of wind and solar development, and construction of hydrogen, ammonia and bioenergy plants as the industrialisation of rural Victoria.

High Probability Technology Case "Current Energy Technology"

Achieves net zero with little technical risk, as only proven technologies are assumed to be used, along with credible assumed improvements in energy supply cost. However, this case relies on the continued supply and distribution of natural gas, including imports or new local supplies into Victoria. Offsets are required to achieve net zero carbon emissions given the "tail" of natural gas maintained to support "harder to abate" industries.

The ongoing use of the existing gas transmission and distribution network reduces the overall expenditure on new energy infrastructure and reduces the environment & social impacts associated with construction and decommissioning works.

The High Probability Technology Case, as with all the other cases, includes a significant ramp up in the use of bioenergy resources to accelerate reaching net zero. The main advantages of the use of bioenergy resources include: continued use of the existing gas transmission and distribution networks to distribute biomethane, dispatchable and distributed electricity generation to complement other renewable sources, creation of jobs in both metropolitan and regional centres, displacement of fossil fuel emissions and avoidance of emissions from landfill and agriculture of a range of proven technologies that have been deployed at scale in other jurisdictions such as Europe.

The High Probability Technology Case has the highest proportion of electrification of any of the primary analysis cases (85%), due to the high level of variable renewable energy (solar PV and onshore wind), requiring by far the highest level of storage using standard batteries than any other case.

The opportunity to eliminate reliance on natural gas and reduce or eliminate the requirement for carbon offsets prior to 2050 exists if significant cost breakthroughs can be made in emerging technologies for example: if either solar thermal power generation (with molten salt thermal storage) or offshore wind (with iron-air battery storage) are able to be commercialised on a cost competitive basis before 2030.

Cost effective, long term, grid scale energy storage and transport technologies such as iron-air batteries and green Hydrogen (combined with fuel cells or Ammonia) will also be important in allowing the variable renewable electricity share to be increased without the need for electrical network re-construction.

While promising progress is being made in a range of technology areas, the likelihood and timing of the potential technology and cost breakthroughs is uncertain, and progress should be closely monitored or actively supported to ensure that Government policy settings remain appropriately calibrated.

The net zero outcome does not rely on any specific emerging technology, or a specific timing in the cases analysed in this study. Other combinations of technologies and implementation dates are possible e.g., other novel battery technologies, compressed air storage, ammonia fuel cells and direct solar-to-hydrogen (photo electrocatalysis).

The rate of energy efficiency improvement was not found to have a significant impact on the state's ability to reach net zero by 2050, but did have a significant impact on the energy generation requirements, their associated infrastructure costs and environmental & social impacts. For energy efficiency to significantly reduce the time to net zero would require a parallel increase in the rate of uptake of low emissions vehicles and a much more aggressive near term (2030) increase in residential and commercial energy efficiency improvement of greater than 20% per decade.

The scale of avoided build and capital expenditure was found to be dependent on the energy efficiency improvement rate, which for the current modelling was assumed to increase from 5% per decade for both electricity and energy gas in the bases analysis cases to 20% in Sensitivity Case 3 "Energy Efficiency". It was also dependent on the energy mix selected plus the inputs and assumptions made for the modelling. The Cost Analysis showed a threefold improvement in net present comparative cost (High Probability Technology Case versus Sensitivity Case 3 "Energy Efficiency"). It may, however, be much higher or lower depending on the modelling inputs and assumptions and also putting a precise and accurate scale on this not found to be possible due to the number variables and unknowns. Otherwise, it would generally be expected that reduced energy demand/consumption through energy efficiency will likely reduce build and capital expenditure costs.

Low level of potential full time energy industry employment relative to the other cases, due to the scale of relatively low complexity energy generation facilities (solar photo-voltaic (PV), wind and storage).

Second lowest net cost compared to the other analysis cases driven by the predominance of solar PV and wind.

Mid Probability Technology Case "Green Ammonia"

Representing the highest proportion of energy gas in the mix (30%) due to the introduction of green Ammonia in 2040, whilst also being the only primary analysis case with no tail of natural gas.

The Mid Probability Technology case also provides the opportunity to maximise the use of natural gas pipeline infrastructure, and the potential to utilise the electricity generation and transmission infrastructure in the Latrobe Valley by converting coal fired power stations to Ammonia (as per Japanese Government "Green Growth Strategy Through Achieving

Carbon Neutrality in 2050") or establishment of new Ammonia fired power generation capacity.

Reasonably high level of potential full time energy industry employment relative to the other Analysis Cases, due to the scale and complexity of the Ammonia fired power generation facilities.

Significantly higher net cost compared to the other cases driven by the supply of green Ammonia and derived green Hydrogen at scale.

Low Probability Technology Case "Solar Thermal & Molten Salt Storage"

Reaches net zero faster than any of the other primary analysis cases, as well as being the only one that did not require offsets. This outcome was achieved due to the highest level of electrification of any of the primary analysis cases (10% energy gas to 90% electrification ratio) which was achievable through the use of solar thermal electricity generation with molten salt (deep duration) thermal storage providing a higher quality of power (equivalent to base load coal) with an improved capacity factor thereby providing a much more efficient outcome than would otherwise be achievable with VRE facilities.

Reasonably high level of potential full time energy industry employment relative to the other Analysis Cases, due to the scale and complexity of the solar thermal / molten storage facilities.

Whilst the Low Probability Technology Case has the lowest probability of occurring, given it has the shortest reference timeframe, should the technology breakthroughs occur by 2030, then it would represent the strongest Hybrid Scenario pathway due to the combination of its relatively low level of net cost, the high level of potential full-time employment, and the ability to reach net zero faster than the other Analysis Cases, all without the need for offsets.

Sensitivity Case 1 "Accelerated Net Zero"

The construction of Sensitivity Case 1 "Accelerated Net Zero", which combined the technology breakthroughs of both the Low and Mid Probability Technology Cases, achieved a time to net zero that was quite similar the Low Probability Case.

Achieving a more significant reduction in the time to net zero might be achieved through implementation of an aggressive, near term (2030) improvement in residential-commercial energy efficiency improvement (greater than 20% per decade) in parallel with a significant near term (2030) increase in the uptake of low emissions road vehicles.

Highest level of potential full time energy industry employment relative to the other Analysis Cases, due to the scale and complexity of both the Ammonia fired power generation facilities, and solar thermal / molten salt plants.

Highest net cost compared to the other cases driven by the importation of green Ammonia, and solar thermal / molten salt storage infrastructure.

Sensitivity Case 2 "Reduced Ammonia"

No significant reduction in the time to reach net zero, along with a mid-ranked net cost would lead to the conclusion that Sensitivity Case 2 "Reduced Ammonia" represents minimal benefit as a Hybrid Scenario pathway compared to the other analysis cases.

Sensitivity Case 2 “Reduced Ammonia” requires slightly higher levels of Carbon offsets compared to the Mid Probability Technology case, as a result of a higher level of coal power and natural gas in the mix due to the reduced green Ammonia levels.

Reasonably high level of potential full time energy industry employment relative to the other Analysis Cases, due to the scale and complexity of the Ammonia fired power generation facilities.

Sensitivity Case 3 “Improved Energy Efficiency”

This case was found to have a very much lower net cost compared to any of the other analysis cases due to the avoidance of energy generation infrastructure and related expenditure resulting from the reduction in energy demand due to improved energy efficiency.

Reasonably low level of potential full time energy industry employment relative to the other Analysis Cases, due to the scale of comparatively low complexity energy generation facilities (solar PV, wind and storage).

Sensitivity Case 4 “Maximum Green Hydrogen”

Despite achieving net zero without the need for offsets, the performance of Sensitivity Case 4 “Maximum Green Hydrogen” in terms of net cost, time to net zero and potential jobs creation was mediocre compared to the other Analysis Cases.

1.8 Considerations

Based on the study results and conclusions, a range of further work and areas of focus related to net zero emissions planning has been identified for consideration.

1.8.1 Monitoring Technology Development

Monitoring of low emissions energy technology development, including a mechanism to predict the potential for a breakthrough by 2030 should be established and provide regular updates (at least once a year) on the potential timing and techno-economic performance of each of the technology categories identified in the current study.

Importantly the scope of the program should be general and cover the low emissions technology categories including energy gas generation and storage, and electricity generation and storage. As future innovation results in promising alternatives to those technologies selected for the current study the program should recommend revision of the current analysis, and subsequently given to net zero emissions planning as required.

Areas of specific focus related to the range of Hybrid Scenario pathways illustrated in Figure 1 are summarised below.

Green Hydrogen at scale
- Lower levelized cost of energy than natural gas
- Supported by offshore wind enables partial replacement of natural gas (as green Hydrogen limited by pipeline materials of construction),
- Provides chemical feedstock enabling, inter-alia, green Ammonia (NH_3) which then allows full replacement of natural gas whilst utilising existing natural gas infrastructure
- Improves variable renewable electricity capacity factor / firming

Solar-thermal, along with molten salt deep duration thermal storage
- Lower levelized cost of energy than solar photo-voltaic (PV) & batteries (firmed solar)
- Deep storage improves electricity yield (compared to solar PV), and variable renewable electricity capacity factor (reducing infrastructure costs)
- Solar fuels industry creates economic growth

Wind offshore, along with deep duration Iron-air battery storage
- Lower levelized cost of energy than onshore wind
- Very high electricity yield compared to onshore, improves variable renewable electricity capacity factor reducing infrastructure costs.

Green Ammonia
- Enabling complete replacement of natural gas, as well as utilization of existing natural gas pipeline infrastructure
- Potential for utilization of Latrobe Valley electrical generation and transmission infrastructure beyond 2050

Bioenergy
- Opportunity for negative emissions contribution based on avoided emissions from agriculture and waste
- Planning to put in place supply chains to maximise the potential of bioenergy

Energy Efficiency

Increasing near term (by 2030) residential-commercial uptake of energy efficiency improvement at a level of 20% per decade, will lead to a very significant level of avoided energy generation infrastructure build and expenditure.

When combined with reducing internal combustion engines (ICE) road vehicle numbers by significantly increasing the uptake of low emissions road vehicles will lead to significant reduction in time to net zero emissions.

Vehicles

Given the significant proportion of overall emissions represented by ICE road vehicles, an enhanced near term (by 2030) increase in the uptake of low emissions vehicles (thereby reducing gasoline & diesel use) would represent a key element of the net zero planning focus.

By implication, this concept should be extended to other categories of heavy transport such as aviation and shipping to amplify the impact on emissions reduction.

Victorian Renewable Energy Target (VRET)

When Variable Renewable Energy (VRE) share represents more than 60% of the electrical mix the intermittency can create instability in the network. To avoid this effect, additional storage will need to be added to the specification of electrical infrastructure.

A network with 100% solar and wind in the electrical mix would require substantial modification to the complete transmission and distribution network. Stability of the network would require additional infrastructure with diminishing returns as the system would need to be over dimensioned (both on generation and storage infrastructures). The cost of such a solution would be significantly higher than a solution with dispatchable energy infrastructure which can work at a fixed nominal capacity and can be started and stopped if necessary. On the contrary solar and wind generation capacity depend on intermittent factors.

1.8.2 Government Support

The options below are provided for consideration by the Victorian Government in order to facilitate the transition envisaged by the current study.

1. Undertaking a strategic level environmental (and social) impact assessments for each Renewable Energy Zone and offshore wind considering the likely staged development nature of the projects and environmental and social receptors in each zone.

2. Facilitating the development of Victoria's Hydrogen and Ammonia industry, the Pipelines Act 2005 should be amended to incorporate the regulation of ammonia pipeline, along with the development of required standards and guidelines.

3. Managing the risk of battery fires with consideration given to developing, in conjunction with stakeholders, appropriate standards/codes for the manufacture, installation, inspection and maintenance of high energy density batteries. These standards/codes should cover the various applications including transport, grid-connected and behind the meter.

4. Ensuring the risk of fire/explosion from hydrogen is no greater than for natural gas, consideration should be given to the development of regulations or codes targeting: standards for the manufacture, installation and use of domestic and industrial hydrogen appliances; training and accreditation for those involved in the installation and maintenance of hydrogen appliances; consideration of the risks posed by hydrogen embrittlement in the design and maintenance of any equipment in contact with hydrogen; and mechanisms to improve leak detection of hydrogen such as odorization.
5. Developing a whole of life stewardship program for batteries and solar PV requiring recycling at end of effective life. The capacity to recycle and reuse this material should be developed to avoid disposal into landfill.
6. Green Ammonia – putting in place the preparatory groundwork for development of an Ammonia transition road-map analogous to the Japanese Government “Green Growth Strategy Through Achieving Carbon Neutrality in 2050” to maximise the potential for utilization of Latrobe Valley electrical generation and transmission infrastructure beyond 2050. The preparatory groundwork may involve undertaking a market survey focusing on green Ammonia supply chain, a detailed infrastructure assessment focusing on location and scale of green Ammonia import facilities along with transport to key users, and a comprehensive technology investigation focusing on Ammonia to power and catalytic cracking to green Hydrogen.
7. Bioenergy – supporting approvals and planning to put in place supply chains to maximise the potential of bioenergy.
8. Energy Efficiency – increasing near term (by 2030) residential-commercial uptake of energy efficiency improvement at a level of 20% per decade, to reduce the level of future energy generation infrastructure build and expenditure.
9. Vehicles – implementing mechanisms to increase the uptake of low emissions road vehicles thereby reducing internal combustion engine (ICE) road vehicle numbers to significantly reduce the time to reach net zero emissions. Furthermore, consider means to extend this initiative to other categories of heavy transport such as aviation and shipping to amplify the impact on emissions reduction.
10. Victorian Renewable Energy Target (VRET) – identifying a cost effective balance between elevated variable renewable electricity share versus security of supply versus upgrades to the existing electricity grid over time. As a corollary to this consideration, a pivot to provision of low emissions, dispatchable energy capacity should be considered.
11. Technology Development – increasing funding to technology development in the areas of low emissions energy gas generation and storage, and deep duration electrical storage.

1.8.3 Further Study

It is considered that a more detailed cost analysis should be conducted to further quantify the benefits of various technology breakthroughs as a function of time. A more granular cost assessment than the generic technology approach used in this study will be beneficial. This will assist in directing research and investment funds to accelerate development of focus technologies. While wind and solar are currently the lowest cost sources of variable renewable electricity, other technologies will be required to firm the grid as the variable renewable electricity share increases.

A separate cost-benefit analysis study to further define the balance between energy efficiency measures and increased renewable energy generation capacity will also be useful, but only if sufficiently detailed input data is available for the study.

A more detailed analysis of how maximum and peak power demands could be satisfied is also required within the context of an integrated national electricity market (NEM). This would account for any existing gas and electricity interconnectors, planned upgrades or newly installed interconnectors, new supplies being brought to market as well as energy storage within Victoria and interstate. The supply and demand balance throughout the whole NEM over time should be assessed to ensure that Victoria's peak demand can reliably be satisfied.

Planning studies should be undertaken to develop feasible options for stage-wise implementation of new energy gas such as green Hydrogen and green Ammonia, identifying the region by region schedule for infrastructure upgrades (in particular distribution) and switch-over from natural gas.

Significant improvements to the completeness and quality of input data quality are required, particularly in the following areas:

- Energy demand forecasts – comprehensive breakdowns of the entire energy system in Victoria
- Low emissions road vehicles – split out for heavy and light vehicles along with fuel consumption rates and uptake forecasts
- Energy efficiency improvement – covering residential & commercial
- Employment – in particular full time equivalent operational jobs rates associated with the energy efficiency industry.
- Emissions offset factors – in particular agro-forestry including terrestrial, marine and soil farming.

Focus on pro-active development of the following classes of energy technologies:

- **Renewable energy gas generation combined with storage**, for example green Ammonia (at scale) with the following specifications
  - Levelised cost of energy parity with natural gas
  - Supported by green hydrogen and offshore wind breakthroughs enables full replacement of natural gas whilst utilising existing natural gas infrastructure. If green Hydrogen combined with ammonia fired power generation is located in the Latrobe Valley, and coupled with offshore wind this then represents a

new future industry for the region as brown coal recedes by converting power stations from coal to ammonia and building new ammonia fired power plants.

- **Renewable electricity generation combined with deep storage,** for solar-thermal with associated molten salt storage, offshore wind and Iron-air batteries with the following specifications:
  - Levelised cost of energy lower than onshore wind
  - Very high electricity yield compared to onshore wind, improves variable renewable electricity capacity factor reducing infrastructure costs (capital and operating expenditure).
  - Molten salt thermal storage provides low cost deep duration grid scale thermal storage for firming of electricity supply from solar thermal
  - Iron-air battery technology provides low cost multi-day grid scale battery storage for firming of electricity supply from offshore wind and other variable renewable electricity sources
- Electricity generation using Ammonia, with the following specifications:
  - Levelised cost of energy parity with natural gas
  - Conversion of existing coal fired power plants, and opportunity for life extension
  - Construction of new Ammonia fired gas turbine power generation plant.
- **Vehicle Analysis** - more detailed vehicle analysis work should be undertaken covering specifically:
  - Vehicle fuel consumption rates, especially heavy versus light
  - Total energy infrastructure requirements for low emissions vehicles, especially Battery Electric Vehicle (BEV) re-charging stations both public and private
  - Public transport uptake rates, and electrification of railways for long distance transport
  - Extend the scope to aviation and water transport.

2 INTRODUCTION

2.1 Document Intent

The purpose of this document is to present conclusions and recommendations developed by the current study and record the basis for the work undertaken during the Net Zero Emissions Scenario Analysis, including methodology, references, assumptions, and results.

2.2 Study Objectives

The study undertook concept level analysis of several net zero emissions pathway cases generating technical data to support Infrastructure Victoria (IV) in the provision of advice requested by the Treasurer of Victoria on the nature and timing of decisions regarding the gas transmission and distribution networks for Victoria in a future where:

- **Victoria's carbon emission reduction targets are achieved;**
- **Sufficient and suitable energy and chemical feedstocks are available** for domestic, commercial, and industrial use; and
- **An option is available for hydrogen and/or biomethane** to be part of the future energy mix.

The 2020-21 Victorian Budget included funding for Government to deliver a Gas Roadmap by the end of 2021, in support of net zero greenhouse gas emissions for the State by 2050.

Complementing the Gas Roadmap, IV's Advice will work backwards from 2050 to **understand the nature and timing of gas infrastructure-related decisions to maximise opportunities and minimise risks** associated with existing and committed gas infrastructure. This Advice will inform Government decision-making over the short, medium and long term.

2.3 Definitions

IV	Infrastructure Victoria
DORIS	DORIS Group
Green Hydrogen	Hydrogen produced through electrolysis using renewable electricity
Blue Hydrogen	Hydrogen produced through steam reforming of natural gas, with Carbon Capture & Storage
Brown Hydrogen	Hydrogen produced through gasification of brown coal, with Carbon Capture & Storage
Biogas	A methane rich gas suitable for injection into the natural gas grid, produced after organic materials (plant and animal products) are broken down by bacteria in an oxygen-free environment, a process called anaerobic digestion
Biomethane	A general term for a renewable substitute for natural gas made from biogenic material. Biomethane can be produced by upgrading biogas

to pipeline quality specifications by removing, inter-alia, Carbon Dioxide. Biomethane can also be produced by converting lignin rich biomass into syngas via gasification and then converting syngas into methane via a catalytic reaction.

Energy generation capacity refers to those facilities which produce energy, which is subsequently used to meet the energy demand of consumers.

2.4 Abbreviations

Acronym	Definition
ABEX	Abandonment Expenditure
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
BEV	Battery Electric Vehicle
BTM	Behind the Meter
CHP	Combined Heat & Power (biogas for heat and electricity generation)
CAPEX	Capital Expenditure
C&D	Construction and Demolition
CFI Act	Carbon Credits (Carbon Farming Initiative) Act 2011
C&I	Commercial and Industrial
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COAG	Council of Australian Governments
COVID-19	Coronavirus 2019
CSIRO	Commonwealth Scientific & Industrial Research Organisation
DAC	Direct Air Capture
DELWP	Department of Environment, Land, Water and Planning
DISER	Department of Industry Science, Energy and Resources
EOR	Enhanced Oil Recovery
EV	Electric Vehicle
GBB	Gas Bulletin Board (AEMO website)
GHG	Green House Gas
GSHP	Ground Source Heat Pump
GSO	Gas Statement of Opportunities (AEMO publication)
GW	Giga Watt (10^9 Watts)

Acronym	Definition
H_2	Hydrogen
HFCV	Hydrogen Fuel Cell Vehicle
ICE	Internal Combustion Engine
IPPU	Industrial Process and Product Use
ISP	Integrated System Plan
kW	Kilo Watt (10^3 Watts)
LGA	Local Government Area
LNG	Liquified Natural Gas
LMP	Longford Melbourne Pipeline
LULUCF	Land Use, Land Use Change and Forestry
MELB	Melbourne region
Mt CO_2-e	Million Tonnes of Carbon Dioxide equivalent
Mt(pa)	Million Tonnes (per annum)
MRF	Material Recovery Facilities
MSW	Municipal Solid Waste
NEM	National Electricity Market
NH_3	Ammonia
OPEX	Operating Expenditure
PJ	Peta Joules (10^{15} Joules)
PTS	Principal Transmission System (also known as the Victorian Transmission System)
PV	Photo Voltaic (solar)
TPA	Tonnes Per Annum
REZ	Renewable Energy Zone
SDGs	Sustainable Development Goals
SWP	South West Pipeline
TRL	Technology Readiness Level (a type of measurement system used to assess the maturity level of a particular technology)
VNI	Victoria – New South Wales Interconnector (electricity) Victorian Northern Interconnect (gas)
VRE	Variable Renewable Electricity (for example solar PV and wind turbine)
VRET	Victorian Renewable Energy Target
V1	V1 is the Ovens Murray Renewable Energy Zone in Victoria's north east
V2	V2 is the Murray River Renewable Energy Zone in Victoria's north west
V3	V3 is the Western Victoria Renewable Energy Zone in Victoria's west
V4	V4 is the South West Renewable Energy Zone in Victoria's south west

Acronym	Definition
V5	V5 is the Gippsland Renewable Energy Zone in Victoria's south east
V6	V6 is the Central North Renewable Energy Zone in Victoria's north
WRRG	Waste and Resource Recovery Group, there are seven across Victoria made up of local governments in the same regional area

2.5 Assumptions

In recognition of the large array of "un-knowns" and limited "knowns" as well as the brief analysis time-frame, a heuristic approach was adopted for this study requiring an extensive array of simplifying assumptions in order to undertake the analysis required to compare the various cases defining the Hybrid Scenario for Net Zero Emissions by 2050.

<table>
<tr><th>Reference</th><th>Assumption</th></tr>
<tr><td>Net Zero Analysis Tool</td><td>Gas to power efficiency: 30%

Coal to power efficiency: 30%

Typical values used in industry. Benchmark data from DISER Australian Energy Statistics 2020 Energy Update Report, Table F – Australian energy consumption by state and territory, by industry and fuel type, energy units, 2018/19), conversion of coal and gas to electricity generated are 28% and 27%).</td></tr>
<tr><td>Net Zero Analysis Tool</td><td>The amount of energy by source (new and hydrocarbon based) is split out by user in accordance with the categories defined in DISER, Table F. It is assumed that the proportion of energy used by each consumer in 2020 may NOT remain the same into the future.</td></tr>
<tr><td>Fossil Fuel Demand Decline</td><td>Fossil fuels (coal, natural gas, diesel & gasoline) will decline in accordance with Table 14 (Section 3.2). The decline profiles are notional and in line with those used in the prior Net Zero Emission Scenario Analysis Study Report May 2021, with adjustments as necessary to suit the specific analysis case.</td></tr>
<tr><td>Renewable Electricity</td><td>Storage:

There are several storage technologies used in the Analysis Cases:

- Residential/commercial/industrial solar: stored with batteries

- Large-Scale solar: stored with batteries

- Solar thermal: stored with molten salt storage

- Wind (offshore + onshore): stored with pumped hydro, and batteries

Batteries refers to Li-ion and Iron-air technologies.</td></tr>
<tr><td>Renewable Electricity</td><td>The life cycle of batteries has to be considered. It is usually around 2000 life cycle, but for the study it was estimated that batteries will have the same lifetime as the solar production assets.</td></tr>
<tr><td>Renewable Electricity</td><td>Conversion efficiencies for renewable electricity:
<table>
<tr><td>Zones</td><td>Rooftop Solar</td><td>Wind</td><td>Offshore Wind</td><td>Large-scale Solar</td></tr>
<tr><td>V1</td><td>14%</td><td>36%</td><td></td><td>25%</td></tr>
<tr><td>V2</td><td>14%</td><td>32%</td><td></td><td>30%</td></tr>
</table></td></tr>
</table>

<table>
<tr><th>Reference</th><th>Assumption</th></tr>
<tr><td></td><td><table>
<tr><td>V3</td><td>14%</td><td>41%</td><td></td><td>25%</td></tr>
<tr><td>V4</td><td>14%</td><td>40%</td><td>43%</td><td>22%</td></tr>
<tr><td>V5</td><td>14%</td><td>34%</td><td>47%</td><td>22%</td></tr>
<tr><td>V6</td><td>14%</td><td>33%</td><td></td><td>28%</td></tr>
<tr><td>MELB</td><td>14%</td><td>1%</td><td></td><td>25%</td></tr>
</table></td></tr>
<tr><td>Cost</td><td>Agriculture is excluded from emissions production.</td></tr>
<tr><td>Cost</td><td>Air transport is excluded from emissions production.</td></tr>
<tr><td>Cost</td><td>Victoria has access to external energy sources, via electricity and gas interconnectors.</td></tr>
<tr><td>Cost</td><td>Cost to consumer of home and vehicle upgrades resulting from a switch to hydrogen or electrification is ignored (cost of transmission for electrical and transmission and distribution for gas are included where required).</td></tr>
<tr><td>Cost</td><td>It is assumed that plant whose utilization is below 100% is physically capable of being turned down to that level.</td></tr>
<tr><td>Cost</td><td>For industrial users of gas, it is assumed that they will either retain their own source of natural gas on the transmission lines that exist, or that the cost of upgrading the networks to hydrogen will cover connections to their facilities. A behind the meter cost including emissions (supply of natural gas) is the most likely outcome for industrial gas users.</td></tr>
<tr><td>Cost</td><td>Plant that is to be decommissioned is assumed to incur all the cost of decommissioning in that analysis time period. This means that the cost of underutilization and decommissioning occur in the same analysis time period.</td></tr>
<tr><td>Cost</td><td>Plant underutilisation capacity is taken as the renewable capacity displacing it.</td></tr>
<tr><td>Cost</td><td>Plant underutilization capacity is taken to be decommissioned at the end of the analysis time period.</td></tr>
<tr><td>Cost</td><td>Plant underutilization capacity is taken to be decommissioned per the AEMO Schedule for Existing, Committed and Anticipated Generators expected retirement year where applicable.</td></tr>
<tr><td>Cost</td><td>Below are the assumed costs for offsets applied where applicable (reference CSIRO, GenCost 2020-21 Section 3.1.7 “Government Climate & Renewable Policies).

2030 Agricultural Carbon Offset: 500.00 $/Hectare
2030 Marine Carbon Offset: 500.00 $/Hectare
2030 Soil Carbon Offset : 500.00 $/Hectare
2040 Agricultural Carbon Offset: 1,000.00 $/Hectare
2040 Marine Carbon Offset: 1,000.00 $/Hectare
2040 Soil Carbon Offset: 1,000.00 $/Hectare
2050 Agricultural Carbon Offset: 2,000.00 $/Hectare
2050 Marine Carbon Offset: 2,000.00 $/Hectare
2050 Soil Carbon Offset: 2,000.00 $/Hectare
2030 Australian Carbon Credit Cost per tonne CO_2 : 30.00 $/tonne
2030 International Carbon Credit Cost per tonne CO_2 : 150.00 $/tonne
2040 Australian Carbon Credit Cost per tonne CO_2: 150.00 $/tonne</td></tr>
</table>

Reference	Assumption
	2040 International Carbon Credit Cost per tonne CO_2: 300.00 $/tonne 2050 Australian Carbon Credit Cost per tonne CO_2: 300.00 $/tonne 2050 International Carbon Credit Cost per tonne CO_2: 500.00 $/tonne
Existing Infrastructure	It is assumed that the LNG Storage Facility Dandenong will still be operational in 2030 to 2050. The storage capacity is currently 680 TJ (based on publicly available information at the time of undertaking the study).
Existing Infrastructure	It is assumed that the Iona Gas Plant Storage Facility will still be operational in 2030 to 2050. The storage capacity 24917 TJ is based on publicly available information at the time of undertaking the study. The facility has plans to expand and it is anticipated that the expansion plans will be complete by 2030.
Existing Infrastructure	Once the Minerva cut-over project is complete the Iona Gas Plant Storage facility will no longer produce gas and act purely as a storage facility (based on publicly available information at the time of undertaking the study).
Proposed Infrastructure	It is assumed that a new natural gas import terminal will be operational by 2025 in the Analysis Cases where LNG imports are included. The assumption that the new import terminal will be operational in this study does not constitute an assessment or comment on its merits by DORIS, IV or the Victorian Government. As with any new project, the timeline is dependent on the regulatory approvals process, third party agreements, construction techniques, and Project execution. The natural gas import could be up to 140 PJ/yr.
Non Proposed Infrastructure	The following projects are not considered to be part of the Analysis Cases: • (AGL) Gas Import Jetty Project has ceased following Victorian Planning Minister's determination on 30 March 2021 that the project would have unacceptable environmental effects. • (Vopak) Port Phillip LNG Import would have a capacity of 636–849TJ/d (17–22.7 million m^3/d), aiming for first imports by 2024.
Hydrogen Production	While every green hydrogen facility is assumed to be grid connected, it is further assumed that all of the electricity required to produce green hydrogen is supplied by renewable energy generation within the same region as the hydrogen production facility. This assumption is designed to increase regional resilience and to limit the need for new inter-regional electricity transmission infrastructure and to manage costs.
Green Hydrogen Production	It is assumed that all of the electricity required to produce green hydrogen is supplied by renewable energy generation proximal to the hydrogen production facility. This is to limit the impact to the electrical transmission grid and should be confirmed based on actual plant locations. If the electricity demand to support green hydrogen production was taken from the grid this would have a significant impact on the transmission system.
Green Hydrogen Production	For large hydrogen production facilities (>1 PJ/yr) the hydrogen production block within the cost estimate is assumed to include the compression required for injection and transmission of hydrogen into the gas or hydrogen transmission network. Small hydrogen production facilities (<1 PJ/yr) are favoured for injection into the local distribution network.
Green Hydrogen Production	Green hydrogen production primary energy is represented by the electricity used to produce the hydrogen from electrolysis of water. In the gas spatial analysis the energy content of the hydrogen is included in the gas energy mix.
Green Hydrogen Transmission	Blending of Hydrogen into the existing natural gas transmission and distribution systems is achievable in 2025 and beyond, and limited to 10% by volume in the transmission system.

Reference	Assumption
Green Hydrogen Distribution	Gas distribution systems will be available for introduction of pure Hydrogen in 2035 (refer Section 2.6.2, item 16).
Green Hydrogen from Ammonia	Green ammonia is assumed to be transported via existing gas transmission pipelines to conversion plants located close to the gas distribution network that will convert the green ammonia to green hydrogen for injection into the LP gas distribution system. Implementation will occur in a staged manner, region-by-region, commencing with the most suitable locations, based on locations for siting conversion plants, readiness of existing infrastructure and requirements for any new infrastructure.
Hydrogen cracking from Ammonia	Green hydrogen production generated by cracking of ammonia into hydrogen is accounted in the gas spatial analysis. A conversion factor of 85% is applied to convert ammonia energy to hydrogen based on the efficiency of ammonia conversion.
Renewable Energy Location	All new renewable generation (large-scale solar, BTM solar, onshore & offshore wind, solar thermal) is assumed to be located in a Renewable Energy Zone (REZ) (refer to DELWP Victorian Renewable Energy Zones Development Plan). Renewable energy has also been located in the Renewable Energy Zones best suited to weather conditions and geography.
Biogas Production	Biogas is derived from feedstock that would otherwise lead to natural methane slip to the environment, thus preventing environmental emissions, and a negative emissions factor will apply.
Vehicles	It was assumed that the level of operating costs for each class of low Carbon vehicle was reflected in the uptake rates. In reality if the operating costs of one class of low Carbon vehicle are significantly lower than the other then this may change the uptake rate.
Vehicles	Forecasting growth of low emissions road vehicles will assume predominantly HFCVs for heavy / long range vehicles (trucks, buses, etc) and predominantly BEVs for light / short range vehicles.
Vehicles	A key assumption in reporting vehicle fuel usage is that HFCV fuel demand is represented only by the electricity required to generate the Hydrogen fuel. Inclusion of the Hydrogen fuel in addition to the electricity required to generate it would be "double accounting" as the energy in the Hydrogen has been provided by the electricity.
Geothermal	Geothermal energy is applied for direct-use heating only and is constrained by the availability of relatively low-quality geothermal resources.
Energy Efficiency	Energy efficiency was included in the analysis by assuming a 5% improvement decade-on-decade applied to both electricity and energy gas mean demand for all Technology Probability Cases. Sensitivity Case No 3 was run to investigate the impact of increasing energy efficiency to 20% improvement decade-on-decade.
Ammonia	A colourless, toxic, pungent, chemical. The boiling point of ammonia at atmospheric pressure is -33.5 ^{o}C. Ammonia can be transported as a liquid in mild carbon steel pipelines at ambient temperature (25 ^{o}C) above pressures of 10 bar.
Emissions	Fugitive emissions rate assumed for all energy gas systems: 5% of volume flow.
Emissions	Calculation of emission rates does not vary significantly over the forecast time period.
Peak Demand	Interconnectors (electricity and gas) are utilised to cover peak demand (refer Section 3.6).
Energy Consumption Split by Region	Energy consumption split by region was "tuned" to match spatial analysis outcomes, and checked for alignment with "consumption snapshot data" taken from AEMO, Victorian Annual Planning Report, November 2020 and, furthermore, was assumed to remain constant from 2025 to 2050:

Reference	Assumption
	Melbourne & Geelong 62% Ovens Murray (V1) 3% Murray River (V2) 10% Western (V3) 9% South West (V4) 12% Gippsland (V5) 2% Central North (V6) 2%
Electrical Energy Split	Victorian electrical energy consumption split residential-commercial 25% / industrial 75% (reference 2021 "Total Sent Out" (Grid) : http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational).
Gas Energy Split	Victorian gas energy consumption split residential-commercial 60% / industrial 40% (reference Australian Gas Infrastructure Group, https://renewable-gas.com.au)
BEV Fuel Consumption	As per KPMG's 2046 Reference Scenario and AZEVIA Model Development Final Report, Infrastructure Victoria 23 May 2018: Light Vehicle 20 kWh / 100 km Heavy Vehicle 100 kWh / 100 km
HFCV Fuel Consumption	As per RACV website: Hyundai Nexo Light Vehicle 1 kg H2 / 100 km Assume same fuel consumption ratio heavy: light as per BEV Heavy Vehicle 5 kg H2 / 100 km
Renewable Electricity	Pumped Hydro will come onstream from 2030.

2.6 Input Data

2.6.1 Hindcast Data

The hindcast data was used to develop a detailed definition of the current (2020) energy mix and infrastructure, providing key input to the analysis. Energy demand, particularly the position of electricity in the current mix, includes both grid and behind the meter.

No	Input Data	Source
1	Intra-day energy demand by type and region	AEMO | 2020 Integrated System Plan database (9 years of electricity demand data (2011 – 2019) for each region of Victoria)
2	Electricity interconnect by state, with costs	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tabs "Interconnector Representation", "Network Capability", "transmission Component Costs" AEMO – Victorian Annual Planning Report, November 2020 (VAPR) AEMO - National Transmission Flow Path (NFTP)
3	Natural gas feedstock by industry (hard to abate)	DISER – Australian Energy Statistics, 2020
	Natural gas infrastructure with capacity	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Gas Infrastructure" AEMO - Victorian Gas Planning Report, 2021 AEMO, "Gas Bulletin Board" website
4	Existing & committed electrical infrastructure	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Maximum Capacity" AEMO, 2020 Electrical Statement of Opportunities, August 2020
5	Energy efficiency uptake rate	Strategy Policy Research Pty Ltd - 2019 Energy Efficiency Forecasts CSIRO – Eco Energy Efficient Building EPA, Energy Efficiency as a Low-Cost Resource for Achieving Carbon Emissions Reductions, 2009 IEA, Multiple Benefits of Energy Efficiency, March 2019
6	Demand management uptake rate	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "DSP"
7	Energy potential per type and zone	AEMO, 2019 forecasting and planning scenarios, inputs, and assumptions – Page 49 "Renewable generation resource profiles"
8	Available footprint for energy infrastructure by type and zone	Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) **Victorian Renewable Energy Zones Development Plan Directions Paper** AEMO 2020 ISP Appendix 5. Renewable Energy Zones
9	Energy infrastructure cost by type	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Regional Build Cost Summary"
10	Emissions by type	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Emissions"
11	General infrastructure data (electrical, natural gas, waste, power gen, transmission etc)	AREMI database and National Map: NationalMap (terria.io)
12	Biogas	ABBA – Australian Biogas & Biomethane Association Victorian Biomass Residues estimates
13	Vehicle Analysis	Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia 12 Months ended 30 June 2020 covering number of vehicles, kilometres travelled, and fuel usage
14	Bioenergy Resources	National Map (www.terra.io) and AREMI database.

No	Input Data	Source
		C&D, C&I, MSW and MRF residuals taken from "Victorian waste flows", 11 October 2019, Prepared for Infrastructure Victoria by Blue Environment Pty Ltd.
15	Ammonia	Fertilizers Europe, "Guidance for inspection of and leak detection in liquid ammonia pipelines", Fertilizers Europe, Issue 2013. Web: Guidance_for_inspection_of_and_leak_detection_in_liquid_ammonia_pipelines_FINAL_01.pdf (fertilizerseurope.com) Blue Environment, "Victorian waste flows", 11 October 2019, Prepared for Infrastructure Victoria by Blue Environment Pty Ltd. Web: https://www.infrastructurevictoria.com.au/wp-content/uploads/2019/10/Victorian-Waste-Flows-Blue-Environment-October-2019-FINAL-REPORT.pdf Victorian Minister for Planning, "Crib Point Gas Import Jetty and Crib Point - Pakenham Gas Pipeline Project", Minister's Assessment under Environment Effects Act 1978, March 2021. Web: https://www.planning.vic.gov.au/__data/assets/pdf_file/0023/517280/Ministers-Assessment-March-2021.pdf Thomas, G. and Parks, G., "Potential Roles of Ammonia in a Hydrogen Economy", US Department of Energy, 2006. Web: https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf
16	Energy Consumption Split	Regional energy split "snapshot" at maximum supply (9,667 MW) taken from AEMO, Victorian Annual Planning Report, November 2020 Electricity split (residential-commercial / industrial) http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational Gas split (residential-commercial / industrial) (reference Australian Gas Infrastructure Group, https://renewable-gas.com.au)

2.6.2 Forecast Data

No	Input Data	Source
1	Energy demand by region (electricity and gas)	AEMO, 2020 Integrated System Plan, July 2020 AEMO, 2020 ISP Model – Traces for the « Central » Scenario, refer AEMO website https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2019-isp-database AEMO – electrical demand min & max to 2040 (useable format) AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "New Entrant Data Summary", "Energy Demand", "maximum Demand", "Rooftop PV", "PVNSG" AEMO Electricity & Gas Forecasting website NATIONAL ELECTRICITY FORECASTING (aemo.com.au)
2	Natural gas reserves forecast & interconnects	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Gas Reserves and Resources", "Gas Expansion Candidates" AEMO Electricity & Gas Forecasting website NATIONAL ELECTRICITY FORECASTING (aemo.com.au) https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2021/2021-victorian-gas-planning-report.pdf?la=en http://forecasting.aemo.com.au/Gas/MaximumDemand/Total http://forecasting.aemo.com.au/Gas/AnnualConsumption/Total
3	Electricity interconnect by state, with costs	AEMO "ISP Inputs and Assumptions Workbook" (version 3.0 11/12/2020) – Tab "Interconnector Representation", "Network Capability", "transmission Component Costs"
4	Road vehicle mix (ICE / BEV / HFCV)	ICEs: Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia 12 Months ended 30 June 2020 EVs: CSIRO, GenCost 2020 Energeia, Distributed Energy Resources and Electric Vehicle Forecasts (Section 4.1 "Installs") AEMO "ISP Inputs and Assumptions Workbook" – Tab "Electric Vehicles", KPMG 2046 Reference Scenario and AZEVIA Model Development Final Report Infrastructure Victoria 23 May 2018 HFCVs: CSIRO - Low Emissions Technology Roadmap (2017)
5	Technology development "learning rates" (GALLM)	CSIRO, GenCost 2020 - Section 3.1.4 "Technologies and Learning Rates" - Appendix A "Global and Local Learning Model"
6	Forecast demand by hard to abate natural gas users	Based on DISER – Australian Energy Statistics, 2020

No	Input Data	Source
7	Victorian Government Interim Emission Reduction Targets	(Victorian) Department of Environment, Land, Water and Planning, defines Victoria's interim greenhouse gas emissions reduction targets. - 2025: emissions to reduce 28–33% below 2005 levels by the end of 2025. - 2030: emissions to reduce 45–50% below 2005 levels by the end of 2030."
8	New Technologies Energy production potential: Ocean Energy technologies (wave /tidal/ thermal/ currents).	CSIRO – Low Emissions Technology Roadmap (2017)
9	Iron-air battery development	Iron air battery backed by Bezos and Gates promises storage at fraction of cost https://reneweconomy.com.au/iron-air-battery-backed-by-bezos-and-gates-hails-storage-at-fraction-of-cost/
10	Ammonia fired power generation development	Japanese Government "Green Growth Strategy Through Achieving Carbon Neutrality in 2050" https://www.meti.go.jp/english/press/2020/1225_001.html
11	Ammonia fired gas turbine development	Mitsubishi Power Commences Development of World's First Ammonia-fired 40MW Class Gas Turbine System https://power.mhi.com/news/20210301.html
12	Solar Thermal development	Solar Thermal https://arena.gov.au/renewable-energy/concentrated-solar-thermal/
13	Solar Thermal costs	The cost of Solar Thermal Power fell by 47% between 2010 and 2019 https://helioscsp.com/the-cost-of-concentrated-solar-power-fell-by-47-between-2010-and-2019/
14	Population Forecast	Department of Environment, Land, Water and Planning, "Victoria in Future 2019", July 2019
15	Employment	Climate Council, Renewable Energy Jobs in 2030, 2016 ENEA, "Biogas Opportunities for Australia" March 2019 Macquarie, Press Release "Australia's 1st Thermal Waste to Energy Facility", October 2018
16	Gas Distribution System Planning for Hydrogen	Multinet's plans for completion in 2033 : https://www.multinetgas.com.au/projects/mains-upgrade-program/ Deloitte Access Economics, "Decarbonising Australia's Gas Networks", (November 2017), Section 3.1.4.2 indicating most distribution pipelines in Australia will be converted to PE by 2035. GPA Engineering, "Hydrogen in the Gas Distribution Networks", (November 2019), Tables 4 and 5 indicate the amount of cast iron and unprotected steel pipe is quite small and reducing.

2.6.3 Cost Data

No	Input Data	Source
1	CAPEX & OPEX: electricity generation plants (gas, coal, solar, wind) and storage + biomass, tidal, fuel cells.	CSIRO, GenCost 2020 - Section 4.2 “Changes in Capital Cost Projections”, Appendix B “Data tables” AEMO “ISP Inputs and Assumptions Workbook” (version 3.0 11/12/2020) – Tab “Build Costs”, “Regional Cost Factors”, “Fixed OPEX”, “Variable OPEX”
2	Schedule: electricity generation plants (gas, coal, solar, wind) and storage + biomass, tidal, fuel cells.	AEMO “ISP Inputs and Assumptions Workbook” (version 3.0 11/12/2020) – Tab “Lead Time and Project Life”
3	CAPEX: powerlines, interconnectors	Dependent on interconnection size type of each line (assume 500kV double circuit) and the cost can range from $1.2m/kM to $2m/km dependent on terrain tower sizes etc. (AEMO modelling does not indicate size of lines) HVDC lines however are Bespoke and would be in the range of $700k/km (400kV) excluding DC converters. AEMO “ISP Inputs and Assumptions Workbook” (version 3.0 11/12/2020) – Tab “Connection Costs”
4	CAPEX: H_2 generation.	CSIRO, GenCost 2020 Section 4.3 “Hydrogen Electrolysers” Appendix B “Data tables”
5	CAPEX: gas pipelines, gas plants	DORIS In-house Cost Database for all new gas pipelines and plants as required including distribution lines where applicable. (Supply, transmission and distribution costs are treated separately, refer item 13 of this table)
6	CAPEX: CCS	Global CCS Institute, Technology Readiness and Costs of CCS, March 2021 Global CCS Institute, Brief, Is CCS expensive? Decarbonisation costs in the net-zero context, May 2020 Greenhouse Gas Control Technologies GHGT-14, CarbonNet-The relative costs for providing a CCS transport and storage service, October 2018 (Extended abstract)
7	CAPEX: BioGas	DORIS In-house Cost Database
8	Decommissioning cost: onshore gas pipelines, gas plants	DORIS In-house Cost Database
9	Carbon Offset values and Carbon Credit Costs	CSIRO, GenCost 2020 Section 3.1.7 “Government Climate & Renewable Policies”
10	Economic Forecasts (GDP, etc)	Deloitte – Long Term Economic Forecasts for AEMO Simplified Victorian specific economic forecast data contained in AEMO Inputs and Assumptions workbook, based on BIS Oxford Economics long term macroeconomic forecasts developed for AEMO in April. Central (or steady progress) scenario was used as main reference.
11	Current clean energy project costs	Global Data – Major Power Developments MAY 2021 AEMO Inputs & Assumptions Workbook contains "project build costs" and "regional cost data" specific to Victoria.
12	Cost Benefit Analysis Methodology	2020 ISP Appendix 2. Cost Benefit Analysis July 2020

No	Input Data	Source
13	Supply, transmission and distribution costs	Core Energy Gas Production and Transmission Costs 2015

2.6.4 Spatial Analysis

No	Input Data	Source
1	Interactive map of Australia with energy infrastructure	NationalMap (terria.io) https://www.nationalmap.gov.au/#share=s-hV8rwS7Mj1sKTc4MHk1thZP5wCV

2.6.5 Emissions & Offset Factors

No	Input Data	Source
1	Emissions Factors	Department of Environment and Energy (2019) National Greenhouse Accounts Factors Australian National Uni, "Global emissions implications from co-burning ammonia in coal fired power stations: an analysis of the Japan-Australia supply chain", 2020. International Hydropower Association (2018) 2018 Hydropower Status Report National Renewable Energy Laboratory Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics, Fact Sheet Think Geoenergy (2020) Sustainability of geothermal energy in district heating networks Kwinana Waste to Energy Project – ARENA Life Cycle Assessment, Kwinana WTE Project Co, Dec 2018 Dirk-Jan van de Ven, et al (2015) The potential land requirements and related land use change emissions of solar energy Pears, A. (2011) Guide to Australian Greenhouse Calculator: Basic Features and Assumptions Energy & Environmental Science (2020) The carbon footprint of the carbon feedstock CO2 Energy Central (2020) Estimating the carbon footprint of hydrogen production
2	Offset Factors	Parks Victoria and DELWP (2015) Valuing Victoria Parks: Accounting for ecosystems and valuing their findings. Report of first phase findings Australian government predicted figure of 90 Mt CO2e /yr for Australia.

3 SPECIFIC WORK METHODOLOGIES

3.1 Technology Breakthroughs

The methodology adopted for the current study is consistent with analysis undertaken by the International Energy Agency (IEA), "Net Zero by 2050 - A Roadmap for the Global Energy Sector", 2021 where it is recognized that, in 2050, a substantial proportion of emissions reduction will come from technologies that are currently at the demonstration or prototype stage of development. The Hybrid Scenario requires that new, low emissions energy generation technologies fill the demand / supply gap with affordable, secure energy at scale whilst also generating low, zero or even negative levels of carbon emissions per unit of energy. For these conditions to be met, it will be necessary for breakthroughs to occur at key points in the future in the performance and cost competitiveness of current & emerging low emissions energy technologies in both generation and storage, for energy gas and electricity.

Technology Probability Cases make it possible to identify the necessary energy technology performance and cost improvements required to support the transition to net zero using on commercially competitive, industrial scale energy generation and storage.

A number of cases were constructed based on the probability of breakthroughs in cost and or performance for several specific energy technologies currently in pre-commercial stage of technology readiness.

The Technology Probability Cases along with the specific technologies selected were not intended to:

- Define the future energy mix, but rather guide the timing and identify the focus for support to energy technology development programs;
- Represent unique solutions. The key criterion regarding technology selection was to ensure breakthroughs are identified across the entire energy supply chain including generation and storage (both gas and electricity). The specific technologies identified for breakthrough in the current study, along with the timing, are not unique and can be changed for other technologies within the same technology category to achieve another feasible net zero solution. For example, the Iron-air battery technology identified for breakthrough in the Mid Probability Technology Case could be replaced by another emerging long duration electrical storage technology, resulting in another feasible net zero solution generated.
- Specify a particular type of greenhouse gas offset. Where individual cases and sensitivities utilize greenhouse gas offsets deliver net zero emissions in 2050, it has been assumed that agro-forestry offsets, specifically soil farming, provides the source of those offsets. This should be seen as illustrative only and does not representative of the only greenhouse offset solution. In this study offsets have only been used to balance the emissions projections in each analysis case and ensure the delivery of net zero emissions by 2050.

Drawing on in-house expertise and credible references including CSIRO's Global – Local & Learning & Modelling (GALLM), a range of energy technologies currently under development were considered in the construction of the cases including those listed in Figure 6 (overleaf).

Figure 5: Technology Readiness Levels

*** Technology Readiness Level (TRL) is a type of measurement system used to assess the maturity level of a particular technology.**

Hybrid Scenario Breakthrough	Technology Readiness Level (2020)	Development Status (2020)
	TRL 1 Basic principles observed TRL 2 Technology concept formulated TRL 3 Experimental proof of concept TRL 4 Technology validated in lab	LAB
(2040) Mid Probability Case	TRL 5 Technology validated in relevant environment TRL 6 Technology demonstrated in relevant environment	PILOT
(2030) Low Probability Case	TRL 7 System prototype demonstration in operational environment TRL 8 System complete and qualified	PILOT
	TRL 9 Actual system proven in operational environment	COMMERCIAL

The High Probability Technology case utilises currently available low emissions energy technologies (primarily solar PV, onshore wind and batteries) with incremental cost reduction over time to deliver additional energy generation capacity through to 2050.

The Mid Probability Technology Case includes technologies currently in the commercial pilot phase (TRL 5 & 6) and assumes a breakthrough to TRL 9 at competitive costs occurs before 2040, thereby allowing the technologies to be utilized to deliver additional energy generation capacity from 2040 and beyond.

The Low Probability Technology Case includes technologies currently in the commercial prototype phase (TRL 7 & 8) and assumes a breakthrough to TRL 9 occurs before 2030, or technologies currently at TRL 9 where a cost breakthrough is assumed to occur, thereby allowing those technologies to be utilized to deliver additional energy generation capacity from 2030 and beyond.

The nomenclature of the primary analysis cases, namely "low", "mid" and "high" refers primarily to the timeframe for the breakthrough with the probability of the assumed breakthrough occurring in 2030 being lower than in 2040, hence the Low and Mid Probability Technology Case names. For the sake of clarity, a breakthrough by 2030 as assumed for the Low Probability Technology Case is considered less likely than a breakthrough by 2040 for the Mid Probability Technology Case.

Taken in combination, the Technology Probability Cases represent the Hybrid Scenario's potential pathways to achieving net zero Carbon emissions by 2050, refer Figure 1, Section 1.3.

Figure 6: Current Technology Readiness Levels of Energy Technologies Reviewed as Part of the Technology Case Selection Process*

Reference: CSIRO, Low Emissions Technology Roadmap (Technical Report), 2017

***** *Technology Readiness Level (TRL) is a type of measurement system used to assess the maturity level of a particular technology.*

Other low emissions energy technologies not listed were also reviewed, most notably green Ammonia

HELE = High Efficiency Low Emissions (refers to fossil fuel power generation systems)

TECHNOLOGY READINESS LEVEL (TRL)		2017	
		Low	High
BioEnergy			
	Ethanol from fermentation of sugar		9
	Biodiesel from esterification of waste oils		9
	Biogas from anaerobic digestion of waste		9
	Drop-in fuels from fast pyrolysis of lignocellulosic biomass	6	8
	Drop-in fuels from hydro-treatment/gasification + FT	8	9
	Electricity from biomass combustion		9
	Electricity from biomass gasification	6	8
	Electricity from co-firing biomass		9
Solar cells			
	Silicon		9
	CdTe		9
	III-V MJ		8
	CIGS	8	9
	Perovskite		6
	Tandem silicon/perovskite	4	5
Wind			
	Onshore system		9
	Fixed offshore system		9
	Floating offshore system	6	7
	Airborne wind	6	7
Batteries			
	Lithium Ion		9
	Advanced lead-acid battery		9
	Zinc bromine flow battery		9
	Iron-Air Battery		7
Other Storage			
	Pumped Hydro Electric Storage (PHES)		9
	Compressed Air Energy Storage		9
	Flywheels		9
Smart Grid			
	Smart appliances Various	2	9
	Advanced inverters	6	9
	Control platforms	6	9
	Market platforms	6	9
	Smart meters	7	9
	Telemetry and sensors	6	9
	System data and models	2	9
	Advanced protection systems	6	9
	Demand forecasting	7	9
	Generation forecasting - solar	7	9
	Generation forecasting - wind	6	9
	Secure communications protocols and architectures	5	9

TECHNOLOGY READINESS LEVEL (TRL)		2017	
		Low	High
Solar thermal			
	Power Tower	8	9
	Parabolic troughs		9
	Linear Fresnel Reflector		6
HELE			
	Supercritical coal		9
	Ultra-supercritical		8
	Black coal IGCC	8	9
	Combined cycle gas turbine		9
	Direct Injection Carbon Engine (DICE)		8
Carbon capture			
	Absorption		9
	Adsorption (solid sorbent)		6
	Chemical looping combustion	4	6
	Membrane separation		6
	Hydrate-based separation	1	2
	Cryogenic distillation	1	3
Carbon Utilisation			
	Enhanced Coal Bend Methane (ECBM)	1	3
	Mineral carbonation and CO2 concreting	8	9
	Algae cultivation	8	9
	Fuel production	5	7
	Plastics	1	2
Nuclear			
	Pressurised water reactors		9
	Boiling water reactors		9
	Pressurised heavy water reactors		9
	Fast neutron reactors	2	8
	SMRs	6	8
	Fusion reactor	1	3
Hydrogen			
	Steam Methane Reforming (SMR)		9
	Coal gasification	8	9
	Biomass Gasification	6	7
	PEM electrolysis	8	9
	Photoelectrochemical	1	2
	Microbial biomass conversion	1	2
	Photobiological	1	2
	Methane cracking	3	4

A summary description of each of the primary technologies assumed for breakthrough is provided below.

- **Green Hydrogen** is produced by electrolysis of water using renewable electricity (typically solar PV and wind). Electrolysis is proven technology at small scale, around 1MW, but is not currently cost competitive with natural gas as a result of efficiency limitations (resulting in the requirement for large inputs of electricity and water). Scale up of electrolyser plants to 20MW or more would achieve significant economies of scale throughout the whole supply chain. Low cost green hydrogen would allow displacement of natural gas for heating purposes as well as for Hydrogen Fuel Cell Vehicles (HFCVs) and other mobility applications where electrification is difficult. The additional challenge for green Hydrogen production is its relatively low pressure operation (leading to the requirement for additional compression of the Hydrogen product for storage, use as HFCV fuel or transport via long distance pipeline). In Sensitivity Case 4, where a very large uptake of green Hydrogen is assumed, the levelised cost of energy of green Hydrogen is assumed to be less than natural gas.
- **Iron-air batteries** are an emerging technology with the potential to provide low-cost, safe, multi-day utility scale electricity storage to stabilise the electricity grid. Lithium ion (Li-ion) battery technology, currently widely used for utility scale electricity storage, is expensive, susceptible to thermal runaway (which may result in fire) and typically has a storage capacity of 2 to 4 hours at its rated power delivery which is not effective for managing multi-day weather events. A multi-day storage technology would have the ability to provide dispatchable, firming power during inclement weather conditions that are simultaneously unfavourable for both wind and solar thereby increasing the security of supply. In the Mid Probability Technology case, where utility scale iron-air batteries are assumed, the breakthrough leads to the cost of storage using iron-air batteries being cheaper than standard batteries.
- **Green Ammonia** is produced catalytically from air and green hydrogen and may be used as a “carrier” of hydrogen, having the benefit of being easier to transport than Hydrogen because it is liquified at relatively low pressures under ambient temperature conditions (or only mildly low temperatures under atmospheric pressure). Ammonia is a widely traded chemical with well-established transport technology such as tanker (ship, rail, road) and existing natural gas infrastructure. Ammonia has the potential to be used directly as a fuel, for instance in power stations, or catalytically converted back (“cracked”) into hydrogen and subsequently fed into a gas distribution network. Co-firing and / or conversion of coal fired power stations in the Latrobe valley is proposed for the use of Ammonia as a fuel, aligning well with the "Roadmap of Growth Strategies for fuel Ammonia industries” (The Japanese Ministry of Economy, Trade and Industry “Green Growth Strategy Through Achieving Carbon Neutrality in 2050” (2021)) which indicates an increased ratio of Ammonia co-firing occurs before 2040. The primary role of Ammonia is to allow renewable energy to be imported into Victoria from distant sources and either used for base load or peaking power generation or converted to hydrogen for distribution to customers within the existing gas distribution network. In the Mid Probability Technology case, where a very large uptake of green Ammonia is assumed, the

levelised cost of energy from Ammonia is assumed, the breakthrough leads to a levelised cost of energy from Ammonia that is parity with natural gas.

- **(Hydrogen) fuel cells** convert Hydrogen to electricity via an electro-chemical reaction and are currently widely used in Hydrogen Fuel Cell Vehicles (HFCVs). However, in the context of the electricity grid, fuel cells, supported by green hydrogen have the potential to be used as a form of long term energy storage and fast reacting dispatchable energy supply. The green Hydrogen would be produced and stored when a surplus of electricity is available, and converted back to electricity when the electricity demand exceeds the variable renewable electricity supply. To enable this technology to compete with other electricity storage options, the cost and efficiency of green hydrogen and fuel cell technology must be improved, and scale up of fuel cells to utility grade installations would be required. In the Low Probability Technology case, where utility scale fuel cells are assumed, the breakthrough leads to the cost of storage using fuel cells being cheaper than standard batteries.
- **Solar thermal** technology utilises lenses and reflectors (heliostats) to concentrate solar radiation onto a targeted location creating high temperatures. The heat is captured by a heat transfer fluid which is used to create steam to power a turbine to generate electricity that is dispatchable i.e. the power output may be adjusted to suit the grid demand. The thermal energy can also be cost effectively stored as molten salt, for reasonably long periods, several hours or more, so that power generation can continue when the sun is not shining. This technology is well proven in Spain and the USA, and while not currently cost competitive in Australia, the costs continue to fall as the technology matures. In the Low Probability Technology case, where significant solar thermal power generation is assumed, the breakthrough results in the levelised cost of energy from solar thermal power generation being less than PV solar with battery storage (firmed solar).
- **Offshore wind** is stronger and more consistent than wind experienced onshore, therefore larger turbines can be used and the average amount of power that can be generated is much greater. In addition, the capacity factor for offshore wind is higher than onshore wind, meaning that there is less variability in power delivery. Whilst offshore wind technology is well proven in other parts of the world, including the UK and Scandinavia, it is not currently cost competitive in Australia and the regulatory framework is being established. In Victoria, the ability for offshore wind to take advantage of existing electricity transmission infrastructure in the Latrobe Valley would be beneficial to its economics. In the Low Probability Technology case, where significant offshore wind power generation is assumed, the breakthrough results in the cost of offshore wind being less than onshore wind.

3.2 Energy Emissions Offset Analysis

The work breakdown and flow that was used for the current study is summarised in Figure 7 identifying the relative position of the “energy-emissions-offset” analysis task which is inter-related to several other activities including the gas and electrical spatial analysis. The general method used to undertake the analysis is summarised in Figure 8 (overleaf) and described in further detail below.

Figure 7: Net Zero Emissions Scenario Analysis Work Breakdown

Energy consumption data from the Department of Industry, Science, Energy and Resources (DISER) Australian Energy Statistics 2020, Table F was used to estimate the total mean energy demand for Victoria in 2020 along with a breakdown identifying those areas relating to the study scope (electricity, energy gas & road vehicles). Notably excluded from the current study scope were Agriculture, aviation and shipping. The 2020 mean energy demand data was then used as the basis for the forecast of mean energy demand to 2050.

Table 15 (overleaf) summarises overall mean energy demand for each analysis case relevant to the study scope (electricity, energy gas and road vehicles) increasing from 732 PJ (2020) to 913 PJ (2050) representing overall growth of approximately 25%.

Whilst not reported in the results, energy demand outside the current study scope (agriculture, non-road vehicles, etc) had to be considered in both the energy demand forecasting and determination of future additional energy generation capacity requirements, as it will be supplied by the energy generation capacity that exists and has been committed by the Australian Energy Market Operator (AEMO). In general, underlying energy demand was assumed to increase by 15% per decade with notable exceptions including:

- Fossil fuels (coal, natural gas, diesel & gasoline) will decline in accordance with Table 14. The decline profiles are notional and in line with those used in the prior Net Zero Emission Scenario Analysis Study Report May 2021, with adjustments as necessary to suit the specific analysis case;
- Renewable electricity to meet the demand of new energy users including low emissions vehicles (BEVs and HFCVs), green Hydrogen and green Ammonia.

Table 14: Fossil Fuel Decline Profiles

Analysis Case	Natural Gas (PJ-therm) Note 1				Coal (PJ-elec) Note 1				Gasoline & Diesel (PJ-therm) Note 1			
	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
High Probability	209	171	128	50	144	89	44	0	318	214	96	0
Mid Probability	209	171	0	0	144	89	0	0	318	214	97	0
Low Probability	209	121	80	20	144	92	45	0	318	222	99	0
Sensitivity 1 “Accelerated Net Zero”	209	174	0	0	144	90	0	0	318	218	99	0
Sensitivity 2 “Reduced Ammonia”	209	171	22	22	144	89	0	0	318	214	97	0
Sensitivity 3 “Energy Efficiency”	209	162	118	47	144	91	45	0	318	203	87	0
Sensitivity 4 “Maximum Green H2”	209	117	66	15	144	89	37	0	318	212	80	0

Notes

1. Energy value reported as:
    a. “Thermal” for natural gas, gasoline and diesel,
    b. “Electrical” for coal.
    c. Low emissions gas includes green Hydrogen, green Ammonia, and biomethane.

Figure 8: General Method for the Net Zero Emissions Scenario Analysis

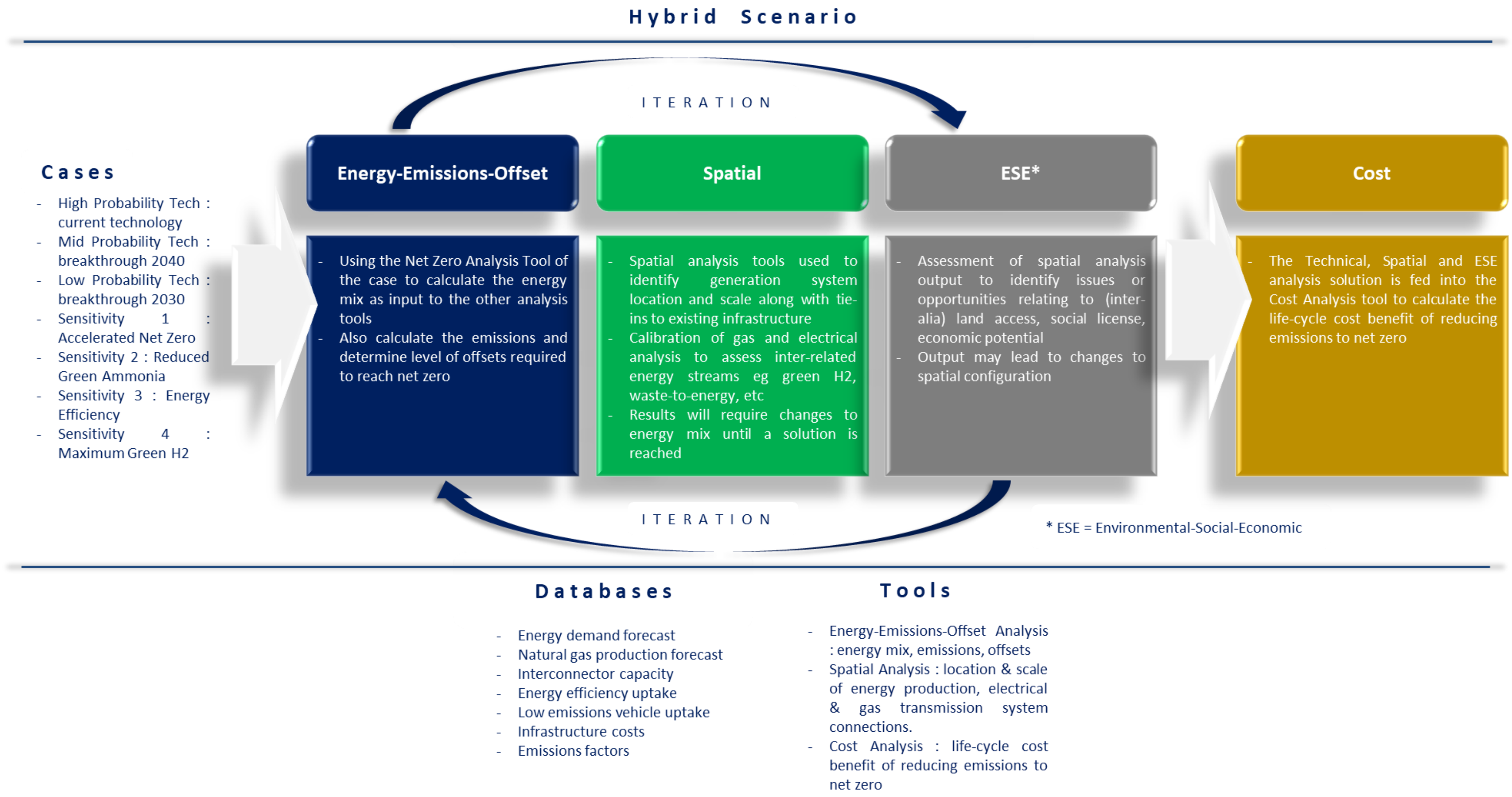


Table 15: Generalised Energy Mix (Mean Annual Demand)

Analysis Case	Energy Gas (PJ)								Electricity (PJ)								Road Vehicles (PJ, Note 3)				Total (PJ)	Approximate Split Energy Gas / Elec
	Natural Gas				Low Emissions Gas (Note 1)				Coal & Natural Gas				Low Emissions Elec. (Note 2)				Gasoline & Diesel					
	2020	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2020**	**2030**	**2040**	**2050**	**2050**	**2050**
High Probability	209	171	128	50	0	34	49	82	149	93	44	0	57	356	545	781	318	214	96	0	913	15 / 85
Mid Probability	209	171	0	0	0	33	141	262	149	93	0	0	57	355	624	651	318	214	97	0	914	30 / 70
Low Probability	209	121	80	20	0	33	50	81	149	97	45	0	57	395	589	812	318	222	99	0	914	10 / 90
Sensitivity 1 "Accelerated Net Zero"	209	174	0	0	0	33	125	203	149	95	0	0	57	346	638	712	318	218	99	0	914	20 / 80
Sensitivity 2 "Reduced Ammonia"	209	171	22	22	0	33	118	181	149	93	0	0	57	355	625	710	318	214	97	0	914	20 / 80
Sensitivity 3 "Energy Efficiency"	209	162	118	47	0	31	42	67	149	96	45	0	57	331	488	678	318	203	87	0	792	15 / 85
Sensitivity 4 "Maximum Green H2"	209	117	66	15	0	49	128	201	149	93	37	0	57	396	553	698	318	212	80	0	914	25 / 75

Notes

2. Low emissions gas includes green Hydrogen, green Ammonia, and biomethane.
3. Low emissions electricity includes NH3, hydropower, solar PV (large scale + non-sched + BTM), solar thermal, wind (onshore + offshore), bioenergy, fuel cells, (storage) - pumped hydro, (storage) - batteries (incl. standard + VPP + BTM + iron-air).
4. Fuel for low emissions vehicles included in Energy Gas and Electricity. Refer Section 3.7 for road vehicle fuel data.

Figure 9 identifies the gap between energy generation capacity required to meet mean demand (study scope) and existing & committed energy generation capacity reported by the Australian Energy Market Operator (AEMO), "ISP Inputs & Assumptions Workbook", version 3.0 11/12/2020. Energy generation capacity refers to those facilities which produce energy, which is subsequently used to meet the energy demand of consumers. One of the key drivers of the generation capacity "gap" expanding over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs)).

Figure 9: Forecast Energy Generation Capacity (High Probability Technology Case)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel)

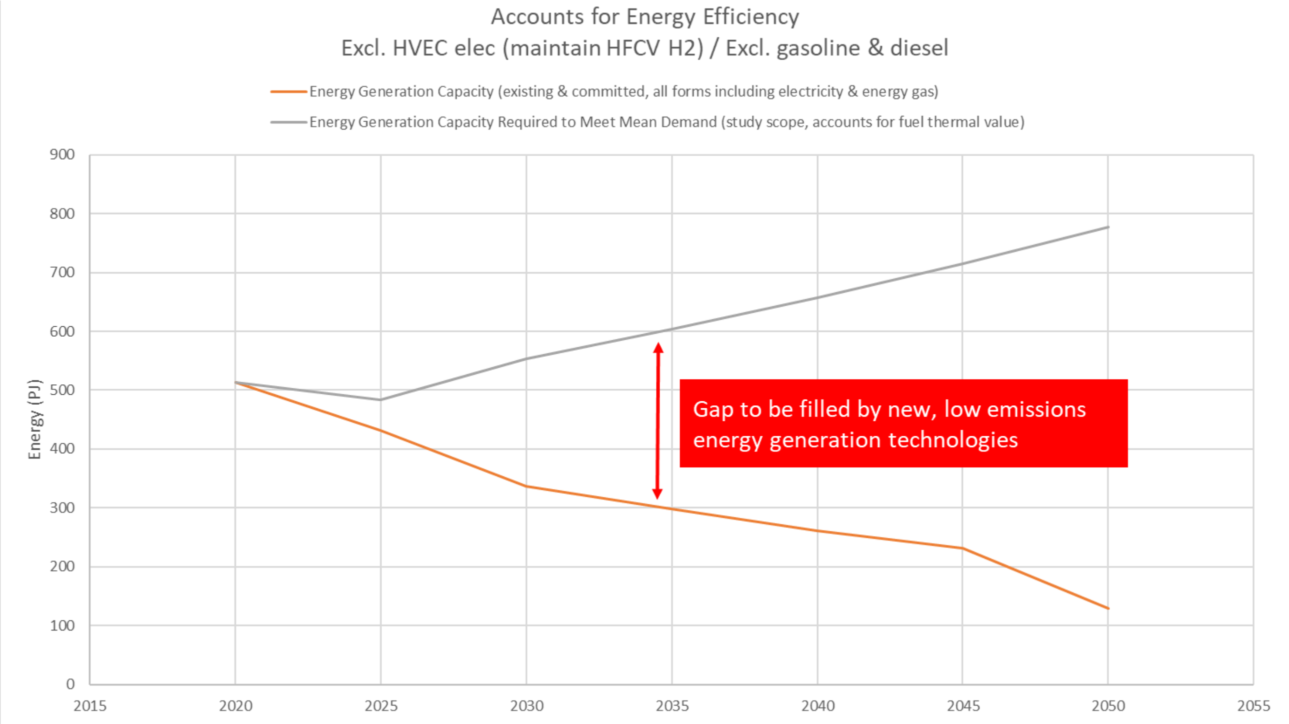
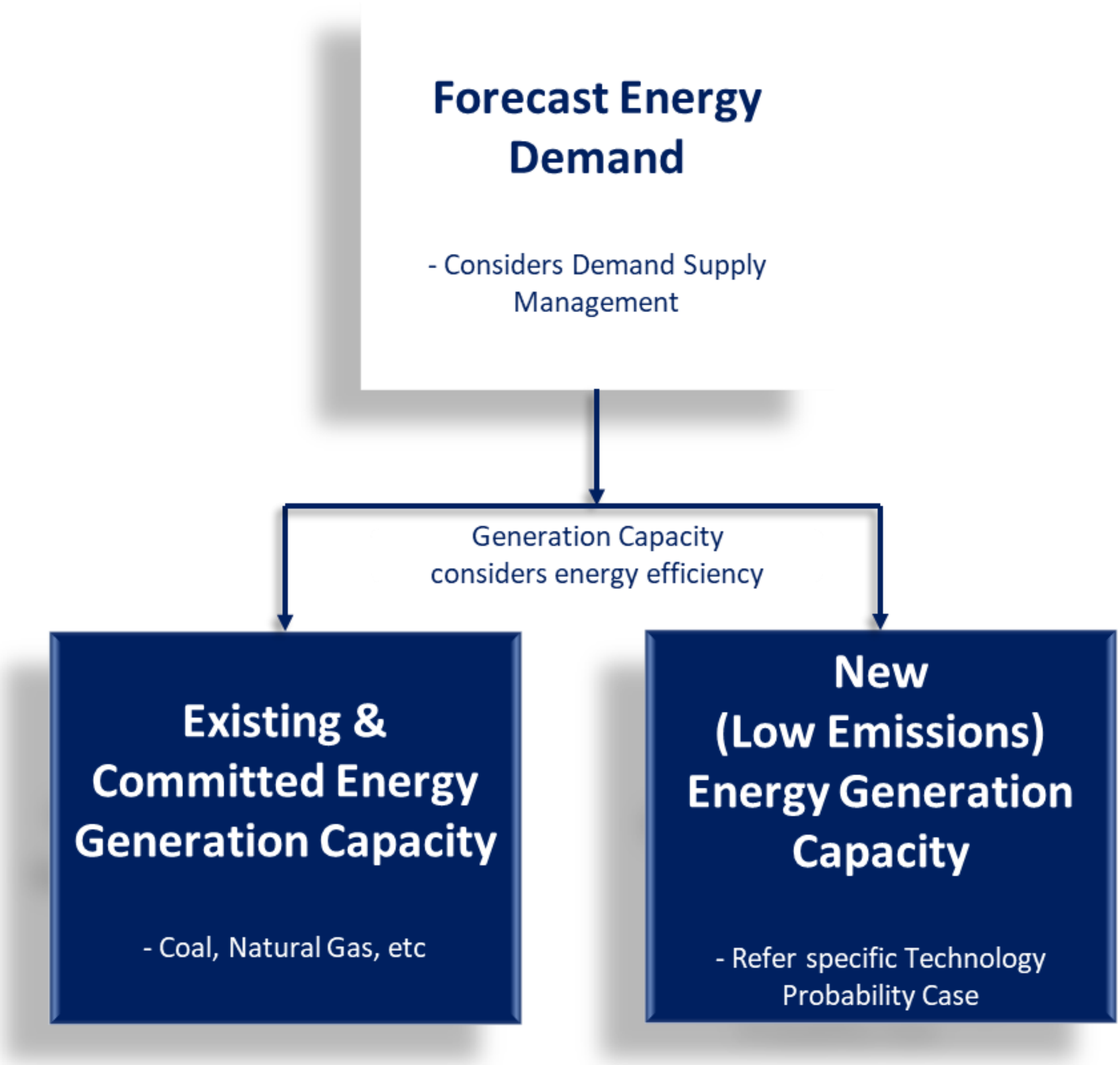


Figure 10 summarises the approach taken to fill the demand / supply gap using new, low emissions energy generation technologies. The calculation of future additional energy generation capacity required to "fill the gap" was complicated by the need to consider the thermal value of fuel versus the generation capacity required to produce it, along with calculation of the entire energy demand (including out of scope) with subsequent extraction of the "in scope" capacity. The energy efficiency calculations to estimate energy demand reduction were also subject to similar complications.

For the sake of clarity, pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030, escalated progressively to a nominal 4 PJ in 2050 in recognition of the increased role that electrical storage will play as Variable Renewable Electricity share increases.

Figure 10: Forecast Energy Demand and Specification of Generation Capacity



Once future energy demand and additional generation capacity data was calculated for each time period, the emissions were calculated applying the factors listed in Section 3.9.5 to each element of the energy mix. For energy gas streams with a global warming potential then fugitive emissions were calculated based on the rates defined in Section 3.9.5, and the relevant emissions factor applied to the fugitive stream. In the event that total absolute emissions were found to exceed zero in 2050, then the level of offsets were calculated by applying the offset factor (refer Section 3.8.5) for the offset type selected to reach a net zero position in 2050. For the current study, offsets derived from soil farming projects have been assumed to illustrate how residual emissions could be managed (refer Section 3.4 for further explanation). A simplified method was adopted to calculate the level of offsets required by determining the quantity required for each time period starting from 2025 and continuing to 2050, where that quantity is the same for each time period. By way of example for the High Probability Technology Case it was found that to offset the 3 Million Te CO2-e in 2050, would require 400 Hectares of soil farming to be established in 2025, and another 400 Hectares of soil farming in 2030, and then again in 2035 and so on until in 2050 a total of 2,400 Hectares of soil farming is operational.

Benchmarking of energy demand forecasts was limited by a lack of other independent forecasts covering electricity, energy gas and road vehicles at the same time, however the references below have been reviewed.

- **(Overall Energy) Department of Industry, Science, Energy and Resources (DISER),** Australian Energy Statistics 2020, Table F – DORIS' forecast growth in energy demand for the coming 30 years (approximately 25%) correlated favourably with DISER's overall energy growth of approximately 20% over the preceding 30 years (1988 to 2018): 1,090 PJ in 1988 to 1,298 PJ in 2018.
- **(Electricity) Australian Energy Market Operator (AEMO)**, ISP22 – shows forecast growth in electricity to 2050 that is significantly lower than DORIS' analysis. DORIS' review of AEMO's forecasts have identified several differences in scope that may provide an explanation. DORIS' modelling covered a broader spectrum of energy including electricity, energy gas and road vehicles, and considered the inter-relationships between each. For example, during preliminary modelling DORIS set very high levels of energy gas in the mix during the latter stages of the transition, resulting in a significantly lower level of electrification, potentially in line with AEMO's modelling estimates. However this high gas / low electricity mix was not adopted due to the high level of resultant overall emissions driven by:
  - Energy gas - a higher level of natural gas in the mix; and
  - Road vehicles - higher levels of ICE vehicles (gasoline & diesel).

  DORIS also identified limited or no energy gas beyond 2040 in AEMO's modelling as another potential explanation for the very high electricity supply required to generate:
  - Low emissions energy gas such as green Hydrogen and green Ammonia; and
  - Low emissions road vehicle fuels (electricity for BEVs and electricity / green Hydrogen for HFCVs)

  DORIS also notes that AEMO's 2020 electricity demand level is approximately 30% lower than DORIS's value which was based on the Department of Industry, Science, Energy and Resources (DISER), Australian Energy Statistics 2020, Table F which covers all sources of energy demand. DORIS' modelling has been centred on Victoria, and only utilised interconnectors (gas and electricity) for the purpose of satisfying peak demand. It is possible that, with AEMO's modelling of the entire NEM, there would be differences in specification of future capacity, and also treatment of demand levels above forecast mean.
- **(Natural Gas) Australian Energy Market Operator (AEMO)**, Figure 6, "Victorian Gas Planning Report", March 2021 indicates growth of natural gas consumption in Victoria of negative 10% from 2020 to 2025.
- **(Road Vehicles) Australian Bureau of Statistics**, "Survey of Motor Vehicle Use, Australia 12 Months ended 30 June 2020" indicates growth of total growth in kilometres travelled per year in Victoria of 145% from 2020 to 2050. There is no HFCV uptake referenced.

- **(Population) Department of Environment, Land, Water and Planning**, Figure 9, “Victoria in Future 2019”, July 2019 indicates population growth in Victoria of approximately 55% from 2020 to 2050.
- **(Economic) Australian Energy Market Operator (AEMO)**, Section 3.1.3, 2019 Forecasting and Planning Scenarios, Inputs & Assumptions, August 2019 indicates 220% forecast growth in Gross State Product across the NEM region from 2020 to 2050.

3.3 Energy Efficiency & Demand Supply Management

Energy efficiency was included in the analysis by assuming a 5% improvement decade-on-decade applied to both electricity and energy gas mean demand for all primary analysis cases. Several credible references including IEA and EPA support the assumed energy efficiency values (refer Section 2.6.1). Sensitivity Case 3 “Energy Efficiency” was run to investigate the impact of increasing energy efficiency to 20% improvement decade-on-decade.

The reduced energy mean demand resulting from energy efficiency improvements was included directly in the calculation of additional energy generation capacity requirement. Given the uncertainty as to which energy demand centres the energy efficiency improvements would be implemented, the reductions in mean energy demand were applied proportionally across all energy demand centres for the purpose of calculating the energy mix and emissions values.

Demand side participation is represented by the capacity margin over the mean demand and was not varied in Sensitivity Case 3. Adjustments to the level of demand side participation will impact the specification of rated capacity of installed energy infrastructure. From a modelling perspective, increasing the level of demand side participation will result in the same outcome as increasing the energy efficiency improvement rate: a reduction in the extent of energy generation capacity required.

3.4 Greenhouse Gas Offsets

The analysis cases presented in this study were developed with the objective of delivering the required emissions abatement across the industry sectors covered by the study scope using low emissions technologies. The absolute emissions results of several analysis cases were found to exceed net zero by 2050, overshooting by 2 or 3 million tonnes CO_2e per year, and in these cases greenhouse gas offsets were utilised to deliver net zero by 2050. The degree to which greenhouse gas offsets were required to achieve net zero emissions by 2050 was not intended to be material and likely falls within the accuracy bounds of the analysis.

Where individual cases and sensitivities utilize greenhouse gas offsets to deliver net zero emissions in 2050, it has been assumed agro-forestry offsets, specifically soil farming, provides the source of those offsets. This should be seen as illustrative only and does not represent the only greenhouse offset solution.

Provided offsets meet required standards of credibility and verifiability, ideally, the choice between using greenhouse gas offsets or other forms of emissions abatement should be driven by whichever offers the lowest cost emissions reduction.

The development of any emissions management strategy should include a balance between the implementation of emissions abatement opportunities, longer-term investment in offset generation projects and acquisition of offsets on market. As the cost and availability of greenhouse gas offsets in 2050 is highly uncertain this study has not determined the role of greenhouse gas offsets based on the cost relative to other low emissions technologies, rather offsets have been used to balance the emissions reductions in the various cases to ensure Victoria achieves net zero emissions in 2050.

Offsets can either be generated via investment in offset projects or purchased on market. Note the emissions abatement via the use of offsets does not occur at the time of investment in an offset project or the purchase of an offset unit. The emissions reduction can only be claimed at the time the greenhouse gas offset is surrendered or cancelled from its registry account. The planning of investment in greenhouse gas offset projects is similar to other projects to abate emissions (for example, CCS, or the development of hydrogen and ammonia infrastructure) and requires long lead times and must be planned well in advance of when the emissions abatement is to be realised. This requires engagement with stakeholder and an up-front estimation of potential costs relative to other abatement opportunities. Conversely, the acquisition and surrender of offsets acquired on market can occur with short notice and can be used to balance out emissions from unexpected sources.

Agro-forestry (specifically soil carbon) offsets has been assumed in this assessment to illustrate one potential pathway to how any residual emissions could be managed. In reality offsets could be sourced from other projects such as:

- Terrestrial (trees), reforestation, afforestation and revegetation of trees and plants
- Marine, carbon is stored in coastal ecosystems and includes mangroves, salt marshes and seagrasses.

The time between undertaking the offset generation project and the greenhouse gas offset being credited can vary greatly dependant on the type of project being undertaken. Under the Australian CFI Act, crediting can occur immediately to as long as 25 years after commencing the project. The Australian Government is considering the upfront crediting of offsets to minimise the time between undertaking the project and the crediting of offsets.

Where this Study provides a land area requirement for the creation of greenhouse gas offsets, the assessment does not incorporate the time lag between undertaking the project and the crediting of the greenhouse gas offset. It is assumed the offsets are credited and surrendered in the year the project is undertaken.

The benefits and trade-offs of emissions abatement, investment in offsets, and purchase of offsets on market are set out in Table 16.

Table 16: Benefits and trade-off emissions abatement vs greenhouse gas offsets

	Benefits	Trade-Offs
Emissions abatement at source (for example through fuel switching, or increased efficiency improvements)	• Reducing emissions at source is highly desirable • Ensures facility management remain focused on improving facility efficiency and emissions reduction	• For many facilities, the cost to reduce emissions may be high – termed 'hard to abate sectors' • New low emissions technologies to deliver abatement may not be deployed or operate as anticipated
Investment in offset generation projects	• Provides a flexible mechanism to manage emission, particularly where the cost of abatement is high • Possible source of new investment in regional communities • Ability to leverage co-benefits e.g. salinity management, broader conservation benefit	• Need to ensure offsets are credible and verifiable • Change land use patterns may cause social dislocation • Possible sterilisation of productive agriculture land • Environmental impacts such as water usage, bush fire risk, monoculture impacts on native habitat require management. • Land use change offsets may be impacted in longer term by climate change.
Purchase of offsets on market	• Flexibility and ability to access at short notice	• Price may be volatile • Need to ensure offsets are credible and verifiable

Unlike most other environmental impacts, there is no direct causal link between an individual source of greenhouse gas emissions and the range of harms collectively referred to as climate change. Rather it is the cumulative global concentrations of greenhouse gases in the atmosphere that are thought to be driving climate change. Consequently, the risks posed by climate change can only be effectively mitigated if global greenhouse gas emissions are reduced. It does not matter if emissions reduction/abatement occurs in jurisdictions A, B or C.

This enables the cost of abatement to be reduced by focusing emissions reductions in areas of lowest cost rather than in a particular facility location. This is managed through tradeable units, referred to as greenhouse gas offsets. A greenhouse gas offset represents a reduction in emissions of carbon dioxide, or other greenhouse gas, made to compensate for greenhouse gas emissions made elsewhere. A greenhouse gas offset may be generated by an activity that either prevents the release of, reduces, or removes greenhouse gas emissions from the atmosphere. In general terms, a greenhouse gas offset is created (credited) from an emissions reduction project and then sold or transferred to a greenhouse gas emitter (including Governments) who can then claim the emissions reduction once the offset is surrendered or cancelled.

By way of example, both jurisdiction A and B emit 100 million tonnes each per year but the cost to reduce emissions in jurisdiction A is \$50 per tonne CO2e, and in jurisdiction, B is \$100 per tonne. If both jurisdictions reduce their emissions by 10% the economic cost is \$1500 million (\$500 million in jurisdiction A and \$1000 million in jurisdiction B). However, if jurisdiction A undertakes an emissions reduction of 20% and sells half of that abatement to jurisdiction B, the overall economic cost is reduced to $1000 million. The transfer of abatement between jurisdictions A and B is referred to as a greenhouse gas offset.

To ensure environmental integrity, the crediting of offsets to greenhouse gas projects are required to be undertaken under credible, verifiable, and tightly regulated schemes. In Australia, the crediting of greenhouse gas offsets is regulated under the *Carbon Credits (Carbon Farming Initiative) Act 2011* (CFI Act) and administered by the Clean Energy Regulator. Similar schemes exist throughout the world.

While this study has assumed agro-forestry and soil carbon offsets, provided the selected greenhouse gas offsets are credible and verifiable the offsets may be sourced and surrendered from any Australian or international offset schemes, the Carbon Active Program provides a current list of offsets that the Australian Government deems to meet appropriate standards. This enables offsets to be sourced at the lowest costs. The exception to this is where a buyer may be willing to pay a price premium where there may be a demonstrable co-benefit attached to a particular type of offset. For example, the creation of offsets from savannah management in Northern Australia has been shown to also provide significant indigenous employment and engagement benefits.

In the context of the current study, greenhouse gas offsets play only a small role in managing the overall emissions reduction effort.

3.4.1 Regulation of Greenhouse Gas Offsets in Australia

The following discussion reflects the regulation of greenhouse gas offsets in Australia at the time of writing this report. It is likely the regulation of these units will continue to evolve with a focus on the recognition of verifiable emissions reductions. Greenhouse gas offsets can be thought of as being regulated both in terms of their use and their creation.

To avoid nefarious claims around emissions reduction and carbon neutrality, the Australian Government has established the Carbon Active Program. The Carbon Active Program was built upon the pre-existing National Carbon Offset Standard. Some stakeholders continue to refer to the National Carbon Offset Standard. This program specifies the types of greenhouse gas offsets that must be cancelled or surrendered when a member of that program claims to be carbon neutral or to be offsetting its greenhouse gas emissions. It is anticipated that offsets recognised by the Carbon Active Program will also be recognised by the Australian State and Territory jurisdictions and include:

- Australian Carbon Credit Units (ACCUs) issued by the Clean Energy Regulator under the framework established by the *Carbon Credits (Carbon Farming Initiative) Act 2011*.
- Verified Emissions Reductions (VERs) issued by the Gold Standard
- Verified Carbon Units (VCUs) issued by the Verified Carbon Standard
- Certified Emissions Reductions (CERs) issued as per the rules of the Kyoto Protocol from Clean Development Mechanism projects, except for:
- long-term (lCERs) and temporary (tCERs); and
- CERs from nuclear projects, the destruction of trifluoromethane, and the destruction of nitrous oxide from adipic acid plants or large-scale hydroelectric projects not

consistent with criteria adopted by the EU (based on the World Commission on Dams guidelines).

- Removal Units (RMUs) issued by a Kyoto Protocol country based on land use, land-use change and forestry activities under Article 3.3 or Article 3.4 of the Kyoto Protocol.

All units must have a vintage year later than 2012.

For the creation of greenhouse offsets in Australia, the effect of this list is to limit the greenhouse offsets that can be created in Australia to either ACCUs or VERs. Historically, significant oil mallee plantings in the Western Australia wheatbelt were undertaken under the Gold Standard VER scheme but in recent years, new greenhouse offset projects have almost exclusively operated under the *Carbon Credits (Carbon Farming Initiative) Act 2011* with the projects creating ACCUs.

Under Australian prudential law, greenhouse gas offsets are prescribed financial products. The implication of this is that a firm wishing to trade in these units must hold an Australian Financial Services Licence. Exemptions exist where firms are purchasing units to meet regulatory obligations and where an offset producer is selling the offsets they have been credited.

Many greenhouse gas offset projects also deliver social, cultural, economic or environmental benefits. The value of these co-benefits is currently not reflected in the traded value of greenhouse gas offsets issued by the Australian Government. The Clean Energy Regulator is implementing a system to track the provenance of Australian Carbon Credit Units which should allow the market to better price these co-benefits.

3.4.2 Carbon Credits (Carbon Farming Initiative) Act 2011

The Carbon Credits (Carbon Farming Initiative) Act 2011 (CFI Act) establishes a process whereby potential offset generation projects are registered by the Clean Energy Regulator. Once registered, an entity (including corporations and bodies corporate) can undertake the offset project, submit regular reports to the regulator and the regulator then issues ACCUs to the entity's registry account.

Note ACCUs only exist as an entry in the Clean Energy Regulator's registry, the Australian National Registry of Emissions Units (ANREU). When ACCUs are sold or transferred this is done by providing notice to the Clean Energy Regulator who then makes an entry in ANREU. To claim an emissions reduction the holder of the ACCU must surrender the ACCU. Effectively, the Clean Energy Regulator cancels the ACCU in ANREU so that it can no longer be traded.

3.4.3 Carbon Credits (Carbon Farming Initiative) Act Methods

For an offset project to be registered under the Carbon Farming Initiative (CFI) Act, a potential project and project proponent must satisfy a range of criteria, the most important being that the offset generation project must be undertaking in accordance with a "crediting methodology". The methodology sets out a broad range of requirements that the offset generation project must follow, limiting potential offset generation projects to only those activities for which a methodology has been developed, such as:

- Changes to vegetation;
- Agricultural practices involving piggeries, beef cattle, dairy, irrigated cotton, soil carbon in agricultural and grazing systems;
- Savannah management practices; and
- Opportunities for improved efficiency and reduced emissions in industry.

CFI Act Methods are regularly revised, and throughout 2021 the Clean Energy Regulator is developing additional “priority” methods in the areas of:

- Soil carbon (to replace the existing method);
- Carbon capture and storage;
- Biomethane;
- Plantation forestry; and
- Blue carbon.

Blue carbon is greenhouse gas offset created from increased carbon in the marine environment, such as from the reestablishment of seagrass meadows.

3.5 Gas Spatial Analysis

3.5.1 General Methodology

The gas spatial analysis has been undertaken by applying the following methodology:

1) Bioenergy and waste resources have been estimated by type, location and forecast into the future using data from 2018 and 2020. The raw data for agricultural residues has been downloaded from the National Map and is taken from the Australian Renewable Energy Mapping Infrastructure (AREMI) database. The data for construction & demolition (C&D), commercial & industrial (C&I), municipal solid waste (MSW) and material recovery facilities (MRF) residuals has been taken from the “Victorian Waste Flows” report, 11 October 2019 (prepared by Blue Environment).

2) A gas spatial analysis modelling tool was used to model all of the existing and potential future major supplies of natural gas, biomethane (forecast), hydrogen (forecast) and ammonia (forecast) as appropriate for the case. The modelling tool covered the transmission gas pipeline system that moves natural gas from point sources to regions of demand, where the gas is distributed to end customers in the distribution network. The transmission network is simplified to connections between the defined regions and does not model each segment in the network individually. The modelling tool selects the location for new gas supplies in order to match supply and demand throughout Victoria and also achieve a desired gas mix as specified by the Net Zero Planning Tool (see Section 3.2). Details of the low-pressure distribution network are simplified as a point sink and not accounted for in detail within the model.

3) Results from the gas spatial analysis modelling tool are then used to generate spatial datasets which are loaded into a geospatial mapping system and used to generate maps.

3.5.2 Key References

The key references for the gas spatial analysis and bioenergy resources and technologies are:

AEMO, (2020), "Victorian Gas Planning Update Report: Gas Transmission Network Planning for Victoria", March 2020. Web: https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report

Bioenergy Australia, (2019), "Biogas opportunities for Australia", Prepared for Bioenergy Australia by Enea Consulting. Web: https://arena.gov.au/assets/2019/06/biogas-opportunities-for-australia.pdf

Deloitte Access Economics, (2017), "Decarbonising Australia's gas distribution networks", Web: https://www2.deloitte.com/au/en/pages/economics/articles/decarbonising-australias-gas-distribution-networks.html

Blue Environment, "Victorian waste flows", 11 October 2019, Prepared for Infrastructure Victoria by Blue Environment Pty Ltd. Web: https://www.infrastructurevictoria.com.au/wp-content/uploads/2019/10/Victorian-Waste-Flows-Blue-Environment-October-2019-FINAL-REPORT.pdf

Blue Environment, "National Waste Report 2020", 4 November 2020, Prepared for Department of Agriculture, Water and Environment by Blue Environment Pty Ltd. Web: https://www.environment.gov.au/protection/waste/national-waste-reports/2020

International Energy Agency, (2020), "Outlook for biogas and biomethane: Prospects for organic growth", Web: https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth

Infrastructure Victoria, (2019), "Recycling and resource recovery infrastructure – Evidence based report". Web: https://www.infrastructurevictoria.com.au/wp-content/uploads/2019/10/Infrastructure-Victoria-Recycling-and-resource-recovery-infrastructure-Evidence-base-report-October-2019-FINAL-REPORT.pdf

Infrastructure Victoria, (2020), "Advice on Recycling and resource recovery infrastructure". Web: https://www.infrastructurevictoria.com.au/wp-content/uploads/2020/03/Advice-on-recycling-and-resource-recovery-FINAL-REPORT.pdf

Institute of Public Affairs, (2008), "Water supply options for Melbourne: An examination of costs and availabilities of new water supply sources for Melbourne and other urban areas in Victoria". Web: https://www.parliament.vic.gov.au/images/stories/committees/enrc/future_water_supply/Submissions_57_110/098_Institute_of_Public_Affairs.pdf

Fertilizers Europe, (2013), "Guidance for inspection of and leak detection in liquid ammonia pipelines". Web: https://www.fertilizerseurope.com/wp-content/uploads/2019/08/Guidance_for_inspection_of_and_leak_detection_in_liquid_ammonia_pipelines_FINAL_01.pdf

Ramboll, (2018), "Kwinana Waste to Energy ARENA Life Cycle Assessment", Prepared for Kwinana Waste to Energy Project by Ramboll. Web: https://arena.gov.au/assets/2018/12/kwinana-waste-to-energy-project-report.pdf

US Department of Energy, (2006), "Potential roles of ammonia in a hydrogen economy", Web: https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf

US EPA, (2021), "LFG Energy Project Development Handbook", Web: https://www.epa.gov/system/files/documents/2021-07/pdh_full.pdf

Victorian Minister for Planning, (2021), "Crib Point Gas Import Jetty and Crib Point – Pakenham Gas Pipeline Project", Web: https://www.planning.vic.gov.au/__data/assets/pdf_file/0023/517280/Ministers-Assessment-March-2021.pdf

3.5.3 Bioenergy Resources

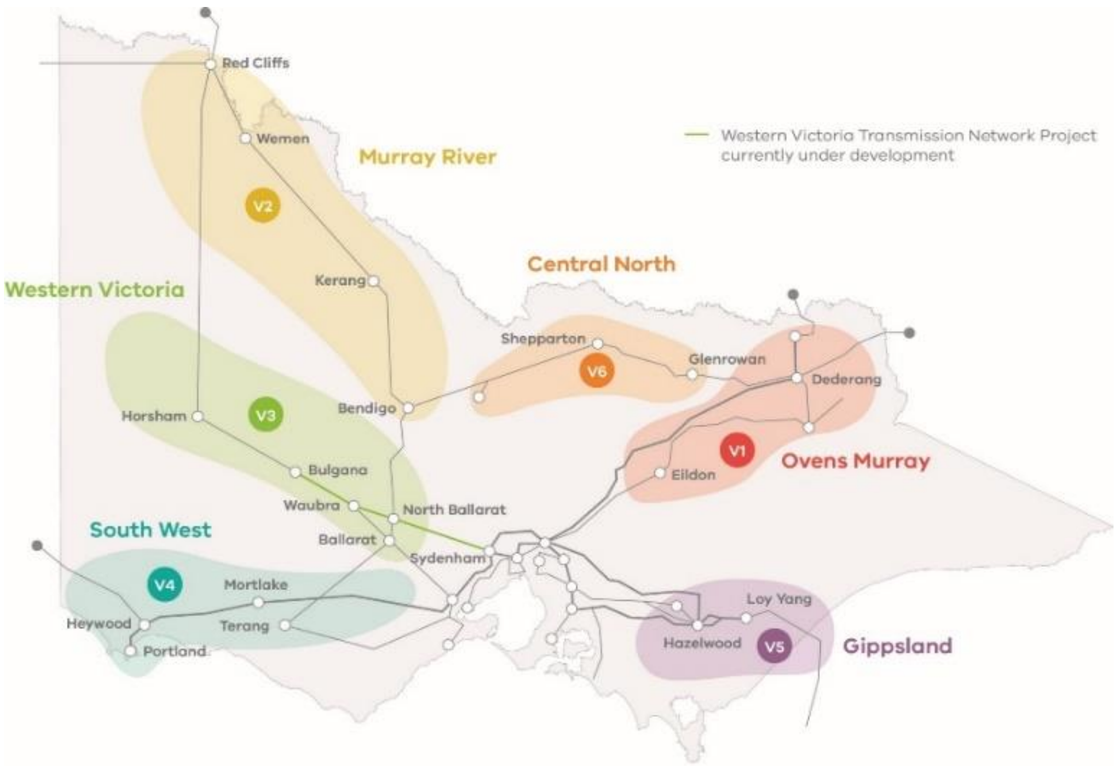
Bioenergy resources refers to energy that is primarily of biogenic origin, which includes the energy fractions of construction & demolition (C&D), commercial & industrial (C&I), municipal solid waste (MSW) and material recovery facility (MRF) residuals, fruit and vegetable wastes, canola residues, agricultural residues such as straw chaff, paunch solids, animal manures (cattle, chicken, pigs), biosolids, and residues from softwood and hardwood plantations.

The bioenergy data from the Australian Renewable Energy Mapping Infrastructure (AREMI) project and contained in the National Map version 1.0 was used to estimate the quantity and spatial distribution of bioenergy resources in the state. The data is available for each of the 79 Local Government Areas and has also been consolidated into the seven Waste Resource Recovery Groups (WRRGs) which have a similar spatial distribution to the natural gas transmission system and the electrical Renewable Energy Zones, as shown in Figure 11.

Figure 11: Similarity between the (a) natural gas transmission system, (b) waste resource and recovery groups and (c) renewable energy zones.

(a)

(b)



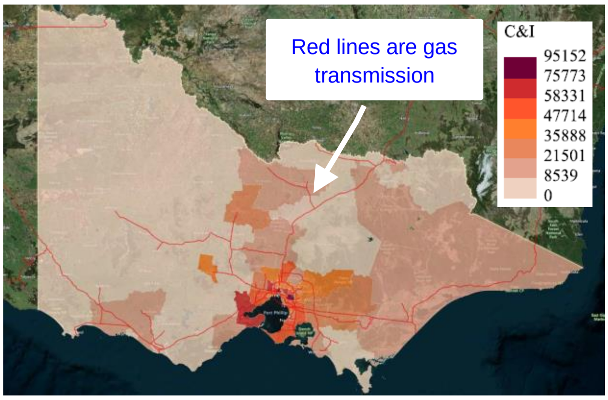
(c)

The bioenergy resources were allocated to the following categories:

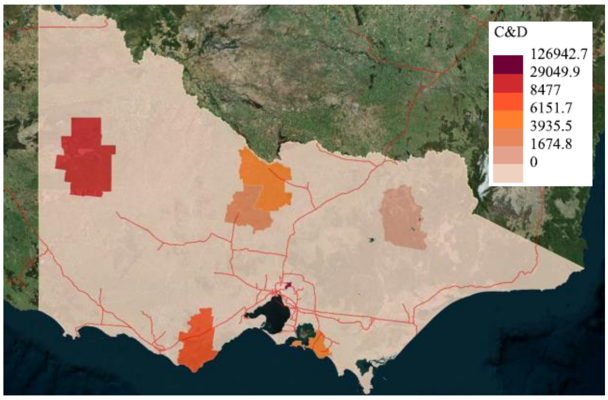
- Construction and demolition waste (C&D);
- Commercial and industrial waste (C&I);
- Municipal solid waste (MSW);
- Material recovery facility (MRF) residuals;
- Fruit and vegetable wastes;
- Canola residues;
- Paunch solids;
- Animal manure (cattle, chicken, piggeries);
- Biosolids;
- Softwood plantation;
- Hardwood plantation;
- Hardwood native; and
- Straw chaff (various straw residues).

Figure 12 and Figure 13 show maps of the main bioenergy and waste resources which describe the locations in which each resource is available.

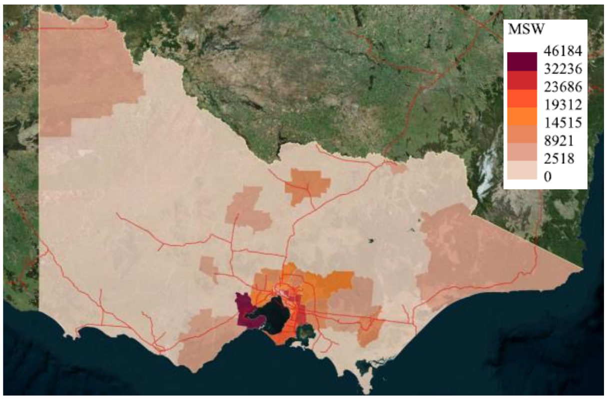
Figure 12: Maps of bioenergy resources in tonnes per annum: (a) C&I, (b) C&D, (c) MSW, (d) fruit and vegetables, (e) canola residues and (f) paunch solids.



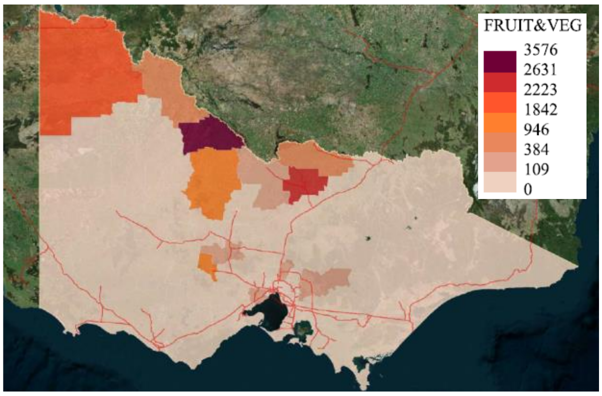
(a) C&I



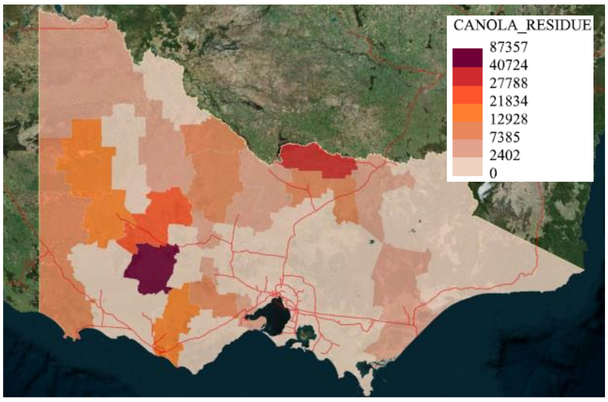
(b) C&D



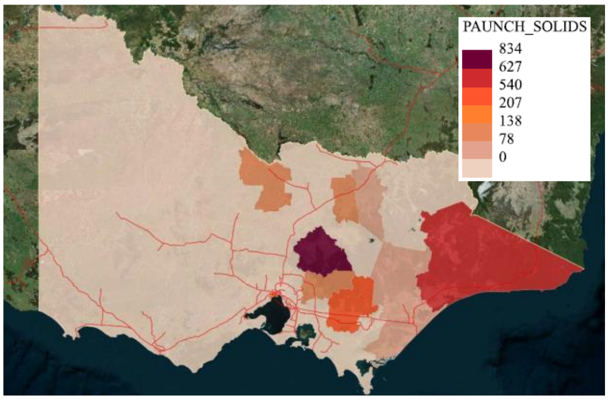
(c) MSW



(d) Fruit and Vegetable wastes

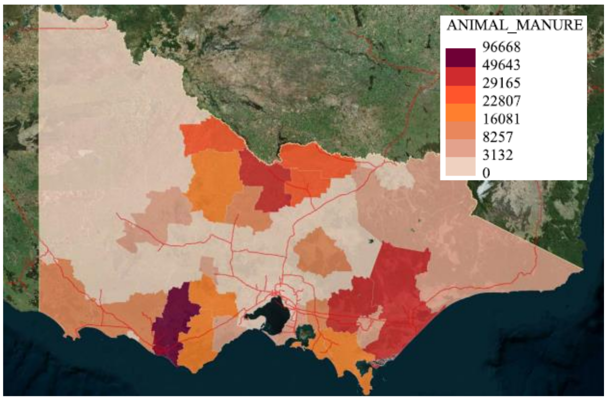


(e) Canola residues

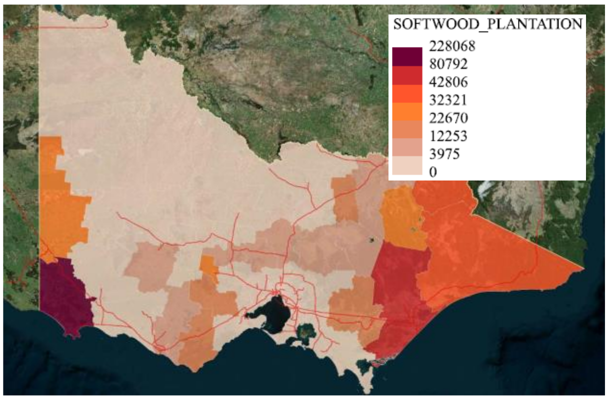


(f) Paunch solids

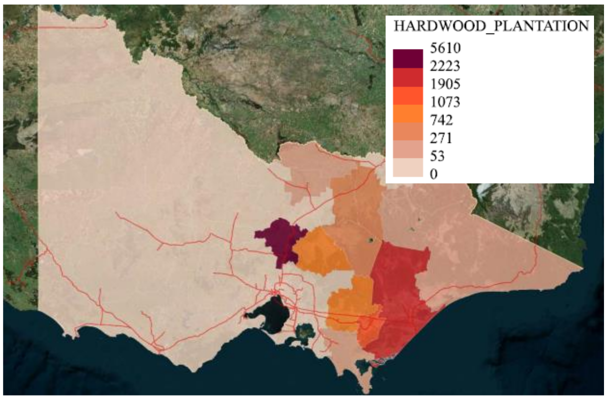
Figure 13: Maps of bioenergy resources in tonnes per annum: (a) animal manure, (b) softwood plantation, (c) hardwood plantation, (d) hardwood native and (e) straw residues.



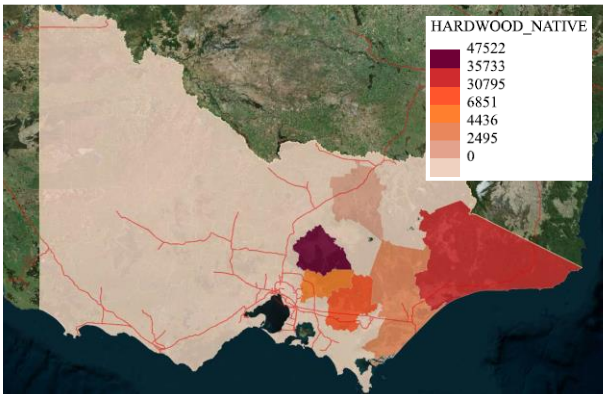
(a) Animal manure



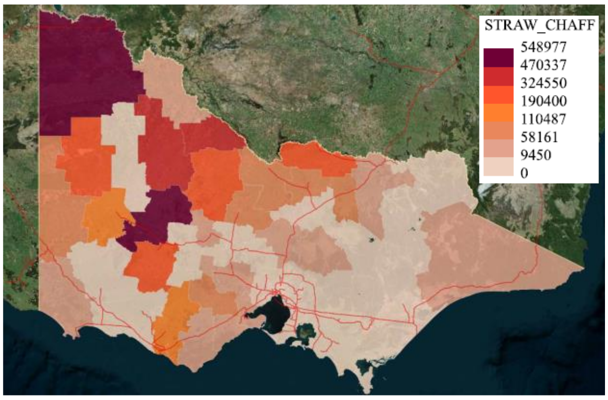
(b) Softwood plantation



(b) Hardwood plantation



(d) Hardwood native



(d) Straw residues

For C&D wastes, 25% of the total were considered suitable for energy recovery by taking into account the typical content of concrete, steel, soil and other inerts from the Victorian waste flows report (Blue Environment, 2019). For C&I wastes a conservative fraction of 35% was selected based on Victorian waste composition data (Blue Environment, 2019). For other waste streams, 100% of the available material was considered suitable for energy recovery. Application of these factors means that the estimated resource availability is probably conservative.

To forecast the tonnes of bioenergy resources that are available in the future, the base case values were increased in line with forecast population increases of 1.5% per annum (around 15% per decade). No waste reduction per capita has been assumed.

Table 17 shows the primary energy in each type of bioenergy resource forecast from 2020 to 2050. Conversion from tonnes per annum to petajoules per annum was undertaken by using representative calorific values for each resource type. Calorific values used were 15 GJ/t for C&I, C&D, canola residues and biosolids (dry), 12 GJ/t for MSW and MRF residuals, 8 GJ/t for fruit & vegetable wastes, paunch solids and animal manure, 20 GJ/t for hard and softwoods and 16 GJ/t for straw residues. It can be seen that the total energy available is around 140 PJ/yr in 2020 increasing to 190 PJ/yr in 2050. These estimates are consistent with earlier studies (Bioenergy Australia, 2019; Deloitte 2017).

Table 17: Primary energy in PJ/yr by bioenergy resource category for 2020 to 2050.

Resource	2020	2030	2040	2050
C & D	3.57	4.15	4.81	5.59
C & I	9.56	11.10	12.88	14.94
MSW	20.62	23.93	27.77	32.22
MRF Residuals	3.13	3.64	4.22	4.90
Fruit and Veg. Wastes	0.32	0.37	0.42	0.49
Canola Residue	5.29	6.13	7.12	8.26
Paunch Solids	0.02	0.03	0.03	0.04
Animal Manure	4.50	5.22	6.06	7.03
Biosolids	1.72	2.00	2.32	2.69
Softwood Plantation	13.34	14.38	15.49	16.69
Hardwood Plantation	0.31	0.33	0.36	0.39
Hardwood Native	4.80	5.17	5.57	6.00
Straw Chaff	72.20	77.80	83.84	90.35
Total (PJ/YR)	**139.38**	**154.23**	**170.89**	**189.59**

Figure 14 shows the spatial distribution of the resources, while Figure 15 shows the spatial distribution of primary energy in petajoules per annum. It can be seen that in the western parts of the state there are significant bioenergy resources, with the potential to produce between about 1 and 10 PJ/yr from a number of Local Government Areas (LGAs). However, these resources are currently stranded from the existing transmission pipeline system. The north of the state also has significant bioenergy resources.

Figure 14: Total bioenergy resources in tonnes per annum.

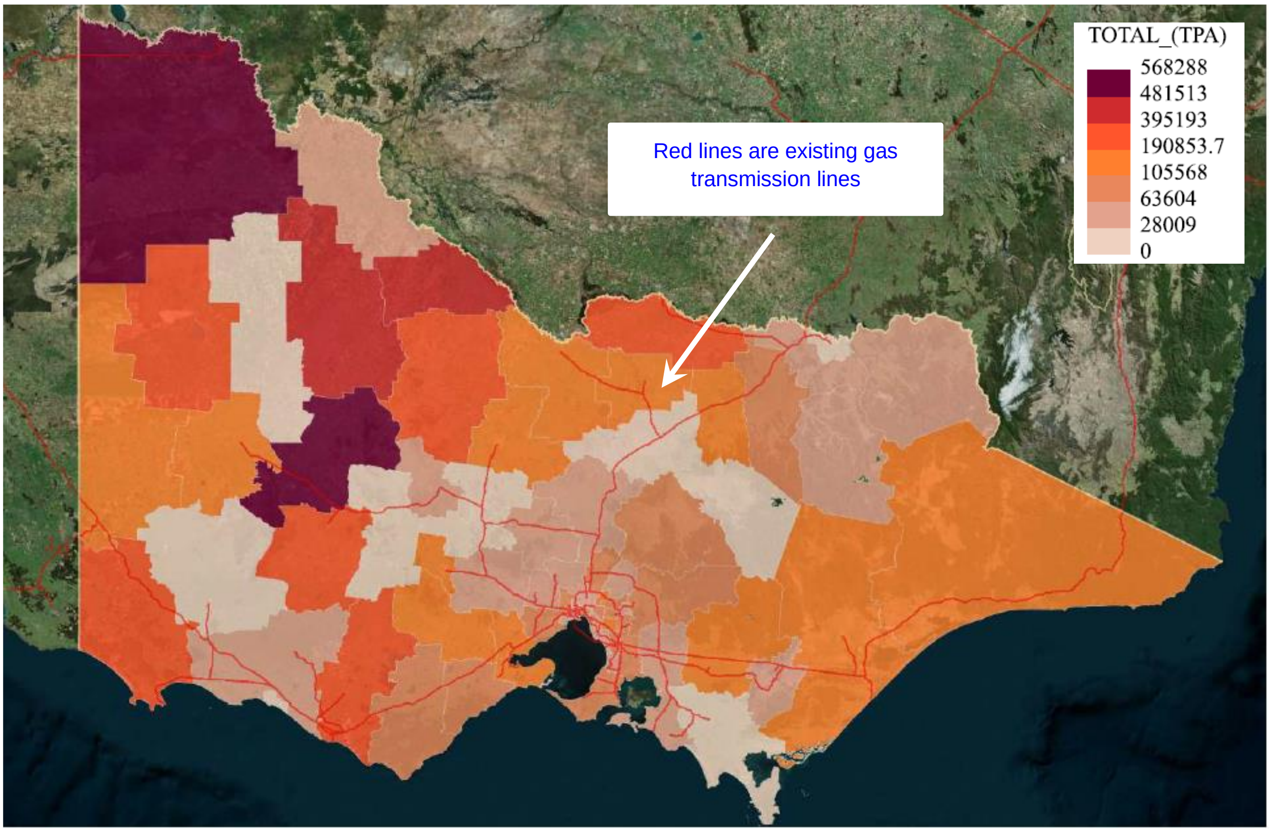
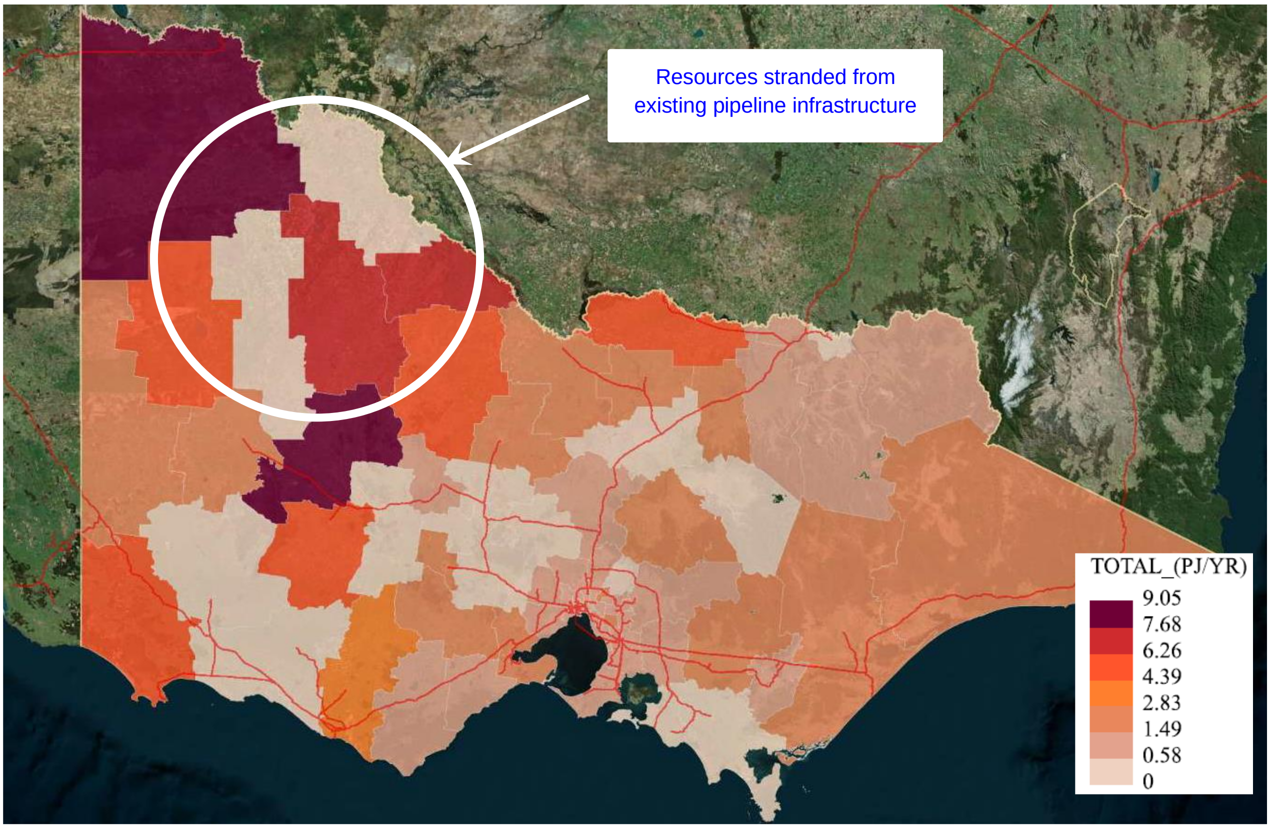


Figure 15: Total bioenergy and waste primary energy in PJ/yr.



3.5.4 Bioenergy Production

Bioenergy production refers to the production of energy from bioenergy resources. The production technologies include i) anaerobic digestion of organics into biogas which is primarily a mixture of methane and carbon dioxide, which may be further upgraded into biomethane ii) conversion of solid biomass, such as wheat crop residues, into electricity and heat via combustion and gasification; and into biomethane via gasification and catalytic synthesis of methane and iii) the conversion of wastes destined for landfill, such as municipal solid waste (MSW) residuals, into electricity and heat with bioenergy plants using conventional incineration.

Biomass generally refers to solid biomass that is unsuitable for conversion in anaerobic digestion because it has a high lignin content. Significant resources available in Victoria include straw residues, softwood and hardwood plantation residues.

The bioenergy production technologies are categorised as:

- Anaerobic digestion;
- Biomass combustion;
- Biomass gasification; and
- Waste to energy.

Further discussion of each bioenergy production technology is provided below.

Anaerobic Digestion

Refers to production of biogas from organics that break down under anaerobic conditions (without oxygen). Anaerobic digestion can be used to form biogas from organics separated from municipal solid waste (MSW), animal manure, canola residues, fruit and vegetables and some other forms of biomass residues. The biogas produced from anaerobic digestion is primarily composed of methane and carbon dioxide. The biogas can be used to produce electricity in gas engines as is already practiced at many landfill sites and some waste water treatment plants. The biogas may also be upgraded into biomethane, by separating out the carbon dioxide, and used to substitute natural gas when injected into the gas pipeline transmission and distribution systems.

In this work, it is assumed that the organics from domestic waste are progressively diverted from landfill, and anaerobic digestion is preferentially applied to produce biomethane and electricity. The assumptions used are aligned with the priorities outlined in a recent report titled *“Advice on Recycling and resource recovery infrastructure”* (Infrastructure Victoria, 2020).

Biomass Combustion

Solid biomass may be converted to electricity and heat in combustion plants. In these plants the biomass is combusted in a furnace to produce heat which is used to generate steam which is runs a steam turbine to generate electricity and/or used for industrial heating purposes.

Biomass Gasification

Biomass gasification refers to the process where the biomass is reacted with sub-stoichiometric quantities of air (or oxygen) to produce a synthesis gas (syngas) composed predominately of carbon monoxide and hydrogen. There are a wide range of common biomass gasification reactor designs including updraft, downdraft and fluidised bed which relate primarily to how the oxidant and solid feedstock are contacted inside the reactor.

The syngas from biomass gasification may be combusted in a gas engine to produce electricity or it may be reacted over a catalyst to form synthetic methane, which is equivalent to natural gas.

Waste to energy

Refers to conventional waste to energy incineration plants which burn the solid waste, predominately municipal solid waste (MSW), to form electricity. While Victoria does not yet have a bioenergy policy, it is assumed that the initial priority will be to increase re-use and recycling of waste and to increase the diversion of organics from landfill to produce electricity and biomethane from anaerobic digestion (Infrastructure Victoria, 2020). In accordance with the waste hierarchy, waste to energy is preferred over landfill and would be deployed to process residuals produced from recycling activities for which there are no higher value uses (Infrastructure Victoria, 2020). In each scenario studied in this work, the assumed deployment of waste to energy plants is kept low and they will supply less than 5% of Victoria’s electricity needs.

3.5.5 Biomethane

In this work, biomethane refers to methane separated from biogas made from anaerobic digestion and methane synthesized from the products of biomass gasification, as in each case the feedstock is of biogenic origin.

Figure 16 shows a schematic of the production of biomethane from biogas and from biomass gasification.

It is assumed that biomethane production from upgrading biogas from anaerobic digestion will dominate in the next 10 – 20 years as it is currently the most mature of the two technologies and has the lowest cost, especially at small scale. While upgrading of biogas into biomethane is relatively simple, most anaerobic digestion plants are small due to the availability of organic wastes which limits the scale of production. Therefore, biogas plants are generally better suited to producing biomethane into the local distribution system.

Biomethane production from biomass gasification may ramp up in the 2020s and 2030s and become commercially significant after 2035. The major advantage of using biomass gasification for biomethane production is that larger processing plants can be built, with each producing petajoules of gas per annum that could be injected into either the high pressure gas transmission network or the low pressure gas distribution network.

Table 18 shows the theoretical total biomethane that can be produced using a combination of anaerobic digestion of organic waste and gasification of solid biomass between 2020 and 2050. This estimate of the theoretical potential is calculated by assuming a conversion efficiency of 43% from the primary energy resource to biomethane.

Figure 16: Biogas and biomethane production processes (IEA, 2020).

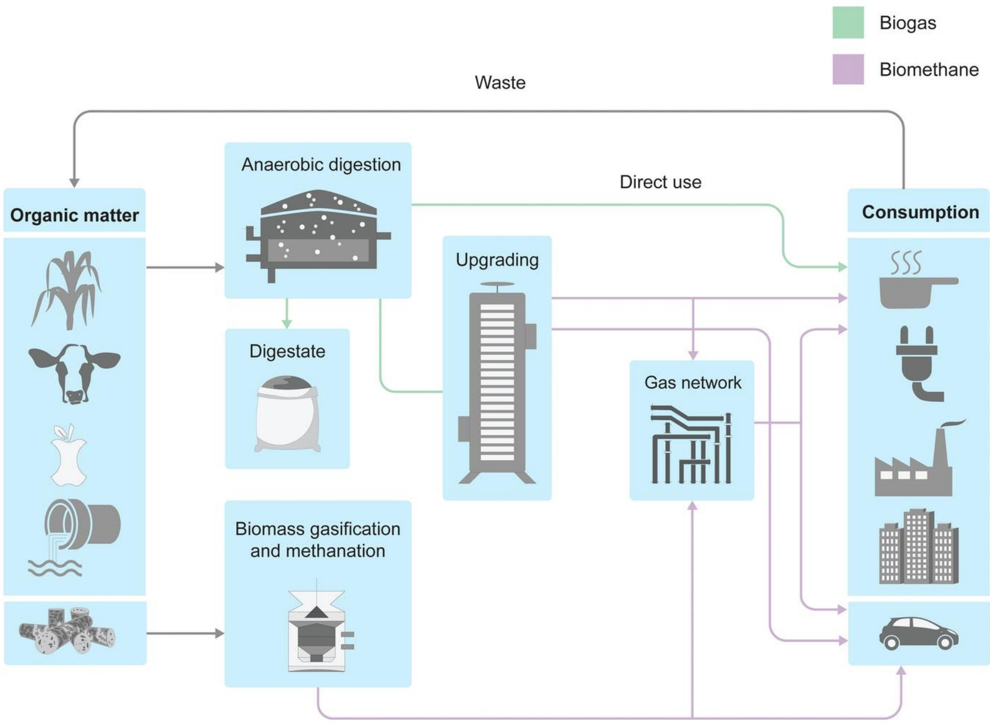


Table 18: Total potential biomethane resource from 2020 to 2050.

Year	PJ/yr-gas
2020	41
2025	46
2030	50
2035	53
2040	56
2045	59
2050	62

As not all of the potential can be realised, the total amount of biomethane has been limited to approximately 45 PJ/yr for all cases. This estimate is consistent with earlier estimates in the literature. For example, Deloitte (2017) estimate the biomethane potential in Victoria at 48 PJ/yr, while Bioenergy Australia (2019) estimated it at 27% of the state's gas consumption, or around 56 PJ/yr.

3.6 Electrical Spatial Analysis

3.6.1 Methodology

The electrical demand per region was estimated using the process summarised below.

1. Identification of inputs into the calculation based on the required energy infrastructure

a. Inputs - (provided by Net Zero Analysis Tool – refer Section 3.2):

- Required additional energy generation capacity by period (5 years period) (in GWh or PJ)
- Share of Gas/Electrical input in this additional generation capacity

b. Define the percentage of supply for each type of new energy system/technology

c. Define the capacity factor of the green energy types

d. Identify the location for implementation of energy technologies within the zones

e. Calculate the amount of new energy required to supply the network based on demand.

2. Calculate the required new energy type infrastructure per renewable energy zone (REZ)

Core inputs:

a. Energy technology types per zone as identified in Step 1

b. Available footprint per energy technology type per zone (if any)

c. Restrictions in the implementation of new technology in each zone

d. Existing energy assets per zone (type, capacity, footprint, efficiency/ load factor, decommissioning date)

e. NEM interconnector capacity (VNI, Haywood and Bass are considered)

f. Calculation of new electrical generation capacity infrastructure per energy technology type and zone.

g. Perform iterative calculations for each 5-year period considering the decommissioning of existing and new assets

Note: The analysis considers a simplistic representation of the transmissions system assuming it would be feasible to expand the system as required to meet the new generation requirements.

3. Define the required infrastructure for storage capacity

a. Required inputs:

- Local information on storage projects (capacity, CAPEX/OPEX, size, footprint, efficiency, lifetime)
- Existing infrastructure (decommissioning date, capacity, zone, efficiency, use)

b. Define the type of storage considered

c. Define the new storage parameters (capacity and efficiency)

d. Considering inputs and time to compensate and produce energy over this time if energy infrastructure were working at normal efficiency, calculate the required capacity storage infrastructure

e. Establish in which zone each storage type will be implemented (i.e., pumped hydro depends on the topography of the zone)

4. Spatial analysis:

a. Using previous steps, define which zone produces surplus electricity and which has a deficit, and balance the zones with electrical flows accordingly.

3.6.2 Assumptions

The Victorian power network consists of approximately 6,000km of high voltage electricity transmission and 150,000 km of electricity distribution.

The majority of electricity within Victoria is generated from the brown coal in the Latrobe Valley and transmitted to Melbourne, being the largest demand centre in the state.

Victoria's electricity transmission network is interconnected with South Australia, New South Wales, Tasmania and indirectly with Queensland. This allows the transportation of electricity from the states when electricity demand in Victoria is relatively high, or exported from Victoria when demand is relatively low.

In this analysis, it is assumed that Victoria will, in the main, be electrically self-sufficient and only utilise the interconnectors from other states for peaking purposes.

The Victorian electrical network forms part of the National Energy Market (NEM) which is operated by the Australian Energy Market Operator (AEMO), including monitoring of supply and demand, voltage and frequency, managing planned and unplanned outages and emergencies, ensuring that Victorian consumers, businesses and industry have access to secure and reliable energy. AEMO also maintains the financial markets that allow energy to be bought and sold.

The basis for the mix of energy technologies utilised in the calculations assumes a number of limits for each new infrastructure and technology type, as summarised below.

1. **Victorian Renewable Energy Target (VRET)**

Victoria has set a VRET of 50% for 2030. This objective is achieved in all the analysis cases with most reaching more than 60% of the VRET by 2030.

When renewable electricity technology represents more than 60% of the electrical mix the intermittency can create instability in the network. To avoid network instability, additional storage infrastructure was incorporated into the calculations with a nominal 1.5 times the required generation capacity selected to ensure a stable and robust network is maintained. Only the infrastructure installed past 60% total electricity generated by renewable sources is multiplied by this factor.

A network with 100% renewables electrical mix (solar and wind) would require substantial modification to the transmission and distribution network. Stability of the network would require much more additional infrastructure with diminishing returns as the system would need to be substantially over dimensioned to maintain a stable network (both on generation and storage infrastructures). The cost of such a solution would be significantly higher than one based on dispatchable energy infrastructure, that can work at a fixed nominal capacity and can be started and stopped as necessary. Solar and wind generation capacity depends on intermittent factors.

2. **Demand**
The demand is never constant, and over any extended period of time there will be low, mean, high and peaks periods as defined below.

Low Demand: storage would be re-charged during low demand, and once achieved spare capacity could be utilized for export to other states or Victorian regions.

Mean Demand: represents the mean of annual demand, measured in kW and used for energy demand forecasting.

Maximum Demand: means the average amount of kW delivered at the point of supply of the consumer and recorded during a thirty-minute period. This value was assumed to be 115% of the mean demand and was used to specify energy generation capacity. On this basis, the current study allows Victoria to independently supply its own power demand up to and including maximum demand, thereby limiting reliance on state interconnectors.

Peak Demand: in an electrical grid, peak demand is the highest electrical power demand occurring over a specified time period (often a year). The peak demand was assumed to be covered by state interconnectors and also partly by storage capacity, meaning that electrical infrastructure (generation, storage, and transmission) has been designed to meet the maximum demand and not the peak demand. During peak consumption, Victoria will have to import electricity from New South Wales, Tasmania or South Australia through the interconnectors.

Electricity demand is measured in kilowatts (kW) and represents the rate at which electricity is consumed. Electricity consumption, on the other hand, is measured in kilowatt-hours (kWh) and represents the amount of electricity that has been consumed over a certain time period.

In the same way, electrical generation infrastructure is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the generated electricity is measured in megawatts hours (MWh) and represents on average the quantity of energy that can be generated by an asset over any given time period (a year for example). The electrical generation depends on the asset capacity factor, being the percentage of the working time of an asset over a time period (a year for example).

Electrical generation over a year (MWh) = **Electrical infrastructure** (MW) x 8760 hours x **Capacity factor** (%)

3. **Wind and Solar Photo Voltaic (PV)**

Wind and solar PV technologies are well known and operate independently at different times of the day, however the split between the two technologies was a key analysis variable, which was set between 40 / 60 to 60 / 40 share (solar PV / wind), depending on the requirements of the analysis case.

4. **Rooftop solar**

The following assumptions were made in the evaluation:

- 5 kW of rooftop solar PV would be installed on half of the 4 million households in Victoria by 2050 (https://www.invest.vic.gov.au/resources) to a maximum of 10 GW.
- "Behind the meter" storage (batteries) was considered to be disconnected from the grid.

5. **Hydropower**

Hydroelectricity contributes a minor portion of the energy supply in future years. It is recognised that future water inflows are likely to decline compared with historical flows however with the low levels of hydropower in the overall energy mix (< 10 PJ / year), failure to deliver this amount of electricity will not have a significant impact on the cases being analysed, as any shortfall could be made up by other energy technologies in the mix.

6. **Transmission Lines**

Upgrades to electricity transmission lines are not identified on the maps with the observable transmission lines corresponding to the existing ones. As the generation capacity will almost double in every case, the associated transmission system will need to be upgraded accordingly.

The current study focuses on generation and storage electrical infrastructure with additional transmission infrastructure estimated on an order of magnitude basis. Upgrades to the existing transmission lines which link the Renewable Zones have been considered. To estimate the cost of these upgrades, AEMO data on transmission component costs have been used.

For each new transmission line, a 500kV double circuit transmission line is used with two 500/330kV or 500/220kV transformers. A total of 6 to 7 lines have been identified to be upgraded for a total of 1500km (on average) of transmission lines.

Transformer cost: $20.43 million per unit (Reference: AEMO – Inputs and Assumption workbook)

Transmission line: $2.46 million per km (Reference: AEMO – Inputs and Assumption workbook)

7. **Decommissioning**

The analysis considered gas and coal power generation infrastructure decommissioning dates published in AEMO's "ISP Inputs and Assumptions Workbook", tab "Existing & Committed electrical infrastructure".

The infrastructure decommissioning planned for 2050 was modelled in the 2045-2050 period.

Table 19: Expected decommissioning dates given by AEMO inputs and assumption workbook.

Name	Technology type	Expected Retirement Date
Loy Yang A Power Station	Steam Sub Critical	2048
Loy Yang B	Steam Sub Critical	2047
Yallourn W	Steam Sub Critical	2029
Somerton	OCGT	2033
Bairnsdale	OCGT	2042
Jeeralang A	OCGT	2039
Jeeralang B	OCGT	2039
Laverton North	OCGT	2070
Mortlake	OCGT	2047
Newport	Gas-powered steam turbine	2039
Valley Power	OCGT	2070
Hume Dam VIC	Hydro	2057
Bogong / Mackay	Hydro	2057
Dartmouth	Hydro	2057
Eildon	Hydro	2057
Murray 1	Hydro	2070
Murray 2	Hydro	2070
West Kiewa	Hydro	2057
Ararat wind farm	Wind	2047
Bald Hills wind farm	Wind	2040
Bulgana Green Power Hub - Wind Farm	Wind	2049
Challicum Hills wind farm	Wind	2033
Cherry Tree Wind Farm	Wind	2050
Crowlands Wind Farm	Wind	2049
Dundonnell Wind Farm	Wind	2045
Elaine Wind Farm	Wind	2049
Kiata wind farm	Wind	2042
Macarthur wind farm	Wind	2038
Mortons Lane wind farm	Wind	2042
Mt Gellibrand wind farm	Wind	2043
Mt Mercer Wind Farm	Wind	2043
Murra Warra Wind Farm - stage 1	Wind	2049
Oaklands Hill wind farm	Wind	2037
Portland wind farm	Wind	2040
Salt Creek wind farm	Wind	2043
Waubra wind farm	Wind	2039
Yaloak South wind farm	Wind	2048
Yambuk wind farm	Wind	2040
Yendon Wind Farm	Wind	2049
Bannerton Solar Park	Large scale Solar PV	2049
Gannawarra Solar Farm	Large scale Solar PV	2048

Name	Technology type	Expected Retirement Date
Karadoc Solar Farm	Large scale Solar PV	2048
Kiamal Solar Farm stage 1	Large scale Solar PV	2049
Numurkah Solar Farm	Large scale Solar PV	2044
Wemen Solar Farm	Large scale Solar PV	2049
Berrybank Wind Farm	Wind	2045
Moorabool Wind Farm	Wind	2044
Murra Warra Wind Farm - Stage 2	Wind	2052
Stockyard Hill Wind Farm	Wind	2045
Cohuna Solar Farm	Large scale Solar PV	2045
Glenrowan West Sun Farm	Large scale Solar PV	2051
Winton Solar Farm	Large scale Solar PV	2051
Yatpool Solar Farm	Large scale Solar PV	2050
Berrybank Wind Farm - Stage 2	Wind	2045
Carwarp Solar Farm stage 1	Large scale Solar PV	2051
Mortlake South Wind Farm	Wind	2051

3.7 Vehicle Analysis

Table 20 indicates the significant share of emissions currently contributed by road vehicles (approximately 25% of the study scope in 2020), demonstrating the uptake of low emissions vehicles will play a vital role in the transition to net zero emissions by 2050.

Table 20: Emissions Summary (High Probability Technology Case)

(Total Emissions per Year, Mill Te CO_2-e)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	37	28	21	14	7	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	2	2	3	4
Elec (generation) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	1	2	3	4	4	4	5
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - waste-to-energy / biogas / biomass	0	-1	-3	-5	-7	-9	-11
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	15	13	11	8	4
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green)	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	14	10	6	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
Vehicles - (HFCV) H2	0	0	0	0	0	0	0
TOTAL EMISSIONS	**87**	**74**	**61**	**47**	**33**	**17**	**3**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**-1**	**-1**	**-2**	**-2**	**-3**
NET EMISSIONS	**87**	**74**	**60**	**46**	**31**	**14**	**0**

The analysis of vehicles was based on hindcast data from the Australian Bureau of Statistics, Survey of Motor Vehicle Use, Australia 12 Months ended 30 June 2020 covering the number of vehicles, kilometres travelled, and fuel usage. The data was compared to that of prior years to check its consistency.

Table 21: Fuel Consumption Summary

Year	Total Distance Travelled (Australia) (Million kilometres)	Total Fuel Consumed (Million Litres)
2020	20	33
2018	19	34
2016	18	32
2014	18	32

The analysis was restricted to road vehicles in Victoria, broken down into two broad categories:

Light vehicles

Passenger vehicles

Motor cycles

Light commercial vehicles

Heavy vehicles

Rigid trucks

Articulated trucks

Non-freight carrying trucks Buses

Forecasting of road vehicle numbers, fuel usage and uptake of low emissions vehicles through to 2050 was based on data from KPMG's 2046 Reference Scenario and AZEVIA Model Development Final Report, Infrastructure Victoria 23 May 2018 however two key gaps in the KPMG data required the current study to develop an independent forecast:

a) unusually high increase in kilometres travelled; and

b) no reference to Hydrogen Fuel Cell Vehicles (HFCVs).

In the absence of reliable forecast data for the uptake of both Battery Electric Vehicles (BEVs) and HFCVs for Victoria from 2020 to 2050, the current study used the following assumptions to develop forecasts of Victorian road vehicle fuel consumption, which remain unchanged from the forecast used for the prior Net Zero Emission *Scenario Analysis Study Report May 2021* (Scenario B):

- KPMG's forecast of the total number of road vehicles;
- Limiting total kilometres travelled per vehicle per year to current levels; and

- Inclusion of HFCVs by nominal reduction in the forecast uptake of BEVs and ICEs.

Table 22 summarises the low emissions vehicle fuel consumption rates assumed for the current study. KPMG's BEV fuel consumption rates were used, noting the significant difference between light and heavy vehicles. Fuel consumption data for the Hyundai Nexo (light HFCV) taken from RACV's website was used for the study. Due to a lack of available data for heavy HFCV fuel consumption, the same BEV fuel consumption ratio heavy: light was applied to HFCVs.

Table 22: Low Emissions Vehicle Fuel Consumption Rates

	BEV		HFCV	
	Fuel Consumption (kWh / 100 km)	**Reference**	**Fuel Consumption (kg H2 / 100 km)**	**Reference**
Light Vehicle	20	KPMG's 2046 Reference Scenario and AZEVIA Model Development Final Report, Infrastructure Victoria 23 May 2018	1	RACV website: Hyundai Nexo
Heavy Vehicle	100		5	Assumed same ratio as BEV heavy: light

3.8 Cost Analysis

3.8.1 Methodology

The structure of the study and the uncertain nature of the scenario factors means that a bottom-up cost estimate based on unit costs, quantities, rates, productivity, and durations cannot be generated. The cost estimate for the purpose of the study was estimated using a combination of bulk rates, unit costs, and quantities where available, and qualitatively / semi-quantitatively scaled or factored costs.

Life-cycle cost estimation (CAPEX / OPEX and ABEX) covered the following systems:

- Gas infrastructure (existing and additional) including production, generation, storage transmission and distribution;
- Electrical infrastructure (existing and additional) including production, generation, storage, and transmission; and
- Industrial energy generation (electricity & energy gas per the spatial analysis excluding "behind the meter" costs).

Cost estimation of the following systems and 'behind the meter' costs were specifically excluded from the scope of work:

- Energy Efficiency;
- Transport;

- Residential and Commercial Use;
- Industrial use;
- Electrical Distribution; and
- Export.

Note that energy efficiency is accounted for through avoided energy generation infrastructure CAPEX due to reduced generation requirements to meet demand.

The following methodology was used to allow a comparison between cases to assess which case may have potential to provide the lease cost over another case. The costs should not be used as absolute / actual numbers or how and when CAPEX is spent but rather for comparison purposes only to assess whether there is a net cost advantage or disadvantage between the cases.

The main reason for doing this is the uncertainty in providing total costs and so it is more appropriate to provide relative costs for each given the study limitations.

Costs have been estimated and presented as annualised costs using an equivalent annual annuity method similar to the AEMO method (see Section 2.6.3, Item No. 11) but simplified to the staged costs linked to key transition milestones, 5-year periods. This was done by converting project costs into a stream of equal annual payments and inflated for the staged costs for assets under development over the period to 2050.

This method has been commonly used to evaluate projects with different asset lifetimes, as it allows assets of different lifespans to be considered on the same basis. By annualising all costs such as change in fuel consumption, OPEX etc, the year-on-year cost of the case can be shown and compared against a ‘Control Scenario’ case. The ‘Control Scenario’ provides a base line to compare each analysis case against allowing the cases to be compared against each other. The ‘Control Scenario’ is described in Section 3.8.4.

Note that the Stage 1 cost analysis method has been improved and results from the current study were not compared to them due to the difference in estimation basis.

3.8.2 Categories of Costs Considered

The main cost categories that influence the total change in costs from the analysis cases were selected to allow comparison of each case against a Control Scenario. The cost categories considered in modelling are listed below and defined in Table 23.

.

- Development capital costs.
- Operating and maintenance costs.
- Fuel consumption costs.
- Generation retirement costs including transmission and distribution where applicable.
- Agro-forestry (Land Area, Hectare)
- Cost of emissions abatement.

Table 23: System Cost Categories

Cost category	Description
CAPEX	Capital expenditure for new generators including production, generation, storage, transmission and distribution (for gas only), annualised.
FOM	Fixed operation and maintenance cost, annualised.
VOM	Variable operation and maintenance cost, annualised.
Fuel	Fuel cost for thermal generation plant, annualised.
Retirement / Rehab	Rehabilitation costs due to generator retirements, transmission and distribution (for gas only), annualised.
Agro-forestry (Land Area, Hectare)	Sequestration / Offsets Added Per Time Period (not cumulative), annualised.
Cost of Emissions Abatement	Cost for abatement of emissions from 2020 to 2050 based on total of above categories net present cost ($/tonne).

3.8.2.1 Description of How Cost Categories were Calculated

Each case cost estimate was based on the existing AEMO generation data in 2021 plus additional new generation to meet the energy demand for each Technology Case (High / Medium / Low Probability) going forward to 2050.

- CAPEX was based on generator or energy supply type build / supply and connection / transmission costs for the energy requirements every 5 years for both electricity and energy gas. Costs were factored where necessary for new solar / wind / solar thermal / batteries (where > 60% of VRE) and commercial readiness technology breakthrough factors to account for lower future CAPEX.
- FOM costs were calculated on an annual basis based on the generator FOM price ($/kW/annum) and average generator capacity (MW, winter/summer).
- VOM costs were calculated on an annual basis based on the generator VOM price ($/MWh sent out) and the calculated MWh sent out accounting for maintenance duration, auxiliary load, and capacity factor.
- Fuel costs were calculated on an annual basis based on the generator Fuel price ($/GJ) and the calculated MWh sent out.
- Natural gas consumption was costed on an annual basis as supply ($/GJ) and transmission costs ($/GJ). Operational costs were included in the supply and transmission costs.
- Electrical transmission lines cost was based on the requirements from spatial analysis (CAPEX provided by electrical).
- Agro-forestry (land area) was costed on an annual basis ($/hectare) added per time period (not cumulative).

The costs are totalled, annualised and discounted to 2021 for electricity generation and energy gas supply and added to the overall totals for comparison with the Control Scenario.

All values presented are 2021 nominal dollars unless stated otherwise.

3.8.3 Calculating Net Costs of Cases Using an Equivalent Annual Annuity Approach

To ascertain the net costs of one analysis case relative to another case, all costs have been annualised (generation, storage, and transmission etc.) using an equivalent annual annuity method. This was done using the formula below, which converts project costs into a stream of equal annual payments and inflated over the economic life of the asset under development. For a transmission asset, for example, this asset life is equivalent to 50 years.

$$P = \frac{C * r}{(1 - (1 + r)^{-t})}$$

Where:

- P equals the annual cost of the development;
- C represents the development's capital costs;
- r is our weighted average cost of capital (WACC); and
- t is the economic life of the asset to be annualised over.

This method has been commonly used to evaluate projects with different asset lifetimes, as it allows assets of different lifespans to be considered on the same basis. By annualising all costs, the year-on-year cost of each case can be compared against another case, and then the costs of each case to be discounted to 2021 to determine the net costs, using the below formula:

$$NPV = \sum_{i=0}^{t} \frac{P_i}{(1 + r)^t}$$

Where:

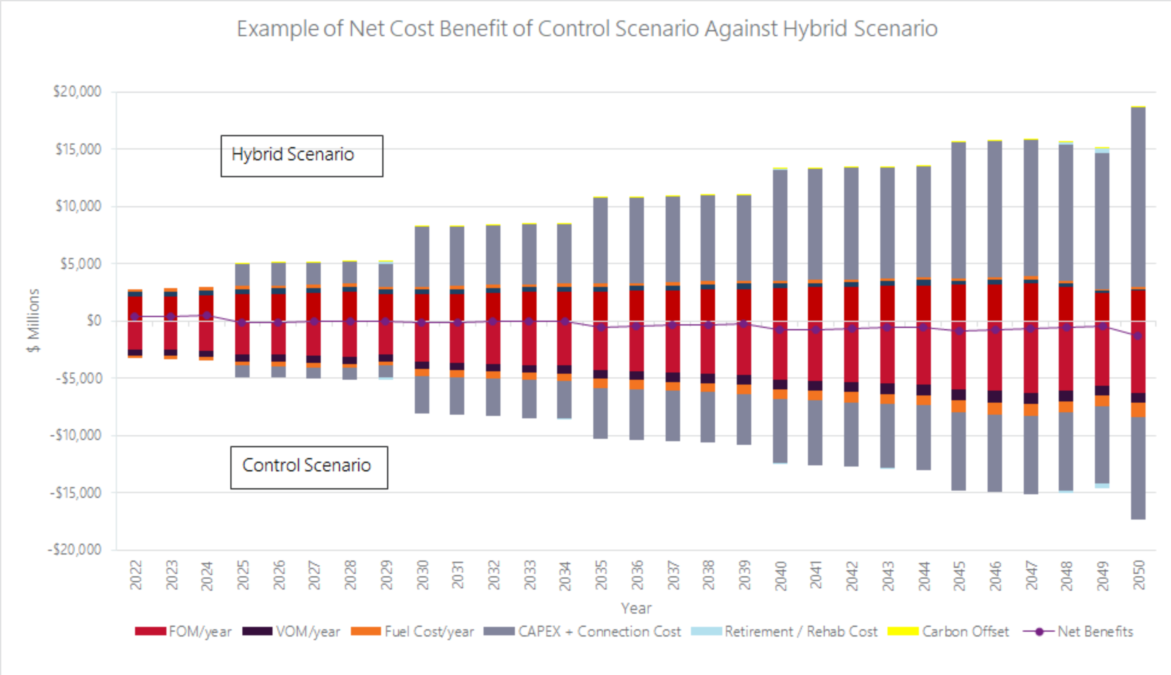
- P_t represents the annualised payments from above;
- r is our weighted average cost of capital (WACC); and
- t is the number of years between 2021 and 2050.

Note that the WACC used (5.9%) was the same in all cases.

As the modelling horizon ends in 2050, it must be noted that annualised costs associated with the cases beyond this point continue for assets with economic life which extend beyond 2050 e.g. annualised costs for an asset development in 2035 with an economic life of 25 years will extend to 2060. This explains in part why the modelling must only be used for comparison purposes between cases to assess whether there may be a potential net cost benefit of one case compared to another in 2050.

This cost analysis presents a number of charts comparing the projected costs over time, as shown in the example below.

Figure 17: Example Interpretation of Relative Costs Diagrams Used



Interpreting the results:

- The stacked columns illustrate the projected values for different classes of costs for each case on an annual basis. Note that the annual costs are highly indicative and provided only for comparisons between the cases.
- A positive value indicates the costs of the analysis case, and a negative value indicates the costs of the Control Scenario.
- The purple line represents the projected annual difference in costs between the two cases. Where the purple line is above the x-axis then the analysis case is returning a greater cost benefit than the Control Scenario. Conversely, where the purple line is below the x-axis, then the Control Scenario is returning a greater cost benefit than the analysis case.
- Annual costs were then converted into a net present cost accumulated over the forecast range and compared to assess whether there is a net cost advantage or disadvantage between the cases.

3.8.4 Description of Control Scenario

The Control Scenario was used as a comparative base line for each analysis case to identify where there are net cost advantages or disadvantages for the selected cost categories. This also allows the hybrid scenarios to be compared against each other. This was done to simplify the number of combinations between scenarios.

The Control Scenario was based on the existing AEMO generation data in 2021 plus additional new generation to meet demand going forward to 2050.

The additional energy mix for new generation in the Control Scenario was based on the Victorian energy consumption for electricity from the DISER Australian Energy Statistics Energy Consumption Table O3 (2019), modified for simplification i.e., only the four main fuel types are used (coal, gas, wind, and solar). Others such as hydro and batteries are assumed to be per the AEMO current, committed and anticipated.

The current natural gas consumption for Victoria was costed going forward to 2050 based on an average consumption over the past 10 years from the DISER Australian energy statistics energy consumption Table C3 (2019). The additional natural gas demand required going forward to 2050 was calculated as a proportion of the additional energy required and costed as CAPEX with supply and transmission costs added.

The cost of additional electrical transmission lines was added per the Technology Cases as it's assumed the demand and generation are both increasing in the same regions regardless of the scenario.

Note that the Control Scenario was not designed to reach net zero by 2050, with estimated emissions tabulated in the results section for each case.

3.8.5 Cost Estimate Inputs and Assumptions

The cost estimate inputs and assumptions considered in modelling are defined in Table 24 for existing electrical generation and energy gas and Table 25 for new generation and energy gas.

Table 24: Cost Estimate Input, Assumption and Exclusions Existing Electrical Generation & Energy Gas

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
Existing Generation				
General				
Inflation Rate	2.5% (assumed)			
WACC (weighted average cost of capital)	5.9% (per AEMO data 2020)			
FOM	Based on average MW capacity per AEMO data (2021) [Ref. Section 2.6.3, Item No. 1]			
VOM	Based on MWh sent out per AEMO data (2021) [Ref. Section 2.6.3, Item No. 1]			
Cost of Fuel	Per AEMO data (2021) [Ref. Section 2.6.3, Item No. 1]			
Existing / Anticipated / Committed Generation	Capital cost assumed already allocated so not included as is the same in each case.			
CAPEX	N/A			
Retirement / Rehab	Cost of existing generation added at year of retirement as lump sum (AEMO data 2021) [Ref. Section [Ref. Section 2.6.3, Item No. 1]			
Life Extension Cost	Excluded as no life extension			
Electricity Generation				
Electricity Transmission Lines	Refer to Cost Estimate Input, Assumption and Exclusions for New Electrical Generation & Energy Gas table.			
Electricity Generation Type	Existing generation per AEMO data (2021)			
Electric Vehicles	Assumed electrical demand included in demand growth for all cases			
Energy Gas				

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
Natural Gas	--------			
Supply and Transmission Cost	Supply Cost ($/GJ) = 5.3 Transmission Cost ($/GJ) = 1.21 (Core Energy Gas Production and Transmission Costs 2015)			
Supply and Transmission	Existing production consumed by Victoria included only Excess gas for export ignored as assumed to be the same in each case.			
Other				
Economic Life	Per AEMO data or assumed 25 years minimum.			
Technical Life	Per AEMO data or assumed 25 years minimum			
Land Acquisition	Excluded. Assumed the same in all cases			
Short Run Marginal Cost	Excluded			
Gas Distribution System Modification Costs	Not included as it is assumed these are already allocated to existing / committed projects e.g. Multinet are planning to complete their LP distribution pipeline replacement work in 2033. The allocated costs would cover all upgrades required, suitable for Hydrogen transport.			

Table 25: Cost Estimate Input, Assumption and Exclusions New Electrical Generation & Energy Gas

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
New Generation				
General				
Inflation Rate	2.5%			
WACC	5.9%			
FOM	Based on average MW capacity per AEMO data	Based on average MW capacity per AEMO FOM (fixed operating and maintenance) cost data where available or assumed for similar technology. [Ref. Section 2.6.3, Item No. 1]		
VOM	Based on MWh sent out per AEMO data	Based on MWh sent out per AEMO VOM (variable operating and maintenance) cost data where available or assumed for similar technology. [Ref. Section 2.6.3, Item No. 1]		
Cost of Fuel	Fuel Price Per AEMO data	Fuel Price Per AEMO data or assumed for similar technology.		
CAPEX	Based on AEMO build and connection cost data	Based on AEMO build and connection cost data where available. New infrastructure costs are based on energy demand only, not by region, and a selected technology with the cost adjusted if necessary.		
Additional Energy Demand Split	75% Coal (Brown Coal) 10% Gas (OCGT Large) 10% Wind (Onshore) 5% Solar PV (Large Scale)	Per study modelling. Not regional specific, based on energy only. Generation based on a selected technology with the cost adjusted if necessary		

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
	(Based on DISER 2019 info without, batteries and hydro as assumed to remain per existing, committed, anticipated)			
Additional demand	Ratio additional energy demand between generator type.	Per study modelling. Not regional specific, based on energy only. Generation based on a selected technology with the cost adjusted if necessary		
Additional Generation capacity factors for new solar/ wind / solar thermal / batteries (where > 60% of connected capacity is renewable electricity)	N/A	2025 - 1 2030 - 1 2035 - 1.5 2040 - 1.5 2045 - 1.5 2050 - 1.5	2025 - 1 2030 - 1 2035 - 1 2040 - 1 2045 - 1 2050 - 1.5	2025 - 1 2030 - 1 2035 - 1.5 2040 - 1.5 2045 - 1.5 2050 - 1.5
Additional Generation commercial readiness technology breakthrough factors to account for lower future CAPEX build costs (Assumed values to make build costs	N/A	Waste to Energy from Y2030 = 0.25 (based on biomass build cost and equivalent to CCGT at 2030 costs)	Waste to Energy from Y2030 = 0.25 (based on biomass build cost equivalent to CCGT at 2030) Batteries from Y2040 = 0.5 (for Iron Air batteries as assumed to be cheaper than lithium-ion batteries. Cost based on standard lithium-ion battery build cost and proportioned accordingly for battery mix)	Waste to Energy from Y2030 = 0.25 (based on biomass build cost equivalent to CCGT at 2030) Batteries from Y2030 = 0.8 (for fuel cells as assumed to be cheaper than lithium-ion batteries. Cost based on standard lithium-ion battery build cost and proportioned accordingly for battery mix)

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
similar to equivalent established technologies)				Solar Thermal (Storage) from 2030 = 0.3 (CAPEX + FOM) (based on Solar Thermal build cost and equivalent to Solar PV at 2030 costs) Wind from Y2030 = 1.0 (for offshore wind based on onshore wind build cost and proportioned accordingly for onshore/offshore wind mix at 2030 costs)
Electricity Generation				
Electricity Transmission Lines	Total cost estimated by electrical spatial analysis and annualised over the timeframe. Assumed demand and generation are both increasing in same region regardless for all Analysis Cases, therefore assumed the same cost for upgrade of transmission lines. Transmission lines covers the main axes that have to be replaced. Distribution is excluded from CAPEX. Distribution lines have not been taken into account due to the complexity and would require a separate study. Additional main transmission lines needed by 2050 are: V1 - MEL 500kV 400km V2 - MEL 500kV 400km V3 - MEL 500kV 270km V3 - V4 500kV 100km V5 - MEL 500kV 145km V6 - MEL 00kV 150km Plus Transformers x 12			
Electric Vehicles	Assumed electrical demand included in demand growth for all cases			
Electricity Generation Type	N/A	No new coal generation		

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
Bioenergy	N/A	FOM based on average from bioenergy technology data (Internal DORIS Data Source) Fuel price based on AEMO new entry data for biomass (Victoria) VOM based on AEMO new entry data for biomass (Victoria) CAPEX based on average from bioenergy technology data (Internal DORIS Data Source) Connection cost based on AEMO new entry data for biomass (Victoria) Maintenance and Auxiliary Load based on AEMO new entry data for biomass (Victoria)		
Wind	AEMO new entry data for Ovens Murray (VIC Medium) used for wind. AEMO new entry data used for offshore wind. Where there is a mix of offshore and onshore wind the average cost is used for building and FOM.			
Large Scale Solar PV	AEMO new entry data for Ovens Murray (VIC Medium) used for large scale solar PV			
Battery Storage	N/A	AEMO new entry data for Battery Storage (8hrs storage) for Victoria. Iron Air batteries and Fuel cells included at same cost and factored (refer above commercial readiness technology breakthrough factors).		
Ammonia (electricity baseload)	N/A	N/A	AEMO new entry data for OCGT (large GT) assumed for NH_3 baseload electricity generation Fuel price assumed as natural gas for OCGT.	N/A
Solar Thermal (storage)	N/A	N/A	N/A	AEMO new entry data for Solar Thermal (8hrs Storage) for Southwest Victoria used for solar thermal storage and factored (refer above commercial readiness technology breakthrough factors).

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
Solar Thermal (Elec gen)	N/A	N/A	N/A	AEMO data for existing Newport Gas-powered steam turbine used for solar thermal electricity generation.
Energy Gas				
Supply and Transmission	No new transmission or distribution pipelines.	210km Bendigo to Sea Lake Pipeline + 150km Echuca to Swan Hill Pipeline biomethane/H_2, so assume natural gas cost per km, at year 2035.	210km Bendigo to Sea Lake Pipeline + 150km Echuca to Swan Hill Pipeline biomethane/H_2, so assume natural gas cost per km, at year 2035.	210km Bendigo to Sea Lake Pipeline + 150km Echuca to Swan Hill Pipeline biomethane/H_2, so assume natural gas cost per km, at year 2035.
	No transmission or distribution pipelines decommissioned	Estimated Extent of Demolition of Existing Gas Transmission Pipelines 2050 - 850km Estimated Extent of Demolition of Existing Gas Distribution Pipelines 2050 - 2500km	Estimated Extent of Demolition of Existing Gas Transmission Pipelines 2040 - 700km Estimated Extent of Demolition of Existing Gas Distribution Pipelines 2040 - 4000km	Estimated Extent of Demolition of Existing Gas Transmission Pipelines 2040 - 1700km Estimated Extent of Demolition of Existing Gas Distribution Pipelines 2040 - 8000km
Supply and Transmission Cost	Supply Cost ($/GJ) = 5.3 Transmission Cost ($/GJ) = 1.21 (Core Energy Gas Production and Transmission Costs 2015) Natural Gas Pipelines, 12", X65, Uncoated = 49,394.38 $/kM (Internal DORIS Data Source) Hydrogen Gas Pipelines, 8", X42, Uncoated = 32,489.35 $/kM (Internal DORIS Data Source) Decommissioning Onshore Gas Plant (% of supply costs) = 8% Decommissioning Onshore Pipelines (% of transmission costs) = 5%			
CAPEX (Natural Gas)	New gas added as Capital Cost from additional energy demand	Natural Gas demand declines therefore no CAPEX		

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
Gas Production	Excess gas for export ignored as assumed to be the same in each case.			
LNG Import	N/A	Supply and transmission costs included for demand.		
Victorian Northern Interconnect Natural Gas Import	N/A	Supply and transmission costs included for demand.		
NSW LNG Import (EGP Pipeline Interconnector)	N/A	Supply and transmission costs included for demand.		
Biomethane	N/A	Supply Cost ($/GJ) = 25 FOM based on average from bioenergy technology data (Internal DORIS Data Source) VOM included in FOM. Fuel price based on AEMO new entry data for biomass (Victoria) CAPEX based on average from bioenergy technology data (Internal DORIS Data Source) Connection cost based on natural gas supply cost (Victoria) Maintenance and Auxiliary Load based on AEMO new entry data for biomass (Victoria)		
Hydrogen	N/A	AEMO new entry data for PEM (Proton Exchange Membrane) Technology except: Fuel price based on AEMO new entry data for biomass (Victoria) Connection cost based on natural gas supply cost (Victoria) Maintenance Load based on AEMO new entry data for Natural Gas OCGT (large GT) (Victoria)		
NH_3	N/A	N/A	AEMO new entry data for PEM (Proton Exchange Membrane) Technology except: Fuel price based on hydrogen at $2/kg (internal DORIS data source).	N/A

Cost Estimate Input, Assumption and Exclusions				
Parameter	**Control Case**	**High Probability Technology Case**	**Medium Probability Technology Case**	**Low Probability Technology Case**
			Future price to make costs competitive to natural gas. Connection cost based on natural gas supply cost (Victoria) Maintenance and Auxiliary Load based on AEMO new entry data for Natural Gas OCGT (large GT) (Victoria) Import price assumed as natural gas fuel price per OCGT (assumed commercial competitive as replacement for natural gas).	
Other				
Economic Life	Per AEMO data or assumed 25 years minimum.			
Technical Life	Per AEMO data or assumed 25 years minimum			
LNG Import Terminal	Capital cost excluded as assumed to be the same in each case.			
Land Acquisition	Excluded. Assumed the same in all cases			
Short Run Marginal Cost	Excluded			
Gas Distribution System Modification Costs	Not included as it is assumed these are already allocated to existing / committed projects e.g. Multinet are planning to complete their LP distribution pipeline replacement work in 2033. The allocated costs would cover all upgrades required, suitable for Hydrogen transport.			

3.9 Environmental-Social-Economic

3.9.1 Methodology

The range of investments required to ensure Victoria achieves net-zero by 2050 will entail a range of environmental and social impacts which will require management. The environmental and social impacts associated with this programme were determined by assessing the likely associated environmental and social stressors along with the likely environmental and social receptors. The most significant environmental and social stressors were identified below.

- General
  - Employment
  - Work force changes
  - Interstate migration
  - Battery, solar PV waste
  - Power line initiated bush fires
- Location specific
  - Land use change
  - Solar thermal bird loss
  - Available fresh water
  - Resistance to industrial development
  - Marine impacts (fishers, whale migration/breading)
  - Hydrogen/Ammonia risk
  - Air quality
  - Hydrogen fire risk
  - High energy density battery fire risk

Each of these stressors and the identified actions to manage or mitigate the impacts are discussed further in the following sections.

The most significant stressors identified were then mapped at a high level to each Renewable Energy Zone for each of the analysis cases, and should not be considered a substitute for the detailed planning and environmental impact assessment that will be required before individual projects proceed. For example, detailed environmental and social impacts are not able to be assessed until the location of the required infrastructure is determined.

3.9.2 General Environmental and Social Impacts

3.9.2.1 Employment

Results of the jobs analysis are provided in Section 4.6.

The current study assesses full time equivalent operational employment in the energy generation industry, engaged in:

- On-site – plant operations & maintenance

- Off-site - logistics & supply, administration & support, engineering design & modification, etc.

Construction related employment has not been estimated and deemed out of scope as key information such as the degree of imported vs locally produced equipment, construction efficiency due to the scale of development, and project and approvals planning conditions were not available. Consideration will need to be given to the skills required by those employed construction and operating these new technologies to avoid a shortage which may increase the cost and potentially delay the role out of these technologies.

The employment numbers estimated represent the number of full-time equivalent positions involved in operating the energy supply infrastructure identified for the various analysis cases. Assessing the net employment impacts of Victoria moving to net zero emissions is beyond the scope of this assessment and would require complex general equilibrium modelling to determine.

The results of the jobs analysis were presented as a “Jobs Index”, being the number of jobs estimated for each analysis case rationalised against the High Probability Technology case in order to provide a focus on comparing the jobs potential between the various cases, rather than on the individual estimates themselves.

It was also decided to estimate employment impacts only at the end of the transition, 2050, rather than for each time period to provide a focus on the potential outcomes of the transition rather than the predicted pivot from fossil fuels.

Several methods were utilised to estimate jobs, depending on the energy type, and results considered order of magnitude accuracy, consistent with the current study approach and methodology.

Power Index

The estimate of jobs associated with most of the energy types was achieved by applying the analysis results published in the Climate Council’s report ”Renewable Energy Jobs : Future Growth in Australia” (2016) to the data generated by the current study.

The breakdown of jobs by energy type provided as Figure 10 “Total FTE Jobs, FY14 to FY30” in the Climate Council report was correlated to the 2030 mean energy mix predicted for the High Probability Technology case in the current study. From this, a Power Index value (Jobs / MW Capacity) was calculated for each energy type. The calculated Power Index was compared to DORIS’ in-house data, and other credible references to identify a Job Index value for use in the current study.

Plant Specific

For some energy generation facilities where either the nameplate capacity did not correlate well with the results of the current study, or the Climate Council report did not cover the energy technology, a typical industry workforce number was applied based on DORIS’ in-house data, or other credible references as required.

Relative Fraction

For estimating employment in the energy efficiency industry, an approach from the Quadrennial Energy Review, “Transforming the Nation's Electricity System” (2017) was adopted where the number of jobs was correlated with the number of jobs in the energy generation industry. While not as obvious as employment in other sectors, energy efficiency represents a significant employment base comprising works undertaking and implementing energy efficiency improvement projects. This contribution became significant for Sensitivity Case 3 “Energy Efficiency” that assumed larger improvement in energy efficiency. There was, however, a low level of confidence that the energy efficiency jobs are as “permanent” as those in other sectors of the energy industry. On this basis the Relative Fraction adopted by the current study was significantly reduced compared to the reference indicated above. Further work should be undertaken to increase the level of confidence in estimating the permanent level of employment in the energy efficiency industry.

Table 26: Basis for Jobs Estimate for each Energy Type

Energy Type	Estimation Method	Reference
Elec (generation) - coal	Power Index	Climate Council Report*
Elec (generation) - natural gas (baseload + peaking)	Power Index	Climate Council Report*
Elec (generation) - NH3	Power Index	Climate Council Report*
Elec (generation) - hydropower	Power Index	Climate Council Report*
Elec (generation) - solar PV (large scale)	Power Index	Climate Council Report*
Elec (generation) - solar PV (rooftop)	Power Index	Climate Council Report*
Elec (generation) - solar thermal - industrial	Power Index	Climate Council Report*
Elec (generation) - wind (onshore + offshore)	Power Index	Climate Council Report*
Elec (generation) - bioenergy	Plant Specific	Macquarie Group, Australia’s first thermal waste-to-energy facility reaches financial close (2018)
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	Power Index	Climate Council Report*
Gas (generation) - natural gas (all sources)	Plant Specific	DORIS
Gas (generation) - biomethane	Plant Specific	ENEA, “Biogas Opportunities for Australia” (2019)
Gas (generation) - H2 (green)	Plant Specific	DORIS
Gas (generation) - NH3 (green)	Plant Specific	DORIS

Energy Type	Estimation Method	Reference
Energy Efficiency	Relative Fraction	Quadrennial Energy Review, "Transforming the Nation's Electricity System", (2017)
Solar Fuels (based on Solar Thermal)	Plant Specific	DORIS

** Climate Council's report "Renewable Energy Jobs : Future Growth in Australia" (2016)*

3.9.2.2 Work Force Change

The energy supply changes envisaged in the current study may lead to changes in the nature and distribution of employment.

Historical electricity generation based in the Latrobe Valley has involved a permanently employed local workforce with strong job security and relatively high wages. The current deployment of large-scale renewable generation appears to be supported by a move to a transient contracted workforce where workers will be brought in to undertake specific tasks. This trend to use of a contracted workforce is not unique to the renewable generation sector and is being experienced by many industries and is likely to continue.

This may result in the workers not living permanently in the Renewable Energy Zones, but rather preferring to commute from Melbourne and surrounds. This would be particularly the case when the scale of renewable generation is small.

As the implementation of renewable generation reaches a critical scale, contractors may choose to re-locate into the Renewable Energy Zones, and the degree to which this occurs will likely depend on the level of community amenity in those zones and proximity to Melbourne.

Large industrial processes, such as the conversion of hydrogen to ammonia or the combustion of hydrogen or ammonia in electricity generation are likely more suited to a full-time dedicated workforce.

Changes in the nature and distribution of employment are also likely to have economic and social impacts on local communities. For example, reduced/increased local employment leading to reduced/increased local economic activity through consumption effects, intra-state migration leading to local population decline/growth.

Managing this change in the nature and distribution of work, enabling local employment, and ensuring the regions provide an appropriate community amenity to attract workers wishing to relocate will require careful planning by State and local government.

3.9.2.3 Interstate Migration

Changes in energy cost (both explicit and implicit, for example, subsidies), combined with any resulting change in the levels of industrial investment and employment may act as a catalyst for migration between Australian States and Territories.

Interstate migration both into and out of Victoria is dependent upon the actions taken in Victoria and by other Australian States and Territories and the relevant impact on energy costs and economic activity in those jurisdictions. While the current study seeks to identify the comparative costs of the transition to net-zero and the resulting jobs in Victoria, it is beyond the scope to assess the broader impacts on economic activity.

As the Victorian Government further implements its plans for progressing to net zero emissions it should ensure the resulting economic activity and community amenity across Victoria remains favourable compared with other Australian States and Territories.

3.9.2.4 Battery, Solar PV Waste

While further advances in technology may increase the operating life of batteries and solar PV, both technologies show declines in capacity over time. Some estimates have suggested a significant decline in the storage capacity of Li-ion batteries after 2000 charge/discharge cycles. Currently available solar photovoltaic cells lose capacity at around 0.5% per year. Without further advances in these technologies the effective operating life of these assets is likely to be between 20 and 30 years.

Given the scale of the deployment of battery and solar PV envisaged in the current study, the retirement of this equipment may result in a significant waste management issue within the next two or three decades. The range of heavy metals and other noxious substances included in these products is likely to exacerbate the disposal challenges of these products if dealt with as a landfill waste but provides opportunities if approached as a recyclable resource. Diverting these products from disposal in landfill is the preferred management action, based on appropriate maintenance.

3.9.2.5 Power Line Initiated Bush Fires

Above ground power lines have been associated with initiating bush fires in Australia and internationally. A literature review suggests the risk of fire initiation arises primarily from lower voltage (22 kilovolts) and “single wire earth return” systems.

The transition to net zero emissions will involve an increase in the use of electricity necessitating the management of the distribution grid to ensure fire risk is minimised.

The analysis cases assume the construction of new high voltage (500 kilovolt) power lines, and the literature review indicated these high voltage power lines are not associated with the initiation of bush fires, possibly because of the increased separation of the conductors and distance of the conductors from vegetation.

The literature review did indicate that fires in proximity to high voltage lines may result in arcing (flashover) as the surrounding ash and smoke significantly lessens the insulation properties of the air separating the high voltage conductors.

3.9.3 Location Specific Environmental and Social Impacts

3.9.3.1 Land Use Change

The implementation of the cases envisaged in this report requires significant investment in new facilities across Victoria, largely in rural areas.

Where land use change is contemplated consideration of Native Title and cultural heritage issues, environmental impacts and local community views will need to be managed.

The deployment of industrial-scale solar farms and greenhouse gas offset projects if not managed, may be incompatible with existing land use. While the deployment of wind farms does not involve the same land-use change, it is accompanied by a reduction in visual amenity.

While land use change may not have been a significant issue in the development of wind and solar farms to date, the scale of the development required in these cases may highlight land use change as a significant issue with local stakeholders.

This risk can be mitigated through engagement with local stakeholders and the use of planning and environmental assessment processes.

3.9.3.2 Solar Thermal Bird Loss

Unlike wind power where birds may be able to avoid rotating turbine blades (due to generated noise), birds may not be able to detect areas of concentrated solar energy associated with solar thermal generation before being exposed to potential injury. Early experience with solar thermal in the United States (C.K. Ho, Review of Avian Mortality Studies at Concentrating Solar Power Plants, AIP Conference Proceedings, May 2016) summarised several studies looking at insect and bird loss through incineration at a number of concentrated solar thermal installations. The paper also identified some of the management measures that have been implemented to manage these impacts.

The development of solar thermal plants is relatively new and additional data on insect and bird mortality and management practices will no doubt become available in time.

If mechanisms to prevent birds from entering the areas of concentrated solar energy are not shown to be effective, these plants may need to be located areas far from the range of threatened or endangered bird life. These issues will need careful consideration in the environmental impact assessment of solar thermal plants.

3.9.3.3 Available Fresh Water

The production of hydrogen requires significant volumes of demineralised water. Based on the reaction stoichiometry, for every kg of hydrogen produced, 9 kg of water must be consumed. However actual consumption rates of electrolysers today are typically 15 to 18kg of water for every kilogram of hydrogen produced. Rounding this number upward and applying a lower heating value for hydrogen of 120 MJ/kg, each petajoule of hydrogen requires approximately 170 000 litres of demineralised water to produce using electrolysis. Most of the analysis cases assume between 30 and 40 PJ of hydrogen generation in 2050, with the exception of Sensitivity Case 4 “Maximum Green Hydrogen” with around 170 PJ of hydrogen generation. On this basis, Sensitivity Case 4 would require an annual water usage in 2050 of 28 megalitres. By comparison, on average, over 5000 megalitres of water are extracted from Victoria’s rivers each year. Most of this water – between 75 and 80 percent – is used for irrigated agriculture, especially dairy. About 15 percent is used by households and businesses in towns and cities. (https://environmentvictoria.org.au/sustainability-hub/water-use/).

Renewable Energy Zones V3 – Western Victoria and V4 – South West in particular, are fresh water constrained and existing water supplies are likely to be unable to provide the additional water required to support the production of hydrogen and projects located in these areas will likely need to include a dedicated water supply in the scope of the project, for example from desalinated ground water, sea water, or treated wastewater in much the same way as resource projects in Western Australia currently do.

This may also be a requirement of hydrogen plants located in the V1- Ovens Murray and V5 – Gippsland Renewable Energy Zones should water supply in these regions become constrained.

3.9.3.4 Air Quality

The combustion of ammonia, if not managed, can result in emissions of unburnt ammonia and nitrous oxides.

These emissions should be manageable through a combination of co-firing, combustor design and end use scrubbing. Importantly these emissions need to be managed alongside similar emissions from other facilities to preserve local air shed quality.

Existing air shed management approaches, environmental regulations and facility licencing are well placed to manage air quality issues.

3.9.3.5 Resistance to Industrial Development

This impact is closely linked to concerns over land use change but involves perceptions that traditional rural areas are being industrialised, arising from the cumulative large-scale development of:

- wind and solar generation (and required battery storage);
- bioenergy plants;
- hydrogen/ammonia plants; and
- overhead power lines.

The use of buried infrastructure, for example, pipelines or power lines, contribute less to concerns around industrialisation and should be preferred where practicable including the consideration of cost in comparison to alternative options.

Fears over industrialisation of traditionally rural areas can be managed through engagement with local stakeholders and the use of planning and environmental assessment processes.

3.9.3.6 Marine Impacts

The widespread deployment of offshore wind will require the management of a range of environmental and social impacts, including:

- impact on coastal fisheries;
- impacts form underwater noise and electromagnetic radiation (from high voltage cables) on marine organisms, with a particular focus on cetaceans;
- impacts on ocean-going birds; and
- visual amenity.

This risk can be mitigated through engagement with local stakeholders and through a well-managed environmental assessment processes though using difference technologies than those utilised for the current study, for example steam methane reforming (hydrogen), and Haber-Bosch (ammonia). Care will be needed where offshore wind farms are located in Commonwealth Waters to ensure this is not perceived as an attempt to bypass Victorian planning and environmental approval laws.

3.9.3.7 Ammonia Risks

Hydrogen and ammonia are currently produced at scale in oil refining and fertiliser/explosives industry. The envisaged expansion in production, including the use of technologies such as electrolysis should be able to be managed under existing major hazard facilities laws.

Ammonia is toxic and an unintended release of ammonia can have human health include rhinorrhoea, scratchy throat, chest tightness, cough, and eye irritation. Symptoms usually subside within 24-48 hours. If ammonia is allowed to build up in the bloodstream it can lead to serious health problems, including brain damage, coma, and death.

Whilst large scale transportation of these commodities by pipeline is less well developed but the level of risk would be comparable to the long-established pipeline transportation of hydrocarbons, provided the design and operation of the pipelines are based on the specific properties of the fluids being transported. In Victoria, the Pipelines Act 2005 regulates the pipeline transportation of hydrogen and can be readily amended to cover the pipeline transport of ammonia.

The combustion of ammonia is not currently common practice, and compared to natural gas and liquid hydrocarbons, has a high ignition temp and low flame velocity which if not managed can result in flame instability and emissions of unburnt ammonia. In addition, the nitrogen contained in ammonia can lead to increased emissions of nitrous oxide when combusted. These differences can be managed by blending the ammonia with hydrogen or gas (biogas or natural gas) to improve combustion efficiency and/or improved combustor design. Post-combustion exhaust scrubbing may also be required to reduce nitrous oxide emissions if these cannot be managed through the combustion process. The technology breakthrough assumed for the Mid Probability Technology Case and Sensitivity 2 “Reduced Ammonia” addresses these limitations, and they should be adequately manageable through the existing facility environmental licencing regulations.

The Victorian Government will need to ensure communities impacted by hydrogen/ammonia, production, transportation, regasification, and end use are informed regarding the health and safety issues related to these products. Globally, work is already being undertaken to inform communities, for example, the United States Department of Homeland Security has undertaken field trials to better understand the health and safety impacts from the unintended release of ammonia.

Proposed Regulatory Changes - Ammonia Pipelines Regulation

The transport of ammonia by pipeline, while currently rare, will need to become common by 2050, and should not present significant risks beyond those already managed by the hydrocarbon industry. Indeed, ammonia has properties similar to liquefied petroleum gas.

Currently, the Victorian Pipelines Act 2005 regulates pipelines transporting petroleum, oxygen, carbon dioxide, hydrogen, nitrogen, compressed air, sulphuric acid and methanol.

Australian Standard AS 2885 sets out the general requirements for the design and operation of gas and liquid petroleum pipelines. The general approach set out in this standard can also be applied to the transportation of ammonia via pipeline although additional guidance documents may be required.

Consideration – to facilitate the development of Victoria's hydrogen and ammonia industry, the Pipelines Act 2005 should be amended to incorporate the regulation of ammonia pipelines, along with the development of required standards and guidelines.

3.9.3.8 Hydrogen Fire Risk

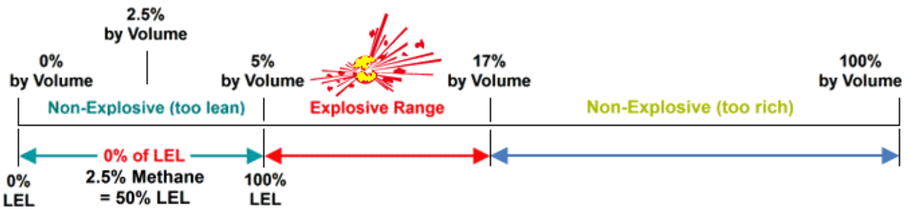
Compared to the use of natural gas (or biogas), hydrogen possesses several properties that increase the risk of fire or explosion including:

- the small size of the hydrogen molecule results in an increased propensity for hydrogen to leak from valves and fittings;
- hydrogen embrittlement, where certain metal alloys (including steel) exposed to hydrogen experience a significant reduction in ductile strength, increasing the risk of the metal fracture; and
- the larger explosive range of hydrogen compared to natural gas.

Issues of leakage and hydrogen embrittlement can be managed through appropriate material selection, facility design, construction and maintenance.

Natural gas will only combust (explode) when mixed with air at concentrations of between 5% and 17% by volume. Below a concentration of 5%, the mixture of natural gas is too lean to combust, and above 17% the mixture is too rich. Consequently, a leak of natural gas will only explode, even if exposed to an ignition source, if the leak results in a concentration in air of between 5% and 17% by volume. Figure 18 diagrammatically shows the explosive limit of natural gas.

Figure 18: Explosive range (limits) for natural gas



By contrast, the explosive range for hydrogen is between 4% and 75%, creating a much higher likelihood that a leak of hydrogen may explode if exposed to an ignition source. The explosive limit for ammonia is between 15% and 28%.

The increased use of hydrogen in industry, households and vehicles envisaged by this study, must be accompanied by measures to ensure the risk of leakage and subsequent combustion are managed appropriately, which may involve:

- Standards for the manufacture, installation and use of domestic and industrial appliances;
- Training and accreditation for those involved in the installation and maintenance of such appliances;
- Consideration of the risks posed by hydrogen embrittlement in the design and maintenance of any equipment in contact with hydrogen; and
- Mechanisms to improve leak detection of hydrogen such as odorization.

With these controls, the risk posed by the increased use of hydrogen should be comparable to the current risk associated with natural gas.

3.9.3.9 High Energy Density Battery Fire Risk

As battery energy density continues to increase, for example in Li-ion batteries, the potential for thermal runaway and battery fires also increases, although mitigated in part by continued technology advances. Given the anticipated scale and diversity of battery use, particularly behind the meter where installations may be less well managed, prudent regulation may be required to manage the risk of fire. This may be done through application of appropriate standards or codes.

3.9.4 Harder to Abate Emissions

The World Economic Forum considers cement, steel, chemicals, aluminium and heavy-duty transport (shipping, trucking and aviation) as 'harder-to-abate', not because those industries lack the technological solutions to reduce emissions but because the cost of those solutions is likely to be higher than in other sectors.

Table 27 outlines how the transition to net zero can be achieved in harder to abate industries that are within the scope of this study. Shipping and aviation are outside the scope of this study and cement is currently not manufactured in Victoria, thereby excluding these sectors from the current study.

Table 27: Transition Options in Harder to Abate Industries in Victoria Covered in the Current Study

Industry	Description	Treatment in the Current Study
Steel	Victoria does not host primary steel production but does produce steel via electric arc furnace and produces a range of steel products. Based on available data (primarily DISER), absolute energy demand, primarily electricity and natural gas, appears to be low compared to other industries such as electricity and aviation.	Electric arc furnace at Laverton North and steel products produced across the state Energy supply included in the current study with electricity, and energy gas.
Chemicals	A range of organic chemicals is produced, with dependence upon hydrocarbon feedstocks. Based on available data (DISER), absolute energy demand levels appear to be low compared to other industries such as electricity and aviation.	Several manufacturers at various sites across Victoria. Energy supply included in the current study with electricity, and energy gas. In terms of chemical feedstock, only natural gas has been covered in the current study, with other petroleum feedstocks such as naphtha considered out of the scope of the current study. Biogas may be able to be used as a substitute feed stock As modelled In the Mid and Low Probability Technology cases, Green Hydrogen and Ammonia provide the opportunity for a new product slate.
Aluminium	Smelting of Alumina to produce Aluminium is the major energy user in this specific industry, with electricity being the key input to the Hall-Héroult process employed in Victoria which covers addition of Alumina to a molten bath of cryolite, addition of electricity via an anode (typically petroleum coke & pitch) with electrolysis occurring at a temperature of approximately 950 °C. Tapping and casting typically occurs at 700 °C to ensure flow of Aluminium. Based on available data (primarily DISER), absolute energy demand in the form of electricity appears to be on a par with other high energy consumption industries such as electricity and aviation.	Carried out in Victoria at Portland (Alcoa). Energy supply included in the current study with electricity. Aluminium as a material of construction in transport vehicles, and construction would represent an efficiency improvement with respect to energy intensity in these industries, potentially aligning with Sensitivity 3 “Energy Efficiency”.
Trucks	Heavy road transport vehicles including trucks and buses currently rely almost entirely on gasoline & diesel fuel in Victoria. Based on available data (Australian Bureau of Statistics), absolute energy demand for heavy road transport vehicles in the form of gasoline & diesel appears to be low compared with other high energy consumption industries such as electricity and aviation.	Transition of Internal Combustion Engine vehicles from gasoline & diesel to low emissions fuels is covered separately in Section 3.7, Vehicle Analysis.

3.9.5 Emissions & Offset Factors

The emissions and offsets factors (along with the literature references) used to calculate absolute and net emissions as described in Section 3.2 are provided in the following tables.

Reference	Electrical Energy Technology	Emissions Factor Units	Emissions Factor Value
1	Elec (generation) - coal	Mill Te CO2e / PJ coal	0.09
1	Elec (generation) - natural gas - baseload	Mill Te CO2e / PJ NG	0.05
2	Elec (generation) - natural gas - peaking	Mill Te CO2e / PJ NG	0.05
3	Elec (generation) - NH3 - baseload	Mill Te CO2e / PJ NG	0.01
1	Elec (generation) - hydropower - industrial	Te CO2e / MWh elec	0.02
4	Elec (generatioon) - diesel	Mt CO2e / PJ diesel	0.07
4	Elec (generation) - solar PV - large scale - variable - industrial	Te CO2e / MWh elec	0.05
4	Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - indu	Te CO2e / MWh elec	0.05
4	Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / comm	Te CO2e / MWh elec	0.05
4	Elec (generation + storage 8 hrs) - solar thermal - industrial	Te CO2e / MWh elec	0.04
4	Elec (generation) - wind onshore - variable - industrial	Te CO2e / MWh elec	0.13
3	Elec (generation) - wind offshore - variable - industrial	Te CO2e / MWh elec	0.01
5	Elec (generation) - geothermal - industrial	kg CO2e / GJ	4.80
6	Elec (generation) - waste to energy (elec from landfill gas) - industrial	Mill Te CO2e / GWh	-0.86

Reference	Gas Energy Technology	Emissions Factor Units	Emissions Factor Value	Fugitive Emissiones Rate
1	Gas (generation) - natural gas - industrial	kg CO2e/ MJ	0.06	5%
1	Gas (generation) - biomethane - industrial	kg CO2e/ MJ	0.06	5%
-	Gas (generation) - green H2 - industrial	kg CO2e/ MJ	0.00	5%
-	Gas (generation) - NH3 (green) [industrial use + conversion to H2 for distributiuon eg res-com]	kg CO2e/ MJ	0.00	5%

Reference	Road Vehicles	Emissions Factor Units	Emissions Factor Value
1	Vehicles - (ICE) gasoline & diesel	Mt CO2e / PJ gasoline	0.07
4	Vehicles - (BEV) electricity	Te CO2e / MWh elec	0.05
4	Vehicles - (HFCV) electricity	Te CO2e / MWh elec	0.05

Reference	Agro-forestry	Offset Factor
		Te CO2e / Hectare
7	Terrestrial	-18.35
7	Marine	-830
8	Soil	-1172

References

1. Department of Environment and Energy (2019) National Greenhouse Accounts Factors
2. Australian National Uni, "Global emissions implications from co-burning ammonia in coal fired power stations: an analysis of the Japan-Australia supply chain", 2020.
3. International Hydropower Association (2018) 2018 Hydropower Status Report
4. National Renewable Energy Laboratory Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics, Fact Sheet
5. Think Geoenergy (2020) Sustainability of geothermal energy in district heating networks
6. Kwinana Waste to Energy Project – ARENA Life Cycle Assessment, Kwinana WTE Project Co, Dec 2018
7. Parks Victoria and DELWP (2015) Valuing Victoria Parks : Accounting for ecosystems and valuing their findings. Report of first phase findings
8. Australian government predicted figure of 90 Mt CO2e /yr for Australia.

3.9.5.1 Avoided Emissions from Bioenergy

The emissions factors for bioenergy projects vary significantly based on the feedstock and its current use, the bioenergy technology applied, the project configuration and the end product such as electricity or biomethane.

In this work, a single average emission factor is used for the conversion of bioenergy resources into electricity. This factor is selected to be representative of the likely mix of feedstocks and conversion technologies employed. It is inevitable that some projects will have higher emissions factors and some will have lower emissions factors. The average emission factor used in this work is -0.86 Million Te CO2e / GWh. This factor is taken from the Kwinana waste to energy plant being constructed in Western Australia (Ramboll, 2018). Biomass combustion and gasification projects producing electricity will have emissions factors close to zero, because the CO_2 emitted during energy production is similar in quantity to the CO_2 consumed during plant growth, while landfill gas projects producing electricity have net emissions factors which are negative, because they avoid methane emissions (US EPA, 2021).

Bioenergy projects make a significant contribution to the emissions reductions in the analysis cases. Bioenergy involves collecting a range of organic materials that if left would decompose to carbon dioxide and methane. By diverting these materials into the generation of bioenergy (electricity and gas) a net greenhouse gas emissions benefit can be achieved by avoiding the atmospheric release of methane.

- Where the organic matter would have aerobically decomposed to carbon dioxide, this is replaced with carbon dioxide released from the combustion of the biofuel resulting in an emissions intensity close to zero. Essentially the carbon dioxide emitted is assumed to balance the carbon dioxide locked up during the growth phase of the organic material (there are some emissions involved in collecting and processing the organic matter)

- Where the organic matter would have anaerobically decomposed to methane, these methane emissions are replaced with carbon dioxide released from the combustion of the biofuel. As methane has a global warming potential 28 times higher than methane, the diversion of this organic material for use has a significant net benefit over allowing the anaerobic decomposition.

The current study has modelled the organic streams available for bioenergy to derive the emissions factor in the Emissions Factor Table (Section 3.9.5).

3.9.5.2 Positive Emissions from Renewables

Several of the renewable to electricity technologies have been assigned a small positive emissions factor. This reflects the full life cycle emissions foot print of the technologies including the Scope 3 emissions arising from manufacture of the technology.

4 COMPARATIVE RESULTS

This section provides results comparing the analysis cases. Results that are specific to each analysis case are provided in subsequent report sections.

4.1 Energy Split by Region and User Type

Presented in the following tables is the split of energy demand by type and region for each of the analysis cases. The assumptions and references used to develop the data is described below.

The results were generated by applying region / energy type / consumer type splits (percentages, see below) to the energy mix data (electricity and energy gas) for the analysis case in question (refer relevant section of subsequent report for details).

The trends observed in the energy split data are observed to closely match the outcomes of the spatial analysis for the case in question (refer relevant section of report for details).

1. Energy consumption split by region was "tuned" to match spatial analysis outcomes, and checked for alignment with "consumption snapshot data" taken from AEMO, Victorian Annual Planning Report, November 2020.

Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
62%	3%	10%	9%	12%	2%	2%

2. Energy consumption split by region remains constant from 2020 to 2050.
3. Electricity split residential & commercial 25% / industrial 75% (ref AEMO, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational).
4. Energy gas split residential & commercial 60% / industrial 40% (reference Australian Gas Infrastructure Group, https://renewable-gas.com.au).
5. The data excludes vehicle fuel (gasoline, diesel, electricity for BEVs, electricity / Hydrogen for HFCVs).
6. Electricity and energy gas refer to all types (fossil and low emissions) defined for the analysis case in question (refer relevant section of report for details).

Table 28: Breakdown of Energy Consumption by Region & User Type - High Probability Technology Case

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	32	2	5	5	6	1	1
energy gas	78	4	13	11	15	3	3
				Industrial			
electricity	95	5	15	14	18	3	3
energy gas	52	3	8	8	10	3	3

2030 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	60	3	10	9	12	2	2
energy gas	68	3	11	11	13	2	2
				Industrial			
electricity	181	9	29	26	35	6	6
energy gas	45	2	7	6	9	1	1

2040 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	76	4	12	11	15	2	2
energy gas	58	3	10	8	11	2	2
				Industrial			
electricity	229	11	37	33	44	7	7
energy gas	39	2	6	5	7	1	1

2050 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	101	5	16	15	20	3	3
energy gas	37	2	7	6	8	1	1
				Industrial			
electricity	303	15	49	44	59	10	10
energy gas	24	1	4	3	4	1	1

Table 29: Breakdown of Energy Consumption by Region & User Type – Mid Probability Technology Case

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	32	2	5	5	6	1	1
energy gas	78	4	13	11	15	3	3
				Industrial			
electricity	95	5	15	14	18	3	3
energy gas	52	3	8	8	10	3	3

2030 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	60	3	10	9	12	2	2
energy gas	67	3	11	10	13	2	2
				Industrial			
electricity	180	9	29	26	35	6	6
energy gas	45	3	7	6	9	1	1

2040 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	83	4	13	12	16	3	3
energy gas	41	2	7	6	8	1	1
				Industrial			
electricity	248	12	40	36	48	8	8
energy gas	27	1	4	4	5	1	1

2050 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	84	4	13	12	16	3	3
energy gas	85	4	14	12	17	3	3
				Industrial			
electricity	251	12	40	36	49	8	8
energy gas	57	3	9	8	11	2	2

Table 30: Breakdown of Energy Consumption by Region & User Type – Low Probability Technology Case

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	32	2	5	5	6	1	1
energy gas	78	4	13	11	15	4	4
Industrial							
electricity	95	5	15	14	18	3	3
energy gas	52	3	8	8	10	2	2

2030 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	66	3	11	10	13	2	2
energy gas	48	2	8	7	9	2	2
Industrial							
electricity	199	10	32	29	39	6	6
energy gas	32	2	5	5	6	1	1

2040 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	83	4	13	12	16	3	3
energy gas	38	2	6	6	7	1	1
Industrial							
electricity	249	12	40	36	48	8	8
energy gas	26	1	4	4	5	1	1

2050 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	106	5	17	15	20	3	3
energy gas	23	1	4	3	5	1	1
Industrial							
electricity	317	15	51	46	61	10	10
energy gas	16	1	3	2	3	1	1

Table 31: Breakdown of Energy Consumption by Region & User Type –Sensitivity 1 "Accelerated Net Zero"

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	32	2	5	5	6	1	1
energy gas	78	4	13	11	15	4	4
				Industrial			
electricity	95	5	15	14	18	3	3
energy gas	52	3	8	8	10	2	2

2030 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	59	3	9	9	11	2	2
energy gas	68	3	11	10	13	2	2
				Industrial			
electricity	176	9	28	26	34	6	6
energy gas	46	2	7	7	9	1	1

2040 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	84	4	14	12	16	3	3
energy gas	36	2	6	5	7	1	1
				Industrial			
electricity	252	12	41	37	49	8	8
energy gas	24	1	4	4	5	1	1

2050 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	92	4	15	13	18	3	3
energy gas	63	3	10	9	12	2	2
				Industrial			
electricity	276	13	45	40	53	9	9
energy gas	42	2	7	6	8	1	1

Table 32: Breakdown of Energy Consumption by Region & User Type –Sensitivity 2 "Reduced Ammonia"

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	32	2	5	5	6	1	1
energy gas	78	4	13	11	15	3	3
				Industrial			
electricity	95	5	15	14	18	3	3
energy gas	52	3	8	8	10	2	2

2030 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	60	3	10	9	12	2	2
energy gas	67	4	11	10	13	2	2
				Industrial			
electricity	180	9	29	26	35	6	6
energy gas	45	2	7	6	9	1	1

2040 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	83	4	13	12	16	3	3
energy gas	40	2	6	6	8	1	1
				Industrial			
electricity	249	12	40	36	48	8	8
energy gas	27	1	4	4	5	1	1

2050 (Electricity & Energy Gas) (PJ)							
	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
				Residential & Commercial			
electricity	91	4	15	13	18	3	3
energy gas	66	3	11	10	13	2	2
				Industrial			
electricity	272	13	44	39	53	9	9
energy gas	44	2	7	6	9	1	1

Table 33: Breakdown of Energy Consumption by Region & User Type –Sensitivity 3 "Energy Efficiency"

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	32	2	5	5	6	1	1
energy gas	77	4	13	11	15	3	3
Industrial							
electricity	95	5	15	14	18	3	3
energy gas	51	3	8	8	10	2	2

2030 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	57	3	9	8	11	2	2
energy gas	63	3	10	9	12	3	3
Industrial							
electricity	172	8	28	25	33	6	6
energy gas	42	2	7	6	8	1	1

2040 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	69	3	11	10	13	2	2
energy gas	50	2	8	7	10	2	2
Industrial							
electricity	207	10	33	30	40	7	7
energy gas	33	2	5	5	7	1	1

2050 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	88	4	14	13	17	3	3
energy gas	29	1	5	4	6	1	1
Industrial							
electricity	263	13	42	38	51	8	8
energy gas	19	1	3	3	4	1	1

Table 34: Breakdown of Energy Consumption by Region & User Type –Sensitivity 4 "Maximum Green H2"

(rounding errors may lead to minor inconsistencies compared to energy mix results)

2020 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	32	2	5	5	6	1	1
energy gas	73	4	12	11	14	3	3
Industrial							
electricity	95	5	15	14	18	3	3
energy gas	50	3	8	8	10	2	2

2030 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	65	3	11	9	13	2	2
energy gas	47	2	8	7	9	2	2
Industrial							
electricity	196	9	32	28	38	6	6
energy gas	33	2	5	5	6	1	1

2040 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	77	4	12	11	15	2	2
energy gas	57	3	10	9	10	2	2
Industrial							
electricity	231	11	37	33	45	7	7
energy gas	40	2	6	6	8	1	1

2050 (Electricity & Energy Gas) (PJ)

	Melbourne & Geelong	V1 Ovens Murray	V2 Murray River	V3 Western	V4 South West	V5 Gippsland	V6 Central North
Residential & Commercial							
electricity	92	4	15	13	18	3	3
energy gas	66	3	12	10	13	2	2
Industrial							
electricity	276	13	44	40	53	9	9
energy gas	46	2	7	7	9	1	1

4.2 Gas Spatial Analysis

For the High Probability Technology case, the major changes in the **gas transmission network** can be summarised as:

- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035.
- Transmission of biomethane/hydrogen gas mixtures from Echuca/Shepparton/Bendigo and Ballarat towards Melbourne from 2035.
- Decommissioning of the Eastern Gas Pipeline from Longford to NSW after 2040.
- Decommissioning of the SEA gas pipeline to South Australia after 2040.

For the High Probability Technology case, the major changes in the **gas distribution networks** can be summarised as:

- Less than 10% of distribution network to be decommissioned.

For the Mid Probability Technology case, the major changes in the **gas transmission network** can be summarised as:

- Addition of an ammonia import terminal with associated facilities to store ammonia and inject it into the gas transmission network from 2040.
- Upgrading (if required) of transmission pipelines to handle ammonia by 2040. Mild carbon steel pipelines should not need upgrading; however this should be confirmed on a case by case basis in future work.
- Addition of a number of ammonia to hydrogen conversion facilities in metropolitan Melbourne by 2040. Estimates are that five to ten such facilities may be required.
- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035 to transport biomethane.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035 to transport biomethane.
- Decommissioning of the Eastern Gas Pipeline to NSW and the gas transmission pipelines between Seaspray and Longford, Longford and Morwell and Longford and Dandenong after 2040.
- Decommissioning of the pipeline infrastructure in the Barwon South West region, around Port Campbell and Warnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia.

For the Mid Probability Technology case, the major changes in the **gas distribution networks** can be summarised as:

- Upgrading of gas distribution networks in Melbourne and Gippsland to handle 100% hydrogen by 2040.
- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland from 2030.

- Biomethane and hydrogen from the Loddon Mallee and Grampians Central West production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat from 2030.
- Potential decommissioning of up to 15% of the distribution network (mostly in regional towns and some parts of Melbourne where it may be difficult to upgrade to hydrogen).

For the Low Probability Technology case, the major changes in the **gas transmission network** can be summarised as:

- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035 to transport biomethane and hydrogen.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035 to transport biomethane and hydrogen.
- Transmission of biomethane/hydrogen gas mixtures from Echuca/Shepparton/Bendigo and Ballarat towards Melbourne from 2035.
- Decommissioning of the Eastern Gas Pipeline from Longford to NSW.
- Decommissioning of the pipeline infrastructure in the Barwon South West region, around Port Campbell and Warrnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia.

For the Low Probability Technology case, the major changes in the **gas distribution networks** can be summarised as:

- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland from 2030.
- Biomethane and hydrogen from the Loddon Mallee and Grampians Central West production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat from 2030.
- Potential decommissioning of up to 30% of the distribution network.

Table 35: Estimated Extent of Addition of Gas Transmission Pipelines

(4,694 kms installed transmission pipelines)

Analysis Case	2030	2040	2050
High Probability	0 km	360 in 2035	0
Mid Probability	0 km	360 in 2035	0
Low Probability	0 km	360 in 2035	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	0	0
Sensitivity Case 3	0	0	0
Sensitivity Case 4	0	0	0

Table 36: Estimated Extent of Decommissioning of Existing Gas Transmission Pipelines

(4,694 kms installed transmission pipelines)

Analysis Case	2030	2040	2050
High Probability	0 km	0	850
Mid Probability	0 km	1700	0
Low Probability	0 km	1700	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	1200	700
Sensitivity Case 3	0	1200	0
Sensitivity Case 4	0	2000	4000

Table 37: Estimated Extent of Decommissioning of Existing Gas Distribution Pipelines

(34,016 kms total installed infrastructure for the 3 fully regulated network suppliers)

Analysis Case	2030	2040	2050
High Probability	0	0	2500
Mid Probability	0	4000	0
Low Probability	0	8000	0
Sensitivity Case 1	0	0	0
Sensitivity Case 2	0	0	0
Sensitivity Case 3	0	0	0
Sensitivity Case 4	0	0	0

<u>Gas Infrastructure Specific to the Mid Probability Technology Case</u>

In the Mid Probability Technology case 100 PJ/yr of green ammonia is imported from 2040 onwards with forecast imports reaching 230 PJ/yr by 2050. The ammonia would be distributed in the existing high pressure gas transmission network which would require minimal modifications to transport ammonia. The ammonia would be transported as a liquid in the high-pressure transmission system and converted to hydrogen before being distributed to end consumers in the low pressure gas distribution system. In this concept, most end customers will consume 100% hydrogen, and some would consume a mix of hydrogen and biomethane with the mix being dependent upon their location and proximity to local biomethane production sources. Pipeline transport of ammonia in liquid form in mild carbon steel pipes is proven in the United States, Ukraine/Russia and Europe with over 7,000 km of ammonia pipelines worldwide.

A significant advantage of this concept is that major modifications required to transport hydrogen in the transmission system are avoided, however, a number of issues will still need to be addressed, including but not limited to:

- Ability of existing gas transmission pipelines to safely transport ammonia;
- Safety aspects and risks to the community, especially in residential areas; and
- Social license aspects, given that ammonia is a hazardous and dangerous good.

Due to the amount of energy required, a significant portion of the ammonia will need to be imported into Victoria either from other states of Australia or overseas. Possible locations where the ammonia could be manufactured include Western Australia, Northern Territory, Tasmania and Queensland as well as many overseas locations.

By definition ammonia is used when there is a need for an energy carrier to move hydrogen from a location where it can be produced to one where it will be consumed. Green ammonia will mostly be produced from renewable electricity and by 2040 it is expected that the

Victorian electricity grid will be mostly renewables and so there is no advantage of using ammonia to move hydrogen if electricity could be used instead in the vicinity of the gas distribution system. The current study rejected the option to use coal gasification with CCS to produce the ammonia in Victoria from brown coal, as per the prior Scenario Analysis Stage 1 study (*Net Zero Emission Scenario Analysis Study Report May 2021*), due to the very high emissions and high CCS costs. So, while some ammonia could be produced in Victoria from renewable sources it is unlikely that 230 PJ/yr can be made locally and therefore it is assumed that most will be imported.

Ammonia vessels will be of a large size and require berthing at a suitable port. Ammonia is a toxic chemical and needs to be stored in refrigerated tanks at below and located away from residential areas.

Further work is required to study which site(s) would be preferred locations for the ammonia import taking into a wide range of factors, including the siting of ammonia to hydrogen cracking plants.

Irrespective of where the ammonia is imported, new facilities will need to be built including: offloading arms on the jetty, construction of one or more dedicated refrigerated storage tanks, boil off gas management system and heating and injection equipment to pressurise the ammonia for injection into the gas transmission network. Along the gas transmission network, new ammonia receiving storage and plants dedicated to cracking it back into hydrogen will also be needed. Suitable locations for ammonia conversion back to hydrogen around Melbourne could be located in Dandenong, Lilydale, Heidelberg, Craigieburn, Deer Park, Sunbury, Altona/Laverton and Geelong. An implication of converting ammonia to hydrogen is that the distribution network in Melbourne will need to be upgraded for 100% hydrogen by 2040.

Infrastructure implications are the same for the Sensitivity Cases 1 and 2 based on the Mid Probability Technology case.

Table 38: Impacts for Hydrogen and Ammonia transport.

Analysis Case	Impacts to Accommodate Hydrogen	Impacts to Accommodate Ammonia
High Probability	No impact as overall flow is less	Not Applicable
Mid Probability	Distribution network upgrades to handle 100% hydrogen required by 2030.	Transmission network compatibility with liquid ammonia transport required by 2030.
Low Probability	No impact as overall flow is less	Not Applicable.

For Sensitivity Case 4 “Maximum Green Hydrogen”, the major changes in the gas infrastructure can be summarised as:

- Assumption that the low pressure distribution system is capable of handling 100% hydrogen by 2035. This assumption is compatible with existing plans the gas operators have to install high density polyethylene (HDPE) linings where needed to ensure the capability to distribute 100% hydrogen at the same or higher flow rates than today.

- Addition of multiple local green hydrogen production plants in each region, producing green hydrogen into the local low pressure distribution systems. Each plant will require electrical connection and sufficient supply of high quality water.
- Decommissioning of the majority of the high pressure natural gas transmission system by 2035. Around 80-85% of the transmission system is not required after 2030.
- The transmission lines from Port Campbell to Melbourne and from Gippsland to Melbourne are used to transport excess natural gas to Melbourne after 2030. The transmission line from Port Campbell to Melbourne could be decommissioned by 2045.
- Gas storage facilities such as Iona and Dandenong LNG are probably not required after 2030 as local green hydrogen production can be readily ramped up and down in each region to meet seasonal demands. Local storage of hydrogen would not be needed.

4.3 Electrical Spatial Analysis

Electrical infrastructure represents a long lead time in planning and implementation stages. The network is unable to sustain ad hoc power connections without network stability being affected. Accordingly, there is currently a 2-to-4-year delay in approvals of renewable energy connections within Victoria.

Data in Table 39 defines the extent of new or upgraded electrical infrastructure required for each analysis case over and above existing and committed electrical infrastructure. The values are presented as a “relative index” and, by way of example for the High Probability Technology Case, calculated below.

$$\textbf{Relative Electrical Generation Infrastructure Index}_{\textbf{Scenario High}} = \frac{A}{B}$$

With:

A = **Electrical Generation Infrastructure Capacity of period 20XX Estimate (MW)** $_{\textbf{Scenario High}}$

B = **Electrical Generation Infrastructure Capacity (MW) of period 2025 Estimate** $_{\textbf{Scenario with Lowest Level of Electrical Infrastructure}}$

All analysis cases start in 2025 with the same amount of additional electrical capacity and for this reason the 2020-2025 period is always considered to have the lowest level of electrical infrastructure with a relative electrical index of 1.

In 2030, all scenarios are similar with respect to additional electrical infrastructure, but between 2035 and 2050 some deviations occur, and a large difference is observed between the High Probability Technology Case with the highest index of 3.3 and the Mid Probability Technology Case with the lowest index of 2.1.

A decrease is present in the Mid Probability Technology Case, Sensitivity 1 “Accelerated Net Zero” and Sensitivity 2 “Reduced Ammonia” between 2045 and 2050 corresponds to all the cases with the use of green ammonia. Between 2045 and 2050, decommissioning of several gas and coal electricity generation infrastructure facilities is observed (all the remaining production assets). It means that if a case has almost reached its 2050 demand in 2045 without gas and coal production, in the 2045-2050 period, there will be more decommissioning in the generation infrastructure than commissioned generation infrastructure.

An analogous approach has been taken to calculating the values for electrical storage infrastructure upgrades presented in Table 40.

Table 39: Relative Extent of Upgrades to Electrical Generation Infrastructure

Analysis Case	2025	2030	2035	2040	2045	2050
High Probability	1.0	1.5	2.0	2.3	2.7	3.3
Mid Probability	1.0	1.5	1.8	2.2	2.2	2.1
Low Probability	1.0	1.5	1.8	1.9	2.1	2.6
Sensitivity 1 « Accelerated Net Zero »	1.0	1.5	1.8	2.1	2.4	2.3
Sensitivity 2 «Reduced Ammonia »	1.0	1.5	2.0	2.2	2.6	2.5
Sensitivity 3 « Energy Efficiency »	1.0	1.5	1.8	1.9	2.2	2.8
Sensitivity 4 « Maximum Green Hydrogen »	1.0	1.2	1.8	2.1	2.4	2.5

To ensure stability of the grid, storage is fundamental as VRE is inherently limited by nature. The same was undertaken for storage infrastructure indicating an average of 25,000% in the energy storage capacity per year between 2025 and 2050. Whilst this value is very large, it is explained by the high quantity of VRE in the mix, requiring high levels of storage to balance the grid, starting from a very low base as there are only two grid-scale batteries in Victoria currently commissioned and approximately 20 proposed.

Table 40: Relative Extent of Upgrades to Electrical Storage Infrastructure

Analysis Case	2025	2030	2035	2040	2045	2050
High Probability	2	7	11	16	21	29
Mid Probability	2	7	10	13	15	19
Low Probability	2	11	15	19	23	33
Sensitivity 1 « Accelerated Net Zero »	2	6	9	16	19	23
Sensitivity 2 « Reduced Ammonia »	2	7	11	12	13	23
Sensitivity 3 « Energy Efficiency »	1	6	9	12	15	22
Sensitivity 4 « Maximum Green Hydrogen »	2	5	5	5	5	12

4.4 Vehicle Analysis

The vehicle analysis results provided in the tables below show the split of heavy and light vehicles, vehicle type, number of vehicle and fuel consumption over time. It should be noted that the vehicle analysis undertaken in the current study was intended only to provide indicative input data to the other analysis centres (energy-emissions-offset-gas-electrical-cost) and identify the key interactions between the other energy systems (electricity and energy gas). On this basis the vehicle analysis undertaken was limited in scope, simplified by assumptions and high level in detail. The optimum low emissions vehicle uptake rate and split (BEV vs HFCV) is considered complex, and beyond the scope of the current study. The infrastructure required to support large numbers of BEVs with a broad geographical spread, for example fast battery charging stations catering for multiple consumers at the same time (particularly in regional locations) would likely represent a high cost, and require a long term project planning.

Table 41 and Table 42 document the road vehicle fuel quantities over time for each class of vehicle. It was assumed that by 2050 there would not be a significant level of ICE vehicles on the road, hence a low level of gasoline & diesel consumption. Gasoline & diesel fuels consumed by ICE vehicles is progressively replaced by new, additional generation capacity including renewable electricity and green Hydrogen production facilities to supply the low emissions vehicles (BEVs and HFCVs). The additional electrical and gas transmission and distribution infrastructure requirements are summarised in Section 4.2 and Section 4.3.

The same rate of low emissions vehicle uptake was adopted for all analysis cases except Sensitivity Case 4 "Maximum Green H2" where the HFCV uptake rate was increased. By comparing the tables it can be seen that the impact of this change on low emissions fuel levels (electricity and Hydrogen) was relatively minor. However it is noted that the rate of uptake of HFCVs, even for Sensitivity Case 4, is still low compared to the total number of road vehicles, and that a much enhanced uptake of HFCVs would be expected to lead to a significant increase in overall electricity required to generate the green Hydrogen required.

The impact of the significant difference in fuel consumption rates for heavy versus light low emissions vehicles can be seen by assessing the results below. With the greater majority of BEVs assumed to be light vehicles, changes in uptake rate (whilst maintaining the same heavy : light ratio) will lead to notable changes in overall fuel consumption levels. In Sensitivity Case 4, in addition to increasing the overall uptake rate of HFCVs, the proportion of light HFCVs was also significantly increased and this can be seen to result in a relatively small increase in overall HFCV fuel consumption. This observation highlights the significant impact of long distance road vehicle usage on the level of fuel consumption and emissions. It is recommended that further work is done to investigate the complex relationship between fuel consumption rates and usage of road vehicle by type, specifically:

- Vehicle fuel consumption rates, especially heavy versus light
- Public transport uptake rates, and electrification of railways for long distance transport

Table 41: Total Fuel Consumption for All Road Vehicles in Victoria (all cases except Sensitivity Case 4)

Year	Internal Combustion Engines (ICE)		Battery Electric Vehicles (BEV)		Hydrogen Fuel Cell Vehicles (HFCV)	
	Total Number Vehicles (Heavy & Light)	Gasoline & Diesel (PJ / yr)	Total Number Vehicles (Heavy & Light)	Electricity (PJ / yr)	Total Number Vehicles (Heavy & Light)	Hydrogen (PJ / yr)
2020	6,103,512	318	Minimal	Insignificant	Minimal	Insignificant
2030	4,550,069	215	1,858,612	20	207,691	24
2040	2,162,377	100	4,982,954	53	231,564	27
2050	Minimal	Insignificant	7,248,440	66	383,829	40

Table 42: Total Fuel Consumption for All Road Vehicles in Victoria (Sensitivity Case 4)

Year	Internal Combustion Engines (ICE)		Battery Electric Vehicles (BEV)		Hydrogen Fuel Cell Vehicles (HFCV)	
	Total Number Vehicles (Heavy & Light)	Gasoline & Diesel (PJ / yr)	Total Number Vehicles (Heavy & Light)	Electricity (PJ / yr)	Total Number Vehicles (Heavy & Light)	Hydrogen (PJ / yr)
2020	6,103,512	318	Minimal	Insignificant	Minimal	Insignificant
2030	4,535,977	215	1,822,092	17	257,493	30
2040	2,142,938	97	4,847,613	44	386,343	41
2050	Minimal	Insignificant	7,197,096	64	435,173	43

Table 43: Uptake of Heavy Road Vehicle by Type (% of Total Heavy Road Vehicles) – all cases except Sensitivity Case 4

Vehicle Type	2020	2030	2040	2050
ICE (heavy)	100%	27%	3%	Minor
BEV (heavy)	Minor	18%	41%	22%
HFCV (heavy)	Minor	56%	56%	78%

Table 44: Uptake of Heavy Road Vehicle by Type (% of Total Heavy Road Vehicles) – Sensitivity Case 4

Vehicle Type	2020	2030	2040	2050
ICE (heavy)	100%	22%	2%	Minor
BEV (heavy)	Minor	8%	15%	15%
HFCV (heavy)	Minor	70%	84%	85%

Table 45: Uptake of Light Road Vehicle by Type (% of Total Light Road Vehicles) - all cases except Sensitivity Case 4

Vehicle Type	2020	2030	2040	2050
ICE (light)	100%	70%	30%	Minor
BEV (light)	Minor	28%	69%	98%
HFCV (light)	Minor	1%	1%	2%

Table 46: Uptake of Light Road Vehicle by Type (% of Total Light Road Vehicles) - Sensitivity Case 4

Vehicle Type	2020	2030	2040	2050
ICE (light)	100%	70%	30%	Minor
BEV (light)	Minor	28%	68%	97%
HFCV (light)	Minor	1%	2%	3%

Figure 19: Split of Heavy Road Vehicles by Type – all cases except Sensitivity Case 4

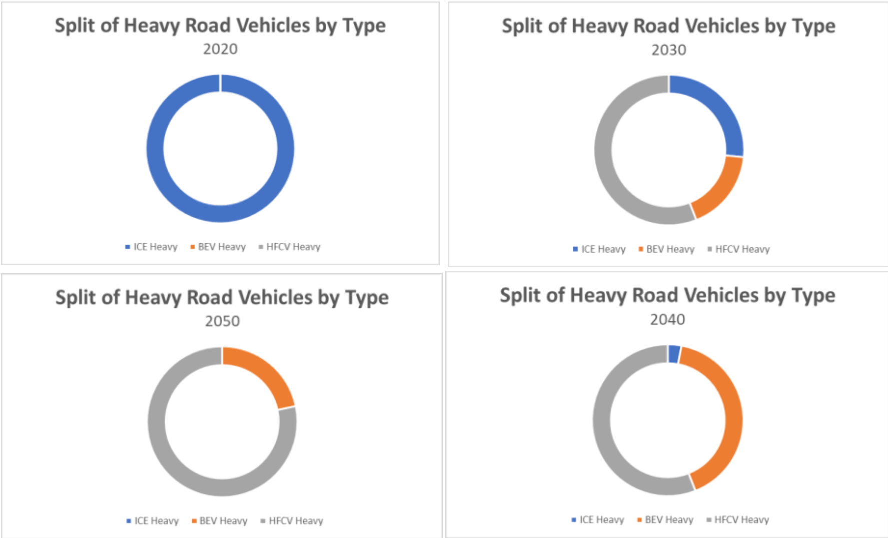


Figure 20: Split of Heavy Road Vehicles by Type – Sensitivity Case 4

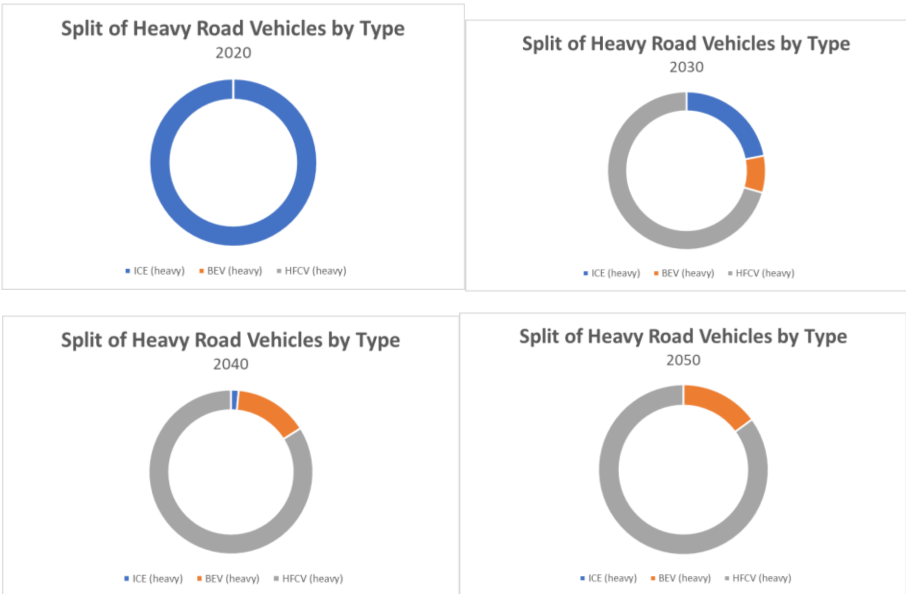


Figure 21: Split of Light Road Vehicles by Type – all cases except Sensitivity Case 4

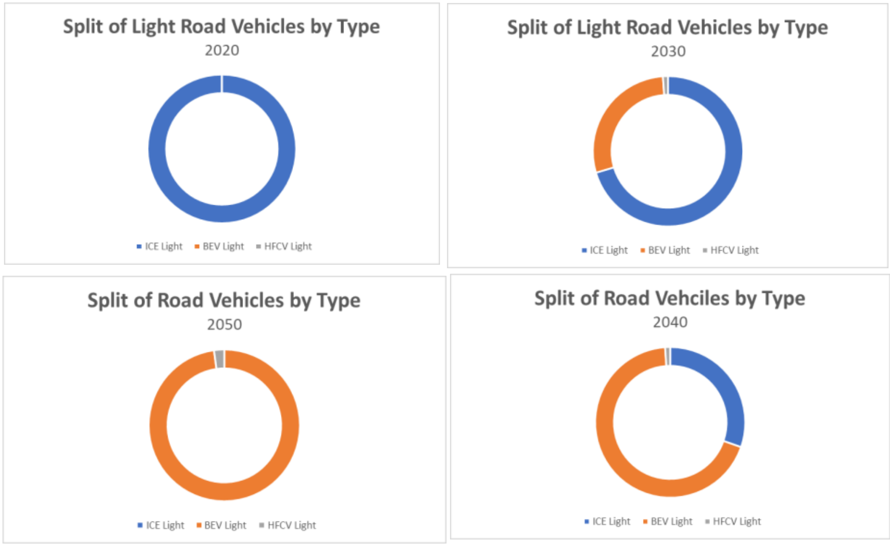


Figure 22: Split of Light Road Vehicles by Type – Sensitivity Case 4

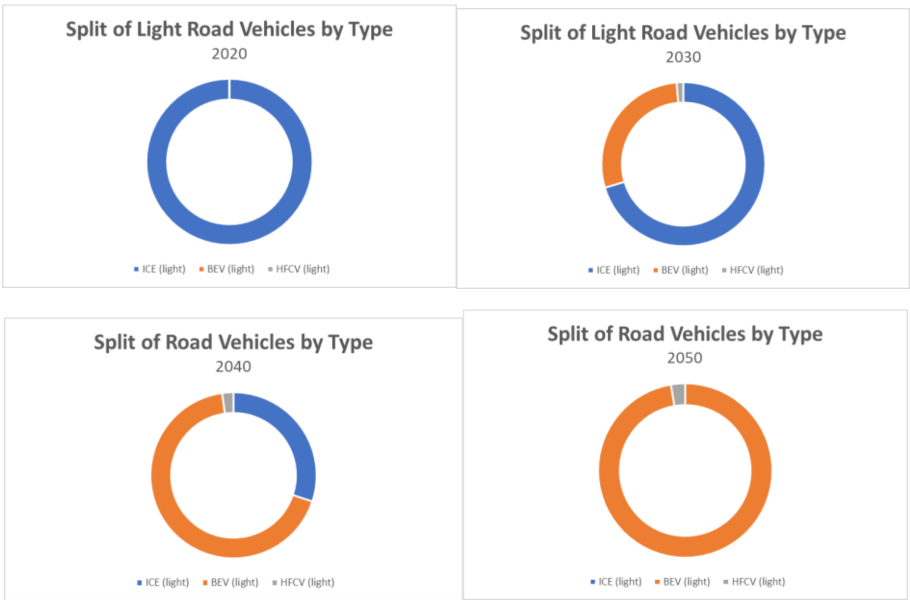


Figure 23: Number of Road Vehicles in Victoria – all cases except Sensitivity Case 4

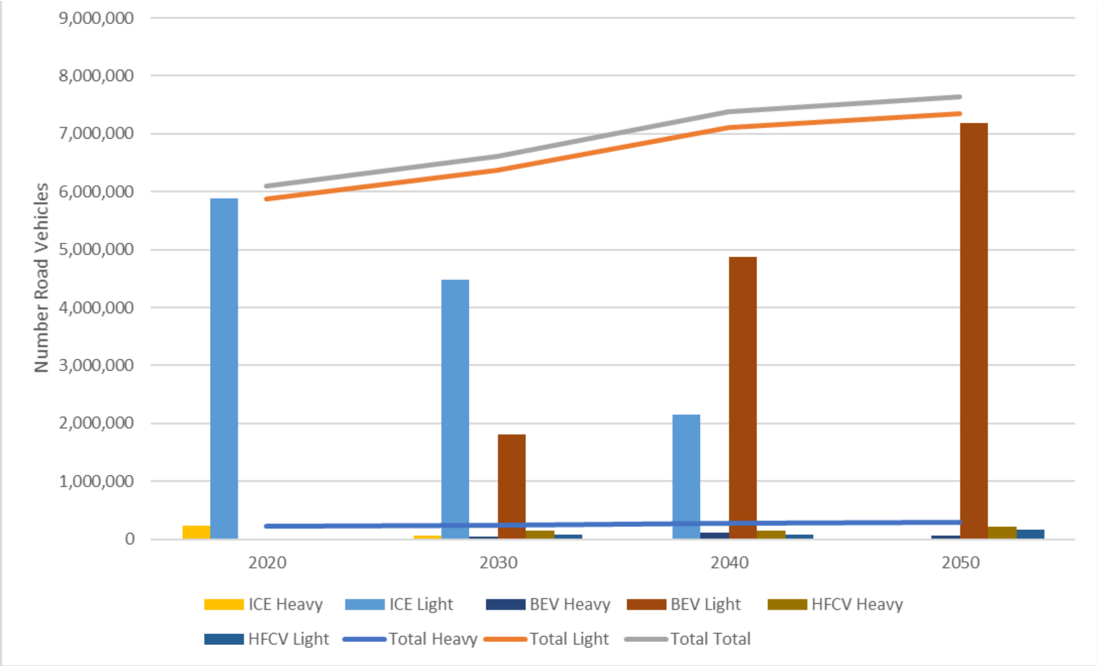


Figure 24: Number of Road Vehicles in Victoria – Sensitivity Case 4

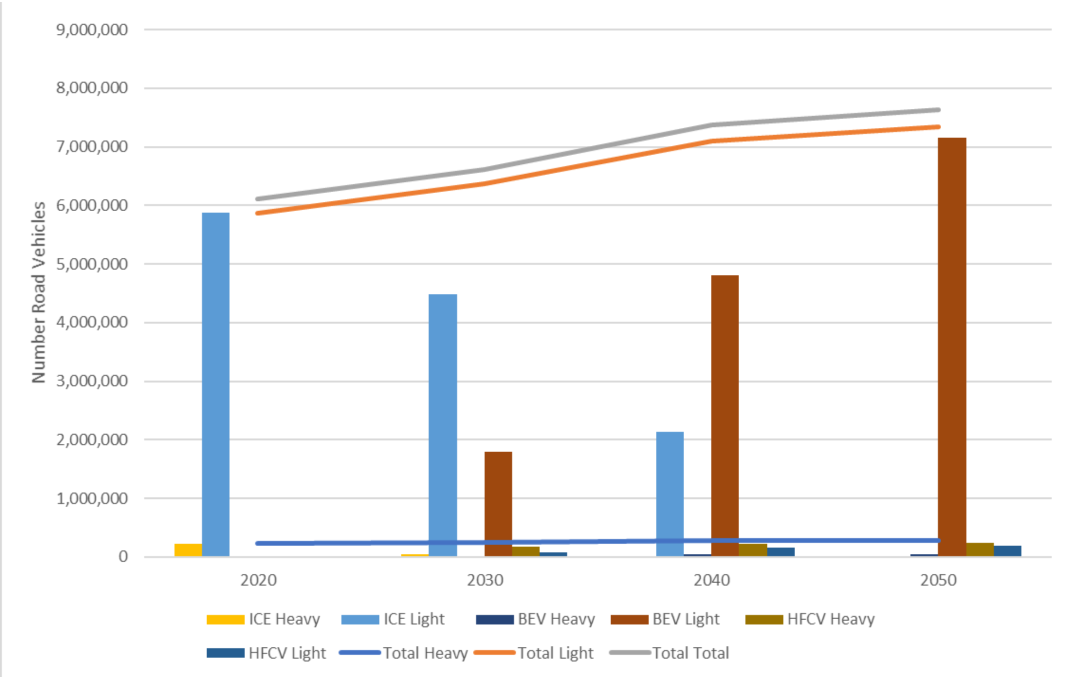


Figure 25: Distance Travelled by Road Vehicles in Victoria – all cases except Sensitivity Case 4

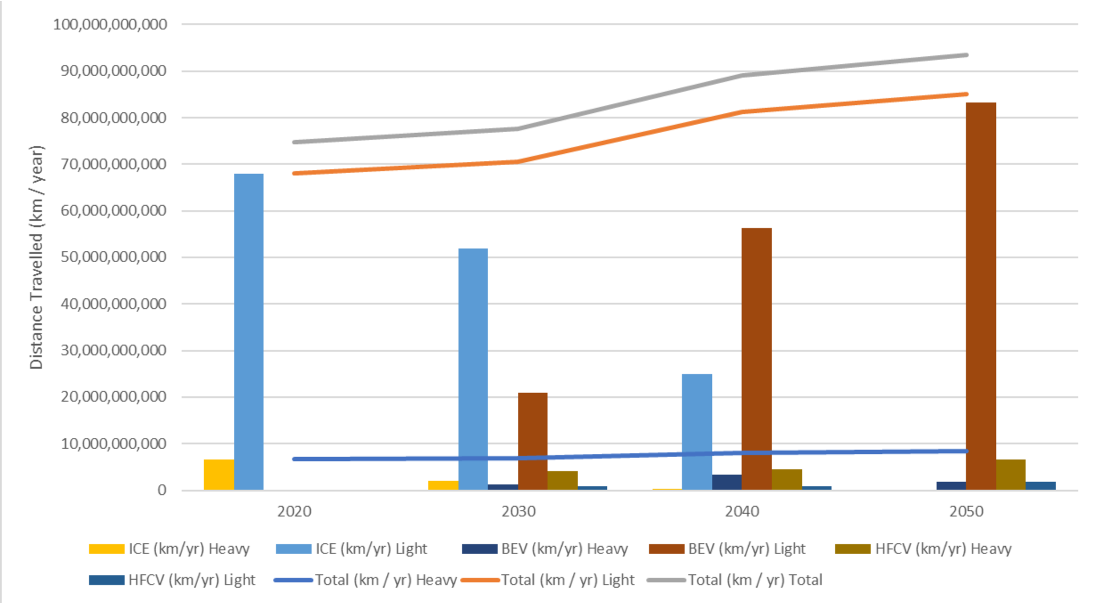


Figure 26: Distance Travelled by Road Vehicles in Victoria –Sensitivity Case 4

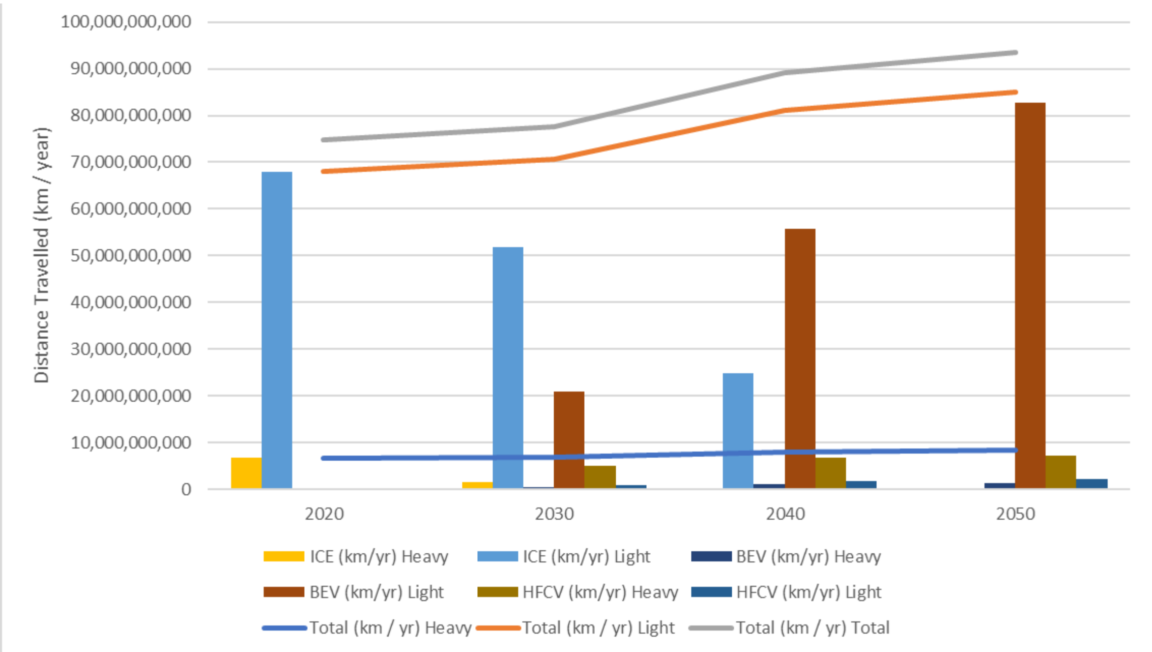


Figure 27: Fuel Consumption by Road Vehicles in Victoria– all cases except Sensitivity Case 4

(H2 fuel is Hydrogen, with electricity required to generate Hydrogen reported separately as part of Energy Mix).

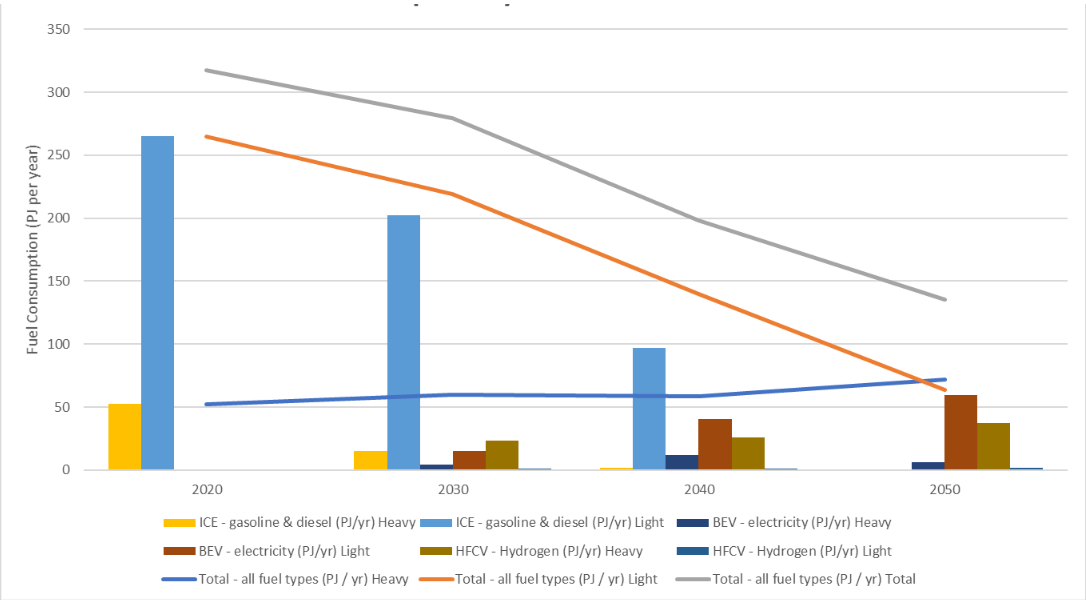
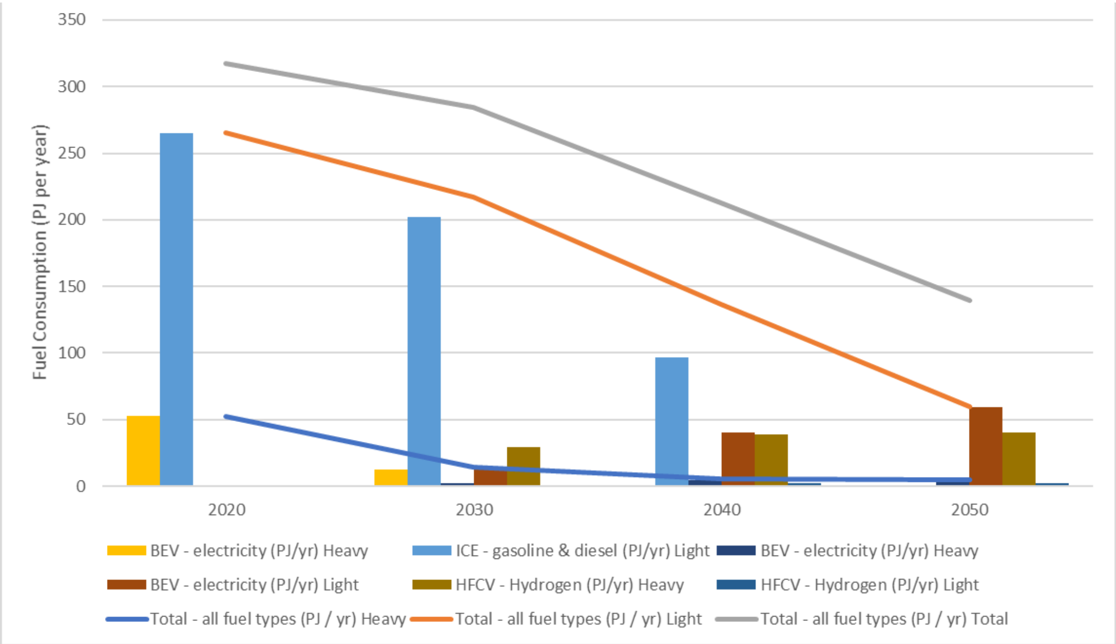


Figure 28: Fuel Consumption by Road Vehicles in Victoria– Sensitivity Case 4

(H2 fuel is Hydrogen, with electricity required to generate Hydrogen reported separately as part of Energy Mix).



4.5 Cost Analysis

The costs (CAPEX, OPEX, ABEX) for each scenario were compiled and compared to a "Control Scenario" to allow a comparison between scenarios and assess which scenario may have potential to provide the least cost compared with other scenarios. Note that the Stage 1 cost analysis has been improved and results were not compared due to a difference in estimation basis.

The main reason for doing this was the uncertainty in providing total costs and so it was more appropriate to provide relative costs for each scenario as there were an infinite number of scenarios and hence an infinite number of possible costs and hence a class type estimate was not possible.

The 'Control Scenario' provides a base line to compare each hybrid scenario against and then this allows the Analysis Cases to be compared against each other. This was done to simplify the number of combinations between scenarios.

The costs were totalled, annualised and discounted to 2021 for comparison with the "Control Scenario".

The net comparative cost was the difference between the "Control Scenario" net present cost and each Analysis Case net present cost. A positive value is considered a net cost benefit to the hybrid scenario, a negative value (red) is considered a net cost increase.

The costs should not be used as absolute numbers but for comparison purposes only to assess whether there was a net cost advantage or disadvantage between the scenarios.

The cost of carbon abatement was effectively the total of the annualised net present cost for each scenario divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost. Again, this was for comparison purposes only to assess whether there was an advantage or disadvantage between the Analysis Cases.

Table 47 shows the estimate of comparative net costs of the analysis cases which suggests that the High Probability Technology Case provides the least cost and was therefore (comparatively) the lowest cost transition scenario compared to the medium and low probability technology case scenarios based on the inputs and assumptions made. The High Probability Technology Case provides the lowest estimated cost of abatement.

Table 47 also shows the estimate of comparative net costs of the sensitivity cases which suggests the Sensitivity Case 3 "Energy Efficiency", similar to the High Probability Technology Case but with reduced energy demand, provides the least cost of all the cases based on the inputs and assumptions made. The Sensitivity Case 3 "Energy Efficiency" provides the lowest estimated cost of abatement for all the Analysis Cases.

The Medium Probability Technology and Sensitivity Case 2 "Reduced Ammonia" cases have a higher net cost due to the early retirement of coal fired generation replaced with new generation CAPEX and OPEX costs mostly related to green hydrogen / ammonia.

The Low Probability Technology Case has a higher net cost compared to the High Probability Technology case mostly due to the higher CAPEX of solar thermal and offshore wind.

Sensitivity Case 1 “Accelerated Net Zero” has a higher net cost compared to all the scenarios due to the higher CAPEX and OPEX of solar thermal, offshore wind plus the early retirement of coal fired generation replaced with new generation CAPEX and OPEX costs related to green hydrogen / ammonia.

Table 47 also shows the cost of abatement which was the result of comparing the Analysis Cases to the Control Scenario. The lower the value the greater benefit to the scenario, the higher the value the greater cost to the Analysis Case.

The results suggest that the High Probability Technology Case provides the lowest estimated cost of abatement compared to the Mid and Low Probability Technology Cases.

The estimate of comparative net costs of abatement for the sensitivity cases suggests Sensitivity Case 3 “Energy Efficiency” is similar to the High Probability Technology Case but with reduced energy demand and provides the lowest estimated cost of abatement for all the Analysis Cases.

The Medium Probability Technology Case and Sensitivity Case 2 “Reduced Ammonia” have a higher cost of abatement even with the early retirement of coal fired generation which was replaced with new generation CAPEX and OPEX costs mostly related to green Hydrogen / Ammonia.

The Low Probability Technology Case has a higher cost of abatement compared to the High Probability Technology case mostly due to the higher CAPEX of solar thermal and offshore wind.

The Sensitivity Case 1 “Accelerated Net Zero” has the highest cost of abatement compared to all the scenarios due to the higher CAPEX and OPEX of solar thermal and offshore wind even with the early retirement of coal fired generation which was replaced with new generation CAPEX and OPEX costs related to green Hydrogen / Ammonia.

Table 47: Comparative Cost Analysis Results

Analysis Case	Estimated Comparative Net Cost ($M)	Estimated Comparative Cost of Abatement ($/tonne CO_{2e})
High Probability	-1,587	89
Medium Probability	-3,563	112
Low Probability	-1,896	93
Sensitivity Case 1 “Accelerated Net Zero”	-5,280	132
Sensitivity Case 2 “Reduced Ammonia”	-2,679	102
Sensitivity Case 3 “Energy Efficiency”	-482	76
Sensitivity Case 4 “Maximum Green H2”	-2,792	103

4.5.1 Introduction of a Carbon Price on Emissions (Hypothetical)

Currently there is no price on carbon emissions in Australia, and it is not known if a price or what offset mechanism, if any, would be used to price carbon in the future.

The following is a hypothetical analysis. It does not include how or who would pay for the price on carbon i.e. no abatement or offset mechanisms were used. It is effectively an additional operating cost for emissions from power generation which means the cost of operating increases.

It was based on a notional dollar value per tonne of CO_2 and the estimated total emissions for existing and new generation for each of the scenarios considered and compared against the Control Scenario to give a net comparative cost for each Analysis Case.

The basis and methodology for the analysis was the same for all scenarios as per the Cost Analysis Methodology with the addition of the cost of CO_2 to the annualised and net costs discounted to 2021.

CO_2 costs were calculated on an annual basis on the generator emissions value (kg CO_2/MWh), the calculated MWh sent out and an assumed CO_2 price increasing between 2025 and 2050. These were then added to the other operating costs etc.

The CO_2 price calculated uses assumed increasing CO_2 price(s) from 2025 to 2050.

- $30/tonne from 2025-2030
- $150/tonne from 2031-2040
- $300/tonne from 2041-2050

The projected carbon prices were based on CSIRO, GenCost 2020-21 Section 3.1.7 “Government Climate & Renewable Policies.

The estimated annual emissions for the Control and Analysis Cases are in Table 48. The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged from the current mix and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose was not emissions reduction.

The Analysis Cases cost for emissions was for the existing generation up to 2050 where net emissions are zero going forward.

The cost of abatement was effectively the gross cost including the price on CO_2 for emissions divided by the emissions abated between 2020 and 2050 which provides a $/tonne CO_2 cost.

Table 48: Estimated Annual Emissions 2020 and 2050

	Control	HYBRID
Estimated Annual Emissions ($Mte\ CO_2$ @ 2020)	87	87
Estimated Annual Emissions ($Mte\ CO_2$ @ 2050)	76	0
Estimate of Cost of Abatement ($/tonne CO_{2e})	1523	Refer summary of result table below.

4.5.2 Summary of Results

Table 49 shows the estimate of comparative costs of abatement of the Analysis Cases. The cost of abatement was the result of comparing the Hybrid Scenario to the Control Scenario. The lower the value the greater benefit to the scenario, the higher the value the greater cost to the scenario.

The results suggest that the High Probability Technology Case provides the lowest estimated cost of abatement compared to the medium and low probability technology case scenarios.

Table 49 also shows the estimate of comparative net costs of abatement for the sensitivity cases which suggests Sensitivity Case 3 “Energy Efficiency” is similar to the High Probability Technology Case but with reduced energy demand and provides the lowest estimated cost of abatement for all the scenarios.

The Medium Probability Technology Case and Sensitivity Case 2 “Reduced Ammonia” have a higher cost of abatement even with the early retirement of coal fired generation which was replaced with new generation CAPEX and OPEX costs mostly related to green Hydrogen / Ammonia.

The Low Probability Technology Case has a higher cost of abatement compared to the High Probability Technology case mostly due to the higher CAPEX of solar thermal and offshore wind.

The Sensitivity Case 1 “Accelerated Net Zero” has the highest cost of abatement compared to all the scenarios due to the higher CAPEX and OPEX of solar thermal and offshore wind even with the early retirement of coal fired generation which was replaced with new generation CAPEX and OPEX costs related to green Hydrogen / Ammonia.

Also, referring to Table 48 estimated emissions, it is observed that the introduction of a price on carbon suggests that the cost of continuing with a similar energy mix currently used for existing and new generation to 2050 (the Control Scenario) has a higher net cost than transitioning to a net zero emissions outcome due to minimal emissions reduction.

Table 49: Comparative Cost Analysis Results with a Carbon Price

Case	Estimate of Comparative Cost of Abatement ($/tonne CO_{2e})
High Probability Technology Case	127
Medium Probability Technology Case	144
Low Probability Technology Case	130
Accelerated Net Zero (Sensitivity Case 1)	166
Reduced NH_3 (Sensitivity Case 2)	135
Energy Efficiency (Sensitivity Case 3)	113
Maximum Green Hydrogen (Sensitivity Case 4)	142

4.5.3 Conclusions

The main conclusions from the analysis are:

- The Control Scenario is less costly than the hybrid scenario in meeting future energy needs but does not meet emissions reduction targets;
- If a carbon cost was introduced in the future, then the Control Scenario would cost more and not meet emissions reduction targets;
- The various Analysis Cases have differing costs of abatement compared to the control scenario; and
- These costs of abatement would also be lower compared to the Control Scenario if a price on carbon was introduced.

The introduction of a price on carbon suggests an increase in the cost of CO_2 abatement when transitioning to a net zero outcome but provides an overall cost benefit due to the reduction in emissions that would be achieved in the analysis cases compared to continuing with a similar energy mix as currently used today (the Control Scenario).

This would provide a cost driver to invest in low emissions energy technology.

4.6 Environmental-Social-Economic

This analysis finds that while there was a range of environmental and social impacts associated with the scale of development envisaged, these are manageable using existing and established processes. Particular care is required to maintain community support, particularly where local stakeholders may view the scale of wind and solar development, and construction of hydrogen, ammonia and bioenergy plants as the industrialisation of rural Victoria. It should be expected that while stakeholders will support the overall approach, "not in my backyard" may become a common refrain. Government will need to ensure stakeholders understand the link between the level of development and the objective of decarbonising the Victorian economy.

Traditionally the assessment of environmental impacts and development of the required management plans is undertaken as individual projects are proposed. These regulatory processes identify the relevant environmental and social impacts and appropriate management control. Public comment and community involvement is a core requirement of these regulatory processes.

Implicit in the scale of the transition envisaged in this Study is that within each Renewable Energy Zone there are likely to be a significantly large number of individual projects. Using the project-by-project approach to assess impacts may not adequately address cumulative impacts. To ensure cumulative impacts are managed, the Victorian Government may wish to consider 'strategic level environmental assessment/s'. This could be undertaken for each Renewable Energy Zone considering the range of project developments likely to be deployed and the environmental and social receptors in each Zone. With regard to the deployment of solar thermal projects, such an assessment could add value by identifying development locations where bird loss does not threaten threatened or endangered species. As the Renewable Energy Zones only cover a small portion of the Victorian coast and offshore wind development may extend into Commonwealth Waters, a separate joint Commonwealth/State strategic level environmental assessment should be considered for the large-scale deployment of offshore wind.

Such assessments would provide consistent environmental and social management measures applicable to investments in each zone, simplifying the approval process for individual project approvals and provide greater investor certainty.

Table 50 summarises the likely investment mix in each Renewable Energy Zone (including Melbourne and surrounds) and the accompanying environmental and social stressors likely to be applicable to that zone.

Table 50: Renewable Energy Zones, Investment Type and Environmental Stressors

Renewable Energy Zone	Net Zero Investment Type	Environmental and Social Impacts
V1 – Ovens Murray	Rooftop solar Solar Bioenergy Li-ion battery storage Greenhouse gas offsets	
V2 – Murray River	Rooftop solar Wind Industrial solar Solar Bioenergy Li-ion battery storage Greenhouse gas offsets	land-use change Solar thermal bird loss
V3 – Western Victoria	Rooftop solar Wind Industrial solar Solar Bioenergy Li-ion battery storage Hydrogen/ammonia production Greenhouse gas offsets	Land-use change Solar thermal bird loss Available fresh water Resistance to industrial development
V4 – South West	Rooftop solar Wind Industrial solar Solar Bioenergy Li-ion battery storage Offshore wind Hydrogen/ammonia production Greenhouse gas offsets	Land-use change Available fresh water Resistance to industrial development Marine impacts (fishers, whale migration/breading)
V5 - Gippsland	Rooftop solar Wind Industrial solar Solar Bioenergy Li-ion battery storage Offshore wind Hydrogen/ammonia production Greenhouse gas offsets	Land-use change Solar thermal bird loss Resistance to industrial development Marine impacts (fishers, whale migration/breading) Hydrogen/Ammonia risk Air quality
V6 – Central North	Rooftop solar Industrial solar Solar Bioenergy Li-ion battery storage Hydrogen/ammonia production Greenhouse gas offsets	Land-use change Available fresh water Resistance to industrial development Hydrogen/Ammonia risk
Melbourne and surrounds	Rooftop solar Industrial solar Solar Bioenergy Li-ion battery storage Ammonia to hydrogen plants Hydrogen distribution networks	Hydrogen fire risk

Table 51 summarises significant environmental and social impacts across the analysis cases. Most issues are common across all cases varying only be degrees. The exceptions being:

- The High and Mid Probability Technology cases, Sensitivity Case 2 - Reduced Ammonia, and Sensitivity Case 3 – Energy Efficiency require greenhouse gas offsets to achieve net zero by 2050. As discussed early this is simply to balance the residual emissions arising as a consequence of the selected technologies and could be reduced by simply increasing the roll out of one or more of the selected technologies.
- The Mid Probability Technology case involves marine impacts associated with the development of ammonia import terminals. These would be comparable to any other port development and could be mitigated through the use of existing port facilities.
- Sensitivity Case 1 – Accelerated Net Zero is also involves marine impacts, but these are associated with the development of offshore wind power. Significant offshore installations will need to address issues such as impacts on cetaceans. An emerging issue in the offshore oil and gas industry is subsea noise, and electromagnetic radiation where high voltage subsea power lines are required.
- The Low Probability Technology Case and Sensitivity Case 1 – Accelerated Net Zero involve the deployment of solar thermal power generation. The global deployment of this technology is limited but has identified the issue of incineration of birds (and insects) that enter the zone of concentrated solar energy. This issue, and management actions will need to be monitored as the technology is deployed more widely.

All cased involve the manufacture of significant volumes of hydrogen via electrolysis (green hydrogen). This process uses substantial volumes of demineralised water. While substantial, these volumes are small in the context of Victoria's current water usage, it should be expected that in areas where these plants are likely to be located there will be community opposition to the diversion of water from community and agricultural purposes. It's likely any green hydrogen plant may have to supply its own water supply, for example from desalinated ground or sea water. This is a particular issue of Sensitivity Case 4 – Maximise Green Hydrogen.

Table 51: Summary of Significant Environmental and Social impacts

Significant Environmental and Social Aspects							
	High Probability Technology Case	Mid Probability Technology Case	Low Probability Technology Case	Sensitivity Case 1 Accelerated Net Zero	Sensitivity Case 2 Reduced Ammonia	Sensitivity Case 3 Energy Efficiency	Sensitivity Case 4 Maximum Green H2
Environmental Aspects							
Are the State interim emissions targets met	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Are greenhouse offset required to achieve net zero emissions in 2050	Yes	Yes (2 million tonnes)	No	No	Yes (3million tonnes)	Yes (3 million tonnes)	No
Is additional land clearing required *(land clearing and related impacts are broadly proportional to the increase in wind and solar development noted below)*	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Is there the potential for impacts to cultural heritage	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Is there potential for disturbance for environmentally sensitive areas	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Is there potential for disturbance for environmentally sensitive areas (marine)		Yes (ammonia import)		Yes (offshore wind)			
Is there the potential for increased environmental impacts (noise/light/odour) to surrounding community resulting from new power generation sources	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Do new technologies present a new or hazardous waste stream	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Do new technologies present a new environmental/safety incident risk							
- hydrogen/ammonia release	Yes	Yes	Yes	Yes	Yes	Yes	Yes
- Li-ion battery fire	Yes	Yes	Yes	Yes	Yes	Yes	Yes
- solar thermal bird loss			Yes	Yes	Yes		
- approximate annual water use for hydrogen production in 2050	7.0 ML	5.8 ML	6.8 ML	6.1 ML	6.1 ML	6.0 ML	28.7 ML
- impacts on air quality	Yes	Yes	Yes	Yes	Yes	Yes	
- marine electromagnetic radiation and noise				Yes (offshore wind)			
Perceptions of rural industrialisation	Yes	Yes	Yes	Yes	Yes	Yes	Yes
- increase in wind power relative to 2020	450%	400%	450%	350%	450%	380%	590%
- increase in solar PV relative to 2020	1800%	1000%	780%	600%	1120%	1600%	1240%
- increase in amount of battery support	19000%	10000%	10000%	10000%	14800%	16000%	9800%
- Deployment of solar thermal power generation			Yes	Yes			
Permanent employment Impacts	Reference Case	2.3 times greater than reference case	2.3 times greater than reference case	2.6 times greater than reference case	2 times greater than reference case	1.1 times greater than reference case	1.4 times greater than reference case
Potential for work force change	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Table 52 summarises the relative employment impacts of each case studied. The values represent an estimate of the number of full-time equivalent positions involved in operating the energy supply infrastructure for each analysis case, rationalised against the High Probability Technology case to provide a focus on comparing the jobs potential between the various cases. Further details of the jobs analysis estimating basis are provided in Section 3.9.

Table 52: Estimated Permanent Jobs in 2050 (Operations Phase)

"On-Site" (Operations & Maintenance) & "Off-Site" (logistics & supply, accounting, admin & support, engineering design & modification, etc)

Analysis Case	Jobs Index (Rationalised to High Probability Case)
High Probability	1.0
Mid Probability	2.3
Low Probability	2.3
Sensitivity 1 "Accelerated Net Zero"	2.6
Sensitivity 2 "Reduced Ammonia"	2.0
Sensitivitiy 3 "Energy Efficiency"	1.1
Sensitivitiy 4 "Maximum Green H2"	1.4

The following observations are made from a review of Table 52:

- **High Probability Technology Case** : low level of potential full time energy industry employment relative to the other cases, due to the scale of relatively low complexity energy generation facilities (solar PV, wind and storage).
- **Mid Probability Technology Case** : reasonably high level of potential full time energy industry employment relative to the other cases, due to the scale and complexity of the Ammonia fired power generation facilities.
- **Low Probability Technology Case** : reasonably high level of potential full time energy industry employment relative to the other cases, due to the scale and complexity of the solar thermal / molten storage facilities.
- **Sensitivity 1 "Accelerated Net Zero"** : highest level of potential full time energy industry employment relative to the other cases, due to the scale and complexity of both the Ammonia fired power generation facilities, and solar thermal / molten salt plants.
- **Sensitivity 2 "Reduced Ammonia"** : reasonably high level of potential full time energy industry employment relative to the other cases, due to the scale and complexity of the Ammonia fired power generation facilities.
- **Sensitivity 3 "Energy Efficiency"** : reasonably low level of potential full time energy industry employment relative to the other cases, due to the scale and

comparatively low level of complexity with energy generation facilities (solar PV, wind and storage).

- **Sensitivity 4 “Maximum Green H2”** : reasonably low level of potential full time energy industry employment relative to the other cases, due to the scale and comparatively low level of complexity with energy generation facilities (solar PV, wind and storage) required to support the large levels of green Hydrogen production.

5 HIGH PROBABILITY TECHNOLOGY CASE

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

5.1 Case Description

The High Probability Technology case utilises low emissions energy technology, primarily solar PV and wind, that are currently capable of delivering commercially competitive energy at an industrial scale to fill the gap between the existing & committed energy generation capacity (Table 55) and the energy demand. This gap is represented by the red arrow in Figure 29 As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

Figure 29: Forecast Energy Demand vs Generation Capacity (High Probability Technology Case)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))

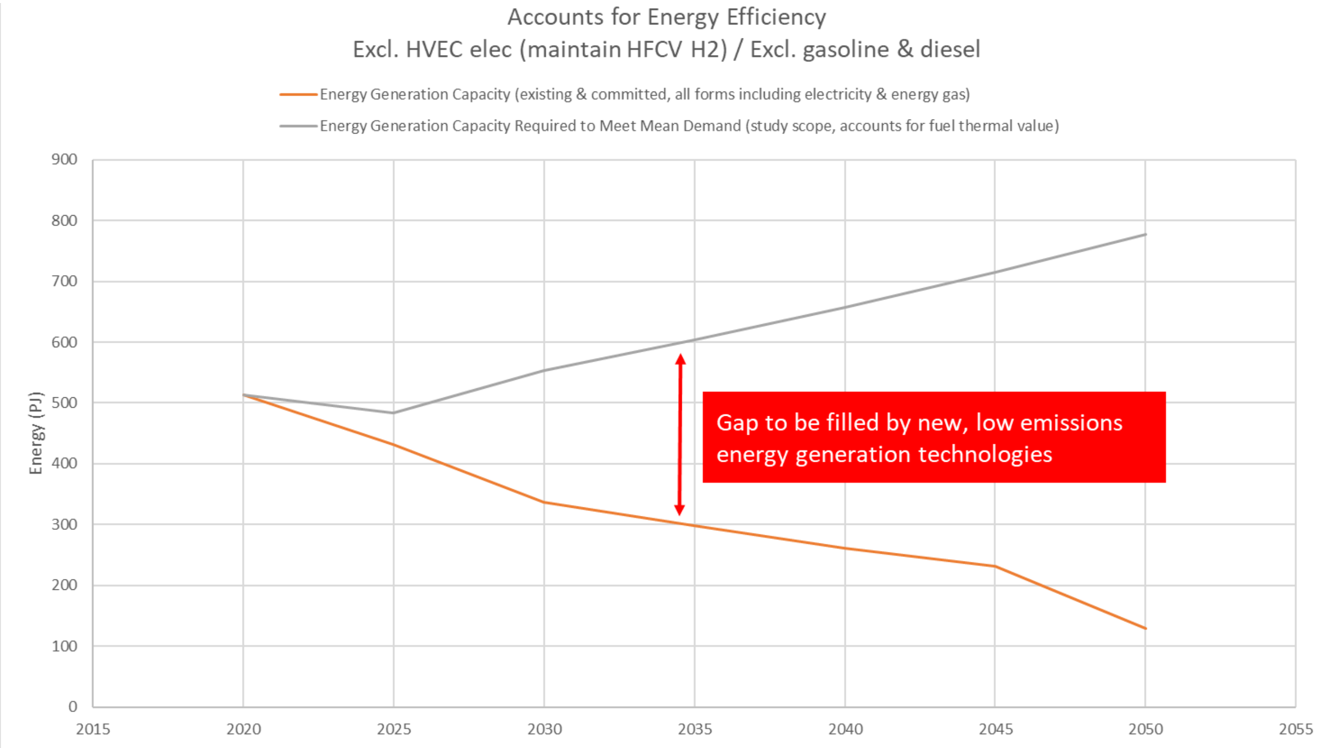


Table 53: Energy Technologies Used to Deliver Additional Capacity for the High Probability Case

Energy Type	Description
elec gen	solar PV
elec gen	wind onshore
elec gen	hydropower
elec gen	bioenergy
elec stg	pumped hydro (storage)
elec stg	batteries (storage)
gas	biomethane
gas	green Hydrogen (limited)

The low emissions technologies utilised for the High Probability Technology case are currently capable of delivering commercially competitive energy at an industrial scale.

A brief description of each of the technologies is provided overleaf.

Table 54: Energy Technology Descriptions High Probability Case

Technology	Description
Solar PV	Electricity generation from solar energy using photovoltaic panels including rooftop and industrial scale installations.
Wind Onshore	Electricity generation from wind energy using onshore wind turbines in industrial scale wind farms.
Hydropower	Electricity generation using the potential energy (elevation) of naturally filled water reservoirs to drive turbines, typically involving dams
Waste-to Energy	Electricity generation from the industrial gasification of organic waste, combustion of the synthetic gas (syngas) to drive a generator. Landfill gas involves the collection of gases, including methane, from urban landfill sites, rather industrial production of syngas.
Biogas	Electricity generation from the industrial production of gases, including methane, from the anerobic digestion of organic materials and combustion to drive a generator such as in sewage treatment plants.
Pumped Hydro	Energy storage using the potential energy (elevation) of water reservoirs where the water is pumped into the reservoir when surplus electricity is available. Electricity generation is then available on demand in the same manner as Hydropower. Pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030.
Batteries	Electrical energy storage using the electrochemical processes within batteries. Lithium-ion (Li-ion) are commonly used in residential scale, commercial scale and industrial scale applications.
Biomethane	Purified biogas, essentially methane gas, that may be used to replace natural gas in the gas distribution network
Green Hydrogen	Hydrogen that is produced from renewable energy such as solar, wind or hydropower such as electrolysis of water to produce hydrogen and oxygen.

The existing & committed energy generation capacity (Table 55) is based on that scheduled by AEMO and the energy demand is limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles

Generation capacity required to meet demand (grey line in Figure 29) is determined by subtracting the fossil fuel thermal value from the overall energy demand.

Green Hydrogen is transported to users via the existing natural gas infrastructure by blending to a maximum concentration of 10% by volume (based on materials compatibility constraints) with the balance comprising biomethane and natural gas. Biomethane production is maximised based on supply chain constraints. Further detail of the treatment of energy gas for the High Probability Technology case is provided in Section 5.3.

The fossil fuel decline profile assumed for the High Probability Technology Case is replicated from the prior Net Zero Emission Scenario Analysis Study Report May 2021, and recorded in (see Table 14 Section 3.2) with a natural gas “tail” to cater for “hard to abate” manufacturing. This natural gas could be imported through one of the state interconnectors (VNI or EGP), or as LNG.

Table 55: Existing & Committed Energy Production Capacity Assumed for Supplying Demand (High Probability Technology Case)

ELECTRICITY	2020		2030		2040		2050	
	Total Capacity MW	Generation per year PJ	Total Capacity MW	Generation per year PJ	Total Capacity MW	Generation per year PJ	Total Capacity MW	Generation per year PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	0	0
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0	0
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (generation) - wind offshore - variable - industrial	0	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
Elec (storage) - "behind the meter" non-aggregated small scale batteries (dis-connected from grid)	94	1	551	3	1,527	10	2,034	13
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**21,668**	**86**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	59	71	26
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	4	1,100	4
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to bal	170	12	170	12	170	12	170	12
Gas (import) - EGP (Eastern gas Pipeline) (to balance demand)	350	0	350	0	350	0	350	0
	1,360	**319**	**1,993**	**153**	**1,782**	**76**	**1,691**	**42**

5.2 Energy Emissions Offsets

5.2.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

5.2.2 Results & Discussion

In the High Probability Technology Case, net zero emissions were achieved in 2050 through a combination of utilising low emissions energy technologies and Carbon offsets (agro-forestry nominated). No Carbon sequestration was required.

Table 56: Mean Demand Energy Mix for the High Probability Technology Case

	2020	2025	2030	2035	2040	2045	2050
	Impact of Energy Efficiency on Energy Generation Capacity (PJ)						
Energy Generation to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	585	650	693	738	793	850
	Cumulative Energy Consumed accounting for Energy Efficiency (PJ)						
Elec (generation) - coal	144	116	89	66	44	22	0
Elec (generation) - natural gas (baseload + peaking)	5	5	4	4	0	0	0
Elec (generation) - hydropower	10	10	10	10	10	10	10
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	48	115	145	180	215	274
Elec (generation) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	28	57	90	105	108	109	127
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	29	38	47
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	2	3	3	3	4
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	1	15	64	91	118	140	190
Gas (generation) - natural gas (all sources)	209	189	171	146	128	84	50
Gas (generation) - biomethane	0	1	4	11	19	27	41
Gas (generation) - H2 (green) [incl HFCV fuel]	0	18	30	30	30	35	41
Vehicles - (ICE) gasoline & diesel	318	265	214	155	96	48	0
Vehicles - (BEV) electricity	0	10	19	35	51	57	64
Vehicles - (HFCV) electricity [GENERATION]	0	21	41	43	45	56	66
TOTAL (PJ)	732	759	867	866	862	844	913

Table 56 reveals that:

- In 2020, gasoline & diesel (ICE vehicles) are the single biggest energy source at approximately 320 PJ-thermal, or approximately 45% of the total, with natural gas in second position at approximately 210 PJ-thermal or approximately 30% of the total, and electricity from coal in third position at approximately 145 PJ-electricity or approximately 20% of the total.
- In 2030, the first and second largest single energy sources remain occupied by gasoline & diesel (ICE vehicles) and natural gas, however in third position electricity from coal has been replaced by solar PV providing approximately 115 PJ-electricity or approximately 15% of the total.
- In 2040, the decline of fossil fuels accelerates, with first position now held by solar PV providing approximately 180 PJ-electricity or approximately 20% of the total. Natural gas remains very significant in second position with approximately 130 PJ-thermal or approximately 15% of the total, however closely followed in third position

is storage* providing approximately 120 PJ-electricity or approximately 15% of the total.

- In 2050, none of the fossil fuels are represented in the top three largest sources. First position remains with solar PV providing approximately 275 PJ-electricity or approximately 30% of the total. Storage* has now moved firmly into second position with approximately 190 PJ-electricity or approximately 20% of the total with third position now occupied by wind with approximately 130 PJ-electricity or approximately 15% of the total.

  *For the High Probability Technology Case, storage includes batteries (current technology) in several modes : large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

Also noteworthy from Table 56 is the increased diversity of energy sources resulting from the transition:

- In 2020 the top three single energy sources (gasoline & diesel, natural gas & coal) represented approximately 90% of the total energy mix;
- In 2030 the top three (gasoline & diesel, natural gas & solar PV) represented approximately 60% of the total energy;
- In 2040 the top three (solar PV, natural gas & storage) represented approximately 50% of the total energy; and
- In 2050 the top three (solar PV, storage and wind) represent approximately 65% of the total energy.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity),

Figure 30 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In 2020, approximately 205 PJ-electricity is consumed, being approximately 50% of the total energy, and approximately 210 PJ-thermal energy gas is consumed being approximately 50% of the total energy.
- In 2030, approximately 410 PJ-electricity is consumed, being almost 70% of the total energy, and approximately 205 PJ-thermal energy gas is consumed being approximately 30% of the total energy.
- In 2040, approximately 545 PJ-electricity is consumed, being approximately 75% of the total energy, and approximately 175 PJ-thermal energy gas is consumed being approximately 25% of the total energy.
- In 2050, approximately 715 PJ-electricity is consumed, being approximately 85% of the total energy, and approximately 130 PJ-thermal energy gas is consumed being approximately 15% of the total energy.

Figure 30: Energy Mix Breakdown for the High Probability Technology Case Covering only Electricity & Energy Gas (excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

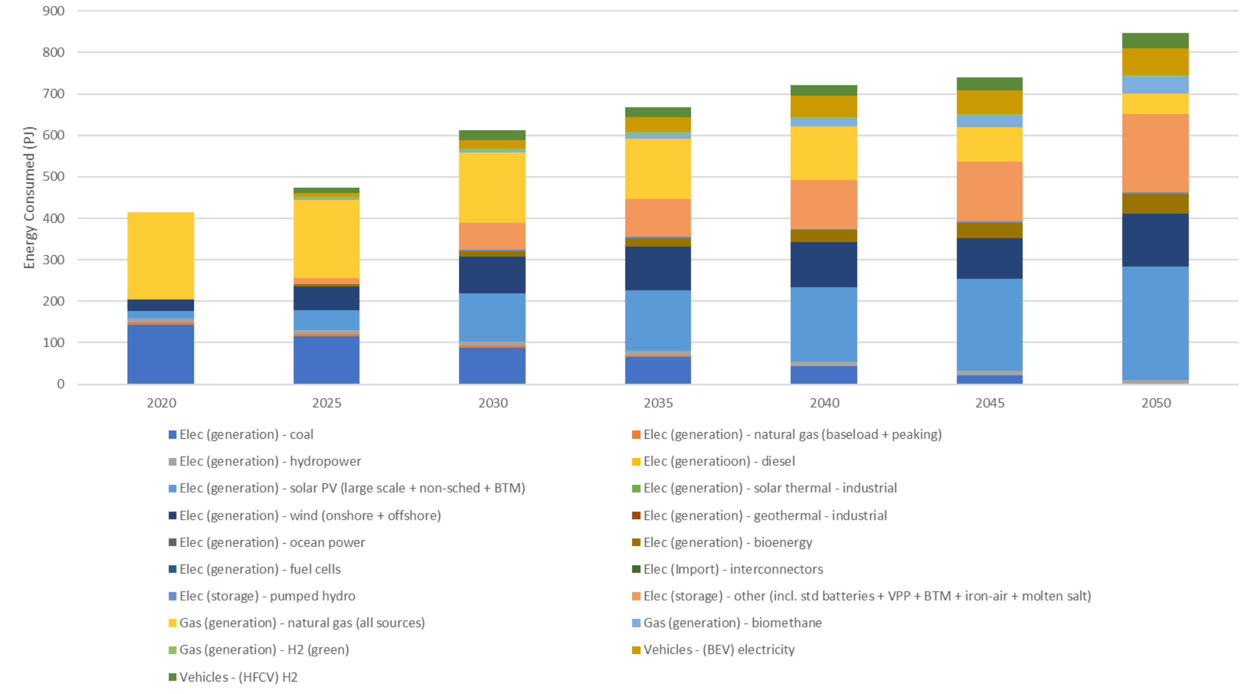


Table 57 : Emissions for the High Probability Technology Case (rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	37	28	21	14	7	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	2	2	3	4
Elec (generation) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	1	2	3	4	4	4	5
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-7	-9	-11
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	15	13	11	8	4
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	14	10	6	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**61**	**47**	**33**	**17**	**3**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**-1**	**-1**	**-2**	**-2**	**-3**
NET EMISSIONS	**87**	**74**	**60**	**46**	**31**	**15**	**0**

Figure 31: Emissions Profile for the High Probability Technology Case

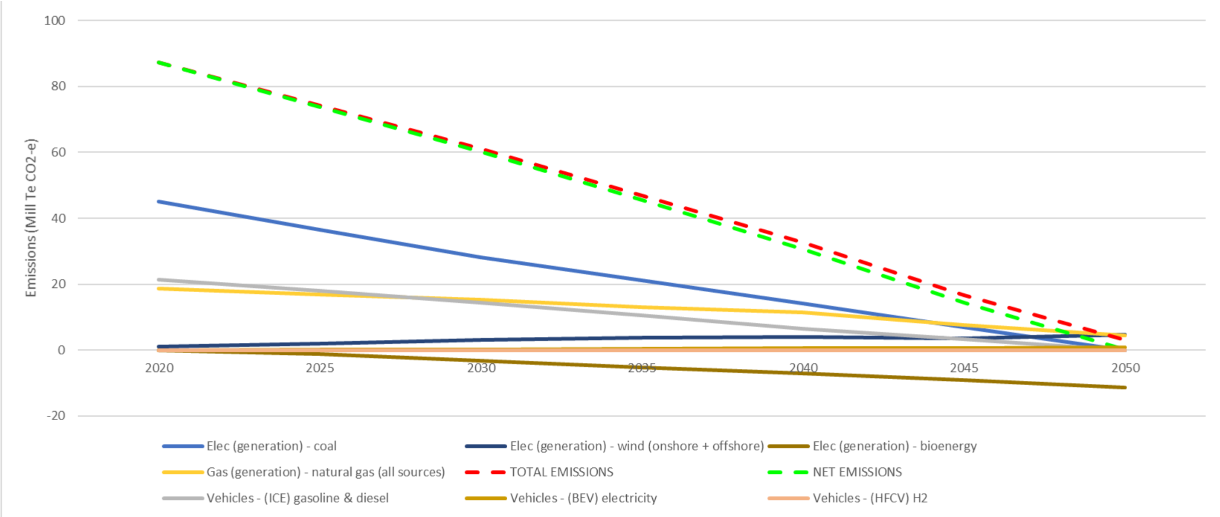


Table 5 (Section 1.6.4) documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for the High Probability Technology case is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be :

- 2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and
- 2030 interim emissions target: up to 9 Million Te CO_2-e to cover out of scope emissions.

Table 57 and Figure 31 illustrate the steady decline in net emissions over time as low emissions technologies replace fossil fuels. Bioenergy is noteworthy as the only technology with a negative emissions contribution (based on avoided emissions from agriculture and waste – refer to Section 3.9.5), providing a dis-proportionately large contribution to reducing emissions. In 2050, despite its limited share of the energy mix (approximately 50 PJ-elec or 5%, set by supply chain constraints), it contributes negative 11 Million Te CO_2-e emissions or approximately 75% of the reduction of emissions to net zero, with the remainder (approximately 25%) contributed by offsets.

On the contrary, coal represents a dis-proportionately large contribution to emissions. In 2020, with approximately 145 PJ-electricity or approximately 20% of the energy mix, coal contributes 45 Million Te CO_2-e emissions (approximately 50% of total). Sitting between bioenergy and coal are :

- Gasoline & diesel (ICE vehicles). In 2020 these fuels represent approximately 320 PJ-thermal consumed (approximately 45% of the total) and contribute approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Natural gas. In 2020 it represents approximately 210 PJ-thermal consumed (approximately 30% of the total) and contributes approximately 20 Million Te CO_2-e emissions (approximately 20% of the total). In 2050 it provides approximately 50 PJ-thermal consumption (approximately 5% of the total) and contributes 4 Million Te CO_2-e emissions (approximately 25% of the total positive emissions).
- Low emissions electricity excluding bioenergy but including hydroelectric, solar PV, wind, pumped hydro and other storage*. In 2020 these low emissions technologies represent approximately 60 PJ-electricity consumption (almost 10% of the total), but contribute only 1 Million Te CO_2-e emissions (approximately 1% of the total positive emissions). In 2050 they provide approximately 730 PJ-electricity consumption – including electricity to charge BEVs and generate green Hydrogen for HFCVs - (approximately 80% of the total) but contribute only approximately 10 Million Te CO_2-e emissions (approximately 70% of the total positive emissions). An explanation description of emissions factors for renewable electricity technologies is provided in Section 3.9.5.

  *For the High Probability Technology Case, storage includes batteries (current technology) in several modes : large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).
- Low emissions energy gases including biomethane and green Hydrogen. In 2050 they provide approximately 80 PJ-thermal consumption – including fuel for HFCVs - (almost 10% of the total) but have no emissions.

Figure 32: Contribution to Emissions by Source for the High Probability Technology Case

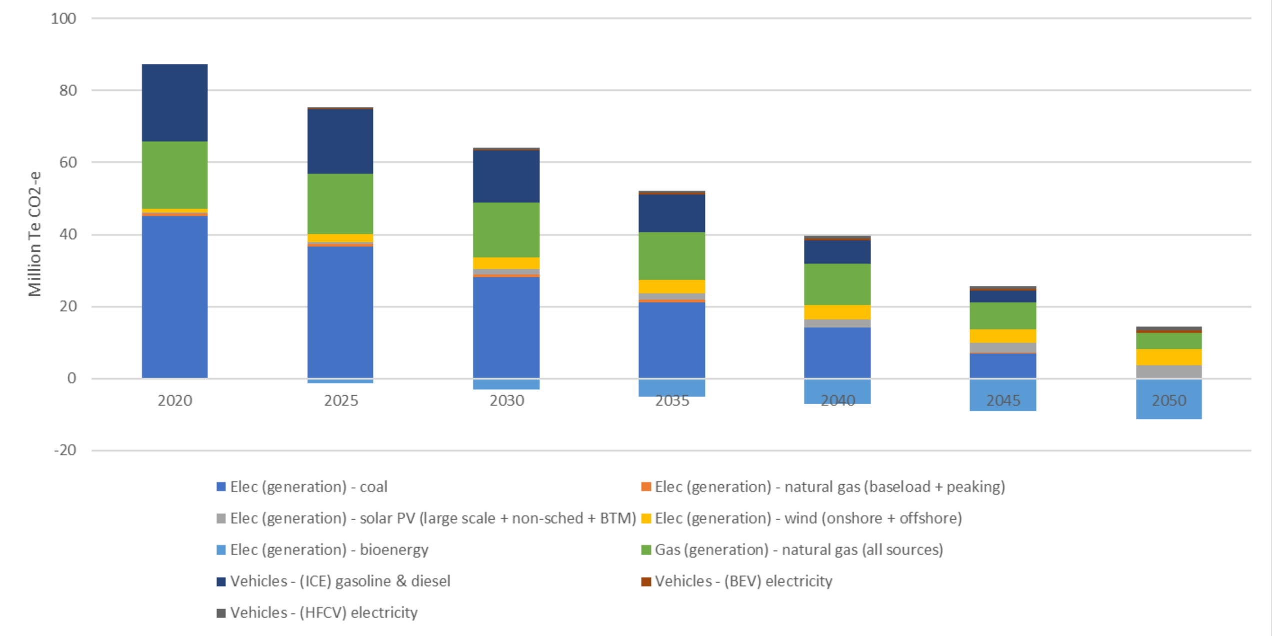


Figure 33: Agro-Forestry Offsets Utilised to Reach Net Zero Emissions for the High Probability Technology Case

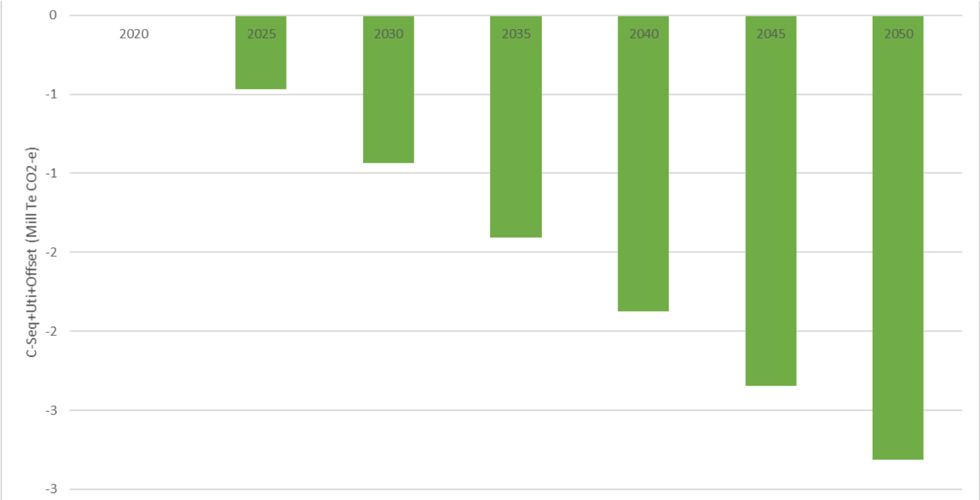
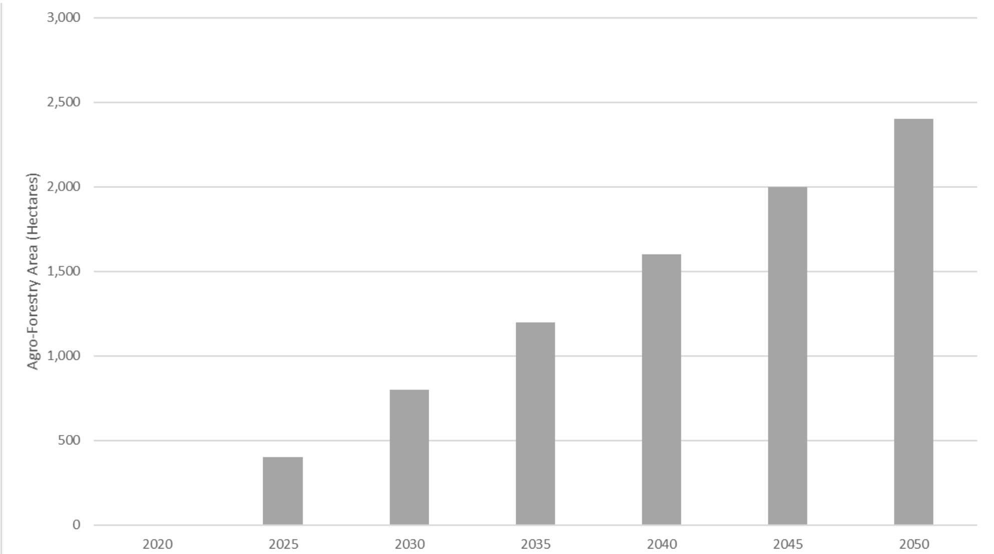


Figure 34: Area Required for Agro-Forestry Offsets in the High Probability Technology Case



For the current study, offsets derived from soil farming projects have been assumed to illustrate how residual emissions could be managed, see Section 3.4 for an assessment of the options, and Section 5.7 for cost estimation. Figure 33 and Figure 34 indicate that 800 hectares are required to be established every decade to achieve net zero emissions in 2050, commencing with 400 hectares in 2025, resulting in a cumulative total of 2,400 hectares in 2050, representing approximately 0.01% of Victoria's total land area.

5.3 Gas Spatial Analysis

5.3.1 Work Description

The proposed energy mix from the global modelling tool is used as an input into the spatial modelling tool. The spatial distribution of the gas demand has been kept in same proportion as the 2020 demand.

5.3.2 Results

In line with the heuristic analysis method and the practical set of starting point data selected, the modelling undertaken produces single non-unique solutions. These solutions should be interpreted as indicative of the trend in the solution but are not fully optimised and subject to a range of assumptions as detailed in other parts of this report.

Table 58 shows the energy gas demand by region from 2020 to 2050. It can be seen that the overall energy gas demand reduces by more than 50% from 209 PJ/yr in 2020 to 94 PJ/yr in 2050. Note that Table 58 refers to the energy gas demand to be distributed to customers via the high pressure transmission pipelines and the low pressure distribution network. Thus, the demand differs from Table 56 which also includes green hydrogen for heavy fuel cell vehicles which is assumed will be distributed to customers separately in compressed or liquified form or generated on-site at refuelling stations.

Table 58: Energy gas demand by region for the High Probability Technology case from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	129	122	111	1013	95	72	59
North East	6	5	6	5	4	4	3
Loddon Mallee	21	19	18	16	15	11	9
Grampians Central West	19	18	17	15	13	11	9
Barwon South West	25	24	21	19	17	13	11
Gippsland	5	4	4	3	3	2	2
Goulburn Valley	5	4	4	3	3	2	2
Total (PJ/yr)	**209**	**196**	**180**	**162**	**151**	**114**	**94**

In 2020 there was a 145 PJ/yr production surplus which is forecast to reduce to a 7 PJ/yr shortfall by 2024 (VGPR Update 2020). The gas demand has been satisfied by:

- 158 PJ/yr from Bass Strait gas fields via Longford gas plant in Gippsland
- 39 PJ/yr from Otway basin gas fields
- 12 PJ/yr from the Victorian Northern Interconnector

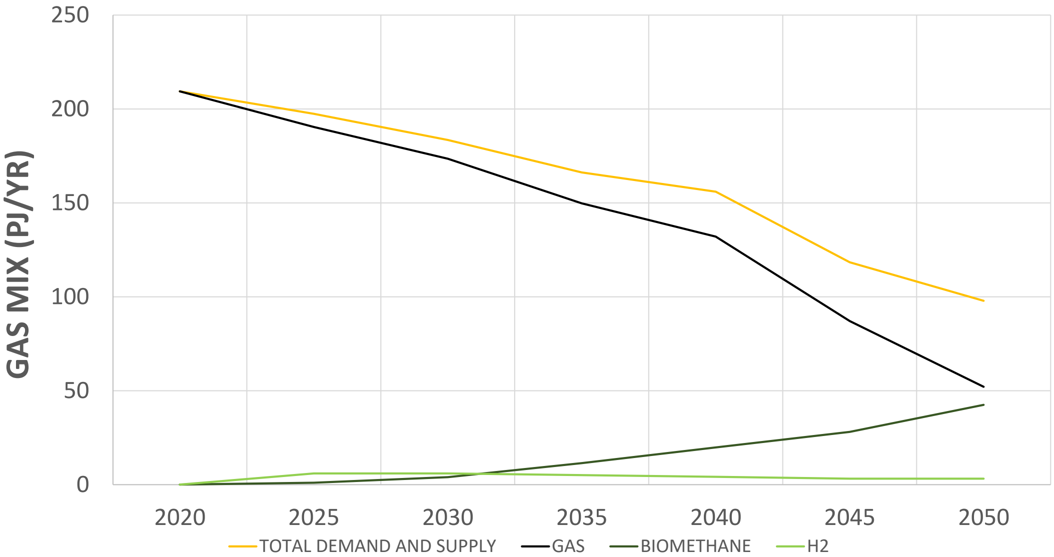
In the High Probability Technology case the overall demand declines and the natural gas supply is supplemented by renewable biomethane and hydrogen blending (up to 10% by volume). Table 59 shows the distribution of energy gas supply by type from 2020 to 2050. Biomethane production ramps up from 1 PJ/yr in 2025 to 43 PJ/yr in 2050. Green hydrogen supply is relatively low ranging from 3 PJ/yr to 6 PJ/yr over the period and reduces after 2030 in order to limit the volume in the gas blend to a maximum of 10% H_2 by volume in the transmission system.

Table 59: Energy gas supply by type for the High Probability Technology case from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	197	174	145	118	100	55	20
New Victorian natural gas production or imports	12	15	26	28	28	29	30
Biomethane	0	1	4	11	19	27	41
H2 (green)	0	6	6	5	4	3	3
Total (PJ/yr)	**209**	**196**	**180**	**162**	**151**	**114**	**94**

Figure 35 shows the energy gas mix in the transmission system from 2020 to 2050. The gas in the figure includes natural gas produced in Victoria, and new Victorian natural gas production, natural gas imported via pipeline from other states and LNG imported via a proposed new import facility.

Figure 35: Energy gas mix in the transmission system for the High Probability Technology case from 2020 to 2050.



There are a number of consequences of the changes in supply and demand. Firstly, the lower overall system demand will mean that fixed costs will be distributed over a smaller gas volume which would likely increase the specific costs in terms of $/GJ. However, these increases are unlikely to be very significant in comparison with the additional costs associated with biomethane and hydrogen production. By 2050, 44 PJ/yr of the 94 PJ/yr demand (47%) will come from biomethane and hydrogen. Production costs for biomethane are expected to range between 10 to 30 $/GJ depending upon bioenergy resource, feedstock cost, plant capacity, technology and other factors (Bioenergy Australia, 2019), while the energy equivalent cost of hydrogen at 2 $/kg is 17 $/GJ and at 3 $/kg is 25 $/GJ. Therefore, it is expected that the production costs for renewable gas will likely be about three times the historical gas cost and will be least twice as expensive in real terms as the current costs for natural gas in Victoria. Appropriate policy settings will need to be in place to manage these changes.

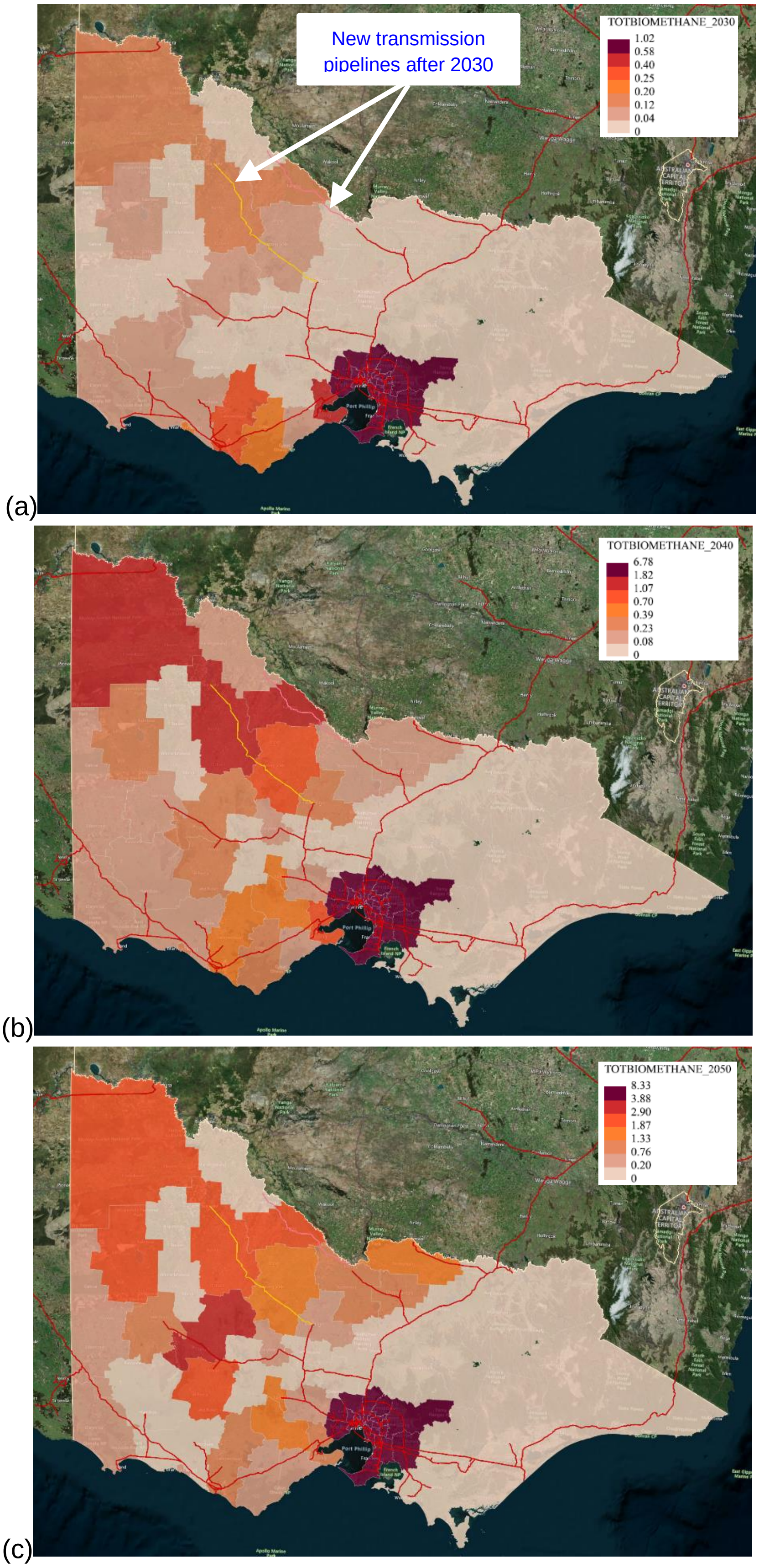
The changes in the demand and supply for the High Probability Technology case are shown in the following table. It can be seen that in 2020, natural gas was predominately transported from Bass Strait/Gippsland (153 PJ/yr) and Otway Basin/Port Campbell (14 PJ/yr) to Melbourne and other centres of demand. By 2050, the demand and supply situation has become more evenly distributed. Biomethane in Melbourne can supply 8 PJ/yr and other supplies account for 12 PJ/yr reducing the gas transmitted to the Melbourne region from 129 PJ/yr in 2020 to 39 PJ/yr in 2050. The Loddon Mallee region becomes self-sufficient in renewable gas and the Grampians Central West region has excess renewable gas capacity to supply other regions. The Goulburn Valley region is also self-sufficient and has excess renewable gas capacity.

Table 60: Regional demand and supply for energy gas in 2020 and 2050. Positive transmission rates mean gas is transmitted to the region, while negative transmission rates mean gas is transmitted from the region.

	2020			2050		
Region	**Demand**	**Supply**	**Transmitted To**	**Demand**	**Supply**	**Transmitted To**
Melbourne	129	0	129	59	20	39
North East	6	0	6	3	0	3
Loddon Mallee	21	0	21	9	9	0
Grampians Central West	19	0	19	9	15	-6
Barwon South West	25	39	-14	11	9	2
Gippsland	5	158	-153	2	20	-18
Goulburn Valley	5	0	5	2	4	-2
From outside Victoria	0	12	-12	0	17	-17

Figure 36 shows the spatial distribution of biomethane production in 2030, 2040 and 2050.

Figure 36: Biomethane production for High Probability Technology case in (a) 2030, (b) 2040 and (c) 2050.



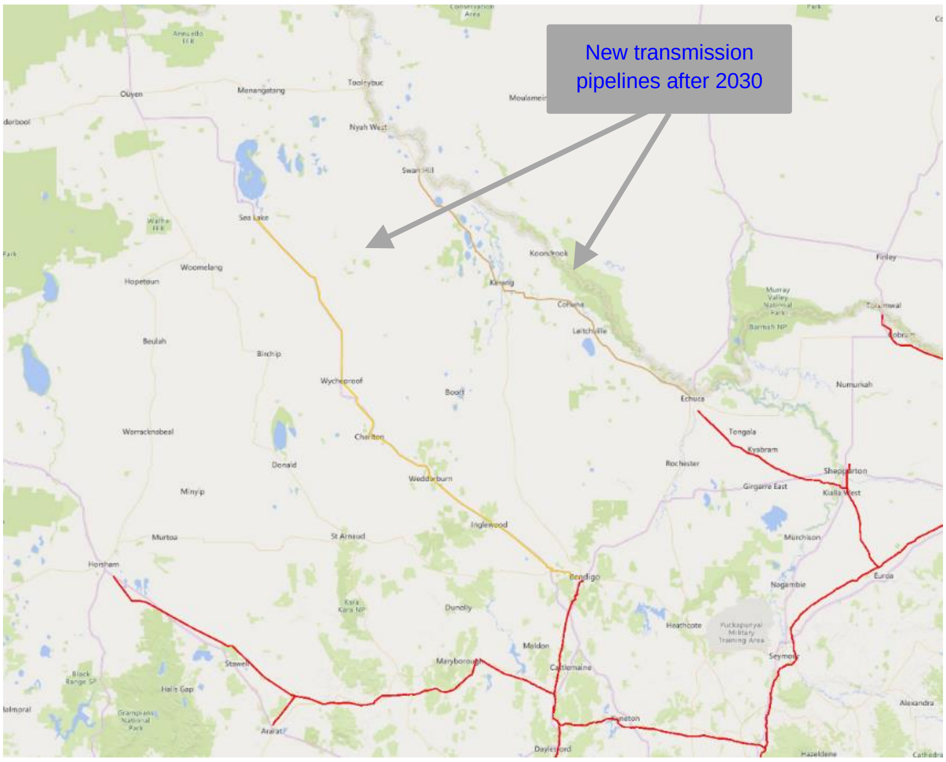
It can be seen that biomethane production is concentrated in Melbourne, the Grampians Central West and Loddon Mallee districts and with some production in Goulburn Valley and North East regions. The production of biomethane comes from upgrading of biogas from anaerobic digestion and gasification of solid biomass to synthesize methane. The biomethane produced in Melbourne is derived from domestic food and organic waste, while the biomethane produced in the Grampians Central West and Loddon Mallee regions are produced mostly from the digestion of animal manure, fruit and vegetable wastes, canola residues as well as the gasification of straw residues.

After 2030, straw residues in Loddon Mallee, Grampians Central West and Barwon South regions are collected and gasified to produce synthetic methane. The resources in the north of the state are not close to existing pipelines, and so two new pipelines are proposed to be built by 2035:

1. Echuca to Swan Hill, 150 kilometres long, capacity 15 PJ/yr
2. Bendigo to Sea Lake, 210 kilometres long, capacity 15 PJ/yr

Figure 37 shows the routes of the proposed pipelines. The pipelines will move gas from the northern and western regions to demand centres in Echuca and Bendigo and then onto other centres. For example, a combination of biomethane production in the north and west and local production around Ararat and Horsham will mean that the western parts of Victoria will be more than self-sufficient in renewable gas production.

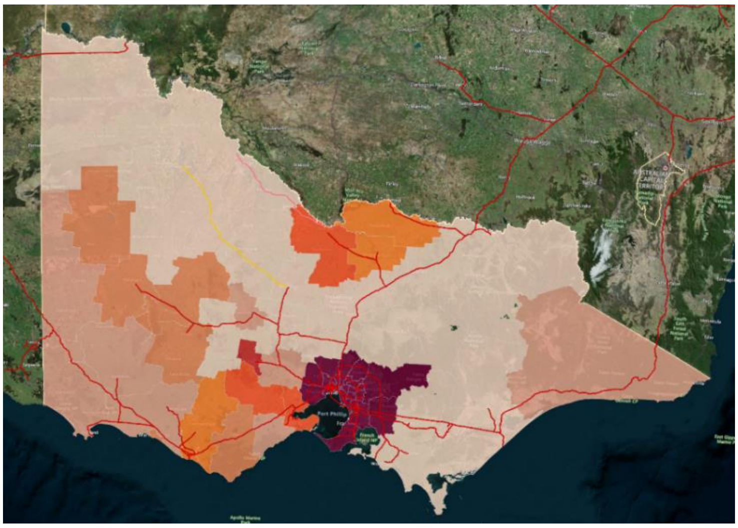
Figure 37: Proposed new pipelines to transport biomethane to market.



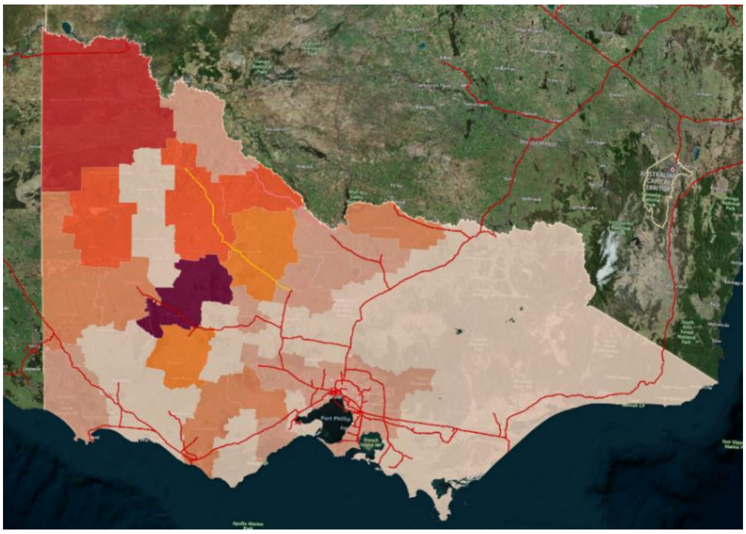
In the High Probability Technology case the additional pipelines are required by 2035. However, it is possible that this infrastructure could be delayed until 2040 if there is a concentrated focus on converting almost all of the readily available organics into biomethane using anaerobic digestion. Alternatively, if more hydrogen can be produced and used locally this would reduce biomethane demand in the transmission system. In the High Probability Technology case there is a demand of 20 PJ/yr for biomethane in 2040, while potential supply from anaerobic digestion is estimated at around 23 PJ/yr and potential supply from biomass gasification is estimated at 33 PJ/yr. In the Loddon Mallee and Grampians Central West regions straw residues are gasified to produce biomethane and its these resources in particular which are currently stranded from the market.

Figure 38 shows the spatial distribution of these sources. In Melbourne biomethane is made from separated organics in domestic waste from anaerobic digestion with total production across the metropolitan area reaching over 8 PJ/yr by 2050. Outside of Melbourne animal manure, canola residues and fruit and vegetable wastes are the main sources of organics for anaerobic digestion in the Barwon South West, Grampians Central West and Goulburn Valley regions.

Figure 38: Biomethane sources: (a) biomethane from anaerobic digestion and (b) biomethane from biomass gasification.



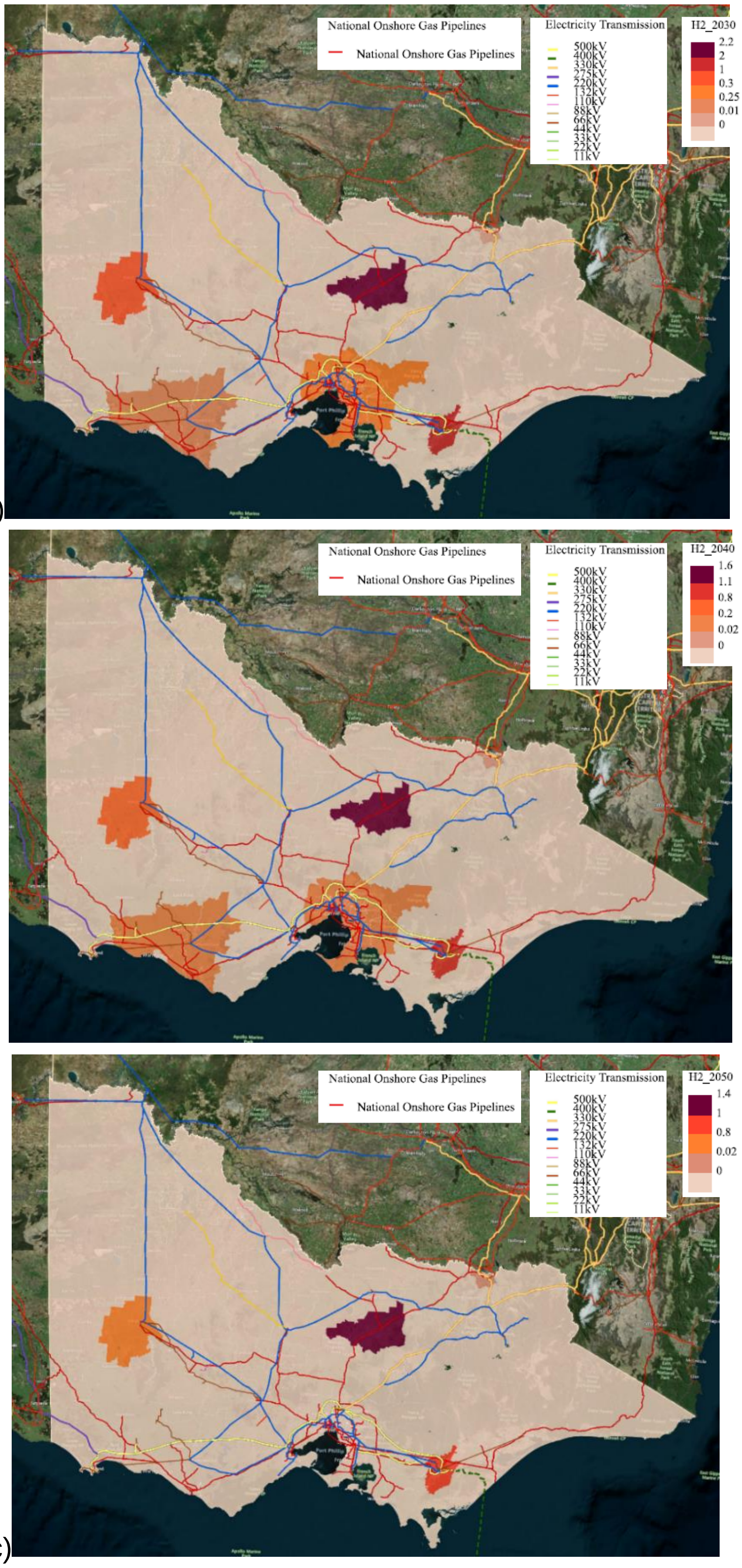
(a)



(b)

The location of green hydrogen generation for the High Technology Probability case is shown in Figure 39. Green hydrogen is produced from electrolysis of water.

Figure 39: Hydrogen generation locations in (a) 2030, (b) 2040 and (c) 2050.



(a)

(b)

(c)

Hydrogen generation has been located close to electrical transmission infrastructure and natural gas pipeline infrastructure as well as in areas where there is significant relatively flat land available. Hydrogen production is located in Latrobe Valley, Gippsland, around Shepparton in the Goulburn Valley, around Stawell and Ararat in the Grampians Central West and in the vicinity of Warrnambool in the Barwon South West. The exact locations for hydrogen production can be further optimised in future as there are many potential options for siting hydrogen production and its injection into the gas transmission system. The proposed solution provided here distributes the relatively modest hydrogen production throughout the state in regions where electrical and transmission infrastructure is available.

Water requirements for the hydrogen production are modest, with a specific demand of 0.15 GL/PJ-H_2 and a peak water demand for hydrogen production of less than 1 GL/year, which is less than 0.02% of the water currently used in agriculture. In 2030, when there is a peak demand of 6 PJ/yr of hydrogen, the associated water consumption is approximately: 0.08 GL/yr in Barwon South West, 0.3 GL/yr in Gippsland, 0.15 GL/yr in Grampians Central West, 0.33 GL/yr in Goulburn Valley and 0.05 GL/yr in Melbourne.

A consequence of the above changes is that the natural gas flows in the transmission system reduce significantly between 2020 and 2050 and in some sections of the network the flow direction will need to be reversed. In the Loddon Mallee region biomethane will flow from the new pipeline from Swan Hill to Echuca and then to Shepparton from 2035 with 2 PJ/yr excess capacity in 2050 that can be sent to Melbourne. NSW would supply circa 20 PJ/yr to Victoria via Victorian Northern Interconnector. Gas flows from Melbourne to the Loddon Mallee, Grampians Central West and Barwon South West regions which have traditionally been about 20 – 25 PJ/yr would reduce to 3 to 6 PJ/yr with only the Barwon South West being deficient in gas supply and requiring a net supply (see Table 60). The Eastern Gas Pipeline could be decommissioned from Longford if there is no longer a need to supply the Bairnsdale Power Station and New South Wales.

5.3.3 Discussion

The proposed solution to the High Probability Technology case has the following characteristics:

- Total biomethane production is ramped up from 1 PJ/yr in 2025 to 41 PJ/yr in 2050.
- Biomethane from anaerobic digestion commences at 1 PJ/yr in 2025 and ramping up to 8 PJ/yr by 2035 and approaching 20 PJ/yr by 2045.
- While biogas production for electricity production and combined heat and power projects is already being practiced at a small scale in Victoria, it is generally accepted that upgrading biogas to biomethane has a total cost of gas production in the range of 10 to 40 $/GJ (Bioenergy Australia, 2019), with the final cost sensitive to a range of factors such as: feedstock pricing, biomethane yield, transport costs, digester size etc. Therefore, to stimulate the modelled supply it is expected that appropriate policy settings will be required. This could include implementation of an ERF method under the Clean Energy regulator, mandates to achieve specific biomethane supply targets and/or regulations to ensure natural gas retailers purchase a specific mix of renewable natural gas, similar to what the Renewable Energy Target has done for the electricity network.

- Biomethane from biomass gasification is deployed commencing in 2030 in the Western and North Western parts of the state using wheat straw residues. Production commences at a relatively low rate of < 1 PJ/y in 2030 and ramping up to just over 20 PJ/yr by 2050. To get this gas to the dominant demand centre in Melbourne, two new pipelines are proposed to be built by 2035.
- The proposed new pipeline routes are indicative and further work is required to establish the economic viability and finalise the optimum route and required extent of the pipelines. The timing of the pipelines could also be deferred if concentrated effort was expended to maximise biomethane production from anaerobic digestion of organics in Melbourne, the Grampians Central West, Barwon South West, Goulburn Valley and other regions.
- Like biomethane production from anaerobic digestion, biomethane from biomass gasification will also need policy support in order to stimulate demand. While biomass gasification is a proven technology, its application to produce biomethane is not yet deployed on a wide scale, mostly due to the cost of production plants. Therefore, in order to improve the commercial readiness index of this technology, additional support for demonstration and first of a kind commercial projects will be beneficial in the next five years, with initial projects constructed in the period 2025 to 2030.
- In regard to biomethane production, the proposed solution leverages the most appropriate bioenergy conversion technology for each resource and considers the commercial readiness of each technology.
- In some sections of the transmission network, as biomethane supplies are brought onstream and specific regions become self-sufficient in gas and then have surplus gas, the direction of flow of the gas will change direction. For example, in the western parts of the state biomethane production will lead to surplus requirements that can be transmitted to regional centres and ultimately Melbourne. These changes would need to be planned in advance and would require relatively minor modifications to the network. The major challenge is likely how to balance biomethane demand and supply at each location in time.
- Hydrogen production is relatively modest as it has been limited to 10% volume in the transmission system. Additional hydrogen production directly into the distribution system could also be considered in Melbourne and regional centres and this would reduce overall demand of fossil derived natural gas even further, though it would likely require modifications to user appliances. Sensitivity Case 4 provides a specific case with hydrogen injection into the distribution system.
- Hydrogen production has been located in areas with good pipeline access and good electrical infrastructure, however the locations are indicative and further work on optimal siting is required. However, selecting different locations will not significantly affect the overall solution. Water consumption for hydrogen production is less than 1 GL/yr.

5.3.4 Gas Pipeline Network Changes

For the High Probability Technology case, the major changes in the gas transmission network can be summarised as:

- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035.
- Transmission of biomethane/hydrogen gas mixtures from Echuca/Shepparton/Bendigo and Ballarat towards Melbourne from 2035.
- Decommissioning of the Eastern Gas Pipeline from Longford to NSW
- Decommissioning of the SEA gas pipeline to South Australia
- For the High Probability Technology case, the major changes in the gas distribution networks can be summarised as:
- Less than 10% of distribution network to be decommissioned.

5.4 Electrical Spatial Analysis

5.4.1 Key References & Assumptions

Victoria regional split:

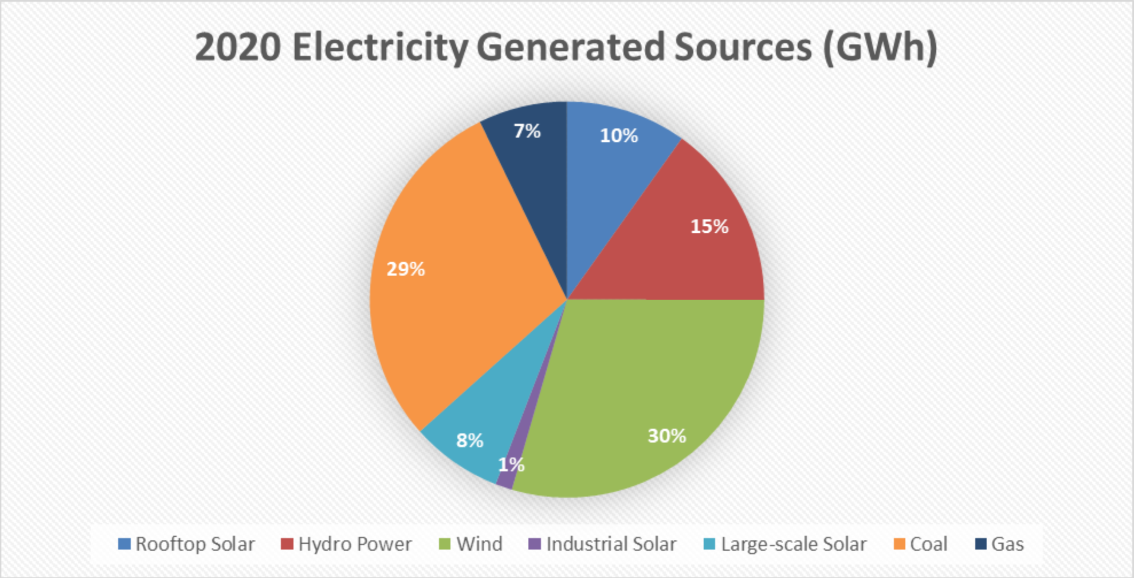
- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

5.4.2 Work Description

For the High Probability Technology Case, the main electrical generation infrastructure are wind, solar PV and bioenergy and the main electrical storage technology is the Li-ion battery (large-scale, industrial and behind the meter scale).

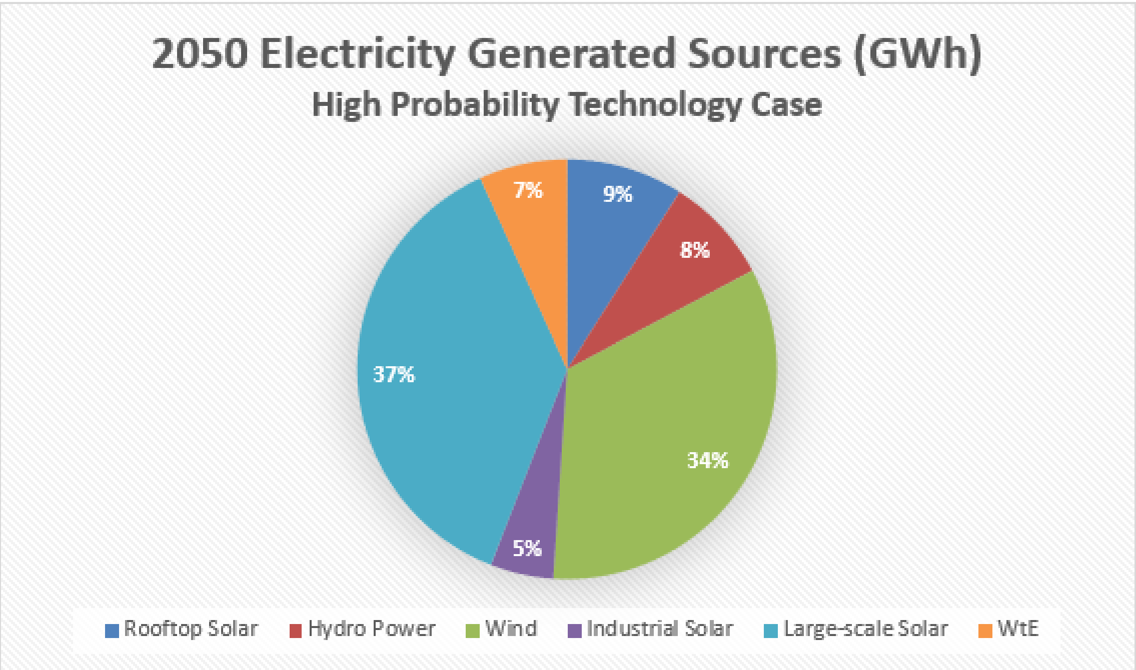
REMINDER: **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents on average the quantity of energy that can be generated by an asset for any given time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage of the working time of an asset over a given time period (a year for example).

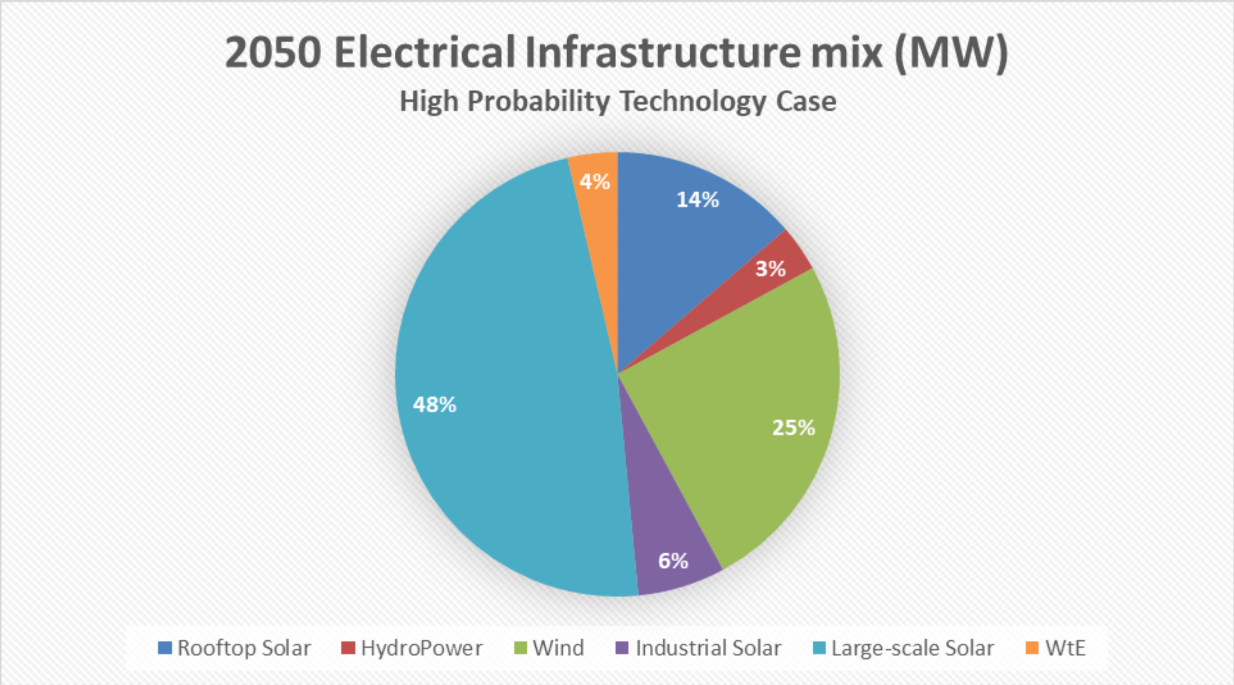
Electrical Generation Mix in 2020:



Electrical Mix in 2050:

(Note Reference in figures to “waste-to-energy” shall be read as “bioenergy”)





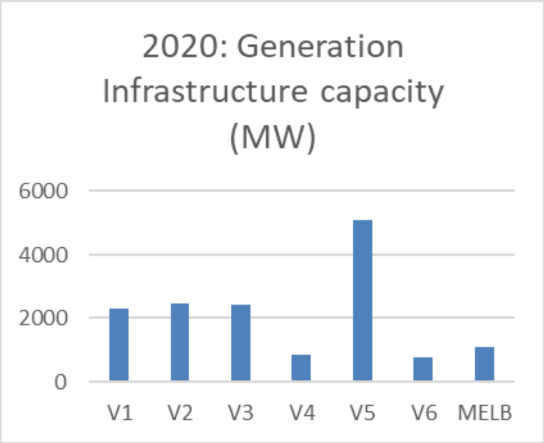
The electrical infrastructure capacity (MW) was found to increase by a factor of 4.3 over those 30 years, while the electrical generation (GWh or PJ) increased by a factor of 1.8. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

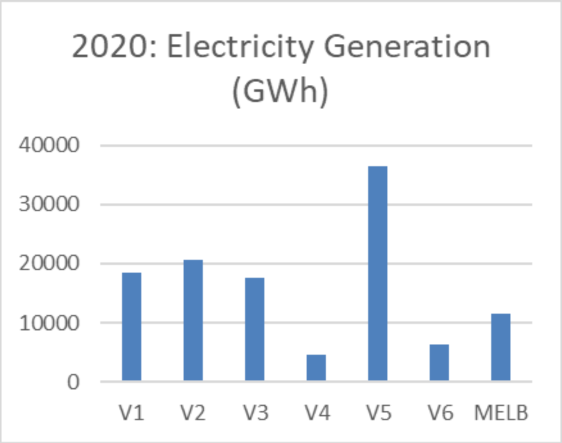
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	214 902	65 807

5.4.3 Results

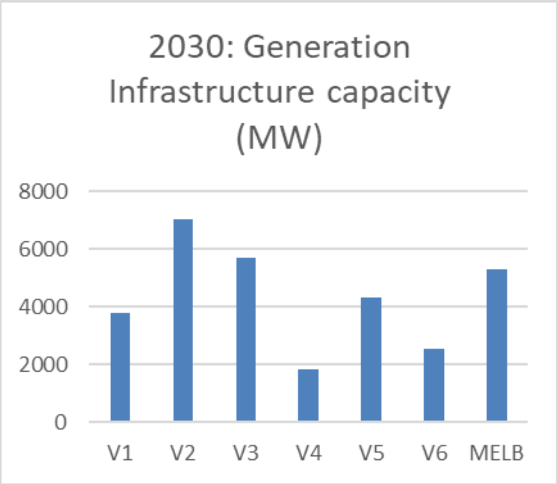
5.4.3.1 Overall Electricity Infrastructure Generation

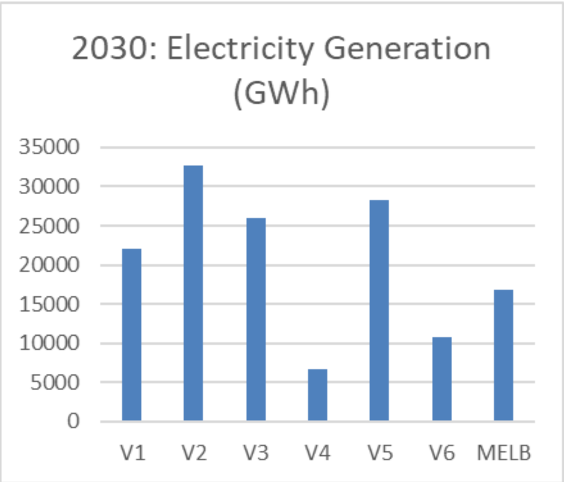
2020 generation infrastructure capacity (MW) and electricity generation (GWh):



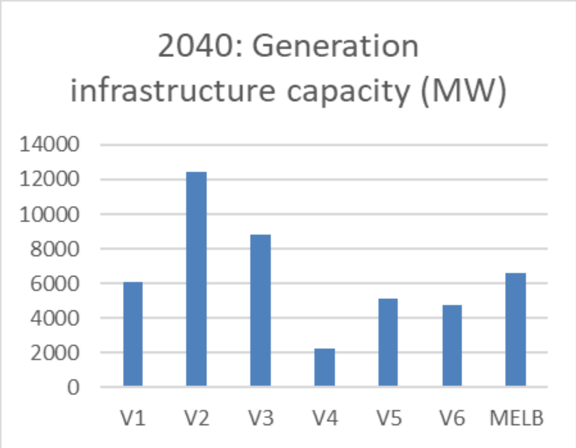


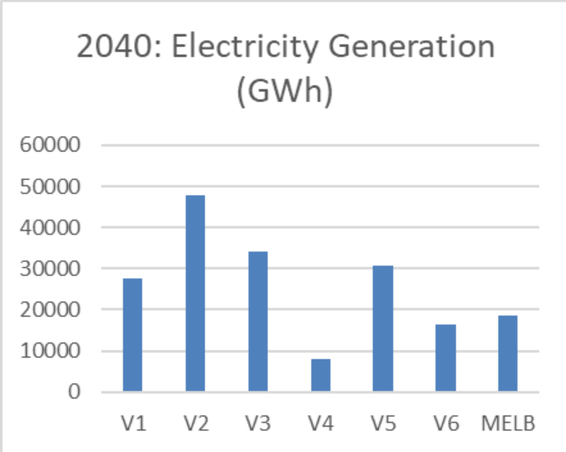
2030 generation infrastructure capacity (MW) and electricity generation (GWh):



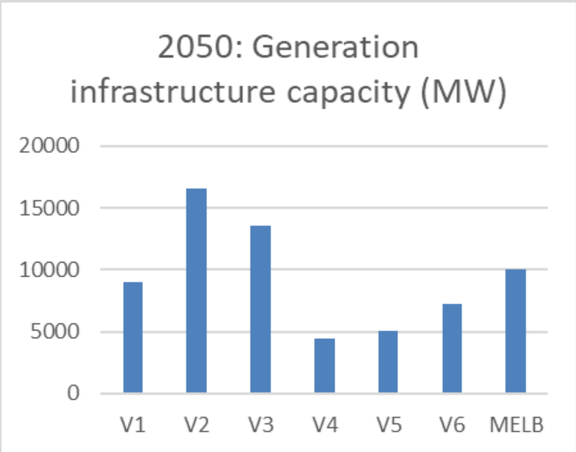


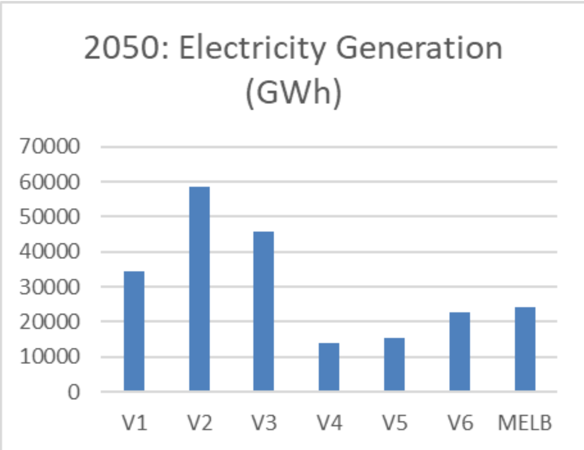
2040 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity in each REZ.
- Ovens Murray (V1), Central North (V6) and Melbourne (MELB) have an averaged generation capacity.
- South West (V4) and Gippsland (V5) have a low generation capacity compared to other REZs.
- Murray River (V2) and Western Victoria (V3) have a high generation capacity.

The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.
REMINDER: The assumptions used here are based on the AEMO’s ISP input and assumptions workbook which we have been used as "relied on information".

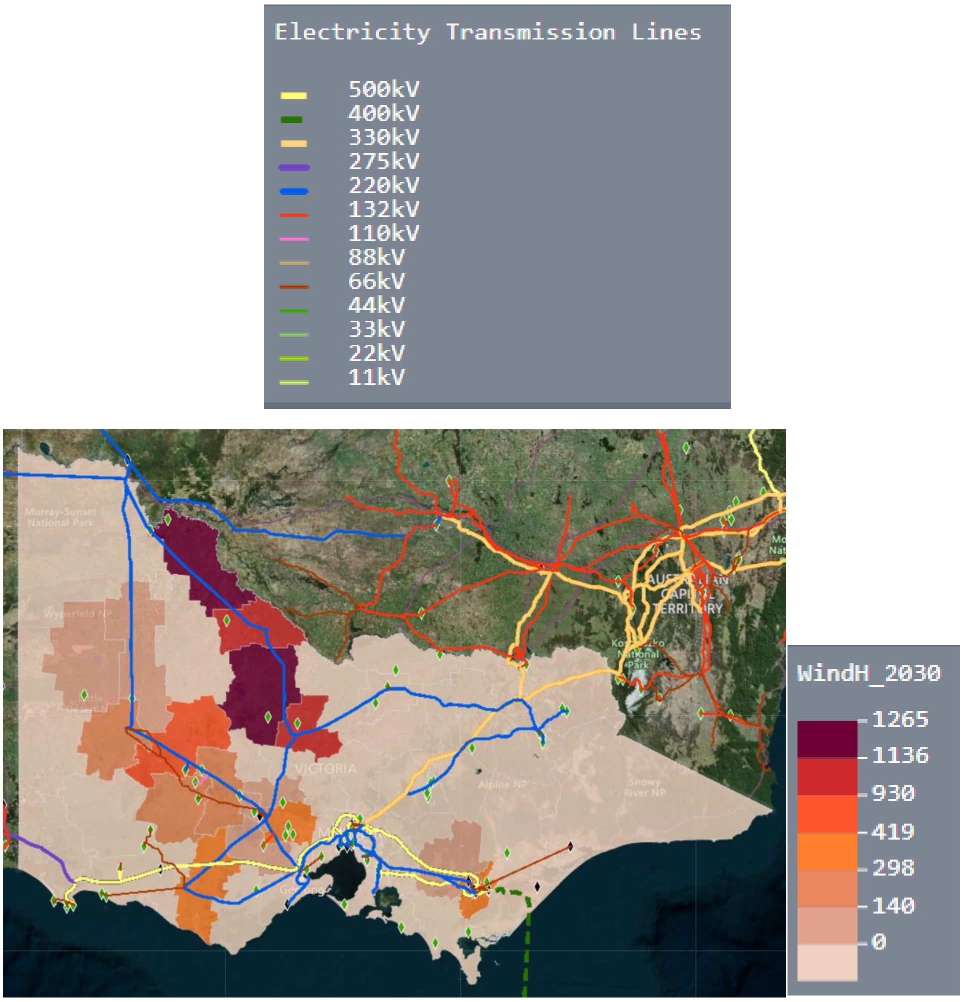
The demand is located mainly in the Melbourne metropolitan region (around 60%), with approximately 10% of demand for each of V2, V3 and V4 (representing all the west side of Victoria) with the last 10% being split between V1, Gippsland (V5) and V6.

Comparing generation location and demand location, the transmission lines between all the regions and Melbourne and between East and West will need to be upgraded as both demand and electrical generation grow.

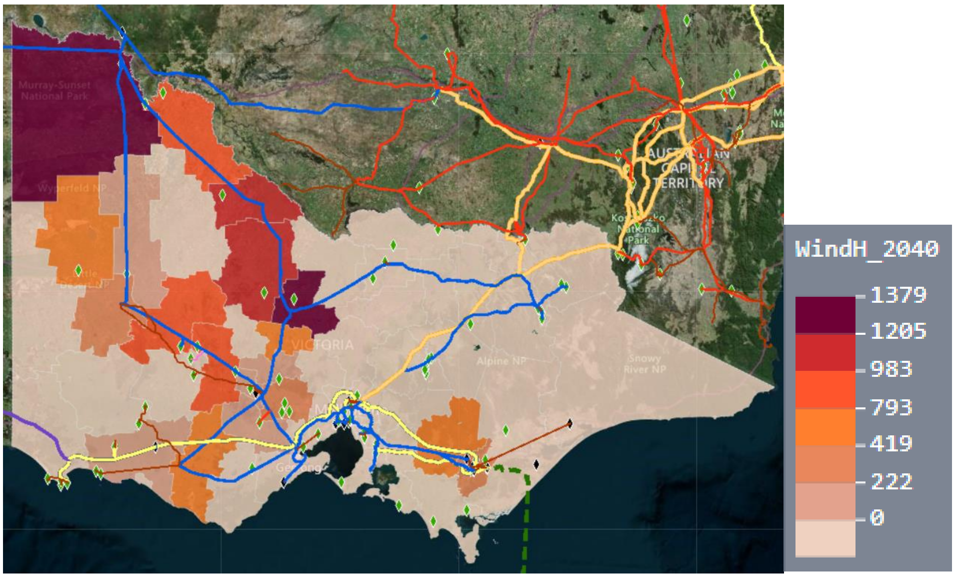
5.4.3.2 Wind

Only the transmission lines existing in 2020 are indicated on the following maps, for all time periods, and the scale (in MW) was fixed to provide consistency. The values shown on the scale represent electrical generation infrastructure in sub regions. Loddon Mallee, for example, has eight subregions.

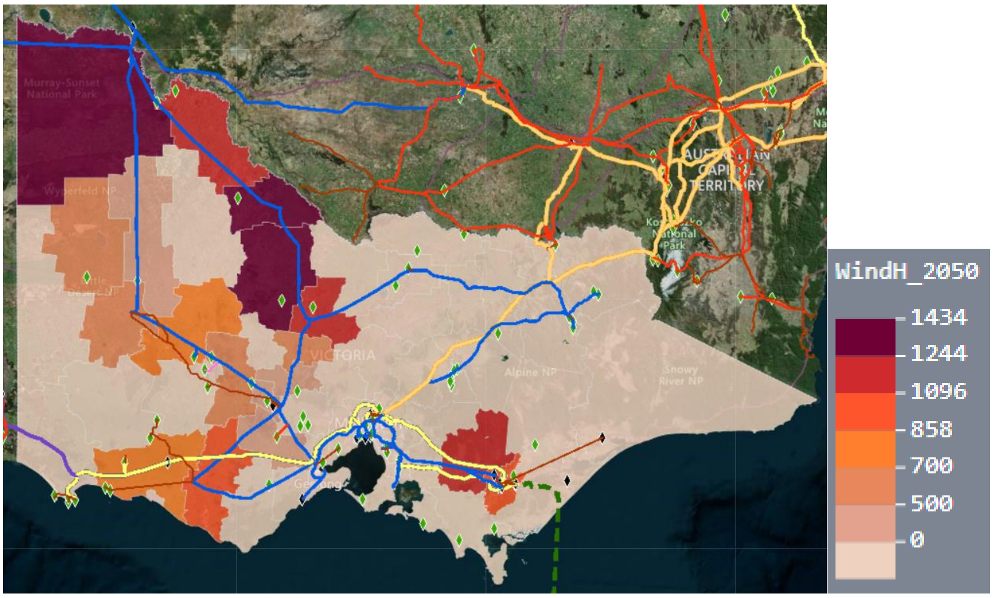
Figure 40: Regions and Sub-regions in Victoria.

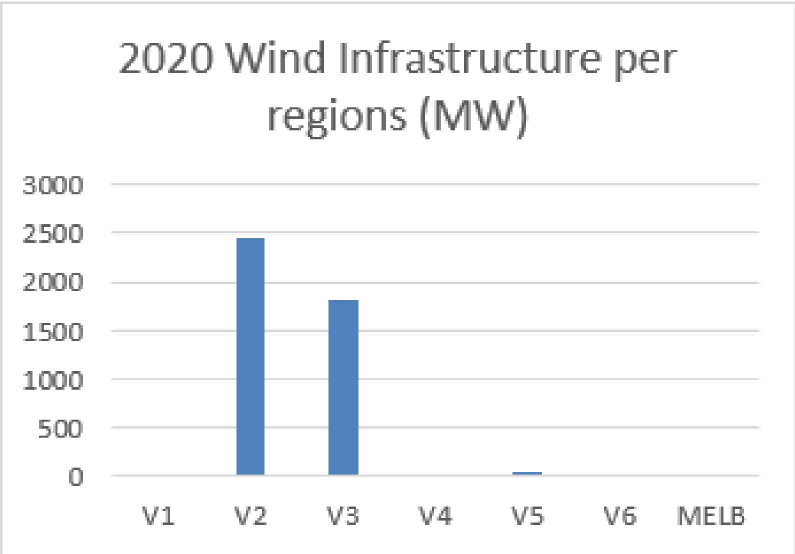

Electricity Transmission Lines
500kV
400kV
330kV
275kV
220kV
132kV
110kV
88kV
66kV
44kV
33kV
22kV
11kV
VICTORIA
WindH_2030
1265
1136
930
419
298
140
0

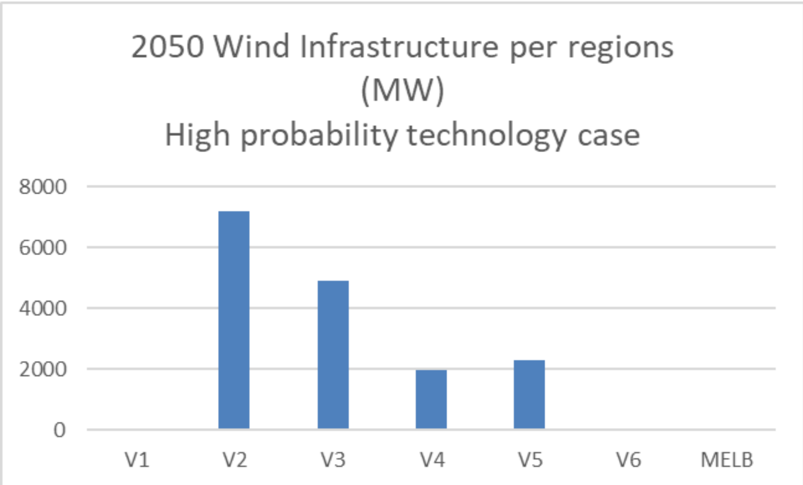
(2030)


VICTORIA
WindH_2040
1379
1205
983
793
419
222
0

(2040)

(2050) 
WindH_2050
1434
1244
1096
858
700
500
0
VICTORIA
AUSTRALIAN CAPITAL TERRITORY


2020 Wind Infrastructure per regions (MW)
3000
2500
2000
1500
1000
500
0
V1
V2
V3
V4
V5
V6
MELB

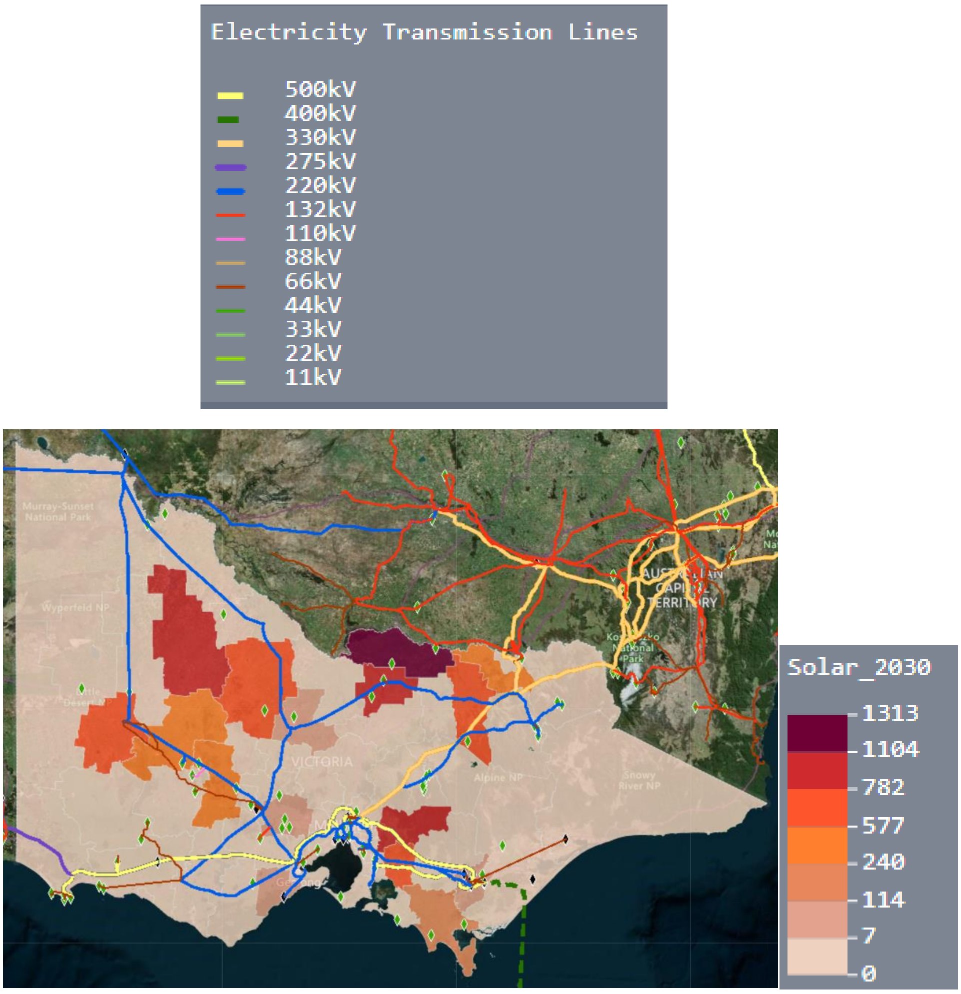

2050 Wind Infrastructure per regions (MW)
High probability technology case
8000
6000
4000
2000
0
V1
V2
V3
V4
V5
V6
MELB

Note: All the locations of existing and committed assets for 2020 wind generation have been taken from AEMO's ISP inputs & assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

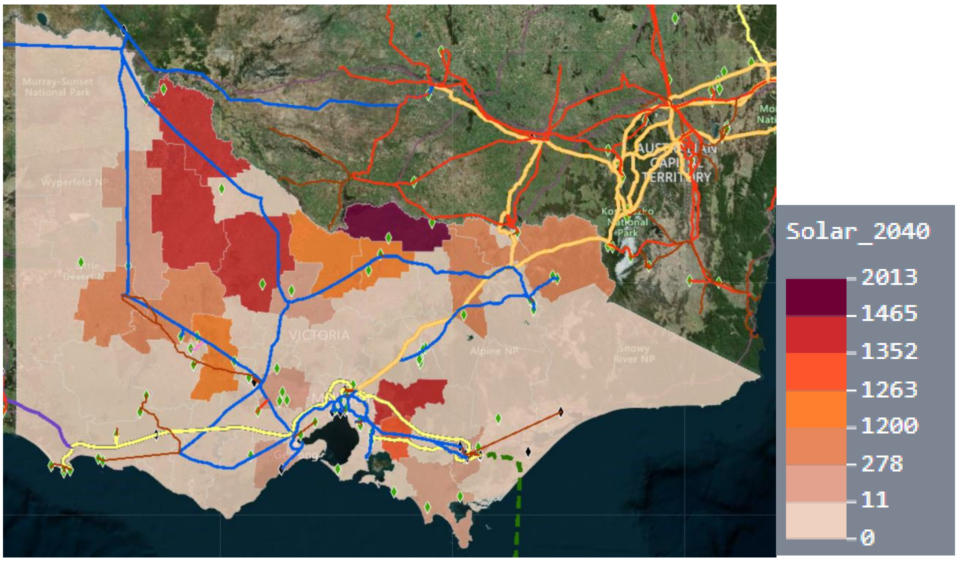
An increasing capacity in wind infrastructure was observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zones alongside the existing transmission lines. The location is based on available open land and associated wind rows. Other approaches could be considered in spatial share of the wind, for example, it might be more accurate to have more wind in V3 and V4 than other regions because wind potential in those regions is higher (around 40% against 32% in V2), and because V3 and V4 are connected to Melbourne, the highest demand location.

The infrastructure was placed in subregions with existing transmission lines and upgrades of those lines will be essential.

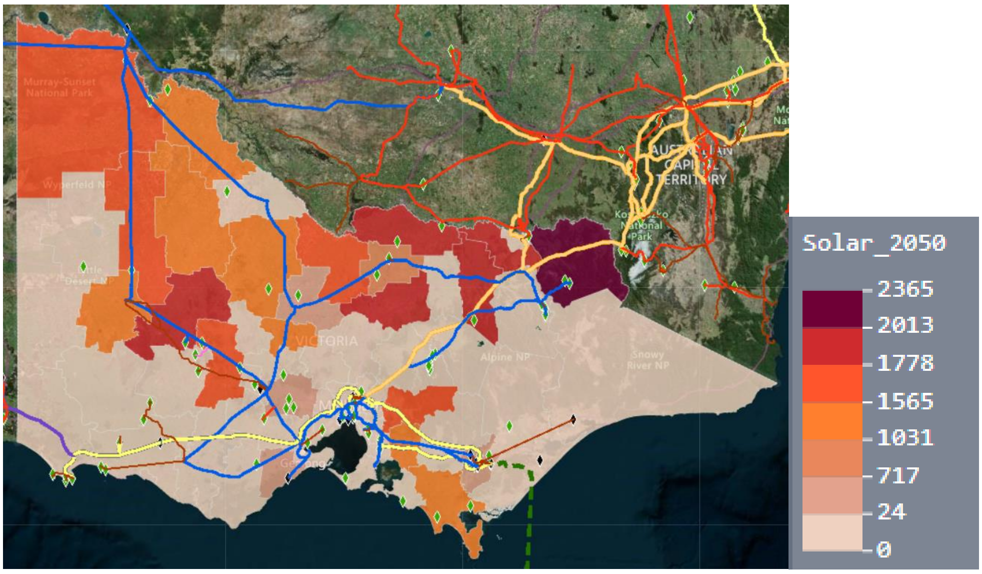
5.4.3.3 Solar



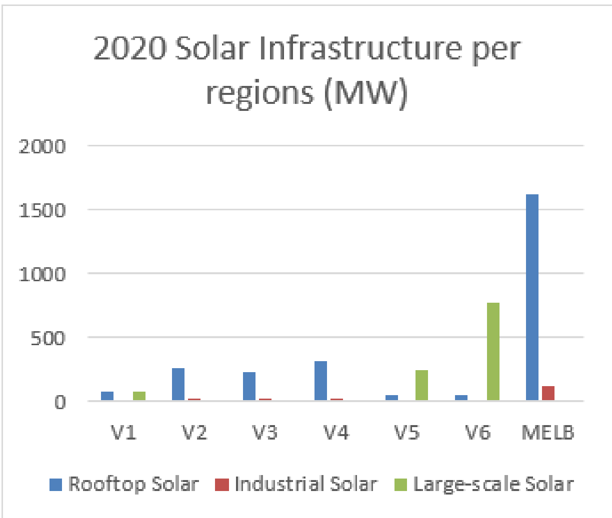
(2030)

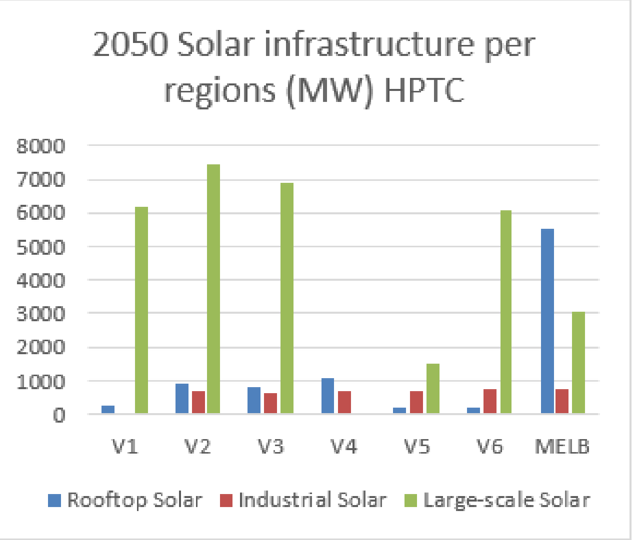

Solar_2040
2013
1465
1352
1263
1200
278
11
0
VICTORIA
Alpine NP

(2040)


Solar_2050
2365
2013
1778
1565
1031
717
24
0
VICTORIA
Alpine NP

(2050)


2020 Solar Infrastructure per regions (MW)
2000
1500
1000
500
0
V1
V2
V3
V4
V5
V6
MELB
Rooftop Solar
Industrial Solar
Large-scale Solar



HTPC: High Technology Probability Case

Solar PV will expand in all the regions in which it has a high potential : V1, V2, V3 and V6. Once again, the locations follow the transmission lines, creating the need for grid upgrades.

Rooftop solar is considered behind the meter electricity shared between regions based on demand in proportion to the population.

In 2050, Victoria is predicted to have :

- 8,910 MW of rooftop solar
- 4,163 MW of industrial solar
- 31,218 MW of large-scale solar
-

5.4.3.4 Bioenergy

Bioenergy has an important role in the mix. As for hydropower, bioenergy is a dispatchable source of power that brings stability to the system. For this reason, in each case, the bioenergy infrastructure was maximised based on the supply chain potential.

By 2050, bioenergy was predicted to provide approximately 7% of the electrical demand with 2,356 MW of installed capacity.

5.4.3.5 Infrastructure to be Installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period. The data represents the additional infrastructure required in each period and not the cumulative total amount.

The values in 2020 are the existing and committed assets, then for each subsequent period the values show the generation infrastructure that has to be added for the specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0
2025	10	0	0	0	0	191	0	0	0	0	0	35	0	450	30	15
2030	23	0	0	0	0	1077	0	0	0	0	0	57	0	1789	50	33
2035	19	0	0	0	0	951	0	0	0	0	0	64	0	1299	61	41
2040	13	0	0	0	0	1163	0	0	0	0	0	59	0	1461	57	29
2045	65	0	0	0	0	1115	0	0	0	0	0	68	0	1158	169	141
2050	58	0	0	0	0	1602	0	0	0	0	0	70	0	2515	251	126
						MW									GWh	

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0
2025	35	0	623	0	32	265	0	0	0	0	0	35	0	1375	92	50
2030	77	0	1652	0	53	1495	0	0	0	0	0	57	0	5468	152	110
2035	64	0	1379	0	65	1189	0	0	0	0	0	64	0	3970	186	138
2040	44	0	1366	0	61	1454	0	0	0	0	0	59	0	4463	174	95
2045	217	0	704	0	180	1394	0	0	0	0	0	68	0	3537	518	471
2050	194	0	1254	0	267	1668	0	0	0	0	0	70	0	7684	768	419
						MW									GWh	

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0
2025	31	0	298	0	29	258	0	0	0	0	0	35	0	1100	73	45
2030	69	0	790	0	48	1454	0	0	0	0	0	57	0	4374	122	99
2035	57	0	659	0	59	963	0	0	0	0	0	64	0	3176	149	124
2040	40	0	653	0	55	1178	0	0	0	0	0	59	0	3571	139	86
2045	196	0	337	0	164	1412	0	0	0	0	0	68	0	2830	414	424
2050	174	0	1999	0	243	1623	0	0	0	0	0	70	0	6147	615	377
						MW									GWh	

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0
2025	42	0	102	0	34	0	0	0	0	0	0	35	0	675	45	60
2030	92	0	269	0	56	0	0	0	0	0	0	57	0	2684	75	133
2035	77	0	225	0	68	0	0	0	0	0	0	64	0	1949	91	166
2040	53	0	222	0	64	0	0	0	0	0	0	59	0	2191	86	114
2045	261	0	115	0	190	0	0	0	0	0	0	68	0	1736	254	565
2050	232	0	1021	0	281	0	0	0	0	0	0	70	0	3772	377	503

Note

Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0
2025	7	0	119	0	34	0	0	0	0	0	0	35	0	425	28	10
2030	15	0	316	0	56	0	0	0	0	0	0	57	0	1690	47	22
2035	13	0	264	0	68	0	0	0	0	0	0	64	0	1227	57	28
2040	9	0	261	0	64	0	0	0	0	0	0	59	0	1380	54	19
2045	43	0	135	0	190	0	0	0	0	0	0	68	0	1093	160	94
2050	39	0	1200	0	282	1409	0	0	0	0	0	70	0	2375	238	84
						MW									GWh	

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0
2025	7	0	0	0	35	233	0	0	0	0	0	23	0	1050	70	10
2030	15	0	0	0	58	1313	0	0	0	0	0	38	0	4175	116	22
2035	13	0	0	0	71	870	0	0	0	0	0	43	0	3032	142	28
2040	9	0	0	0	66	1064	0	0	0	0	0	40	0	3408	133	19
2045	43	0	0	0	197	1020	0	0	0	0	0	46	0	2701	395	94
2050	39	0	0	0	293	1465	0	0	0	0	0	46	0	5868	587	84
						MW									GWh	

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	1617	0	0	0	125	0	0	982	0	0	0	0	0	0	0	0
2025	215	0	0	0	29	259	0	0	0	0	0	35	0	2425	162	310
2030	475	0	0	0	48	1458	0	0	0	0	0	57	0	9643	268	685
2035	396	0	0	0	59	483	0	0	0	0	0	64	0	7002	328	857
2040	272	0	0	0	55	591	0	0	0	0	0	59	0	7872	307	590
2045	1348	0	0	0	164	283	0	0	0	0	0	68	0	6238	913	2918
2050	1201	0	0	0	244	0	0	0	0	0	0	70	0	13551	1355	2599
						MW									GWh	

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

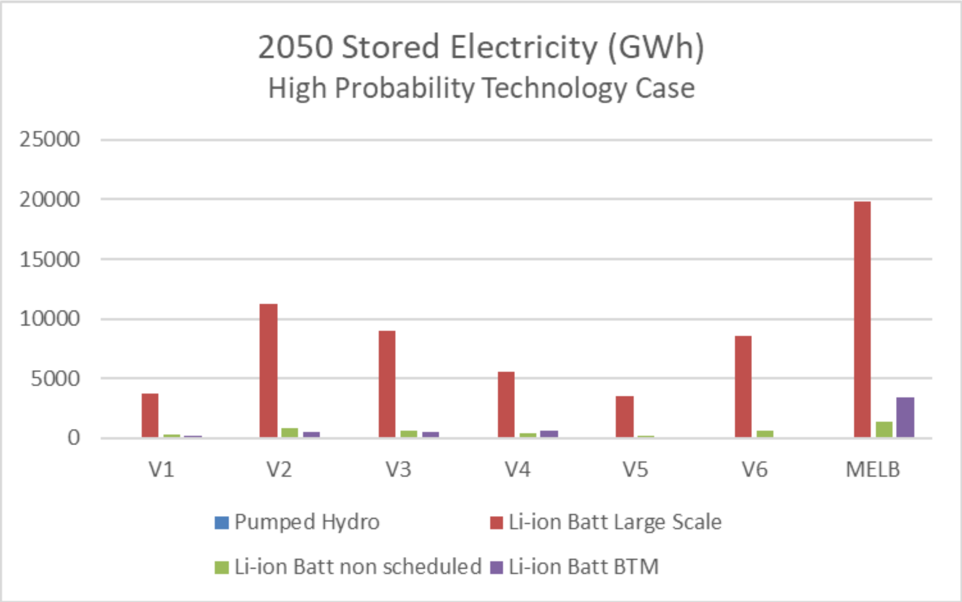
5.4.4 Discussion

The High Probability Technology case was found to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (behind the meter, industrial and large scale)
  - Pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar and wind represents between 75 and 80% of the electrical mix creating grid instability that requires compensation by additional generation and storage facilities. Starting in 2035 all additional wind, solar PV and battery infrastructure is multiplied by 1.5.
- The share of wind and solar PV in 2050 is 55% solar PV (excluding behind the meter) and 45% wind.
- New transmission lines are needed as the grid will have to support a lot more electricity. Upgrades of the following lines are considered likely (to be confirmed through further work):
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assumes it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers representing around 25% more infrastructure than exists today.
- All the connection between the facilities and the grid have been taken into account in the cost analysis, but not shown on the maps.
- The storage is calculated depending on the quantity of solar and wind, with the objective to cover the nights without solar production and to be able to cover a week without wind generation.



5.5 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

5.6 Environment & Social Analysis

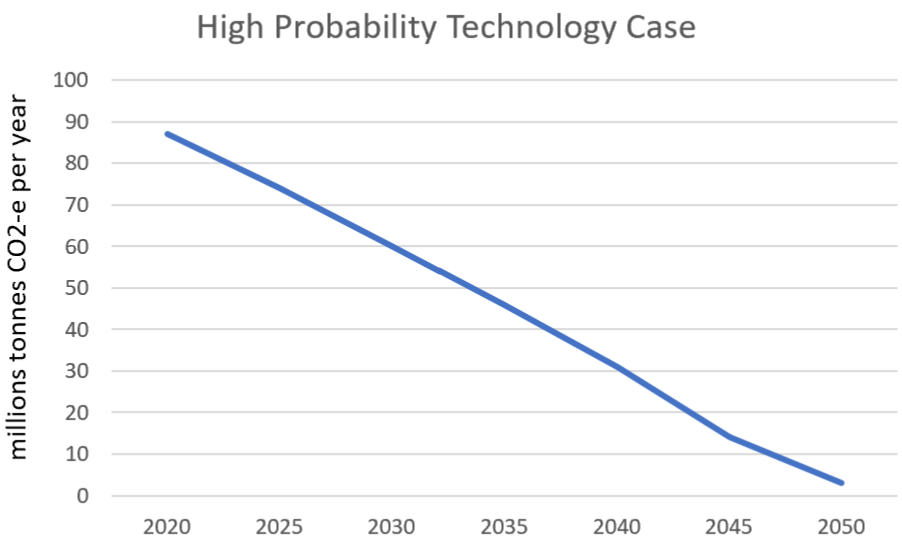
5.6.1 Work Description

The environmental and social components of the High Probability Technology case have been assessed via a desk-top study using key aspects from environmental and social perspectives and summarised in Table 51.

5.6.2 Results

In the High Probability Technology Case, emissions reductions are achieved by utilising current commercially available technology. Figure 41 shows the estimated emissions reduction profile for this case, with a linear decline in greenhouse gas emissions towards a residual of around 3 million tonnes CO2-e per year in 2050. In this study these residual emissions are assumed to be offset to achieve net zero in 2050.

Figure 41: Emissions Reduction Profile – High Probability Technology Case



The High Probability Technology case scenario results in the slowest drop in emissions of the High, Mid and Low cases in order to reach Net Zero by 2050. With the most significant decrease coming after 2040 (refer to Figure 41).

Electricity generation from coal remains the highest source of emissions up until 2040, where natural gas takes over by a margin of 1 in 2045. Vehicles - (ICE) gasoline & diesel remains the third highest emissions up until and including 2040.

The High case relies heaviest, with the exception of Sensitivity Case 3 - Energy Efficiency, on the utilisation of Solar PV to meet energy and emission factors. The High case, along with Low case, also have the highest use of biogas and biomethane.

5.6.3 Discussion

The proposed high probability case has the following environmental and social considerations:

- Key investments to achieve the net zero emissions target by 2050 include:
  - Compared to 2020; 18 times more solar PV, 4.5 times more wind capacity, and 190 times the level of battery support
  - Significant investments in biomethane, bioenergy and hydrogen production.
  - By 2050, 3 million tonnes per year of abatement being provided by greenhouse gas offsets
  - Additional gas pipelines (to transport biogas)
  - Strengthened electricity grid

  Much of this investment is located in greater Melbourne, Western and North Eastern Victoria
- The main drivers of employment in this case are:
  - wind (25%)
  - rooftop solar PV (22%)
  - battery storage (16%)
  - large scale solar PV (15%)
  - energy efficiency (9%)
- The construction of two new pipelines to meet proposed increases in biomethane production (150 km and 210 km in length) will result in the potential impact to environmentally sensitive terrestrial areas. There is the possibility that these construction projects may traverse national parks, wildlife management areas, rivers or wetlands. There may be opportunities to reduce the clearing required for these energy production methods if existing infrastructure corridors, such as transmission lines, are used.
- The increase in energy production from solar PV and wind (onshore) from 2020 to 2050 may require greater amounts of land clearing to support the infrastructure. There may be opportunities to reduce the clearing required for these energy production methods if existing cleared or infrastructure areas are used.
- Development of wind large scale solar, bioenergy and hydrogen/ammonia projects in rural areas will require careful management to avoid community concerns over rural industrialization. Similarly, if offsets are sourced locally, care will be required to avoid community concerns around rural industrialization and land use change.
- The large reliance on solar PV with battery support to meet energy demand will require the attention to the management of end of life recycling.
- Bioenergy projects will need to manage air quality impacts (odour)
- With the increase in renewable generation the numbers of batteries to support residential and commercial solar systems increases dramatically, requiring the management of fire risk, and end of life recycling.
- The increase in onshore wind power generation may result in impacts to sensitive environments (such has habitat loss, noise etc.) depending on the locations and methods for construction. There may also be a reduction in visual amenity for locations where wind farm infrastructure is developed.

- Given the requirement for construction and land-clearing, there may be the potential for cultural heritage risks or impacts. These will need to be further analysed on a case-by-case assessment during planning phases and should include community and stakeholder consultation.
- Construction works associated with new infrastructure for renewable energy technologies (namely Biogas and Solar PV) may also increase the risk of environmental impacts (such as spills, fires, etc.).

5.7 Cost Analysis

5.7.1 Results

Figure 42 presents the net difference between the High Probability Technology Case and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs

Figure 42 demonstrates that:

- The High Probability Technology Case projects a material reduction in fuel, FOM and VOM costs, as a result of the reduction of fossil fuel generation and expanded development and sharing of new variable renewable electricity resources, providing a net annualised benefit of approximately $2.5 billion in 2050.
- The High Probability Technology Case projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $8.5 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the High Probability Technology Case are represented by the purple line in Figure 42. By 2050, the High Probability Technology Case is forecast to provide a net cost increase of around $6 billion by 2050.

For the High Probability Technology Case, the net costs show a gradual negative trend due to the increased annual CAPEX costs for new generation to meet the increased energy demand which returns a net cost increase.

Figure 42: Net Costs of the Control Scenario relative to the High Probability Technology Case

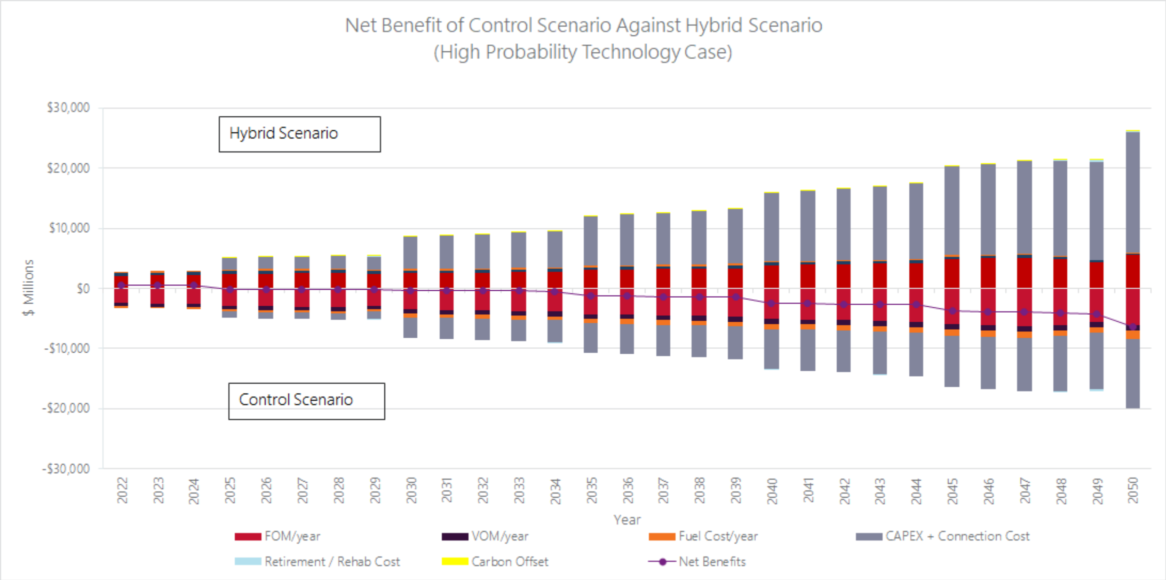


Table 61 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the High Probability Technology Case, in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the High Probability Technology Case, discounted back to present value, is $7.7 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$1.6 billion (NPC).

The estimated cost of CO_2 abatement is $89/te CO_2.

Table 61: Net Costs of the Control Scenario relative to the High Probability Technology Case

Cost Category[2]	Net Cost of Control Against Technology Case (High Probability)		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$5,322	-$2,571
FOM	$2,475	$1,927	$548
VOM	$435	$237	$198
Fuel	$419	$177	$242
Retirement / Rehab	$48	$52	-$4
Agro-forestry (Land Area, Hectare)	$0	$0.2	-$0.2
Gross Cost	$6,127	$7,715	-$1,587
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	-
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	-
Cost of CO_{2e} Abatement[3] ($/tonne)	$582	$89	$493

Notes:
1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

5.7.2 Discussion

The increased CAPEX combined with the overall energy mix for the High Probability Technology Case compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity.

OPEX and fuel costs savings for the High Probability Technology Case compared to the Control Scenario are also expected due to the reduction in fossil fuel generation and expanded development and sharing of new variable renewable electricity resources but not sufficient to offset the CAPEX increase.

Retirement costs are marginally higher in the High Probability Technology Case as this includes decommissioning of gas transmission and distribution lines and the existing, anticipated and committed generation being retired by 2050. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The High Probability Technology Case cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross net present cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

5.8 Risk & Opportunity Analysis

5.8.1 Key References & Assumptions

The preceding Scenario Analysis Stage 1 study (Net Zero Emission Scenario Analysis Study Report May 2021) was used as the key reference for this study and informed the framing of the Hybrid Scenario to be studied.

Existing, proven, commercially viable and commercial scale technologies have primarily been assumed for the High Probability Technology Case. Energy production and power generation technologies and costs are based on the AEMO Inputs & Assumptions Workbook used to support the 2020 Integrated System Plan.

The key assumptions for this High Probability Technology Case are:

- Victorian natural gas production is ongoing in 2050 at a relatively low level;
- Gas imports into Victoria are possible via existing pipeline interconnectors and/or Victorian LNG imports;
- Green hydrogen (electrolysis using renewable energy) at large scale becomes technically viable and commercially competitive by 2025;
- Hydrogen blending into the existing natural gas transmission and distribution system is possible and limited to 10% by volume;
- Net zero is achieved by the application of carbon offsets generated by investment in agro-forestry projects.

5.8.2 Work Description

The Stage 1 study (Net Zero Emission Scenario Analysis Study Report May 2021) identified a number of risks associated with an over reliance on either electrification or energy gas in meeting Victoria's future energy demand and the development of a hybrid scenario was recommended.

This study presents a hybrid scenario with a more balanced energy mix which also attempts to retain and utilise existing natural gas transmission and distribution infrastructure as far as possible.

The High Probability Technology Case maintains a declining "tail" of natural gas in the energy mix along with other energy gases, biomethane and green hydrogen while renewable electricity from onshore wind and PV solar continue to grow to meet the electricity demand and produce green hydrogen.

The study team reviewed the risks and opportunities identified in the Stage 1 study and assessed the key risks associated with this hybrid scenario, focussing on the implementation risks and rather than the inherent risks since a risk and opportunities comparison between scenarios was not contemplated in this Study. Implementation risks are the risk of the technology not being adopted in the timeframe given for the Analysis Case, due to either cost or technology development or both, whereas inherent risks are those associated with the technology once implemented.

5.8.3 Results

The High Probability Technology Case is considered to be feasible with a low implementation risk compared with the scenarios analysed in the Stage 1 study. A range of potential natural gas sources are available to meet the demand requirements for this case.

There is moderate risk that cost competitive green hydrogen will not be available by 2025 but as green hydrogen makes up a minor portion of the overall energy mix, then the 2025 timing is not critical.

Whilst the quantity of carbon offsets required to achieve net zero is modest, such reliance on offsets to reach net zero creates a risk, especially with competition for such offsets from hard to abate energy sectors.

The opportunity to achieve net zero emissions significantly earlier than 2050 exists, based on potential technology breakthroughs which may allow the use of natural gas to be curtailed more rapidly than assumed in this High Probability Technology Case.

5.8.4 Discussion

To manage the energy transition risks consistent with the findings and recommendations from the Stage 1 scenario analysis (Net Zero Emission Scenario Analysis Study Report May 2021), the Hybrid Scenario developed under this study.

- Does not incorporate CCS and the use of biomethane, bioenergy is maximised;
- Hydropower within Victoria is assumed to continue at current levels.
- Pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030.
- A balanced uptake of battery electric vehicles and hydrogen fuel cell vehicles is assumed.

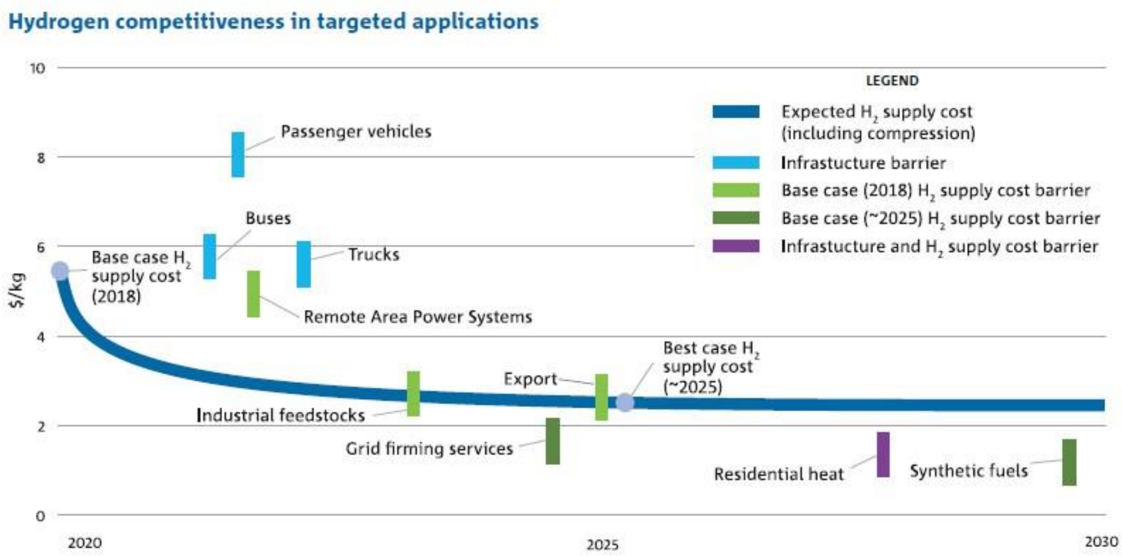
In this Analysis Case, the use of offsets is preferred over CCS implementation to achieve net zero, as it provides a more flexible approach with the ability to adjust the scale and timing of the offsets depending on the emissions reduction results actually being achieved. CCS projects involve a long lead time and significant capital expenditure and therefore greater certainty before an investment decision can be made.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

Achieving net zero emissions in this scenario does not require CCS to be implemented, but CCS could be established for a low carbon hydrogen or ammonia export industry, which has not been included in this scenario analysis. However, large scale brown hydrogen with CCS will make net zero more difficult to achieve, as not all of the emissions can practically be captured from the power plants' flue gas and fugitive methane emissions from coal mining cannot be prevented. There is also a risk that green hydrogen would become cost competitive with hydrogen produced from fossil fuels along with CCS within the economic life of the project which could render CCS unviable.

The CSIRO National Hydrogen Roadmap (2018) anticipated that the hydrogen supply cost from grid connected renewable electricity could reach $2.29-2.79/kg by 2025 as shown in Figure 43.

Figure 43: Hydrogen Competitiveness in Targeted Applications (Courtesy of CSIRO)



A blend of 10% hydrogen with 90% natural gas and biogas in the existing gas transmission and distribution system may to be possible by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

The maintenance of an energy gas "tail", including natural gas, in this High Probability Technology Case serves two primary functions:

- It provides peaking power generation capacity to cover any shortfall from variable renewable energy generation sources, PV solar and wind.
- It allows ongoing use of the existing gas transmission and distribution system (subject to commercial considerations) and delays or reduces the requirement to upgrade the electrical infrastructure, thus optimising the use of the combined infrastructure assets and minimising infrastructure CAPEX and decommissioning costs.

However, opportunities also exist to reduce the level of natural gas required whist maintaining a competitive and reliable energy system and potentiality improve the safety of the system. Two such options are explored in the Mid and Low Probability Technology Cases to follow.

If combination of technology breakthroughs from the Mid and Low Probability Technology Cases were to occur, it may be possible to achieve net zero emissions significantly earlier than 2050 as discussed in the sensitivity analysis in Section 8.9 for Sensitivity Case 1 ”Accelerated Net Zero”.

The main risk implementation associated with this High Probability Technology Case is the availability of a reliable source of natural gas. Whist a range of gas sources have been allowed for in the study, any combination of these sources would be acceptable to underpin the feasibility of this hybrid case.

Production from existing Victorian gas fields is currently in decline, but if new gas exploration is successful, this will arrest the decline to some degree. The moratorium on onshore oil and gas exploration was lifted as of 1st July 2021. According to the Victorian Gas Program, Victoria is likely to have between 128 – 830 PJ of potential new discoveries of conventional gas in parts of Gippsland and south-west Victoria.

Gas is currently able to be imported into Victoria and exported from Victoria, via the existing interconnector pipelines to New South Wales (and onwards to Queensland), South Australia and Tasmania. Queensland remains the gas source with the greatest potential, but most of this gas is currently exported overseas in the form of LNG. However, the opportunity exists to direct a more reliable quantity of gas from Queensland to domestic customers.

Additional gas supplies may also be available from New South Wales in the future, for instance from the proposed Narrabri coal seam gas project by Santos or the proposed Port Kembla LNG import terminal by Australian Industrial Energy. The Northern Territory is also a potential future source of natural gas, for example, from the onshore Beetaloo basin.

The import of LNG into Victoria is also possible, with various projects having been proposed previously. If an LNG import terminal is established, there is the opportunity to accelerate the reduction in net emissions by importing carbon neutral LNG. Carbon-neutral LNG involves offsetting the carbon emissions from the LNG supply chain through the purchase of carbon offsets. Carbon neutrality can only be achieved through the offsetting of product lifecycle emissions, or all the emissions associated with the production, transportation, and use of a specific product.

6 MID PROBABILITY TECHNOLOGY CASE

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

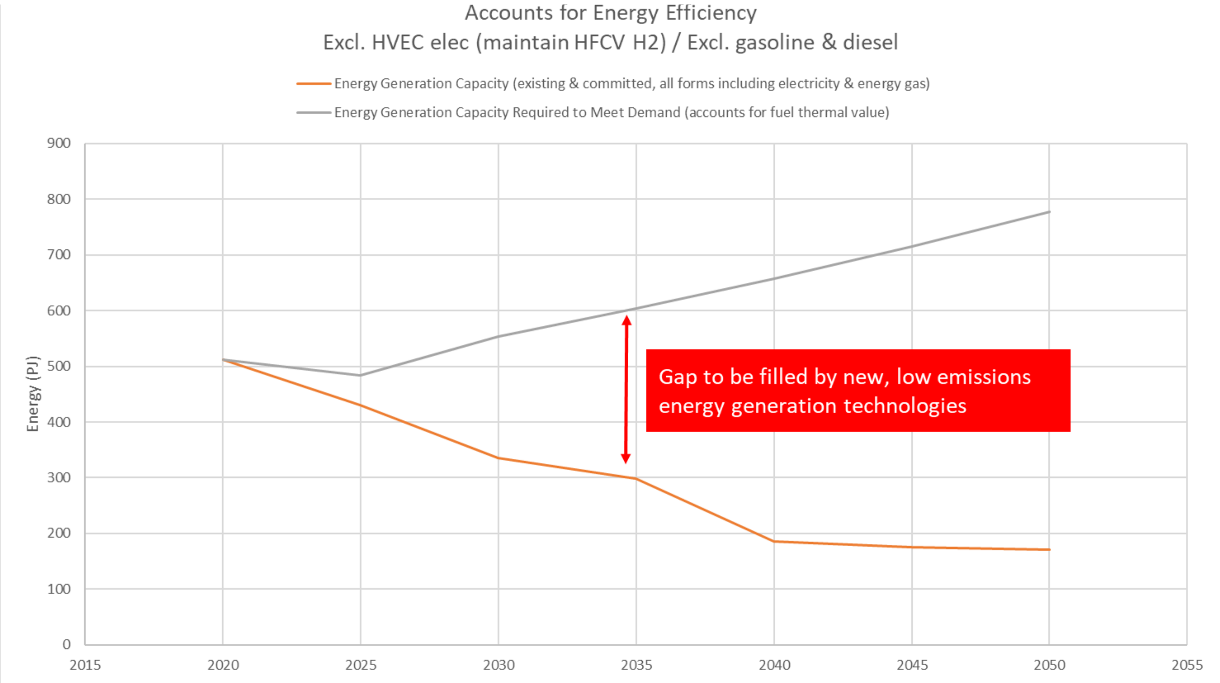
6.1 Case Description

The Mid Probability Technology case utilises primarily green Ammonia (NH_3) plus other low emissions energy technologies (see Table 62) to replace natural gas entirely, plus allow electrical generation and transition infrastructure in the Latrobe Valley to be utilized beyond 2050.

The gap between existing and committed energy generation capacity (Table 64) and the energy generation capacity required to meet forecast demand (grey line in Figure 44) for the Mid Probability Technology Case is represented by the red arrow in Figure 44.

Figure 44: Forecast Energy Demand vs Generation Capacity (Mid Probability Technology Case)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))



The energy generation capacity required to meet forecast demand (grey line in Figure 44) is:

- Limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles
- Determined by subtracting the fossil fuel thermal value from the overall energy demand.

As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

To accommodate the new energy technologies identified for the Mid Probability Case, modifications were made to the existing & committed energy generation capacity scheduled by AEMO (Table 64) and the fossil fuel decline profile assumed for the prior *Net Zero Emission Scenario Analysis Study Report May 2021* (see Table 14 Section 3.2). A summary of the modifications is provided below.

- Natural Gas Production:
  - 2025 – 2035: assume linear decline based on 2020/2025 rate = 33% per 5 years
  - 2040+: no natural gas production or imports (replaced by NH_3)
- Green Ammonia Implementation
  - Green ammonia will be transported via existing gas transmission pipelines for direct use customers and conversion plants located close to the gas distribution network that will convert the green ammonia to green hydrogen for injection into the LP gas distribution system. Implementation will occur in a staged manner, region-by-region, commencing with the most suitable locations, based on locations for siting conversion plants, readiness of existing infrastructure and requirements for any new infrastructure.
- Coal Fired Power
  - Coal fired power stations decommissioned 2040, ahead of the schedule contained in the current AEMO plan.

Table 62: Energy Technologies Used to Deliver Additional Capacity for the Mid Probability Case

Energy Type	Description
electricity generation	solar PV
electricity generation	wind onshore
electricity generation	hydropower
electricity generation	bioenergy
electricity generation	**FUEL CELLS**
electricity generation	**GREEN AMMONIA (NH3)**
electricity storage	pumped hydro (storage)
electricity storage	batteries (storage)
electricity storage	**IRON-AIR BATTERY**
energy gas	biomethane
energy gas	**GREEN HYDROGEN (H2)**
energy gas	**GREEN AMMONIA (NH3)**

The Mid Probability Technology case refers to technologies currently in the commercial pilot phase (TRL 5 & 6) and assumes a breakthrough to TRL 9 at competitive costs occurs before 2040, thereby allowing the technologies to be utilized to deliver additional energy generation capacity from 2040 and beyond.

A brief description of each of the technologies listed in Table 62 that are not included in the High Probability Technology case is provided in Table 63, along with a more detailed description below.

Table 63: Energy Technology Descriptions Mid Probability Case

Technology	Description
Fuel Cells	Electricity generation from hydrogen using a chemical reaction with oxygen that produced electricity and emits water vapour. Assumed to be industrial scale in this context as distinct from hydrogen fuel cells for transportation.
Green NH3 (Ammonia)	Electricity generation from the combustion of green Ammonia which is then used to create steam to drive a steam turbine or for direct combustion in a gas turbine. Currently TRL 5. Green ammonia is produced from green hydrogen and nitrogen separated from air using renewable electricity. Currently TRL 9.
Iron-air Battery	Electrical energy storage using the electrochemical processes, in this instance iron and air in a controlled and reversible rusting process. Currently TRL 6.

The energy technology breakthroughs identified for the Mid Probability Case include

- **FUEL CELLS** improves Variable Renewable Electricity capacity factor, therefore reduces Variable Renewable Electricity infrastructure requirements (Capital Expenditure, Operating Expenditure). Fuel cells become cheaper than standard batteries.
- **GREEN AMMONIA (NH_3)** enables full replacement of natural gas whilst utilising existing natural gas transmission infrastructure along with potential to utilize existing electrical generation and transmission infrastructure in the Latrobe Valley beyond 2050. Green Ammonia reaches cost parity with natural gas. In the Mid Probability Technology Case, green Ammonia is implemented in two ways:
  - **Energy Gas : natural gas is replaced entirely by green Ammonia.** Commencing in 2040, green Ammonia is introduced into the existing natural gas transmission infrastructure and gas suppliers would provide the option for industrial consumers to procure either green Ammonia or green Hydrogen (produced by catalytic conversion of green Ammonia downstream of the pipeline offtake point). The gas supplier will only supply green Hydrogen to residential and commercial consumers, through catalytic conversion of green Ammonia and subsequent transport via the gas distribution infrastructure. The source of green Ammonia, conversion to green Hydrogen along with related location options is described in Section 6.3.
  - **Ammonia to Power : early replacement of coal.** The green Ammonia to power industry is located in the Latrobe Valley presenting an economic opportunity for the region as brown coal recedes. Commencing in 2040, coal fired power generation is de-commissioned and replaced with new build Ammonia fired gas turbine generation systems located proximal to the existing coal fired power stations to allow access to the existing electricity transmission infrastructure. Whilst not analysed in the Mid Probability Technology Case, an opportunity would exist to convert the coal fired power stations to burn Ammonia and continue operation in 2050 and beyond. This opportunity would require near term investment to ensure that integrity is managed appropriately to the point of conversion. Conversion could be achieved in multiple stages, including installation of high efficiency boilers initially through to the final stage of installing the Ammonia burners, representing a key part of the technology breakthrough. The Japanese Ministry of Economy, Trade and Industry “Green Growth Strategy Through Achieving Carbon Neutrality in 2050”, 2021 provides a "Roadmap of Growth Strategies for fuel Ammonia industries” indicating an increased ratio of Ammonia co-firing occurs before 2040, aligning closely to the Mid Probability Technology case.
- **IRON-AIR BATTERY** improves Variable Renewable Electricity capacity factor, therefore reduces Variable Renewable Electricity infrastructure requirements (Capital Expenditure, Operating Expenditure). Iron-air batteries become cheaper than standard batteries.
- **GREEN HYDROGEN (H_2)** enables replacement of natural gas at scale, providing chemical feedstock to enable, for example, green Ammonia production. The Mid

Probability Technology Case allows green Hydrogen (cracked from green Ammonia) to fully replace natural gas by 2040 with transport to consumers via natural gas distribution infrastructure. Prior to 2040 green Hydrogen is transported to users via the existing natural gas transmission & distribution infrastructure by blending to a maximum concentration of 10% by volume (based on materials compatibility constraints) with the balance comprising biomethane and natural gas. Biomethane production is maximised based on supply chain constraints.

Table 64: Existing & Committed Energy Production Capacity Assumed for Supplying Demand (Mid Probability Technology Case)

ELECTRICITY	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	MW	PJ	MW	PJ	MW	PJ	MW	PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	3,325	85
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0	0
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (generation) - wind offshore - variable - industrial	0	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
Elec (storage) - "behind the meter" non-aggregated small scale batteries (dis-connected from grid)	94	1	551	3	1,527	10	2,034	13
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**24,993**	**171**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	0	71	0
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	0	1,100	0
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to balance demand)	170	12	170	12	170	0	170	0
Gas (import) - EGP (Eastern gas Pipeline) (to balance demand)	350	0	350	0	350	0	350	0
	1,360	**319**	**1,993**	**153**	**1,782**	**0**	**1,691**	**0**

6.2 Energy Emissions Offsets

6.2.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

The key assumptions used in the modelling of the energy, emissions and offsets associated with the Mid Probability Technology Case were the same as those used for the High Probability Technology Case, with the following exceptions:

- Natural Gas Production:
  - 2025 – 2035: assume linear decline based on 2020/2025 rate = 33% per 5 years
  - 2040+ : no natural gas production or imports (replaced by NH_3)
- Coal Fired Power
  - Coal fired power stations are converted to Ammonia and continue operation in 2050 and beyond. (i.e., not decommissioned in 2050 per current AEMO plan).

6.2.2 Results & Discussion

In the Mid Probability Technology Case, net zero emissions was achieved in 2050 through a combination of utilising low emissions energy technologies and greenhouse gas offsets. No geo-sequestration (CCS) was required.

Table 65: Mean Demand Energy Mix for the Mid Probability Technology Case

	2020	2025	2030	2035	2040	2045	2050
	Impact of Energy Efficiency on Energy Generation Capacity (PJ)						
Energy Generation to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	585	650	693	738	793	850
	Cumulative Energy Consumed accounting for Energy Efficiency (PJ)						
Elec (generation) - coal	144	116	89	66	0	0	0
Elec (generation) - natural gas (baseload + peaking)	5	5	4	4	0	0	0
Elec (generation) - NH3	0	0	0	0	125	124	124
Elec (generation) - hydropower	10	10	10	10	10	9	9
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	47	115	145	146	146	147
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	28	58	89	105	109	108	114
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	30	30	37
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	2	3	3	3	3
Elec (storage) - batteries (incl. standard + VPP + BTM + iron-air)	1	15	65	91	103	104	105
Gas (generation) - natural gas (all sources)	209	189	171	146	0	0	0
Gas (generation) - biomethane [distribution system)	0	1	4	11	12	27	38
Gas (generation) - H2 (green) [incl HFCV fuel]	0	18	29	30	32	31	34
Gas (generation) - NH3 (green) [industrial use + conversion to H2 for distributiuon eg res	0	0	0	0	97	122	190
Vehicles - (ICE) gasoline & diesel	318	266	214	154	97	41	0
Vehicles - (BEV) electricity	0	10	19	35	51	49	55
Vehicles - (HFCV) electricity [GENERATION]	0	21	41	43	46	48	57
TOTAL (PJ)	**732**	**759**	**867**	**867**	**862**	**843**	**914**

Table 65 reveals that:

- In 2020, as per the High Probability Technology Case, gasoline & diesel (ICE vehicles) is the single biggest energy source at approximately 320 PJ-thermal, or approximately 45% of the total, with natural gas in second position at approximately 210 PJ-thermal or approximately 30% of the total, and electricity from coal in third position at approximately 145 PJ-electricity or approximately 20% of the total.
- In 2030, as per the High Probability Technology case, the first and second largest single energy sources remain occupied by gasoline & diesel (ICE vehicles) and natural gas. As per the High Probability Technology Case, third position shifts from electricity from coal to solar PV providing approximately 115 PJ-electricity or approximately 15% of the total.
- In 2040, as a result of technology breakthroughs and subsequent introduction of green Ammonia and Iron-Air batteries, the Mid Probability Technology case differentiates significantly from the High Probability Technology case, with no use of either natural gas or coal. A significant degree of planning would be required to manage this transition successfully, and would likely be undertaken in stages, on a region by region basis, over the years leading up to 2040. In this year the first position is held by solar PV providing approximately 145 PJ-electricity or approximately 15% of the total. Electricity from green Ammonia is now in second position with approximately 125 PJ-thermal or approximately 15% of the total. Further detail regarding the potential location for Ammonia power generation infrastructure is provided in Section 6.3. Third position is held jointly by storage* providing approximately 105 PJ-electricity and wind providing approximately 110 PJ-electricity or approximately 12% of the total each.
- In 2050, no fossil fuels are utilised, once again representing a difference between the Mid and High Probability Technology Cases. In this year, green Ammonia gas represents the single biggest energy source at approximately 190 PJ-thermal or approximately 20% of the total. Solar PV has dropped to second position with approximately 150 PJ-electricity or approximately 15% of the total and third position now occupied by electricity from green Ammonia (NH_3) with approximately 125 PJ-electricity just under 15% of the total.

  *For the Mid Probability Technology Case, storage includes both Iron-air batteries and current technology batteries. The Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

Also noteworthy from Table 65 is the increased diversity of energy sources resulting from the transition.

- In 2020 the top three single energy sources (gasoline & diesel, natural gas & coal) represented approximately 90% of the total energy mix;
- In 2030 the top three (gasoline & diesel, natural gas & solar PV) represented approximately 60% of the total;
- In 2040 the top three (solar PV, electricity from Ammonia, and storage* / wind) represented approximately 55% of the total; and

- In 2050 the top three (Ammonia gas, solar PV and electricity from Ammonia) represent approximately 50% of the total.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity), Figure 45 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In 2020, as per the High Probability Technology case, approximately 205 PJ-electricity is consumed, being approximately 50% of the total, and approximately 210 PJ-thermal energy gas is consumed being approximately 50% of the total.
- In 2030, as per the High Probability Technology case, approximately 410 PJ-electricity is consumed, being almost 70% of the total, and approximately 205 PJ-thermal energy gas is consumed being approximately 30% of the total.
- In 2040, approximately 580 PJ-electricity is consumed, being approximately 80% of the total, and approximately 140 PJ-thermal energy gas is consumed being approximately 20% of the total.
- In 2050, there is a significant pivot towards a higher degree of energy gas compared to the High Probability Technology case (due to introduction of Ammonia gas), with approximately 595 PJ-electricity is consumed, being approximately 70% of the total, and approximately 260 PJ-thermal energy gas consumed being approximately 30% of the total.

Figure 45: Energy Mix Breakdown for the Mid Probability Technology Case Covering only Electricity & Energy Gas (excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

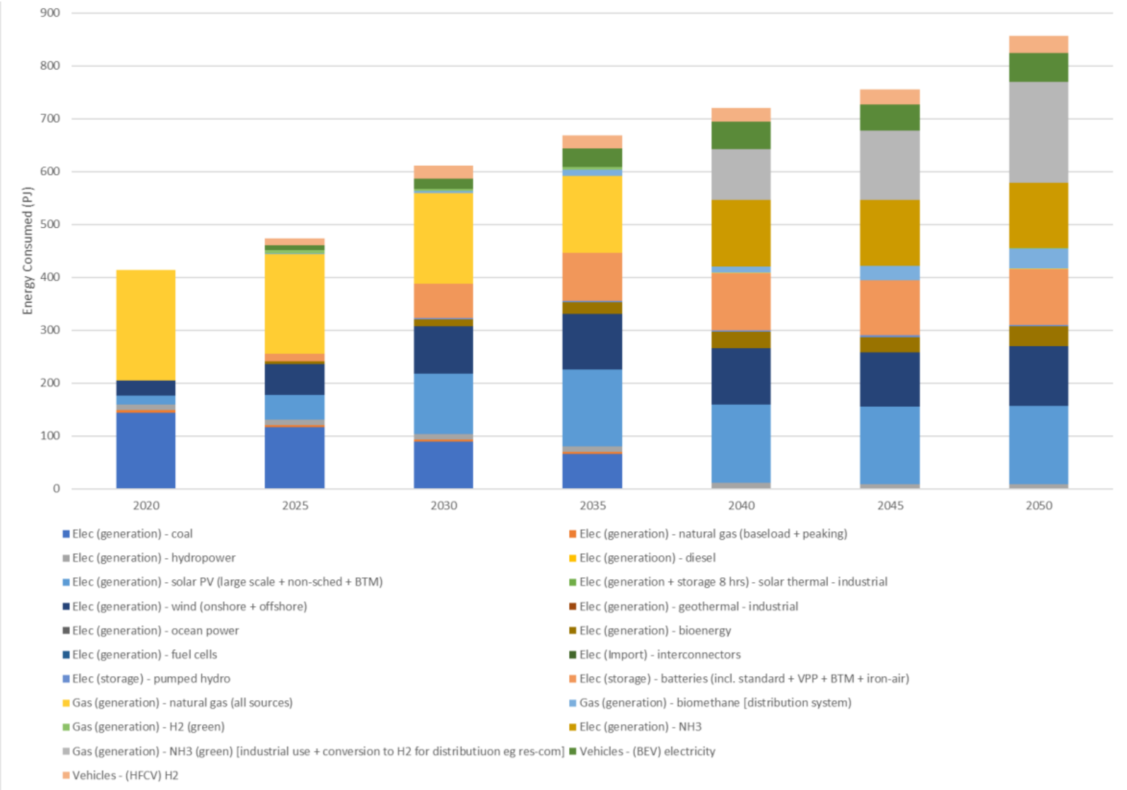


Table 66: Emissions for the Mid Probability Technology Case

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	36	28	21	0	0	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - NH3	0	0	0	0	4	4	4
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	2	2	2	2
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	1	2	3	4	4	4	4
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-7	-7	-9
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - batteries (incl. standard + VPP + BTM + iron-air)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	15	13	0	0	0
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Gas (generation) - NH3 (green) [industrial = NH3 / res-com = convert to H2]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	15	10	7	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**61**	**46**	**10**	**7**	**3**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**-1**	**-1**	**-2**	**-2**	**-3**
NET EMISSIONS	**87**	**74**	**60**	**45**	**8**	**5**	**0**

Figure 46: Emissions Profile for the Mid Probability Technology Case

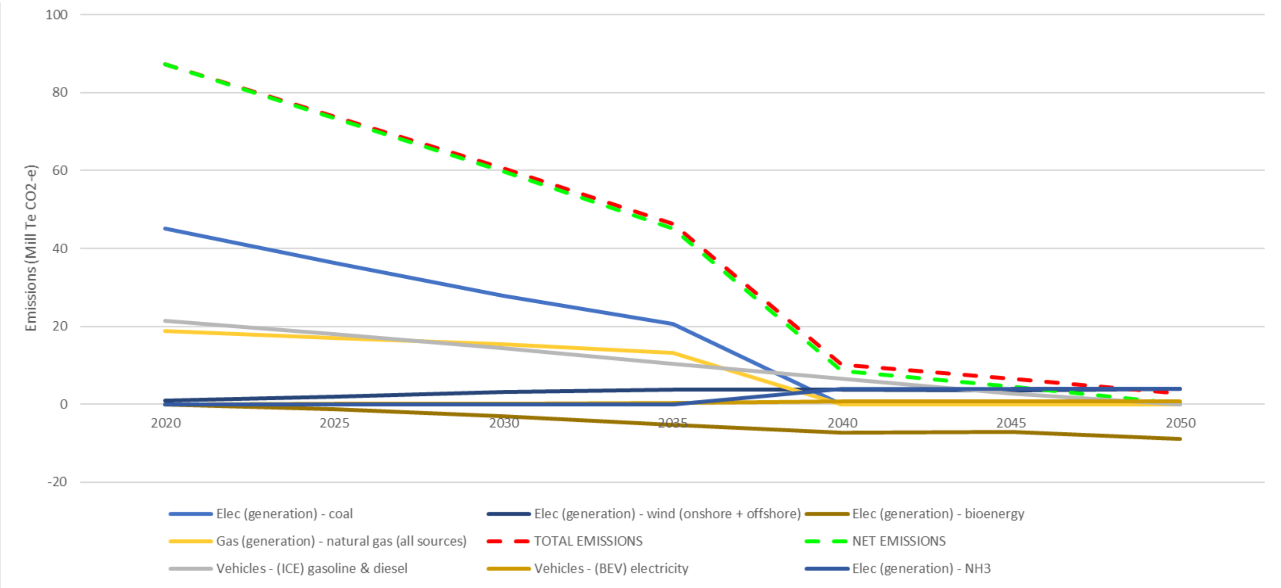


Table 5 (Section 1.6.4) documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for the Mid Probability Technology case is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be :

- 2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and
- 2030 interim emissions target: up to 9 Million Te CO_2-e to cover out of scope emissions.

Table 66 and Figure 46 illustrate that the Mid Probability Technology case has a significantly different emissions decline profile over time compared to the High Probability Technology case, with a sharp decline occurring in 2040 due to the introduction of Ammonia and Iron-air batteries resulting in stoppage of both natural gas and coal.

As per the High Probability Technology case, bioenergy is noteworthy as the only technology with a negative emissions contribution (based on avoided emissions from agriculture and waste – refer to ESE Methodology Section 3.9.5), providing a dis-proportionately large contribution to reducing emissions. In 2050, despite its limited share of the energy mix (approximately 40 PJ-electricity or just under 5%, set by supply chain constraints), it contributes approximately negative 10 Million Te CO_2-e emissions or approximately 60% of the reduction of emissions to net zero, with the remainder (approximately 40%) contributed by offsets.

On the contrary, as per the High Probability Technology case, coal represents a dis-proportionately large contribution to reducing emissions. In 2020, with approximately 145 PJ-elec or approximately 20% of the energy mix, coal contributes 45 Million Te CO_2-e emissions (approximately 50% of total). Sitting between bioenergy and coal are :

- Gasoline & diesel (ICE vehicles). In 2020, as per the High Probability Technology case, these fuels represent approximately 320 PJ-thermal consumed (approximately 45% of the total) and contribute approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Natural gas. In 2020, as per the High Probability Technology case, it represents approximately 210 PJ-thermal consumed (approximately 30% of the total) and contributes approximately 20 Million Te CO_2-e emissions (approximately 20% of the total).
- Low emissions electricity excluding bioenergy, but including electricity from Ammonia, hydroelectric, solar PV, wind, pumped hydro and iron-Air batteries and other storage*. In 2020, as per the High Probability Technology case, these low emissions technologies represent approximately 60 PJ-electricity consumption (almost 10% of the total) but contribute only 1 Million Te CO_2-e emissions (approximately 1% of the total positive emissions). In 2050 they provide approximately 610 PJ-electricity consumption – including electricity to charge BEVs and generate green Hydrogen for HFCVs - (almost 70% of the total) but contribute only approximately 10 Million Te CO_2-e emissions (approximately 90% of the total positive emissions).

  *For the Mid Probability Technology Case, storage includes both Iron-air batteries and current technology batteries. The Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

- Low emissions energy gases including biomethane, green Hydrogen and green Ammonia. In 2050 they provide approximately 260 PJ-thermal consumption – including fuel for HFCVs - (approximately 30% of the total) but have no emissions.

Figure 47: Contribution to Emissions by Source for the Mid Probability Technology Case

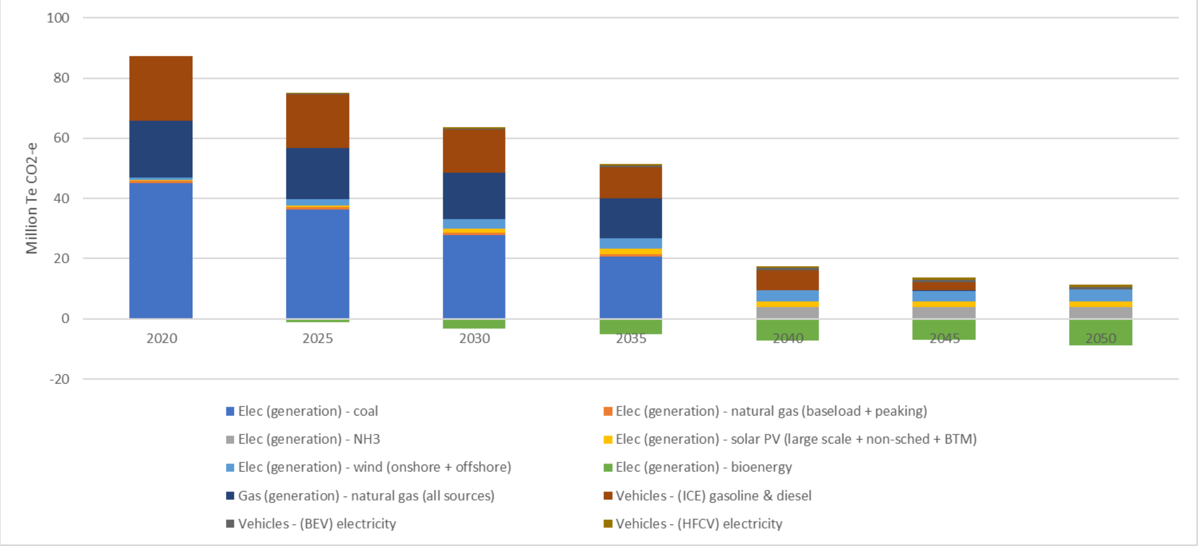


Figure 48: Agro-Forestry Offsets Utilised to Reach Net Zero Emissions for the Mid Probability Technology Case

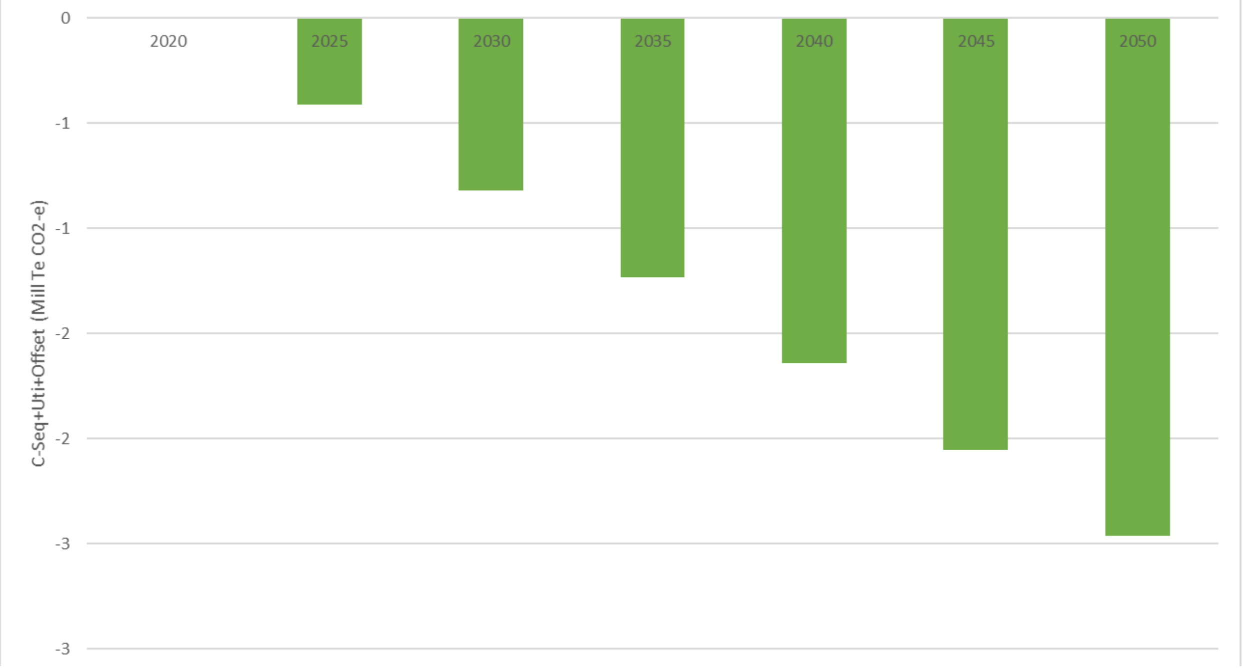
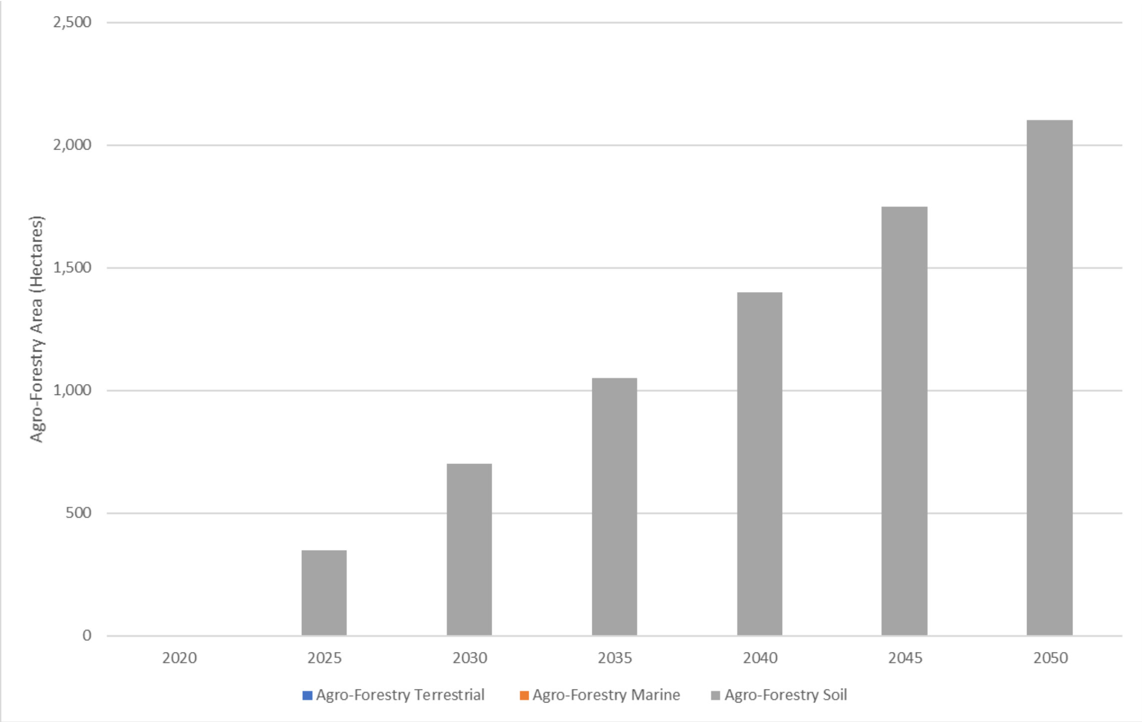


Figure 49: Area Required for Agro-Forestry Offsets in the Mid Probability Technology Case



The Mid Probability Technology case requires slightly lower levels of Carbon offsets compared to the High Probability Technology case.

For the current study, offsets derived from soil farming projects have been assumed to illustrate how residual emissions could be managed, see Section 3.4 for an assessment of the options, and Section 6.7 for cost estimation.

Figure 48 and Figure 49 indicate that 700 hectares are required to be established every decade to achieve net zero emissions in 2050, commencing with 350 hectares in 2025, resulting in a cumulative total of 2,100 hectares in 2050, representing approximately 0.01% of Victoria's total land area. This compares to the High Probability Technology case with a cumulative total of 2,400 hectares in 2050,

6.3 Gas Spatial Analysis

6.3.1 Work Description

The proposed energy mix from the global modelling tool is used as an input into the spatial modelling tool. The spatial distribution of the gas demand has been kept in same proportion as the 2020 demand.

6.3.2 Results

Table 67 shows the energy gas demand by region from 2020 to 2050.

Table 67: Energy gas demand by region for the Mid Probability Technology case from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	129	123	113	103	68	93	142
North East	6	5	6	5	3	4	7
Loddon Mallee	21	19	18	17	11	15	23
Grampians Central West	19	18	17	15	10	13	21
Barwon South West	25	24	22	20	13	18	28
Gippsland	5	4	4	3	2	3	4
Goulburn Valley	5	4	4	3	2	3	4
Total (PJ/yr)	**209**	**197**	**182**	**166**	**110**	**150**	**230**

Table 68 shows the distribution of gas supply by type from 2020 to 2050. Biomethane production ramps up from 1 PJ/yr in 2025 to 38 PJ/yr in 2050. Green hydrogen supply is relatively low ranging from 1 PJ/yr to 6 PJ/yr over the period.

Table 68: Energy gas supply by type for the Mid Probability Technology case from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	197	174	145	118	0	0	0
New local Victorian natural gas and imports	0	16	29	32	0	0	0
Biomethane	0	1	4	11	12	32	46
H2 (green)	0	6	5	5	1	1	2
NH3 (green)	0	0	0	0	97	122	190
Total	**209**	**197**	**182**	**166**	**110**	**150**	**230**

Figure 50 shows the energy gas mix in the transmission system for the Mid Probability Technology case from 2020 to 2050.

Figure 50: Energy gas mix in the transmission system for the Mid Probability Technology case from 2020 to 2050.

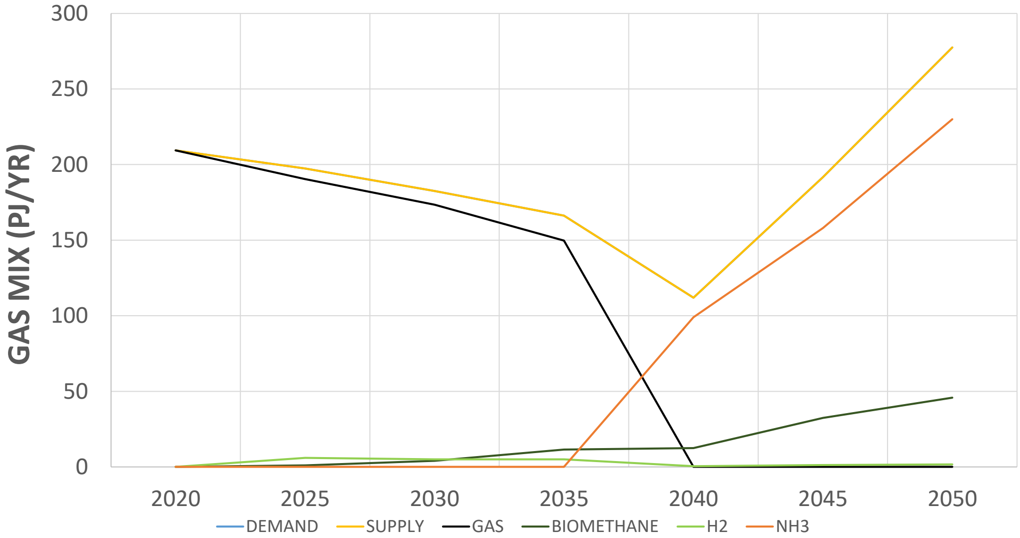
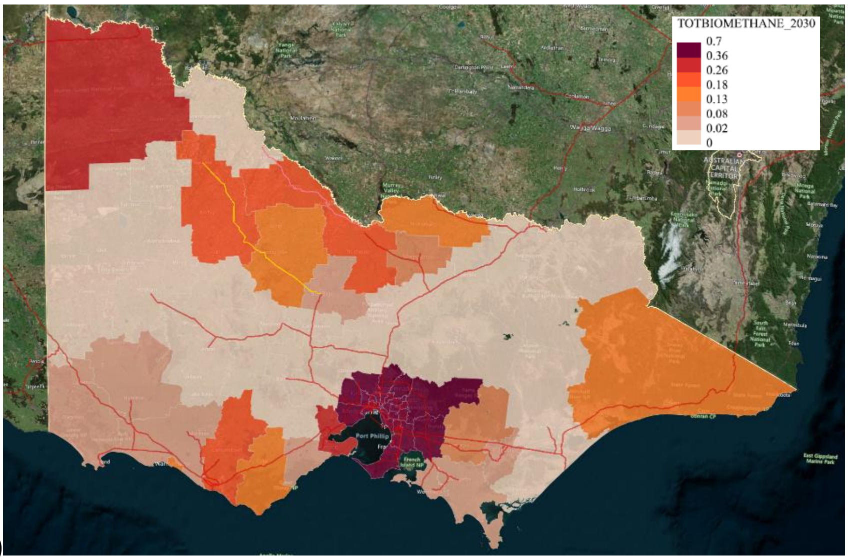
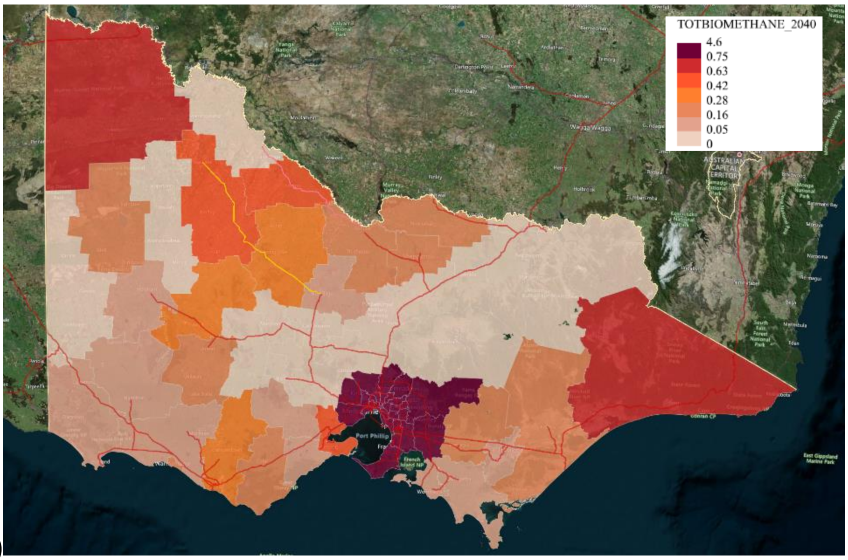


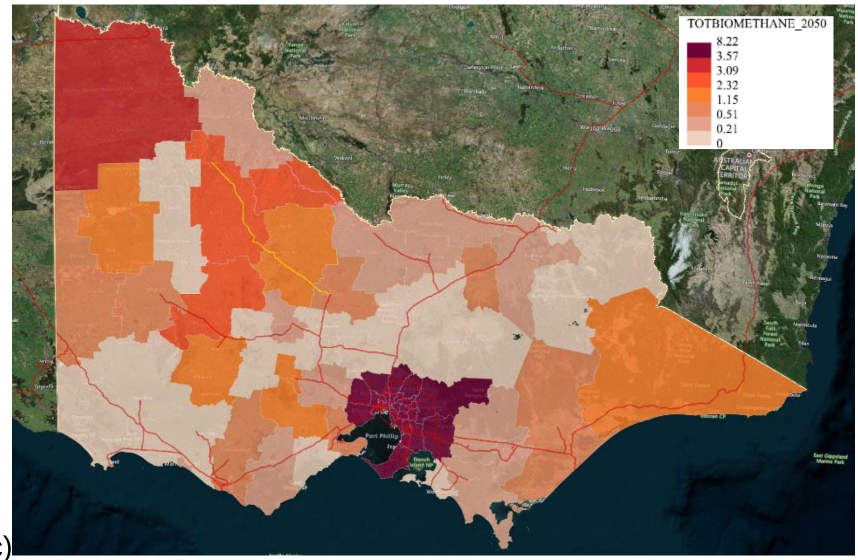
Figure 51: Biomethane production for Mid Probability Technology case in (a) 2030, (b) 2040 and (c) 2050.



(a)



(b)



(c)

Figure 51 shows the spatial distribution of biomethane production in 2030, 2040 and 2050 for the Mid Probability Technology case. It can be seen that biomethane production is concentrated in Melbourne, the Grampians Central West and Loddon Mallee regions and Goulburn Valley and North East regions with some production in Gippsland . The main difference between this case and the High Technology Probability case is that biomethane production is mostly limited to injection into the local gas distribution networks, so that from 2040 onwards the imported ammonia can be distributed via the high-pressure gas transmission system. Due to the high concentration of biomethane production in the north west of the state, it is likely that the north western transmission system could be separated and used exclusively to transport biomethane to meet demand in the major regional centres in the north and west such as Swan Hill, Bendigo and Horsham.

The production of biomethane is generated from upgrading of biogas from anaerobic digestion and gasification of solid biomass to synthesise methane. Figure 52 shows the spatial distribution of these sources. As with the High Technology Probability case, it can be seen that major sources of biomethane from anaerobic digestion are in Melbourne, the Loddon Mallee, Grampians Central West and Barwon South West regions.

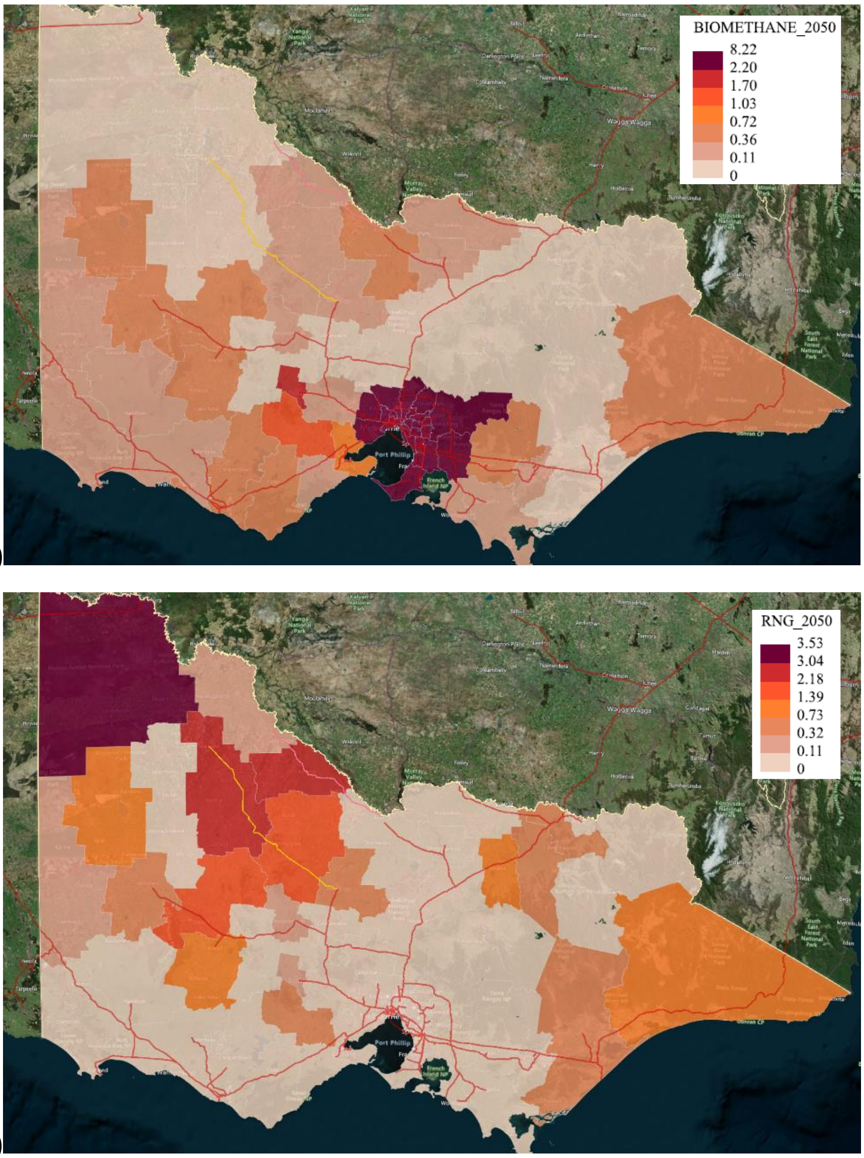
In Melbourne biomethane is made from the separated organics from domestic waste, with total production across the metropolitan area reaching over 8 PJ/yr by 2050. This biomethane would be predominately injected into the gas distribution system at low pressure. Outside of Melbourne animal manure, canola residues and fruit and vegetable wastes are the main sources of organics.

After 2030, straw residues in Loddon Mallee, Grampians Central West and Barwon South West regions are collected and gasified to produce biomethane. The resources in the north of the state are not close to existing pipelines, and so two new pipelines are proposed to be built by 2035:

1. Echuca to Swan Hill, 150 kilometres long, 15 PJ/yr.
2. Bendigo to Sea Lake, 210 kilometres long, 15 PJ/yr.

In this case, these pipelines would carry biomethane and would also be suitable for hydrogen. As with the High probability Technology case, this infrastructure could potentially be deferred to 2035 or 2040 if biomethane production from other areas is maximised and/or hydrogen production for location distribution could be increased.

Figure 52: Biomethane sources in 2050: (a) biomethane from anaerobic digestion and (b) biomethane from biomass gasification.

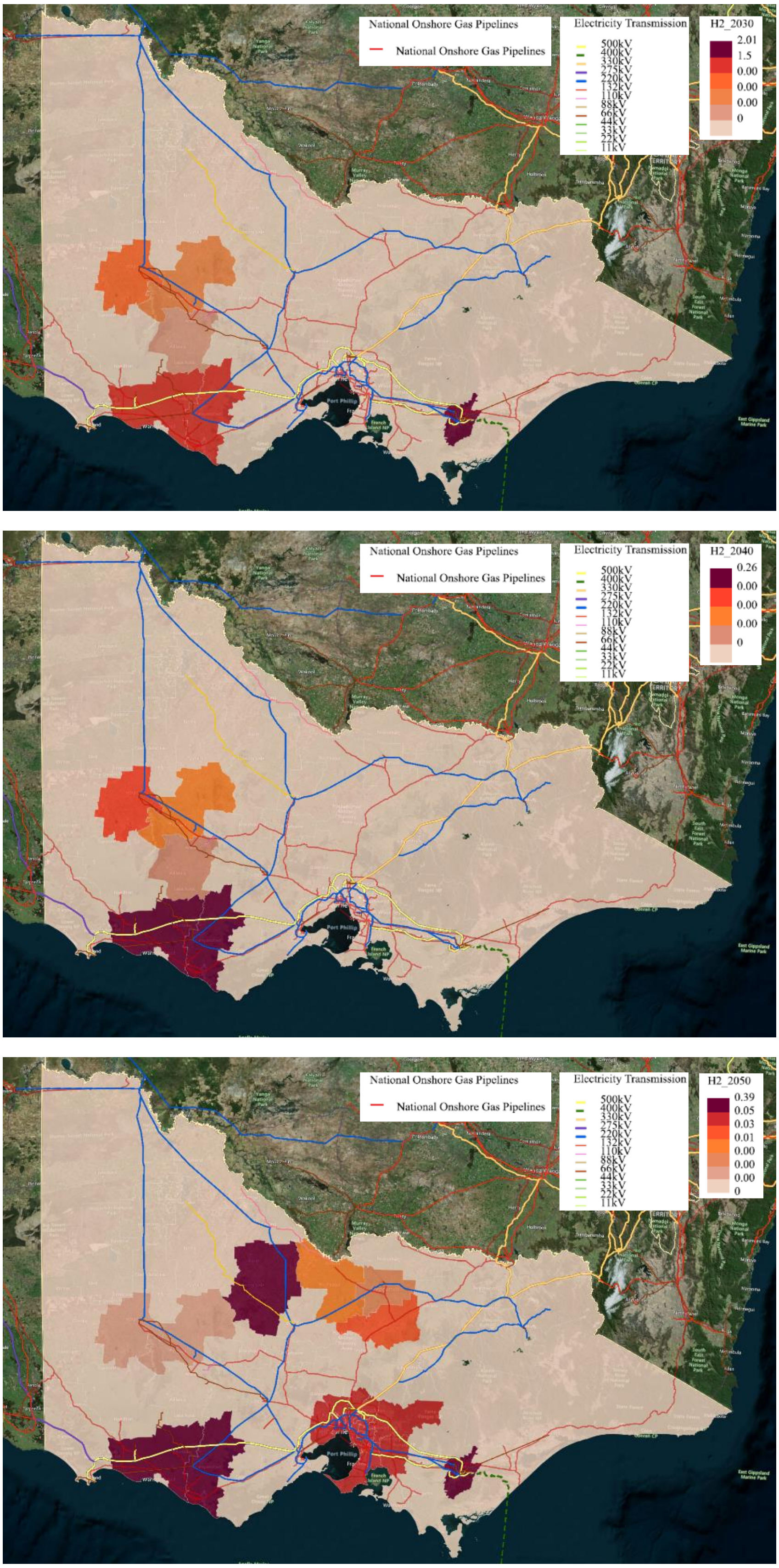


(a)

(b)

The location of green hydrogen generation for the Mid Probability technology case is shown in Figure 53. Hydrogen generation has been located close to electrical transmission infrastructure and natural gas pipeline infrastructure as well as in areas where there is significant relatively flat land available. Hydrogen production is located in Latrobe Valley in Gippsland, around Shepparton in Goulburn Valley, around Stawell and Ararat in the Grampians Central West, and in the vicinity of Warrnambool in the Barwon South West. Hydrogen use in the Mid Probability Technology case will be limited to 10% hydrogen by volume in the gas mix to 2040 and then preferably injected into the distribution systems after 2040 when they are converted to 100% hydrogen. As shown in Table 68 hydrogen production after 2040 is <2 PJ/yr and therefore not a significant contributor in the overall energy mix and several of the early plants will have already been decommissioned.

Figure 53: Hydrogen generation locations for Mid Probability Technology case in (a) 2030, (b) 2040 and (c) 2050.



As with the High Probability Technology case, water use for manufacture of hydrogen from electrolysis is not significant. During the peak demand for hydrogen, the associated water consumption is approximately: 0.5 GL/yr in Barwon South West, 0.1 GL/yr in Grampians Central West and 0.5 GL/yr in Gippsland.

The Mid Probability Technology case involves importing 100 PJ/yr of green ammonia from 2040 onwards with forecast import of 190 PJ/yr by 2050. The ammonia would be distributed in the existing high pressure gas transmission network which would only require minor modifications to transport ammonia in liquid form, whereas the transport of hydrogen would require major modifications to the pipeline infrastructure. Thus, to avoid these upgrades, ammonia would be transported in the high-pressure transmission system and converted to hydrogen before being distributed to end consumers in the low-pressure gas distribution system. In this concept, end customers will consume a mixture of hydrogen and biomethane with the mix being dependent upon their location and proximity to local biomethane production sources. In many locations end consumers will use 100% hydrogen after 2040 It is assumed that the low-pressure gas distribution system will have been upgraded to handle 100% hydrogen by then and that the major implication will be the need to replace or at least modify appliances that currently use natural gas to use hydrogen.

This concept will require a lot further study and investigation before being implemented. Ammonia (anhydrous) is colourless and toxic and is classed as a hazardous substance and dangerous good in Australia. Ammonia is flammable, a skin irritant and toxic when inhaled and very toxic to aquatic life. It is poisonous with an Occupational Safety and Health Administration (OSHA) exposure limit of 50 ppm and is immediately fatal at concentrations of 10,000 ppm (1%) (US DOE, 2006). Therefore, a number of issues will need to be addressed, including but not limited to:

- Ability of existing gas transmission pipelines to safely transport ammonia. Detailed assessment of any modifications required.
- Safety aspects and risks to the community, especially where high pressure gas transmission lines are in proximity to residential areas.
- Social license aspects, given that ammonia is a hazardous and dangerous good and toxic when inhaled and potentially fatal in event of any leaks.

In the United States ammonia is transported via over 5,000 km of pipelines from Louisiana to Indiana, Iowa, Nebraska and from Texas to Oklahoma, Kansas and Nebraska. The pipeline is made from mild carbon steel with the main branches having diameters of 200 to 250 mm. The pipeline is underground and does not experience corrosion (Fertilizers Europe, 2013) The main use of the ammonia in this case is as a fertiliser for farming. Ammonia is also transported over long distances via pipeline in Ukraine and Russia with a total pipeline length of 2,424 km (Fertilizers Europe, 2013). In seven countries of Europe and the UK there are numerous shorter pipelines of 24 km or less that are used for local transport of ammonia between the harbour, storage sites and local customers. Therefore, the transport of ammonia in pipelines is well proven. In liquid form, ammonia has a hydrogen density about 45% higher than liquefied hydrogen and can be liquefied under mild conditions (boiling point is -33.5 ^{o}C, US DOE, 2006). The main cause of pipeline failure incidents in Europe are shown in Table 69. Fertilizers Europe provides guidelines for inspection and detection of leaks in liquid ammonia pipelines (Fertilizers Europe, 2013).

Table 69: Cause analyses of ammonia pipeline incidents in Europe (Fertilizers Europe, 2013).

Cause of incident	% of all incidents	Subdivision
External interference	49.8	Digging, piling, ground works, anchor, bulldozer, excavator, plough, protecting casing/sleeves
Construction defects / material failures	16.7	
Corrosion	15.1	
Ground movement	7.1	Dyke Break, erosion, flood, landslide, mining, river
Hot-tap made by error	4.6	
Other and unknown	6.7	Design error, lightning, maintenance
Total	100	

Due to the amount of energy required to produce ammonia, a significant portion of the ammonia will need to be imported into Victoria. The imported ammonia may be produced in other states of Australia, such as Western Australia, South Australia, Queensland, Tasmania or in many overseas locations. By definition ammonia is used when there is a need for an energy carrier to move hydrogen from a location where it can be produced to one where it will be consumed. Green ammonia will mostly be produced from renewable electricity; by 2040 the electricity grid will be mostly renewables and so there is no advantage of using ammonia to move hydrogen if electricity could be used instead in the vicinity of the gas distribution system. We have also discarded the option to use coal gasification with CCS to produce the ammonia in Victoria from brown coal, as per our stage one study. So, while some ammonia could be produced in Victoria from renewable sources it is unlikely that 230 PJ/yr can be made locally and therefore it is assumed that most will be imported.

Ammonia vessels will be of a large size and require berthing at a suitable port. Ammonia is a toxic chemical and needs to be stored in refrigerated tanks at below and located away from residential areas. There are a number of options that could be considered for the import of ammonia into Victoria including:

- Portland
- Geelong, Corio Bay
- Point Henry, Port Philip Bay
- Crib Point, Western Port Bay
- Long Island Point, Western Port Bay

Portland is a relatively small port with limited space available for siting new refrigerated storage tanks and is also surrounded by a residential community. Portland is also located a long way from major demand centres.

Geelong terminal at Corio Bay already has crude oil import facilities for the Viva Energy refinery and is potentially suitable for siting the ammonia import. Similarly, Point Henry on Port Philip Bay has an existing jetty infrastructure that could be repurposed for ammonia import since the Point henry Aluminium Smelter has shut down. Point Henry has a lot of space for siting of new storage tanks and is not currently near any residential areas, however this could change in the future.

Crib Point has recently been rejected as a site for LNG import, due to marine discharges from the floating storage and regasification vessel. The ammonia import option would be configured differently, with construction of dedicated ammonia offloading arms on the existing jetty and ammonia storage on land with associated boil off gas, heating and injection equipment into transmission lines. The Minister's Assessment of the Crib Point import terminal found that *"effects of other parts of the project, particularly the pipeline component, could be managed within acceptable limits"* (Victorian Minister for Planning, 2021) and based on this we assume that new and modified onshore infrastructure will be acceptable by 2040. Further technical studies, planning and environmental assessments, and community consultation would be required to determine the suitability of Crib Point for future ammonia import.

Long Island Point on Western Port Bay serves the BlueScope steel plant and Esso gas plants in the vicinity. This could also be considered for importing ammonia, especially once the Bass Strait gas fields have significantly declined.

Further work is required to study which site(s) would be preferred locations for the ammonia import taking into a wide range of factors, including the siting of ammonia to hydrogen cracking plants. As the major demand centres for the ammonia will be in Melbourne and in the Latrobe Valley for power generation, the preferred import site(s) will probably be located on the eastern side of Melbourne, and would include Crib Point, Long Island Point. Locations west of Melbourne in Geelong and at Point Henry are also potentially attractive. Portland is likely to be less favoured for the reasons mentioned above.

Irrespective of where the ammonia is imported, new facilities will need to be built including offloading arms on the jetty, construction of one or more dedicated refrigerated storage tanks, boil off gas management system and heating and injection equipment to pressurise the ammonia for injection into the gas transmission network.

Along the gas transmission network, new ammonia receiving storage and plants dedicated to cracking it back into hydrogen will also be needed. A conceptual representation of these facilities is shown in Figure 54 indicating the ammonia to hydrogen conversion will require oil and gas type equipment including storage tanks, pumps, furnace, cracking reactor and purification columns. These facilities will also need to be sited appropriately, at an appropriate distance from residential communities. Therefore, further study will be required to assess the potential locations and feasibility of the integrated ammonia to hydrogen scheme. For the purposes of illustration of the Mid Probability Technology case, we have selected the Long Island Point jetty as the location for receiving imported ammonia and then considered how the ammonia could be distributed to the major demand centres and converted back into hydrogen for distribution to end consumers. Figure 55 shows the Melbourne region.

Figure 54: Conceptual ammonia to hydrogen fuel processing system (from US DOE, 2006)

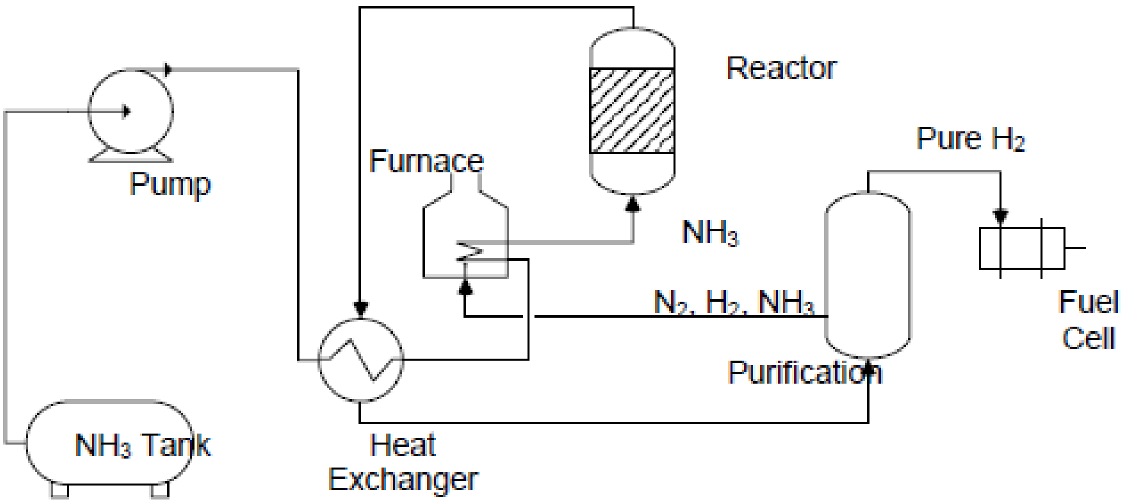


Figure 55: Melbourne Region showing existing high pressure gas transmission network.

This is only a very high-level conceptual plan and cannot be considered an engineered solution to the problem taking into account all necessary factors and variables. For the Long Island Point import site a new ammonia import terminal would be located close to the jetty. The following transmission pipelines will be upgraded, if required, at a minimum to take ammonia:

1. Pipeline to Dandenong -- 39 kms
2. Dandenong to Morwell -- 127 kms

At the Dandenong terminal, which is currently owned and operated by Elgas, ammonia would be stored and converted back into hydrogen. Hydrogen could then be injected into the local low pressure gas distribution system after suitable upgrades have been completed. As can be seen in Figure 56 the Dandenong gas terminal is located in an industrial area and away from residents and thus seems suitable for an ammonia to hydrogen facility. Of course, detailed assessment of suitability will be required if this option is to be progressed in future.

Figure 56: Dandenong terminal: (a) general layout, (b) close up view.

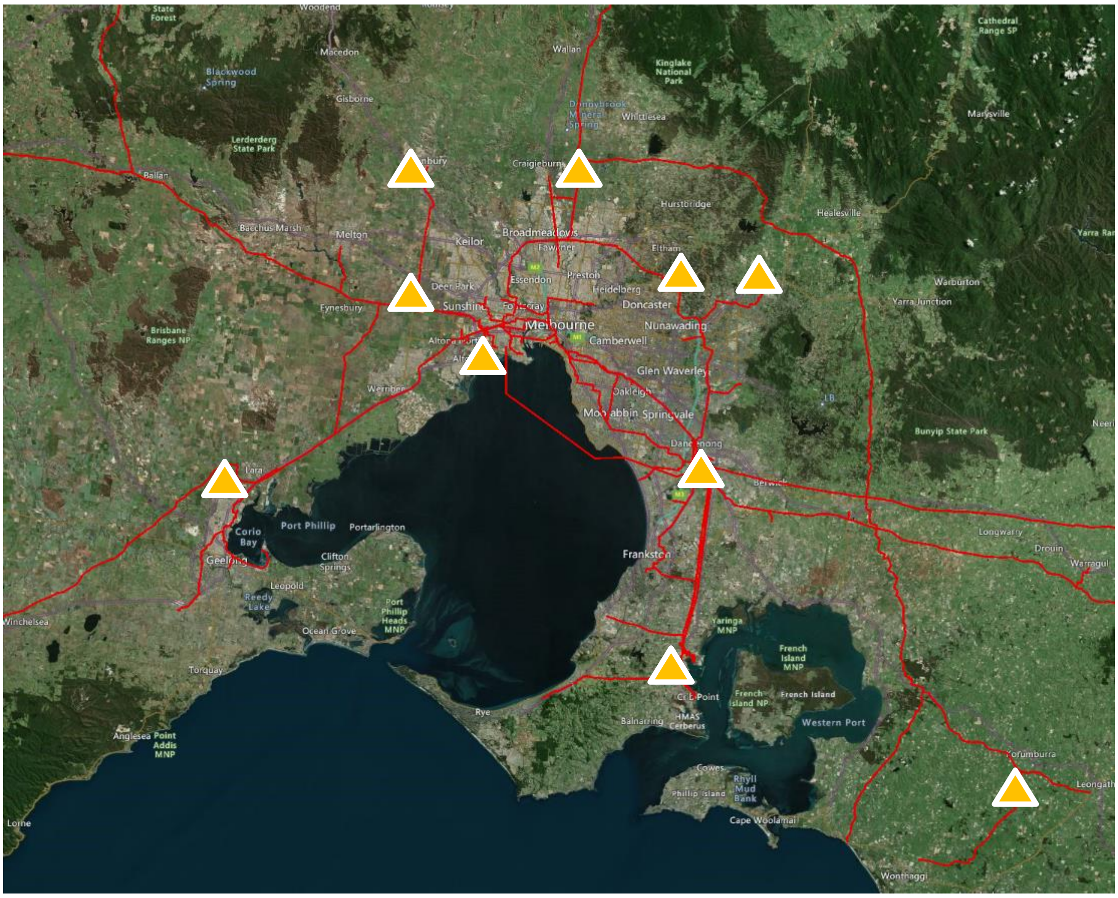
a)

b) 

Other suitable locations for ammonia conversion back to hydrogen could be in Lilydale, Heidelberg, Craigieburn, Deer Park, Sunbury, Altona/Laverton and Geelong. Figure 57 shows general areas where ammonia to hydrogen conversion facilities could be located. In all cases these are not located close to residential housing. Depending upon the exact location of ammonia to hydrogen conversion, some high-pressure gas transmission lines may be able to be decommissioned. For example, for some small regional centres it may be more cost-effective to electrify a small number of households than modify the transmission system, install a dedicated ammonia to hydrogen conversion facility and upgrade appliances. For simplicity, the base assumption is that ammonia would be transported in the existing network.

An implication of converting ammonia to hydrogen is that the distribution network will need to be upgraded for 100% hydrogen by 2040. Although in practice it is likely that the changeover would be done in stages over a reasonable period of time (5 years or more).

Figure 57: Potential sites for ammonia to hydrogen conversion facilities around Melbourne.



6.3.3 Discussion

The proposed solution to the Mid Probability Technology case has the following characteristics:

- Total biomethane production commences at 1 PJ/yr in 2025 and rises to 46 PJ/yr by 2050.
- Biomethane production from anaerobic digestion is deployed in the 2020s commencing at 1 PJ/yr in 2025 and ramping up to 8 PJ/yr by 2035 and to 23 PJ/yr by 2050.
- While biogas production for electricity production and combined heat and power projects is already being practiced at a small scale in Victoria, it is generally accepted that upgrading biogas to biomethane has a total cost of gas production in the range of 10 to 40 $/GJ, with the final cost sensitive to a range of factors such as: feedstock pricing, biomethane yield, transport costs, digester size etc. Therefore, to stimulate the modelled supply it is expected that appropriate policy settings will be required.
- Biomethane from biomass gasification is deployed commencing in 2030 in the north western parts of the state converting wheat straw residues producing at a relatively low rate of < 1 PJ/y and ramping up to 23 PJ/yr by 2050. This gas would be used

locally and distributed regionally using two new pipelines that are proposed to be built by 2035.

- The proposed pipeline routes are indicative and further work is required to establish the economic viability and finalise the optimum route and required extent of the pipelines. The Alternatives such as small scale liquefaction could also be considered.
- Like biomethane production from anaerobic digestion, biomethane from biomass gasification will also need policy support in order to stimulate demand. While biomass gasification is a proven technology, its application to produce biomethane is not yet commercially practiced due to cost. Therefore, in order to improve the commercial readiness index of this technology, additional support for demonstration and first of a kind commercial projects will need to be encouraged in the next five years, with initial projects constructed by 2030.
- Similarly, to the High Probability Technology case, the proposed solution leverages the most appropriate bioenergy conversion technology for each resource and considers the commercial readiness of each technology.
- Hydrogen production is relatively modest as it has been limited to 10% volume in the transmission system before 2040 and injection into the distribution system when ammonia import commences. Additional hydrogen production directly into the distribution system could also be considered in Melbourne and some regional centres and this would reduce overall demand of fossil derived natural gas even further. This would be a particularly good solution, as the pre-investment into upgrading distribution systems for 100% hydrogen is required from 2040 when ammonia is imported into the gas transmission system.
- Hydrogen production has been located in areas with good pipeline access and good electrical infrastructure, however the locations are indicative and further work on optimal siting is required. However, selecting different locations will not affect the overall solution.
- The major distinguishing feature of this case over the High Probability Technology case is the importation and use of ammonia in parts of the high pressure gas transmission system from 2040. A number of import locations have been identified. The import of ammonia will require new infrastructure for loading arms, jetty modifications, refrigerated storage and equipment to heat and inject the ammonia into the gas transmission system.
- In addition, new infrastructure will be required to convert ammonia into hydrogen for distribution in the low pressure gas distribution system to end customers. This process requires oil and gas equipment and will need to be sited at a suitable distance from residential areas. A number of general locations where this conversion of ammonia into hydrogen could be undertaken have been identified around Melbourne.
- To handle 100% hydrogen modifications of the distribution system will also be required and end users will need appliances that can use up to 100% pure hydrogen.
- While ammonia importation has a big impact on reducing emissions, it also requires a lot of new infrastructure to be installed, commissioned and brought online. Fortunately, this could be staged over a decade or so. A detailed study of the risks and benefits of ammonia importation and distribution will be required in the future.

6.3.4 Gas pipeline network changes

For the Mid Probability Technology case, the major changes in the gas transmission network can be summarised as:

- Addition of an ammonia import terminal at either Long Island Point, Crib Point or Geelong with associated facilities to store ammonia and inject it into the gas transmission network from 2040.
- Upgrading (if required) of transmission pipelines to handle ammonia by 2040. Mild carbon steel pipelines should not need upgrading; however, this should be confirmed on a case by case basis in future work.
- Addition of a number of ammonia to hydrogen conversion facilities in metropolitan Melbourne by 2040. Estimates are that five to ten such facilities may be required.
- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035.
- Decommissioning of the Eastern Gas Pipeline to NSW and the gas transmission pipelines between Seaspray and Longford, Longford and Morwell and Longford and Dandenong.
- Decommissioning of the pipeline infrastructure in the Barwon South West region, around Port Campbell and Warrnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia.
- For the Mid Probability Technology case, the major changes in the gas distribution networks can be summarised as:
- Upgrading of gas distribution networks in Melbourne and Gippsland to handle 100% hydrogen by 2040.
- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland from 2030.
- Biomethane and hydrogen from the Loddon Mallee and Grampians production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat from 2030.
- Potential decommissioning of up to 15% of the distribution network (mostly in regional towns and some parts of Melbourne where it may be difficult to upgrade to hydrogen).

6.4 Electrical Spatial Analysis

6.4.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley

- MEL: Metropolitan (Melbourne and surroundings)

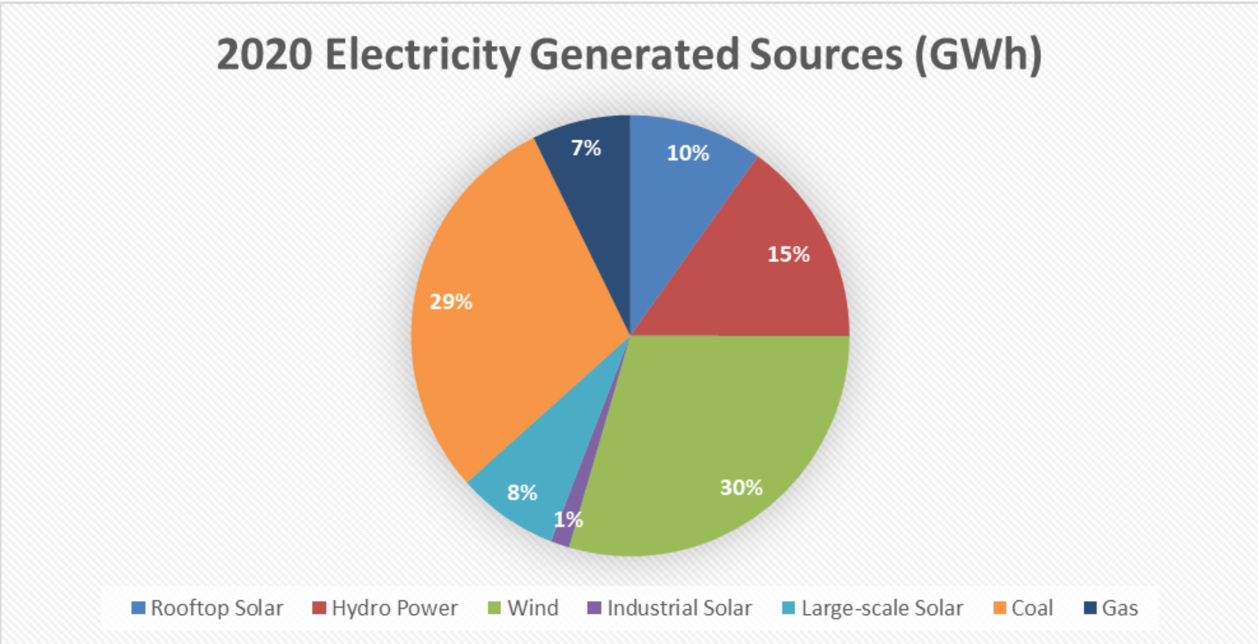
6.4.2 Work Description

For the Mid Probability Technology Case, the main electrical generation infrastructure are wind, solar PV and Bioenergy, as High Probability Technology Case, but with a high presence of ammonia in the mix, and the main electrical storage technology is the Li-ion battery (large-scale, industrial and behind the meter scale).

In this section, data relating to ammonia refers to additional electricity generation capacity based on ammonia combustion.

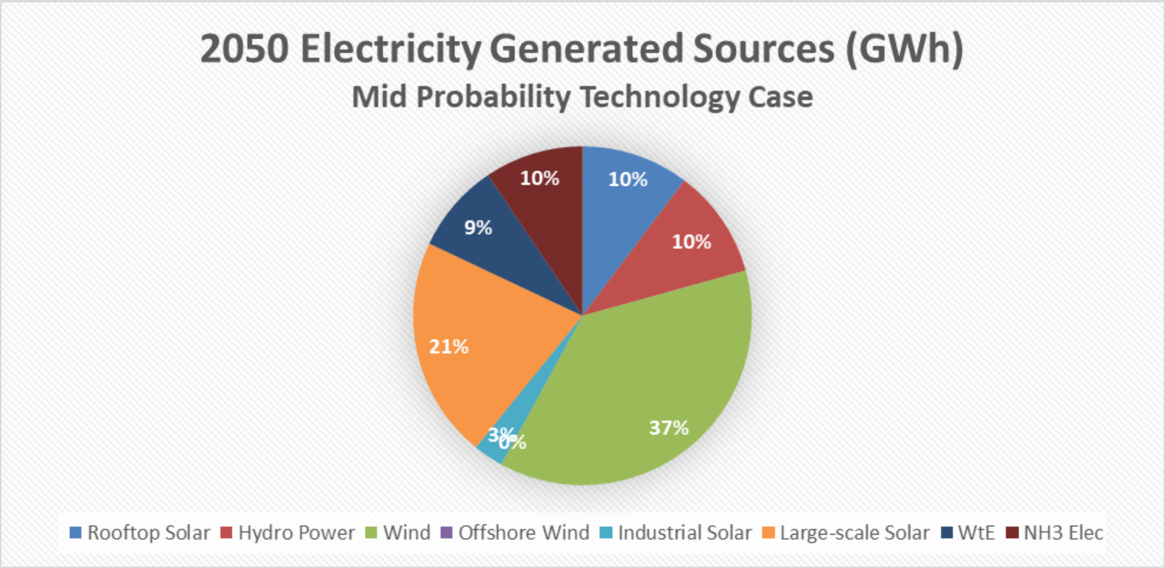
REMINDER: **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

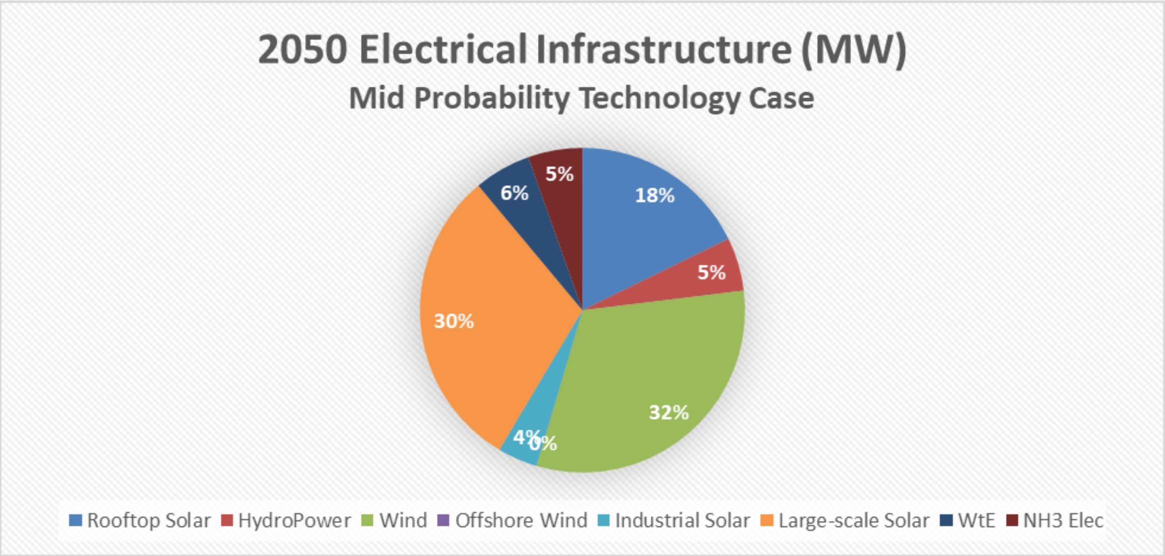
Electrical Generation Mix in 2020:



<u>Electrical Mix in 2050:</u>

(Note Reference in figures to “waste-to-energy” shall be read as “bioenergy”)





As seen in the charts above, the electrical infrastructure capacity (MW) was found to increase by a factor of 2.8 over 30 years, whilst the electrical generation (GWh or PJ) increased by a factor of 1.5. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

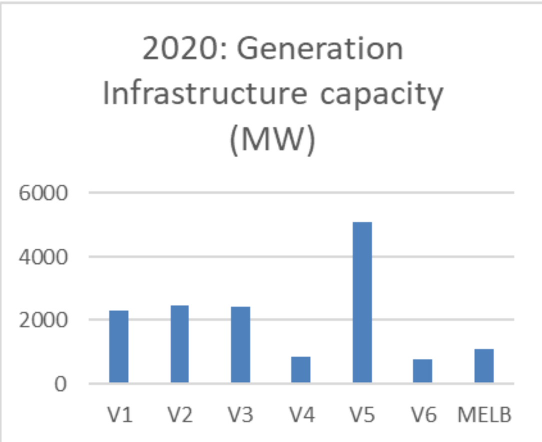
The Mid Probability Technology Case resulted in less electrical infrastructure in the energy mix than the High Probability Technology Case because the objective was to use green Ammonia.

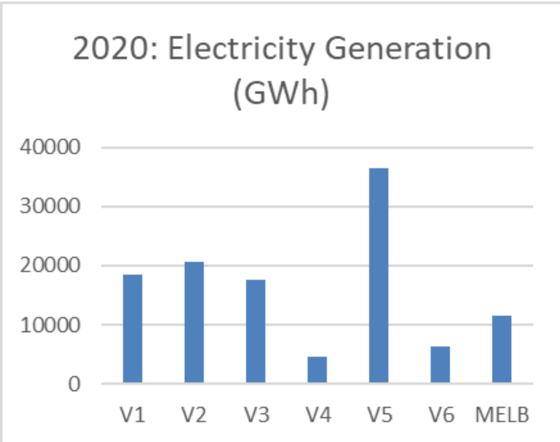
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	170 284	42 282

6.4.3 Results

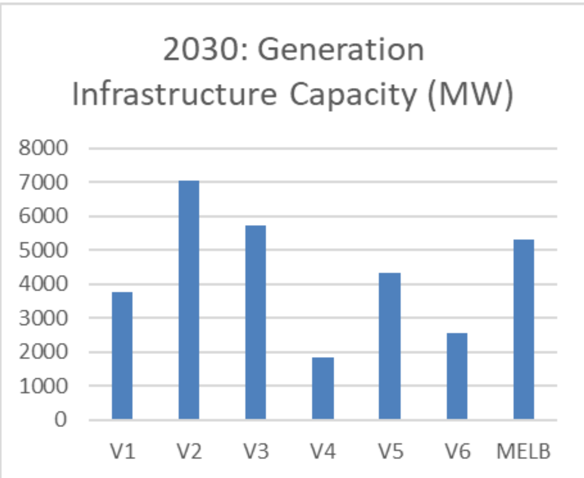
6.4.3.1 Overall Generation

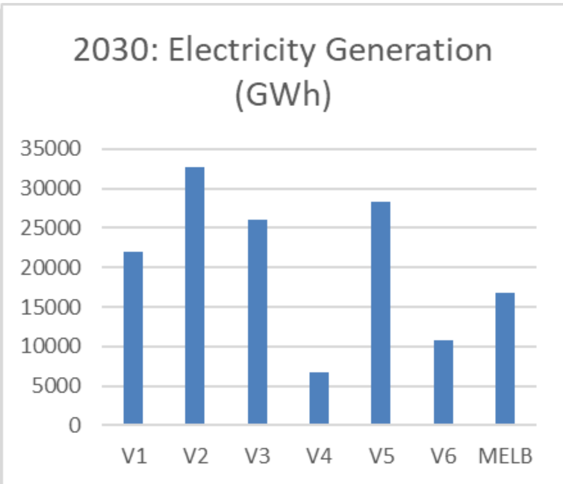
2020 generation infrastructure capacity (MW) and electricity generation (GWh):



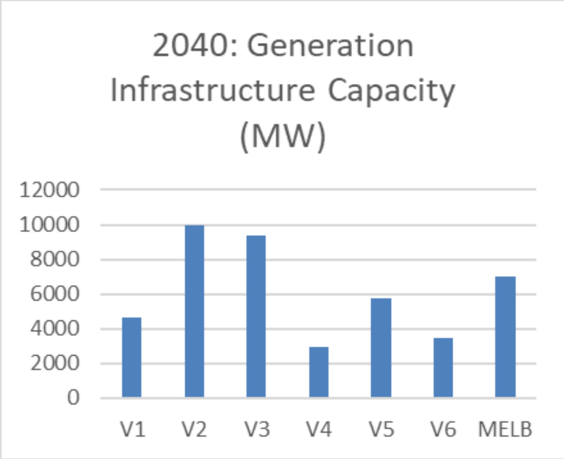


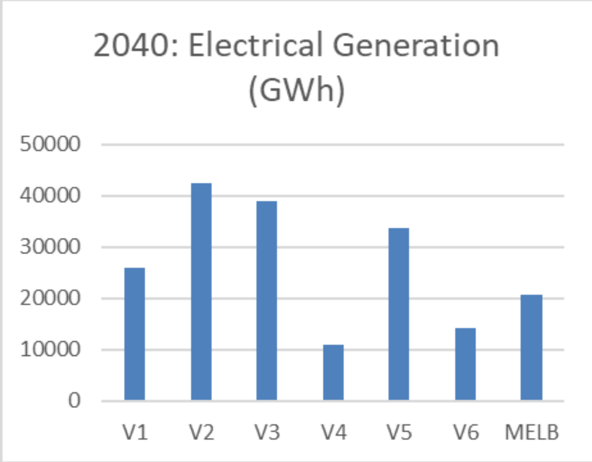
2030 generation infrastructure capacity (MW) and electricity generation (GWh):



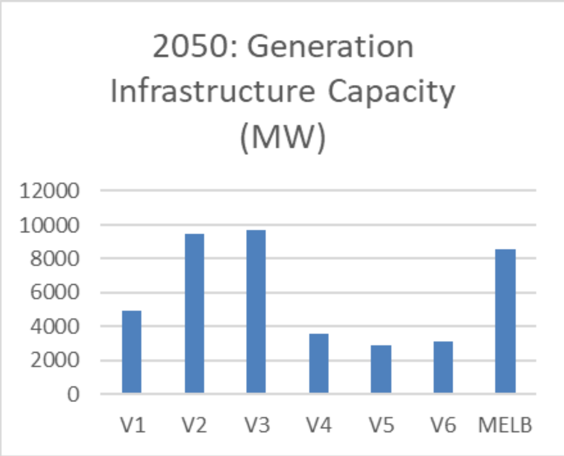


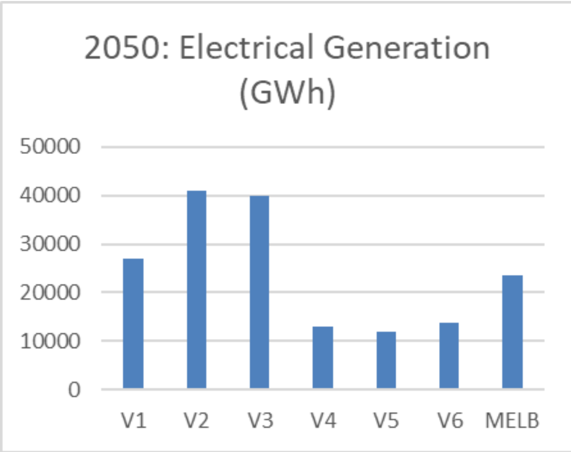
2040 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity for each REZ.
- Ovens Murray (V1), Central North (V6), South West (V4) and Gippsland (V5) have a low generation capacity.
- Melbourne (MELB), Murray River (V2) and Western Victoria (V3) have a high generation capacity.

The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

REMINDER: The assumptions used here are based on the AEMO's ISP inputs and assumptions workbook which has been used as "relied upon information".

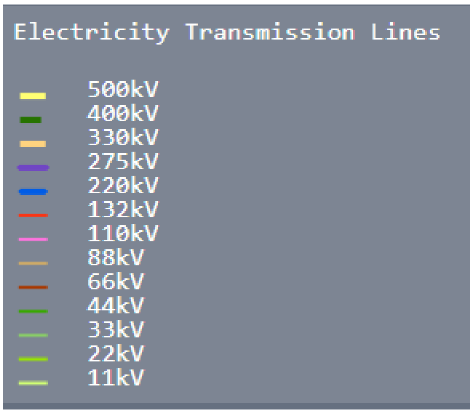
The demand is located mainly in the Melbourne metropolitan region (around 60%), with approximately 10% of demand for each of V2, V3 and V4 (representing all the west side of Victoria), with the last 10% is split between V1, Gippsland (V5) and V6.

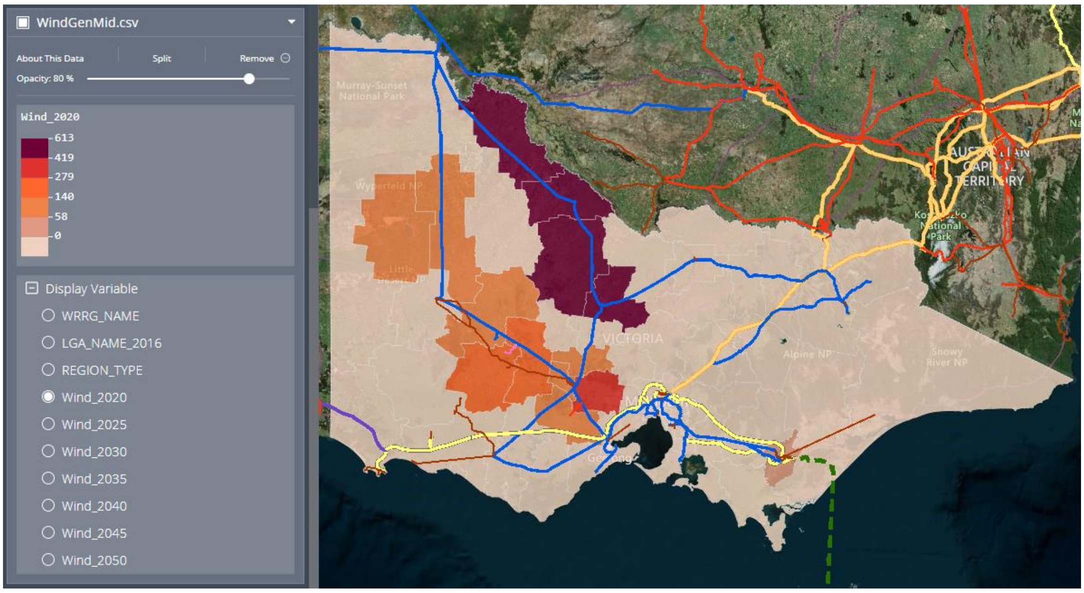
Comparing generation location and demand location, the existing transmission lines between all the regions and Melbourne and between East and West will need to be upgraded as both demand and electrical generation grow.

6.4.3.2 Wind

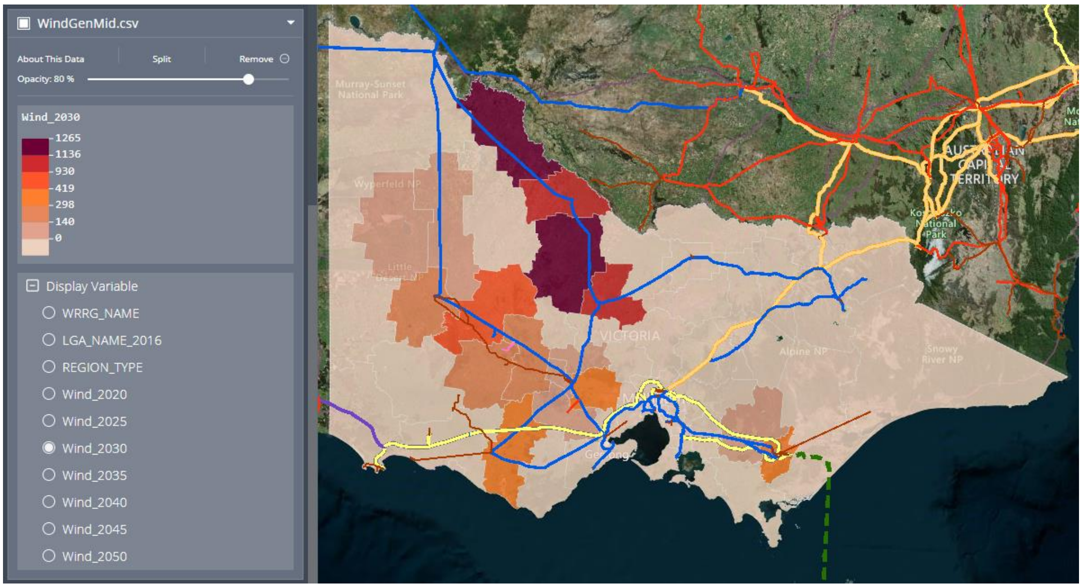
Only the transmission lines existing in 2020 are indicated on the following maps, for all time periods, and the scale (in MW) was fixed to provide consistency. The values shown on the scale represent electrical generation infrastructure in sub regions. Loddon Mallee, for example, has eight subregions.

Figure 58: Regions and Sub-regions in Victoria.

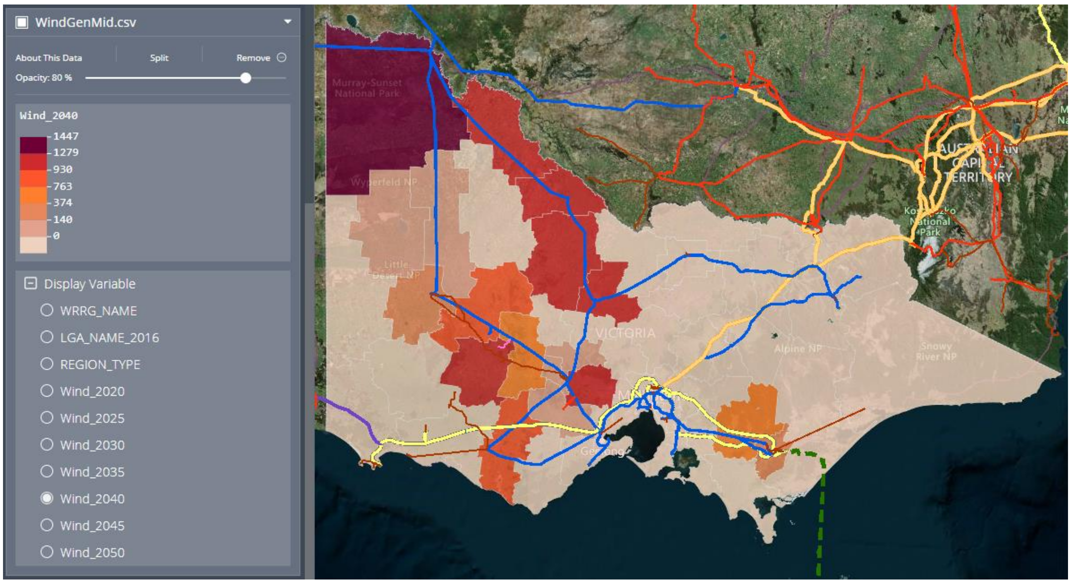

Electricity Transmission Lines
500kV
400kV
330kV
275kV
220kV
132kV
110kV
88kV
66kV
44kV
33kV
22kV
11kV


WindGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
Wind_2020
613
419
279
140
58
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
Wind_2020
Wind_2025
Wind_2030
Wind_2035
Wind_2040
Wind_2045
Wind_2050
VICTORIA
Alpine NP

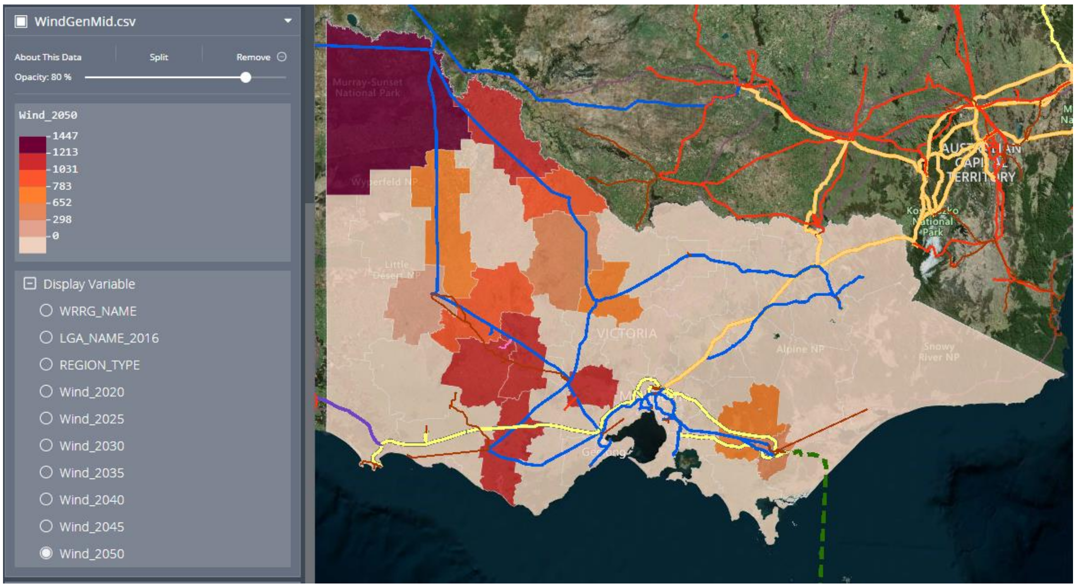
(2020)


WindGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
Wind_2030
1265
1136
930
419
298
140
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
Wind_2020
Wind_2025
Wind_2030
Wind_2035
Wind_2040
Wind_2045
Wind_2050
VICTORIA
Alpine NP

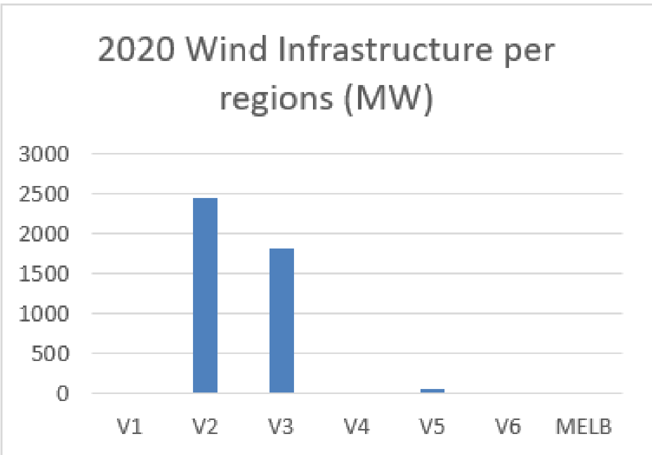
(2030)

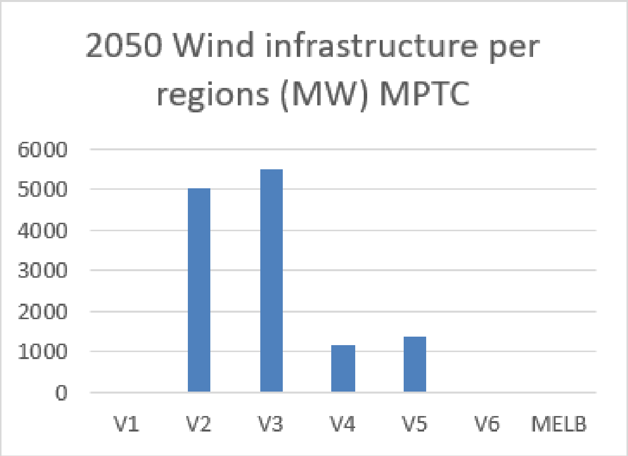

WindGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
Wind_2040
1447
1279
930
763
374
140
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
Wind_2020
Wind_2025
Wind_2030
Wind_2035
Wind_2040
Wind_2045
Wind_2050
VICTORIA

(2040)


WindGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
Wind_2050
1447
1213
1031
783
652
298
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
Wind_2020
Wind_2025
Wind_2030
Wind_2035
Wind_2040
Wind_2045
Wind_2050
VICTORIA

(2050)


2020 Wind Infrastructure per regions (MW)
3000
2500
2000
1500
1000
500
0
V1
V2
V3
V4
V5
V6
MELB



MPTC: Mid Probability Technology Case

Note: All the locations of existing and committed assets for 2020 wind generation have been taken from AEMO's ISP inputs & assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zones alongside the existing transmission lines. The location is based on available open land and associated wind rows.

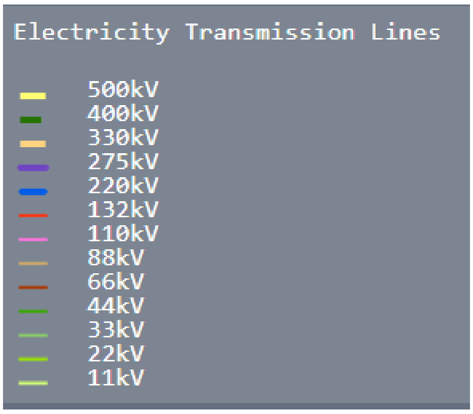
Further work may consider wind generation infrastructure being more balanced between V2, V3 and V4.

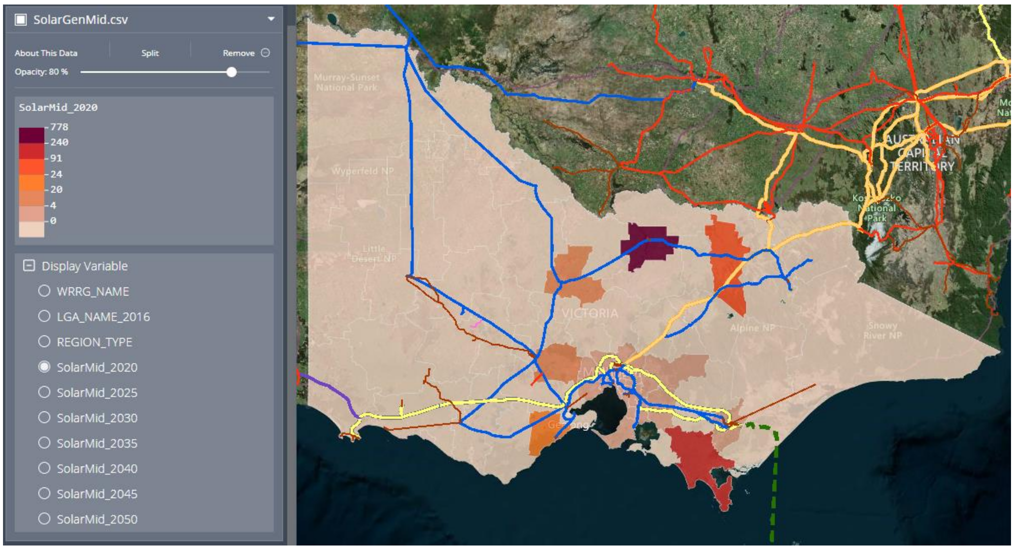
By 2050, wind represents 37% of the electrical mix with 13,125 MW of infrastructure capacity.

6.4.3.3 Solar PV

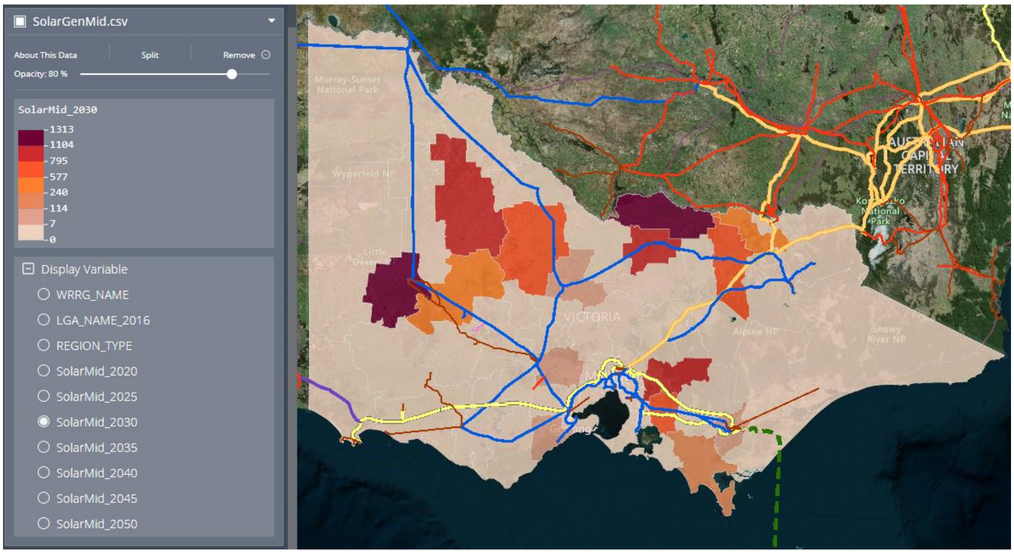
The transmission lines indicated in the following schematics show the 2020 existing infrastructure for all time periods.

The scale (in MW) was fixed for consistency, and the values shown on the scale represents the electrical generation infrastructure by sub region. Loddon Mallee, for example, has eight subregions.

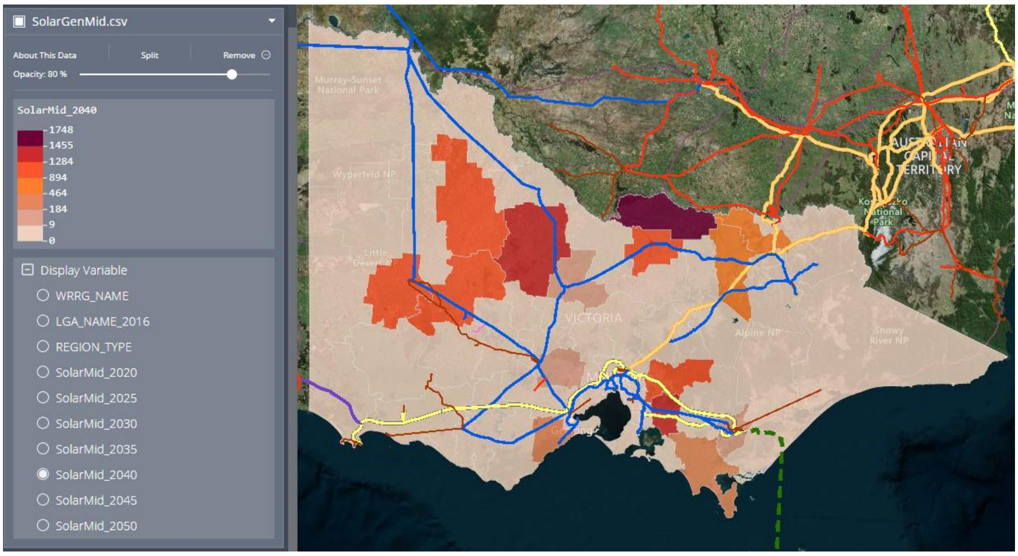

Electricity Transmission Lines
500kV
400kV
330kV
275kV
220kV
132kV
110kV
88kV
66kV
44kV
33kV
22kV
11kV


SolarGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
SolarMid_2020
778
240
91
24
20
4
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
SolarMid_2020
SolarMid_2025
SolarMid_2030
SolarMid_2035
SolarMid_2040
SolarMid_2045
SolarMid_2050
VICTORIA
Alpine NP
Snowy River NP
Wyperfeld NP

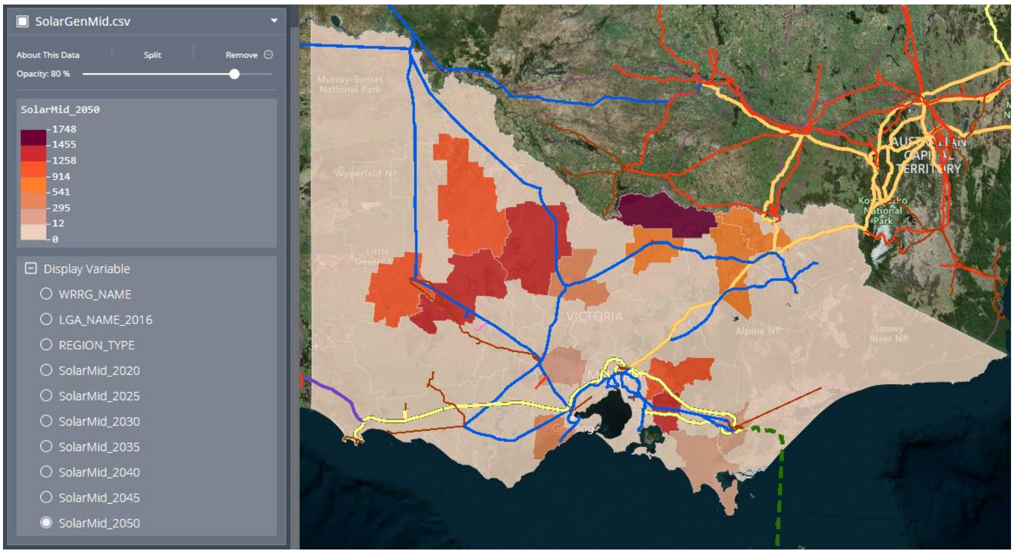
(2020)


SolarGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
SolarMid_2030
1313
1104
795
577
240
114
7
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
SolarMid_2020
SolarMid_2025
SolarMid_2030
SolarMid_2035
SolarMid_2040
SolarMid_2045
SolarMid_2050
VICTORIA
Alpine NP
Wyperfeld NP

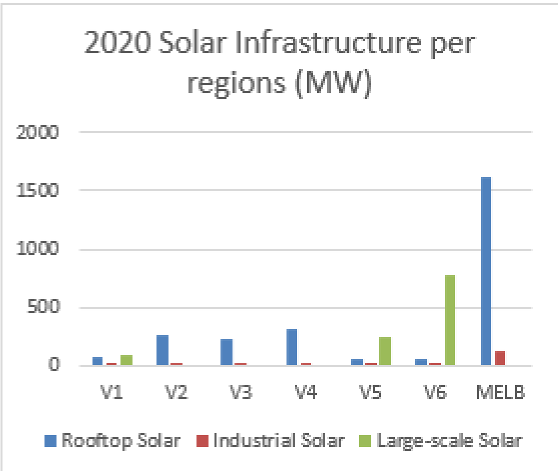
(2030)

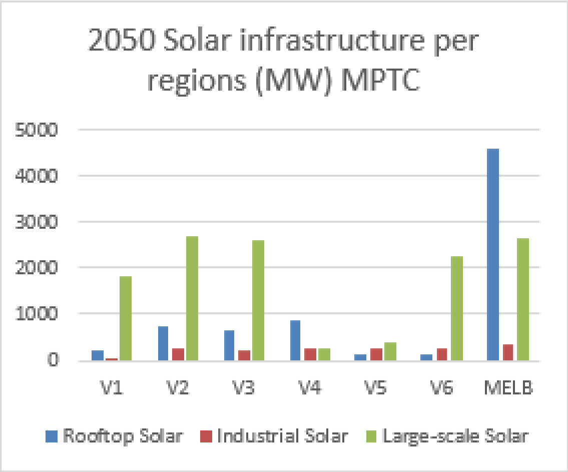

SolarGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
SolarMid_2040
1748
1455
1284
894
464
184
9
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
SolarMid_2020
SolarMid_2025
SolarMid_2030
SolarMid_2035
SolarMid_2040
SolarMid_2045
SolarMid_2050
VICTORIA

(2040)


SolarGenMid.csv
About This Data
Split
Remove
Opacity: 80 %
SolarMid_2050
1748
1455
1258
914
541
295
12
0
Display Variable
WRRG_NAME
LGA_NAME_2016
REGION_TYPE
SolarMid_2020
SolarMid_2025
SolarMid_2030
SolarMid_2035
SolarMid_2040
SolarMid_2045
SolarMid_2050
VICTORIA

(2050)


2020 Solar Infrastructure per regions (MW)
2000
1500
1000
500
0
V1
V2
V3
V4
V5
V6
MELB
Rooftop Solar
Industrial Solar
Large-scale Solar



As for the High Probability Technology Case, solar PV will expand in all the regions in which it has a high potential : V1, V2, V3 and V6. Once again, location of infrastructure is aligned with the transmission lines.

In 2050, Victoria is predicted to have:

- 7,394 MW of rooftop solar PV generation being 10% of electrical mix.
- 1,657 MW of industrial solar PV generation being 2.8% of electrical mix.
- 12,663 MW of large-scale solar PV generation being 20.8% of electrical mix.

Compared to the High Probability Technology Case, the capacity represented by solar PV is much less important for the Mid Probability Technology Case because of the presence of green Ammonia.

6.4.3.4 Bioenergy

By 2050, Bioenergy represents approximately 8% of the electrical demand with 2,356 MW of installed capacity.

6.4.3.5 Infrastructure to be installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period. The data represents the additional infrastructure required in each period and not the cumulative total amount.

The values in 2020 are the existing and committed assets, then for each subsequent period the values represent the generation infrastructure that has to be added for this specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	10	0	0	0	0	191	0	0	0	0	0	35	0	450	30	15	0	0	0	0
2030	23	0	0	0	0	1077	0	0	0	0	0	57	0	1789	50	33	0	0	0	0
2035	19	0	0	0	0	317	0	0	0	0	0	64	0	866	41	28	0	0	0	0
2040	35	0	0	0	0	65	0	0	0	0	0	61	0	271	34	51	0	2435	0	315
2045	26	0	0	0	0	67	0	0	0	0	0	68	0	104	30	37	0	2398	0	12
2050	30	0	0	0	0	0	0	0	0	0	0	68	0	81	43	65	0	4152	0	12
	MW												GWh						MW	

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	35	0	623	0	32	265	0	0	0	0	0	35	0	1375	92	50	0	0	0	0
2030	77	0	1652	0	53	1495	0	0	0	0	0	57	0	5468	152	110	0	0	0	0
2035	64	0	919	0	43	660	0	0	0	0	0	64	0	2647	124	92	0	0	0	0
2040	118	0	880	0	36	135	0	0	0	0	0	61	0	827	104	170	0	7439	0	315
2045	86	0	281	0	32	139	0	0	0	0	0	68	0	319	91	124	0	7327	0	12
2050	100	0	484	0	46	0	0	0	0	0	0	68	0	247	132	215	0	12686	0	12
	MW												GWh						MW	

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0	0	0
2025	31	0	298	0	29	258	0	0	0	0	0	35	0	1100	73	45	0	0	0	0
2030	69	0	790	0	48	1454	0	0	0	0	0	57	0	4374	122	99	0	0	0	0
2035	57	0	440	0	39	642	0	0	0	0	0	64	0	2118	99	83	0	0	0	0
2040	106	0	2416	0	33	132	0	0	0	0	0	61	0	661	83	153	0	5951	0	315
2045	78	0	773	0	29	135	0	0	0	0	0	68	0	255	73	112	0	5862	0	12
2050	90	0	643	0	42	0	0	0	0	0	0	68	0	198	105	194	0	10149	0	12
	MW												GWh						MW	

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0	0	0
2025	42	0	102	0	34	0	0	0	0	0	0	35	0	675	45	60	0	0	0	0
2030	92	0	269	0	56	0	0	0	0	0	0	57	0	2684	75	133	0	0	0	0
2035	77	0	150	0	45	186	0	0	0	0	0	64	0	1299	61	111	0	0	0	0
2040	141	0	398	0	38	38	0	0	0	0	0	61	0	406	51	204	0	3652	0	315
2045	103	0	127	0	33	39	0	0	0	0	0	68	0	157	45	149	0	3597	0	12
2050	119	0	131	0	48	0	0	0	0	0	0	68	0	121	65	258	0	6228	0	12
	MW												GWh						MW	

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	119	0	34	0	0	0	0	0	0	35	0	425	28	10	0	0	0	0
2030	15	0	316	0	56	0	0	0	0	0	0	57	0	1690	47	22	0	0	0	0
2035	13	0	176	0	45	186	0	0	0	0	0	64	0	818	38	18	0	0	0	0
2040	24	0	468	0	38	38	0	0	0	0	0	61	0	256	32	34	0	2299	0	315
2045	17	0	150	0	33	39	0	0	0	0	0	68	0	99	28	25	0	2265	0	12
2050	20	0	154	0	48	0	0	0	0	0	0	68	0	76	41	43	0	3921	0	12
	MW												GWh						MW	

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	0	0	35	233	0	0	0	0	0	23	0	1050	70	10	0	0	0	0
2030	15	0	0	0	58	1313	0	0	0	0	0	38	0	4175	116	22	0	0	0	0
2035	13	0	0	0	47	435	0	0	0	0	0	43	0	2021	95	18	0	0	0	0
2040	24	0	0	0	40	89	0	0	0	0	0	41	0	631	79	34	0	5681	0	210
2045	17	0	0	0	35	91	0	0	0	0	0	45	0	244	70	25	0	5595	0	8
2050	20	0	0	0	50	0	0	0	0	0	0	45	0	189	101	43	0	9688	0	8
	MW												GWh						MW	

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell	NH3
2020	1617	0	0	0	125	0	0	982	0	0	0	0	0	0	0	0	0	0	0	0
2025	215	0	0	0	29	259	0	0	0	0	0	35	0	2425	162	310	0	0	0	0
2030	475	0	0	0	48	1458	0	0	0	0	0	57	0	9643	268	685	0	0	0	0
2035	396	0	0	0	39	644	0	0	0	0	0	64	0	4668	219	571	0	0	0	0
2040	730	0	0	0	33	132	0	0	0	0	0	61	0	1458	183	1053	0	13120	0	315
2045	535	0	0	0	29	135	0	0	0	0	0	68	0	563	161	771	0	12923	0	12
2050	617	0	0	0	42	0	0	0	0	0	0	68	0	436	232	1335	0	22374	0	12
	MW												GWh						MW	

Note Reference in table to “waste-to-energy” shall be read as “bioenergy”

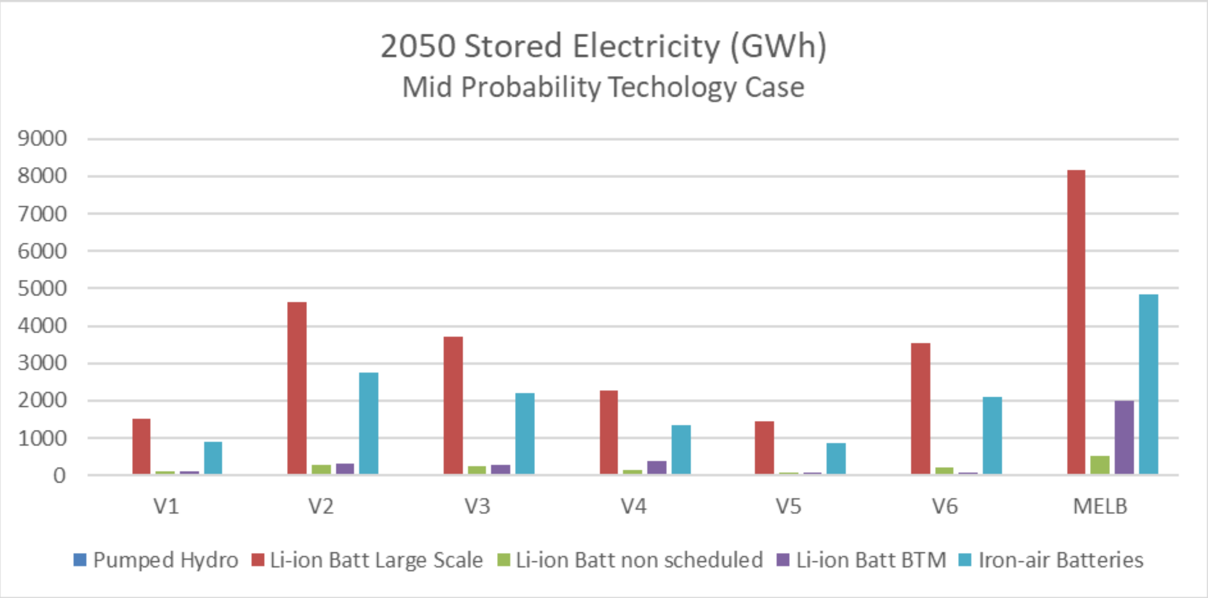
6.4.4 Discussion

The Mid Probability Technology Case was found to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (Behind the meter, industrial and large scale)
  - Iron-air batteries (starting on 2035)
  - Green Ammonia (NH_3) (starting in 2035)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar and wind represents 70% of the electrical mix creating grid instability that requires compensation by additional generation and storage facilities, with all new wind, solar and battery capacity multiplied by 1.5.
- The share of wind and solar in 2050 is 40% solar PV (excluding behind the meter) and 60% wind. It is the only scenario with more wind than solar PV in the mix. It is important to note that wind has a much bigger capacity factor than solar.
- New transmission lines are needed as the grid will have to support a lot more of electricity. Upgrade of the following lines are considered likely (same as High Probability Technology Case):
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers, representing approximately 25% more infrastructure than exists today.
- All the connections between the facilities and the grid have been taken into account in the cost analysis, but not shown on the maps.
- The storage is calculated depending on the quantity of solar and wind, with the objective to cover the nights without solar production and to be able to cover a week without wind generation.



6.5 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

6.6 Environmental & Social Analysis

6.6.1 Work Description

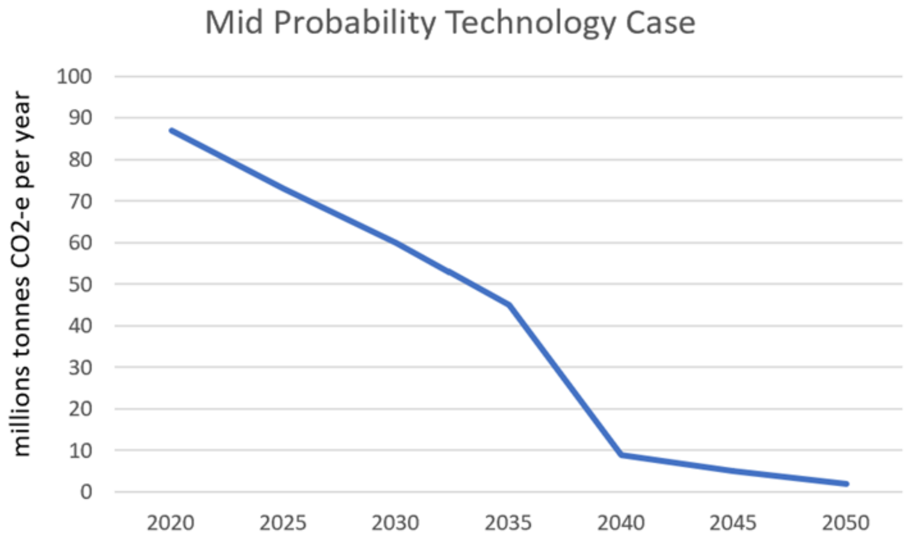
The environmental and social components of the Mid Probability Technology Case have been assessed via a desk-top study using key aspects from the environmental and social perspectives and presented in Table 51.

6.6.2 Results

In the Mid Probability Technology Case, emissions reductions are achieved by incorporating new energy technologies, namely green ammonia, green hydrogen and iron-air batteries. Figure 59 shows the modelled emissions reduction profile for this case. The profile shows a linear decline in emissions to 2035 and then a step reduction between 2035 and 2040. The assumed technologies deliver a residual emission in 2050 of around 2 million tonnes per year which are then offset.

.

Figure 59: Emissions Reduction Profile – Mid Probability Technology Case



- The Mid Probability Technology Case scenario results in the fastest drop in emissions of the High, Mid and Low cases in order to reach Net Zero by 2050. With the most significant decrease between 2035 to 2040 (Refer to Figure 59).
- Electricity generation from coal is still the highest source of emissions up until 2035, where coal and natural gas are phased out. Vehicles - (ICE) gasoline & diesel remains the third highest emissions up until 2035 before being the highest in 2040.
- The Mid case relies heaviest on the utilisation of green (NH_3) and green Hydrogen to meet energy and emission requirements. Utilisation of biogas and biomethane are also reduced.

6.6.3 Discussion

Relative to the high probability technology case the mid probability technology case makes significantly greater use of ammonia to both generate electricity and as a source of hydrogen for distribution in the gas networks. This results in a reduction in the need for renewable (solar and wind) generation and corresponding battery backup.

The proposed Mid Probability Technology Case has the following environmental and social considerations:

- Key investments to achieve the net zero emissions target include:
  - Compared to 2020: 10 times more solar PV, four times as much wind capacity and approximately 100 times more battery storage – this is less than that required in the high probability technology case.
  - Significant investment in biomethane, bioenergy, hydrogen and ammonia production.

  - A significant amount of electrical generation from ammonia - listening the need for renewable energy generation and battery storage compared to the high probability technology case.
  - The import of significant volumes of ammonia and the construction of new pipelines to transport the imported ammonia to the Melbourne gas distribution grid and the Latrobe Valley.
  - By 2050, just under three million tonnes per year of abatement being provided by greenhouse gas offsets.
  - Additional pipelines to transport ammonia.
  - Strengthened electricity grid.
- This case offers approximately 2.4 times greater full time employment opportunities compared to the high probability technology case. The main driver of employment in this case is electrical generation from ammonia with around 60% of all jobs. Other employment contributors are:
  - wind (10%)
  - energy efficiency (9%)
  - rooftop solar PV (6%)
  - battery storage (4%)

  While not as obvious as employment in other sectors, energy efficiency represents a significant employment base comprising works undertaking and implementing energy efficiency improvement projects.
- The construction of two new pipelines to meet proposed increases in biomethane production (150 km and 210 km in length) will result in the potential impact to environmentally sensitive terrestrial areas. There is the possibility that these construction projects may traverse national parks, wildlife management areas, rivers or wetlands. There may be opportunities to reduce the clearing required for these energy production methods if existing infrastructure corridors, such as transmission lines, are used.
- Along with these upgrades to existing gas pipelines, infrastructure and new pipelines will be required to enable compatibility with the use of ammonia and hydrogen. New ammonia pipelines are required to connect a proposed ammonia import terminal with both the gas reticulation system (vis conversion to hydrogen) and to large electrical power generators in the Latrobe Valley.
- In addition to the environmental and social factors discussed in the High Probability Technology Case, the increased reliance on ammonia requires the management of the various safety and air quality risks posed by the large scale use of ammonia.
- The use of marine terminals to import ammonia has the potential to create a range of impacts to the marine environment in proximity to those terminals which will need to be managed.
- To achieve net zero by 2050, offsets (ranging between 1-2 mill Te CO_2-e) are required from 2030, along with the negative 9 Million Te CO_2-e emissions generated by bioenergy generation methods. The number of offsets by bioenergy generation methods is the least of all three probability cases and matched only by the Sensitivity Case 3.

- As with the High case scenario there is no requirement for commissioning offshore geo-sequestration (CCS).
- A greater than 50% reduction in fossil energy sources (from 2020 consumption figures) occurs within 15 years for both coal and gasoline and diesel vehicles. A 100% reduction is achieved by 2050. This will have significant benefit to environmental quality and population health as the amount of noxious pollutants and airborne toxins, such as of volatile organic compounds and carbon monoxide from vehicular emissions and mercury, lead, sulfur dioxide, nitrogen oxides and particulates from coal, are reduced.
- The reduction in usage of transportable energy sources (for example coal, natural gas, gasoline and diesel) not only reduce the emissions profile of the state, but also contribute to a larger reduction in emissions outside the scope of this report through reducing the emissions outputs from transporting these commodities (e.g., trucking gasoline and diesel, transport of coal from source to point of energy generation).
- Solar PV becomes the highest energy contribution by 2040, and therefor land use impacts (environmental and socio-economic) are to be expected through its steady uptake given there is less opportunity for solar projects to share land with agricultural uses. However, land impacts from utility-scale solar systems can be minimized by siting them at lower-quality locations such as brownfields, abandoned mining land, or existing transportation and transmission corridors.
- With the increase in solar PV the numbers of batteries to support residential and commercial solar systems increases. In addition to the resourcing required to source materials batteries present a fire risk, management of this fire hazard will require careful consideration.
- Uptake of onshore wind power generation, albeit less than the Low and High Case, may result in impacts to sensitive environments (such has habitat loss, noise etc.) depending on the locations and methods for construction. There may also be a reduction in visual amenity for locations where wind farm infrastructure is developed.
- Land use impacts may be minimised for onshore wind generation through opportunities for utilising existing agricultural land for wind infrastructure.
- Given the requirement for construction and land-clearing, there may be the potential for cultural heritage risks or impacts. These will need to be further analysed on a case-by-case assessment during planning phases and should include community and stakeholder consultation.
- The construction works associated with bringing the new energy technology sources into the system up until 2050 will result in a positive employment scenario, which should contribute to sustained jobs growth. Unlike the High case scenario, it is proposed that coal fired power stations are converted to Ammonia and continue operation in 2050 and beyond. Both reducing some of the impact on employment in Latrobe Valley and environment impacts by utilising current infrastructure and footprints.
- The reduction in coal energy production will both reduce the public health impacts of the public and those employed through the coal industry.
- Bioenergy projects will need to manage air quality impacts (odour)
- The Mid Case scenario of earlier reduction in emission rates towards Net Zero, opportunity for workforce transition from coal to green Ammonia (NH_3), use of

existing infrastructure and environmental footprint represent a positive spread across social, economic and environment sectors.

6.7 Cost Analysis

6.7.1 Key References & Assumptions

Refer to Section 3.8.5.

6.7.2 Work Description

Refer to Section 3.8 for details of the work description.

6.7.3 Results

The figure below present the net difference between the Medium Probability Technology Case and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Figure 60 demonstrates that:

- The Medium Probability Technology Case projects a material increase in fuel, FOM and VOM costs, as a result of the increase in fuel cost for the expanded development and sharing of new variable renewable electricity resources in particular green hydrogen / ammonia, providing a net annualised cost increase of approximately $9 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.
- The Medium Probability Technology Case projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $4.5 billion in 2050.

The annual net costs of the Medium Probability Technology Case is represented by the purple line in Figure 60. By 2050, the Medium Probability Technology Case is forecast to provide a net cost increase of around $14 billion by 2050.

For the Medium Probability Technology Case, the net costs are relatively neutral until 2040 where they become negative until 2050 where coal fired generation is replaced with green hydrogen / ammonia and hence increased fuel and CAPEX spend.

Figure 60: Net Costs of the Control Scenario relative to the Medium Probability Technology Case

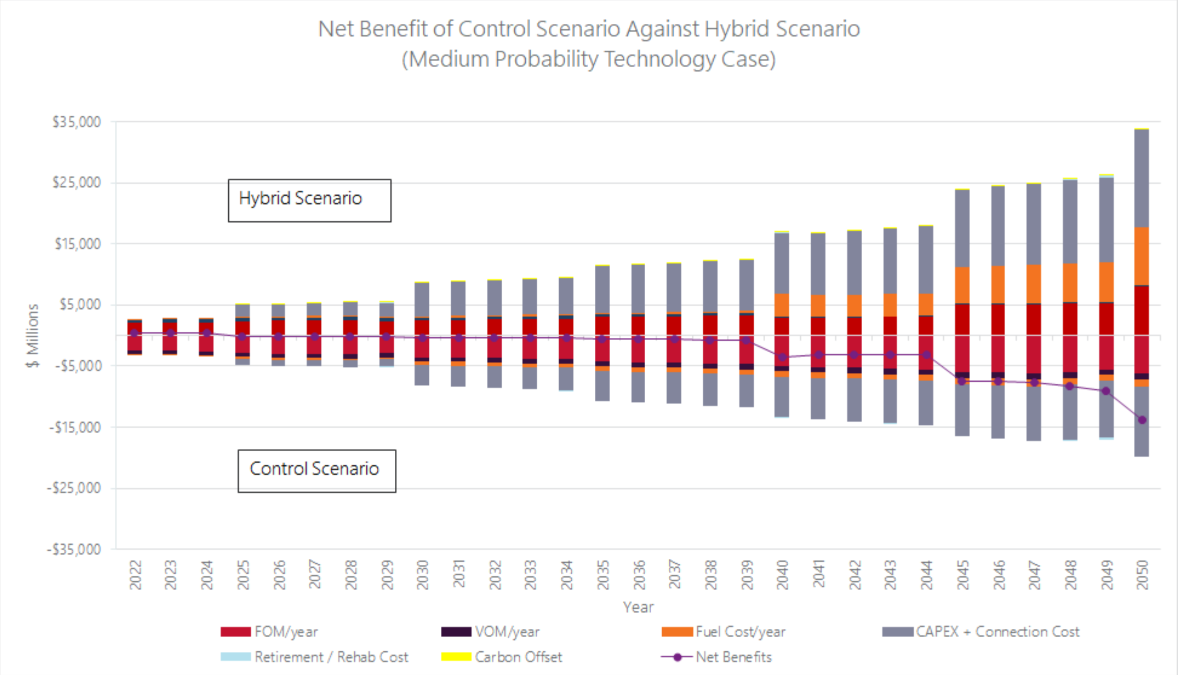


Table 70 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Medium Probability Technology Case, in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the Medium Probability Technology Case, discounted back to present value, is $9.7 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$3.6 billion (NPC).

The estimated cost of CO_2 abatement is $112/te CO_2.

Table 70: Net Costs of the Control Scenario relative to the Medium Probability Technology Case

Cost Category[2]	Net Cost of Control Against Technology Case (Medium Probability)		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$4,623	-$1,872
FOM	$2,475	$2,565	-$90
VOM	$435	$304	$130
Fuel	$419	$2,133	-$1,714
Retirement / Rehab	$48	$65	-$17
Agro-forestry (Land Area, Hectare)	$0	$0.14	-$0.14
Gross Cost	$6,127	$9,690	-$3,563
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement[3] ($/tonne)	583	112	471

Notes:

1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

6.7.4 Discussion

The increased CAPEX combined with the overall energy mix for the Medium Probability Technology Case compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity. For cost estimating purposes this assumes all coal fired generation is retired and replaced with new ammonia fired generation (gas turbine) in 2040. This approach is likely more costly than life extension, conversion plus OPEX for the existing coal fired generation but the risks and uncertainties of continuing with the existing generation in regard to life extension suggests this is the correct assumption to make. Note that there is an opportunity for cost reduction if conversion and life extension is possible, but this involves a greater technology risk.

OPEX and fuel costs increase for the Medium Probability Technology Case compared to the Control Scenario are also expected due to the replacement of coal fired generation with green hydrogen / ammonia and expanded development and sharing of new variable renewable electricity resources.

Retirement costs increase in the Medium Probability Technology Case as the existing coal fired generation is retired early by 2040 plus decommissioning of gas transmission and distribution lines. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Medium Probability Technology Case cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

6.8 Risk & Opportunity Analysis

6.8.1 Key References & Assumptions

The preceding Scenario Analysis Stage 1 study (*Net Zero Emission Scenario Analysis Study Report May 2021*) was used as the key reference for this study and informed the framing of the Hybrid Scenario to be studied.

Existing, proven, commercially viable and commercial scale technologies supplemented by emerging technologies have primarily been assumed for the Mid Probability Technology Case. Energy production and power generation technologies and costs are based on the AEMO Inputs & Assumptions Workbook used to support the 2020 Integrated System Plan.

Additional technologies from CSIRO’s GenCost 2020 report were also considered.

The key assumptions for this Mid Probability Technology Case are:

- Green hydrogen (electrolysis using renewable energy) at large scale becomes technically viable and commercially competitive by 2025.
- Hydrogen blending into the existing natural gas transmission and distribution system is possible and limited to 10% by volume in the high pressure gas transmission system.
- Green ammonia is able to be imported into Victoria by 2040 at a cost that is competitive with other forms of energy.
- Iron-air batteries become technically viable and commercially competitive for peaking power support by 2040.

6.8.2 Work Description

The Stage 1 study (*Net Zero Emission Scenario Analysis Study Report May 2021*) identified a number of risks associated with an over reliance on either electrification or energy gas in meeting Victoria’s future energy demand and the development of a hybrid scenario was recommended.

This study presents a Hybrid Scenario with a more balanced energy mix which also attempts to retain and utilise existing natural gas transmission and distribution infrastructure as far as possible.

The Mid Probability Technology Case introduces the following emerging technologies which were not considered in the High Probability Technology Case, as described below.

- Construction of new ammonia fuelled gas turbine power plants;
- Conversion of ammonia to hydrogen on an industrial scale for dedicated hydrogen offtake customers or blending into the existing natural gas distribution network;
- Iron-air batteries to provide low cost, long-duration, grid-scale battery storage.

These low carbon technologies reduce the reliance on natural gas for peak period electricity generation and direct heating, also allowing the use of natural gas and coal fired power generation to be phased out by 2040.

The study team reviewed the risks and opportunities identified in the Stage 1 study and assessed the key risks associated with this hybrid scenario, focussing on the implementation risks rather than the inherent risks since a risk and opportunities comparison between scenarios was not contemplated in this study. Implementation risks are the risk of the technology not being adopted in the timeframe given for the Analysis Case, due to either cost or technology development or both, whereas inherent risks are those associated with the technology once implemented.

6.8.3 Results

The Mid Probability Technology Case possesses a moderate implementation risk as it relies on the scale up of electrolysers and moderate cost reduction of green hydrogen production by 2025 and the large-scale use of green ammonia for power generation and industrial use by 2040.

The ability of the existing natural gas transmission and distribution network to handle a blend of 10% hydrogen with 90% natural gas and biogas by 2025 is considered feasible, with a low implementation risk. Upgrading the low-pressure gas distribution system to handle 100% hydrogen will take more time to implement, but the 2040 timeframe is also considered feasible.

There is a moderate risk to cost competitive green ammonia being available by 2040 as this relies primarily on the continued reduction in the supply cost of green hydrogen and scale up of electrolyser stacks as well as the development of ammonia production processes compatible with hydrogen delivered from low pressure electrolysers.

There is a moderate to high risk to retrofitting existing coal fired power plants for 100% ammonia fuel by 2040, but cofiring with coal and ammonia or purpose-built ammonia fired generation by 2040 is more likely based on existing technology development. Therefore, the installation of ammonia fuelled gas turbine power generation has been assumed, as is considered to be the more likely technology solution.

Conversion of ammonia to hydrogen for dedicated hydrogen offtake customers or blending into the existing natural gas distribution network is technically proven, but the supply cost for complete supply chain from green hydrogen to ammonia production, ammonia transportation and storage, hydrogen production and hydrogen distribution must become competitive with other competing forms of energy.

Iron-air batteries, or some other form of low-cost, long-term battery storage are also assumed to be commercialised by 2040 in this Mid Probability Technology Case. Given that promising progress is being made in this area, with a 1MW pilot project planned for start-up in 2023 (https://www.energy-storage.news/iron-air-long-duration-battery-startup-form-energy-closes-us240-million-funding-round/), it is not unrealistic to assume that this will come to fruition.

Whist the quantity of carbon offsets required to achieve net zero is modest, there is a risk to reliance on offsets to reach net zero, especially with competition for such offsets from hard to abate energy sectors.

6.8.4 Discussion

Achieving an incremental cost breakthrough with green hydrogen to make it commercially competitive with other energy sources by 2025 will be challenging, but it not outside of the realms of possibility. It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces. Therefore a blend of 10% hydrogen with 90% natural gas and biogas in the existing gas transmission and distribution system may be possible by 2025.

The conversion of hydrogen to ammonia is a well proven technology using the Haber-Bosch process, where hydrogen and nitrogen are reacted together at high temperatures and pressures to produce ammonia. In addition, a number of new technologies are currently under development which have the potential reduce the cost of this conversion process.

It is assumed that the green ammonia used to fuel the power plants for 2040 onwards will be imported. Ammonia may also be used by industrial consumers for heating purposes or as a chemical feedstock including fertiliser manufacture.

Ammonia is essentially a long-distance energy and hydrogen carrier, being easier to transport than hydrogen. For local energy production, it would be more cost effective to use the electricity directly, rather than use it to produce green hydrogen and then convert it to ammonia and potentially back to electricity or hydrogen again. If locally produced hydrogen is available, it would be more efficient to inject hydrogen into the gas transmission and/or distribution system.

Ammonia co-firing trials are currently being conducted in coal fired power plants, with the eventual goal of modifying such plants or building new plants to operate on 100% ammonia. In December 2020 the Japanese government released its “Green Growth Strategy Through Achieving Carbon Neutrality in 2050” which contained a Roadmap of Growth Strategies for Fuel Ammonia Industries, culminating in ammonia fired power generation in the 2040’s.

In addition, manufacturers such as Mitsubishi are developing gas turbines capable of using 100% ammonia fuel, with management of NOx emissions being a primary area of focus.

Ammonia may also be converted back to hydrogen, but this will only be viable if the cost of the imported ammonia and cost and efficiency of the subsequent conversion process is competitive with green hydrogen produced in Victoria.

The benefit of distributing ammonia, rather than hydrogen, to industrial customers is that the existing gas transmission pipeline network may be utilised, thus overcoming the 10% hydrogen blend limit whilst avoiding the significant CAPEX and construction lead time associated with installing a dedicated hydrogen transmission system.

One of the risks associated with the use of ammonia is its toxicity and it can cause skin burns and eye damage as well as being toxic to aquatic life. To manage this risk, the use of ammonia has been limited to industrial scale electricity generation and industrial consumers where the OHS risks can be effectively managed.

The optimum level of ammonia supplied to enable retention of the existing gas transmission infrastructure whist minimising the overall infrastructure investment will depend on supply costs for the various available energy sources at that time including costs to connect the energy sources to the grid. The opportunity exists to develop a green ammonia industry in Victoria and/or reduce the amount of ammonia imported into Victoria.

The commercialisation of long term and low-cost battery technologies, such as the iron-air battery being developed by Form Energy will transform the energy mix by firming the delivery of variable renewable energy, primarily from wind and PV solar.

Form Energy describes its technology as a “rechargeable iron-air battery capable of storing electricity for 100 hours at system costs competitive with legacy power plants. Made from iron, one of the most abundant minerals on Earth, this front-of-the-meter battery will enable a cost-effective, renewable energy grid year-round.” (https://formenergy.com/technology/)

The 100 hours storage capacity compares favourably with 2-4 hours for typical lithium-ion battery storage and due to the absence of hazardous materials, another advantage of iron-air batteries is that grid scale installations may safely be located in urban areas.

While iron-air battery technology is yet to be commercially proven, with a pilot project planned to become operational in 2023, the Mid Probability Technology Case does not assume that such technology is introduced until 2040, so there is ample time for the technology to be proven or for alternative long term battery storage systems to be developed.

In this Analysis Case, the use of offsets is preferred over CCS implementation to achieve net zero, as it provides a more flexible approach with the ability to adjust the scale and timing of the offsets depending on the emissions reduction results actually being achieved. CCS projects involve a long lead time and significant capital expenditure and therefore greater certainty before an investment decision can be made.

7 LOW PROBABILITY TECHNOLOGY CASE

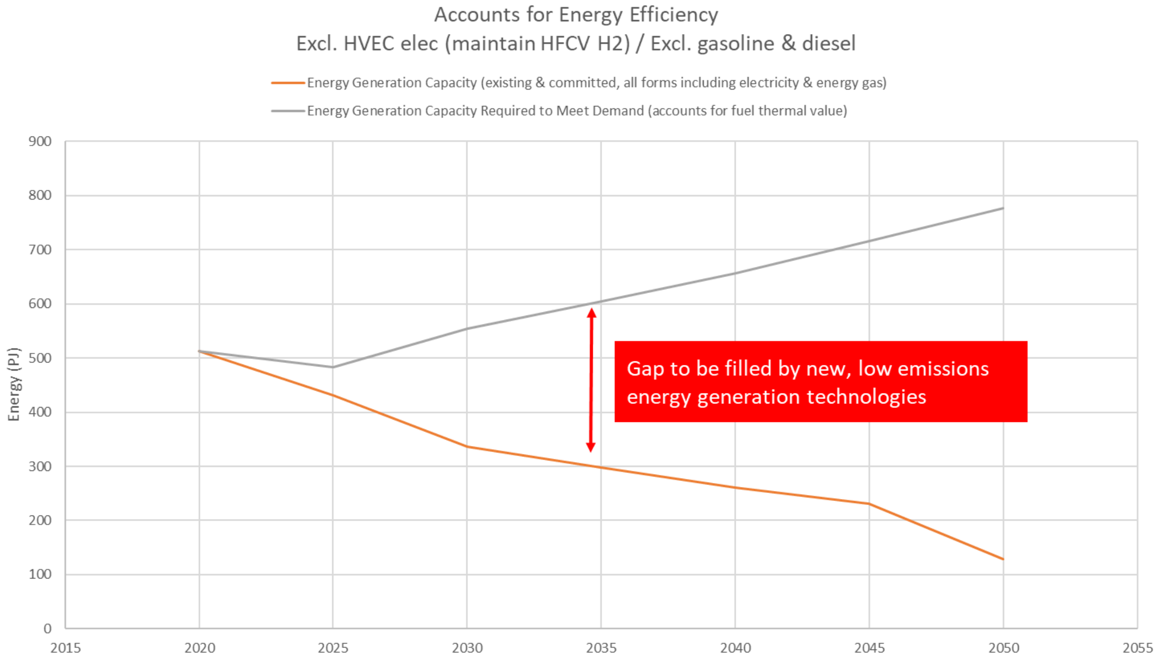
Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

7.1 Case Description

The Low Probability Technology case utilises primarily solar thermal and deep duration storage (molten salt) to provide an enhanced level of high-quality electrical power in the mix, with the potential to reduce firming infrastructure requirements. Other low emissions energy technologies are also utilised (see Table 71) to fill the gap between the existing & committed energy generation capacity (see Table 73) and the energy demand. This gap is represented by the red arrow in Figure 61.

Figure 61: Forecast Energy Demand vs Generation Capacity (Low Probability Technology Case)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))



The energy generation capacity required to meet forecast demand (grey line in Figure 60) is:

- Limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles
- Determined by subtracting the fossil fuel thermal value from the overall energy demand.

As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

To accommodate the new energy technologies identified for the Low Probability Case, a slight modification (described below) was made to the fossil fuel decline profile assumed for the prior Net Zero Emission Scenario Analysis Study Report May 2021 with a natural gas "tail" provided to cater for "hard to abate" manufacturing (see Table 14 Section 3.2). This natural gas could be imported through one of the state interconnectors (VNI or EGP), or as LNG.

- **Natural gas**: natural gas has a lower share of the energy mix given the increased share of green Hydrogen.

Table 71: Energy Technologies Used to Deliver Additional Capacity for the Low Probability Case

Energy Type	Description
elec gen	solar PV
elec gen	wind onshore
elec gen	hydropower
elec gen	bioenergy
elec gen	**WIND OFFSHORE**
elec gen & stg	**SOLAR-THERMAL**
elec stg	pumped hydro (storage)
elec stg	batteries (storage)
gas	biomethane
gas	**GREEN H2**

A brief description of each of the technologies listed in Table 71 that have not already been covered in the High or Mid Probability Technology cases is provided Table 72, and described in further detail below, with green Hydrogen included for the sake of completeness.

The Low Probability Technology case refers to technologies currently in the commercial prototype phase (TRL 7 & 8) and assumes a breakthrough to TRL 9 occurs before 2030, or technologies currently at TRL 9 where a cost breakthrough is assumed to occur, thereby allowing those technologies to be utilized to deliver additional energy generation capacity from 2030 and beyond. For the sake of clarity, a breakthrough by 2030 as assumed for the Low Probability Technology Case is considered less likely than a breakthrough by 2040 for the Mid Probability Technology Case.

Table 72: Energy Technology Descriptions Low Probability Case

Technology	Description
Wind Offshore	Electricity generation from wind energy using offshore wind turbines in industrial scale wind farms. Currently TRL 9.
Solar-Thermal	Electricity generation from industrial scale solar energy used to generate steam to drive a steam turbine. Assumed to be integrated with thermal energy storage using molten salt. Currently TRL 9.
Green Hydrogen	Hydrogen that is produced from renewable energy such as solar, wind or hydropower such as electrolysis of water to produce hydrogen and oxygen.

The energy technology breakthroughs identified for the Low Probability Case include

- **WIND OFFSHORE** improves electricity yield, therefore reduces Variable Renewable Electricity infrastructure requirements (Capital Expenditure, Operating Expenditure). Levelised Cost of Electricity (LCOE) becomes lower than onshore wind
- **SOLAR-THERMAL** improves electricity yield compared to solar Photo-Voltaic (PV), and also Variable Renewable Electricity capacity factor, therefore reduces Variable Renewable Electricity infrastructure requirements (Capital Expenditure, Operating Expenditure). Solar thermal becomes cheaper solar Photo-Voltaic (PV) & batteries (firmed solar)
- **GREEN HYDROGEN** enables partial replacement of natural gas (as green Hydrogen is limited by materials of construction) and improves Variable Renewable Electricity capacity factor / firming. Green Hydrogen becomes cheaper than natural gas. Green Hydrogen is transported to users via the existing natural gas infrastructure by blending to a maximum concentration of 10% by volume (based on materials compatibility constraints) with the balance comprising biomethane and natural gas. Biomethane production is maximised based on supply chain constraints. Further detail of the treatment of energy gas for the Low Probability Technology case is provided in Section 7.3.

Table 73: Existing & Committed Energy Production Capacity Assumed for Supplying Demand (Low Probability Technology Case)

ELECTRICITY	2020		2030		2040		2050	
	Total Capacity		Total Capacity		Total Capacity		Total Capacity	
	MW	PJ	MW	PJ	MW	PJ	MW	PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	0	0
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
Elec (storage) - "behind the meter" non-aggregated small scale batteries (dis-connected from grid)	94	1	551	3	1,527	10	2,034	13
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**21,668**	**86**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	59	71	26
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	4	1,100	4
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to balance demand)	170	12	170	12	170	12	170	12
	1,360	**319**	**1,993**	**153**	**1,782**	**76**	**1,691**	**42**

7.2 Energy Emissions Offsets

7.2.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

7.2.2 Results & Discussion

In the Low Probability Technology Case, net zero emissions was achieved prior to 2050 as a result of utilising low emissions energy technologies only, without the need for greenhouse gas offsets or geo-sequestration.

Table 74: Mean Demand Energy Mix for the Low Probability Technology Case

	2020	2025	2030	2035	2040	2045	2050
	Impact of Energy Efficiency on Energy Generation Capacity (PJ)						
Energy Generation to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	585	650	693	738	793	850
	Cumulative Energy Consumed accounting for Energy Efficiency (PJ)						
Elec (generation) - coal	144	117	92	69	45	22	0
Elec (generation) - natural gas (baseload + peaking)	5	5	5	5	0	0	0
Elec (generation) - hydropower	10	10	11	11	10	10	10
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	47	67	76	86	99	116
Elec (generation) - solar thermal - industrial	0	0	76	113	131	148	177
Elec (generation) - wind (onshore + offshore)	28	58	86	95	98	100	125
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	30	39	47
Elec (generation) - fuel cells	0	0	5	7	11	13	17
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	3	3	3	3	4
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	1	15	72	100	121	144	186
Gas (generation) - natural gas (all sources)	209	186	121	79	80	35	20
Gas (generation) - biomethane	0	1	4	12	20	28	41
Gas (generation) - H2 (green) [incl HFCV fuel]	0	18	29	29	30	35	40
Vehicles - (ICE) gasoline & diesel	318	267	222	163	99	49	0
Vehicles - (BEV) electricity	0	10	20	37	52	59	64
Vehicles - (HFCV) electricity [GENERATION]	0	21	43	46	47	57	66
TOTAL (PJ)	732	759	867	866	863	843	914

Table 74 reveals that:

- In 2020, as per the High Probability Technology Case, gasoline & diesel (ICE vehicles) is the single biggest energy source at approximately 320 PJ-thermal, or approximately 45% of the total, with natural gas in second position at approximately 210 PJ-thermal or approximately 30% of the total, and electricity from coal in third position at approximately 145 PJ-electricity or approximately 20% of the total.
- In 2030, as a result of technology breakthroughs and subsequent introduction of offshore wind, solar thermal, fuel cells and green Hydrogen, the Low Probability Technology Case differentiates from the High Probability Technology case, with reduced levels of natural gas. Green Hydrogen "optimised" for constraints including transmission pipeline materials, and spatial (water source, land availability). In this year gasoline & diesel (ICE vehicles) remains the single biggest energy source at approximately 220 PJ-thermal, or approximately 25% of the total, natural gas also remains in second position with approximately 120 PJ-thermal or just under 15% of

the total. Third position is held by coal providing approximately 90 PJ-electricity or approximately 10% of the total.

- In 2040, electricity from solar thermal represents the single biggest mean energy demand centre at approximately 130 PJ-electricity or approximately 15% of the total. Storage* is in second position with approximately 120 PJ-electricity or just under 15% of the total. Third position is jointly occupied by both wind with approximately 100 PJ-electricity and gasoline & diesel (ICE vehicles) with approximately 100 PJ-thermal each representing approximately 10% of the total.
- In 2050, as per the High Probability Technology case, a tail of natural gas is present to cover hard-to-abate manufacturing industries. Depending on the location and magnitude of hard to abate gas demand, natural gas would still remain a component of the "energy gas blend" transported through the existing natural gas infrastructure (along with biomethane & green Hydrogen), and / or it may be reticulated to discrete industrial users in a segregated distribution system utilising existing infrastructure if available, or new build if required. In this year, storage* represents the single biggest mean energy demand centre at approximately 185 PJ-electricity or approximately 20% of the total. Solar thermal is in second position with approximately 175 PJ-electricity or approximately 20% of the total and third position is occupied by wind with approximately 125 PJ-electricity just under 15% of the total.
- Net zero Carbon emissions is achieved prior to 2050 without the need for offsets, as a result of bioenergy.

*For the Low Probability Technology Case, storage includes both molten salt (associated with solar thermal) and current technology batteries. The molten salt systems are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

Also noteworthy from

Table 74 is the increased diversity of energy sources resulting from the transition:

- In 2020, as per the High Probability Technology Case, the top three single energy sources (gasoline & diesel, natural gas & coal) represented approximately 90% of the total energy mix.
- In 2030 the top three remain as gasoline & diesel, natural gas & coal representing approximately 50% of the total.
- In 2040 the top three (solar thermal, storage* and wind / gasoline & diesel) represent approximately 50% of the total; and
- In 2050 the top three (storage*, solar thermal and wind) represent approximately 55% of the total.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity), Figure 62 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In 2020, as per the High Probability Technology case, approximately 205 PJ-electricity is consumed, being approximately 50% of the total, and approximately 210 PJ-thermal energy gas is consumed being approximately 50% of the total.
- In 2030, there is a slight increase in the level of electrification compared to the High Probability Technology case, with approximately 450 PJ-electricity consumed, being approximately 75% of the total, and approximately 155 PJ-thermal energy gas consumed being approximately 25% of the total.
- In 2040, there is once again a slight pivot towards a higher degree of electrification compared to the High Probability Technology case, with approximately 590 PJ-electricity consumed, being approximately 80% of the total, and approximately 130 PJ-thermal energy gas consumed being almost 20% of the total.
- In 2050, there is a significant pivot towards a higher degree of energy gas compared to the High Probability Technology case, with approximately 745 PJ-electricity is consumed, being almost 90% of the total, and approximately 100 PJ-thermal energy gas consumed being just over 10% of the total.

Figure 62: Energy Mix Breakdown for the Low Probability Technology Case Covering only Electricity & Energy Gas

(excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

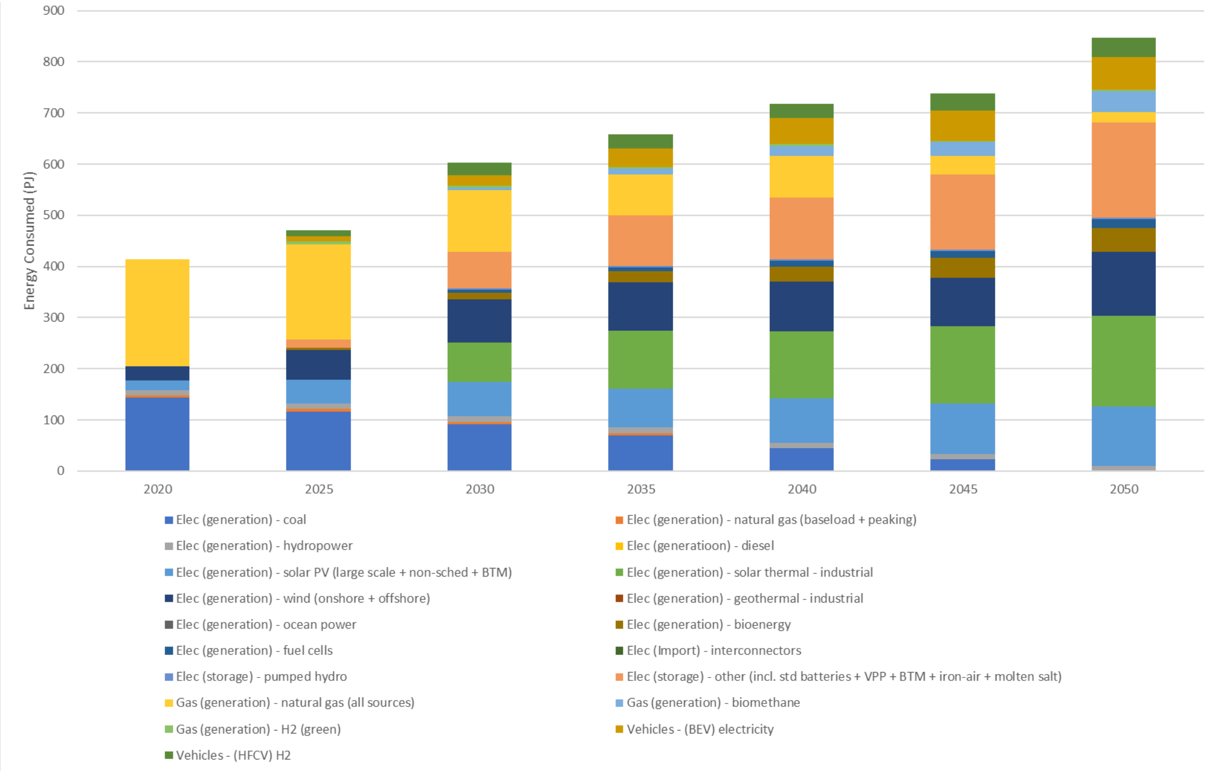


Table 75 and Figure 63 illustrate that the Low Probability Technology case has a gradual decline profile in emissions over time, similar to the High Probability Technology case. This stems from the fact that both natural gas and electricity from coal continue to be utilised during the introduction of offshore wind, solar thermal and fuel cells and green Hydrogen.

As per the High Probability Technology case, bioenergy is noteworthy as the only technology with a negative emissions contribution (based on avoided emissions from agriculture and waste – refer to ESE Methodology Section 3.9.5), providing a dis-proportionately large contribution to reducing emissions. In 2050, despite its limited share of the energy mix (approximately 50 PJ-electricity or approximately 5%, set by supply chain constraints), it contributes approximately negative 10 Million Te CO_2-e emissions leading to a net deficit of emissions.

As per the High Probability Technology case, coal represents a dis-proportionately large contribution to reducing emissions. In 2020, with approximately 145 PJ-elec or approximately 20% of the energy mix, coal contributes approximately 45 Million Te CO_2-e emissions (approximately 50% of total). Sitting between bioenergy and coal are :

- Gasoline & diesel (ICE vehicles). In 2020, as per the High Probability Technology case, these fuels represent approximately 320 PJ-thermal consumed (approximately 45% of the total) and contribute approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Natural gas. In 2020, as per the High Probability Technology case, it represents approximately 210 PJ-thermal consumed (approximately 30% of the total) and contributes approximately 20 Million Te CO_2-e emissions (approximately 20% of the total). In 2050 it represents approximately 20 PJ-thermal consumed (less than 5% of the total) yet contributes approximately 2 Million Te CO_2-e emissions (approximately 20% of the total positive emissions).
- Low emissions electricity excluding bioenergy, but including electricity from solar thermal, fuel cells, hydroelectric, solar PV, wind, pumped hydro, molten-salt storage and other storage*. In 2020, as per the High Probability Technology case, these low emissions technologies represent approximately 60 PJ-electricity consumption (almost 10% of the total) but contribute only 1 Million Te CO_2-e emissions (approximately 1% of the total positive emissions). In 2050 they provide approximately 765 PJ-electricity consumption – including electricity to charge BEVs and generate green Hydrogen for HFCVs - (almost 85% of the total) but contribute only approximately 8 Million Te CO_2-e emissions (approximately 80% of the total positive emissions).

  *For the Low Probability Technology Case, storage includes both molten salt (associated with solar thermal) and current technology batteries. The molten salt systems are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).
- Low emissions energy gases including biomethane and green Hydrogen. In 2050 they provide approximately 80 PJ-thermal consumption – including fuel for HFCVs - (just under 10% of the total) but have no emissions.

Table 75: Emissions for the Low Probability Technology Case

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	37	29	22	14	7	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	1	1	1	1
Elec (generation) - solar thermal - industrial	0	0	1	1	1	2	2
Elec (generation) - wind (onshore + offshore)	1	2	3	3	3	2	3
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-7	-9	-11
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	11	7	7	3	2
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	15	11	7	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**57**	**41**	**27**	**11**	**-2**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NET EMISSIONS	**87**	**74**	**57**	**41**	**27**	**11**	**-2**

Figure 63: Emissions Profile for the Low Probability Technology Case

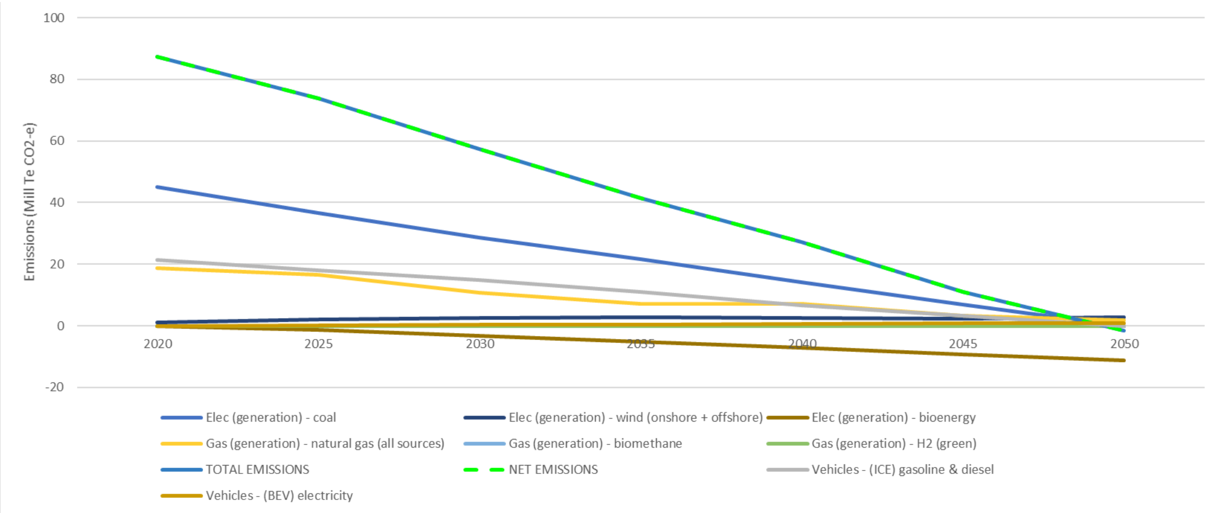
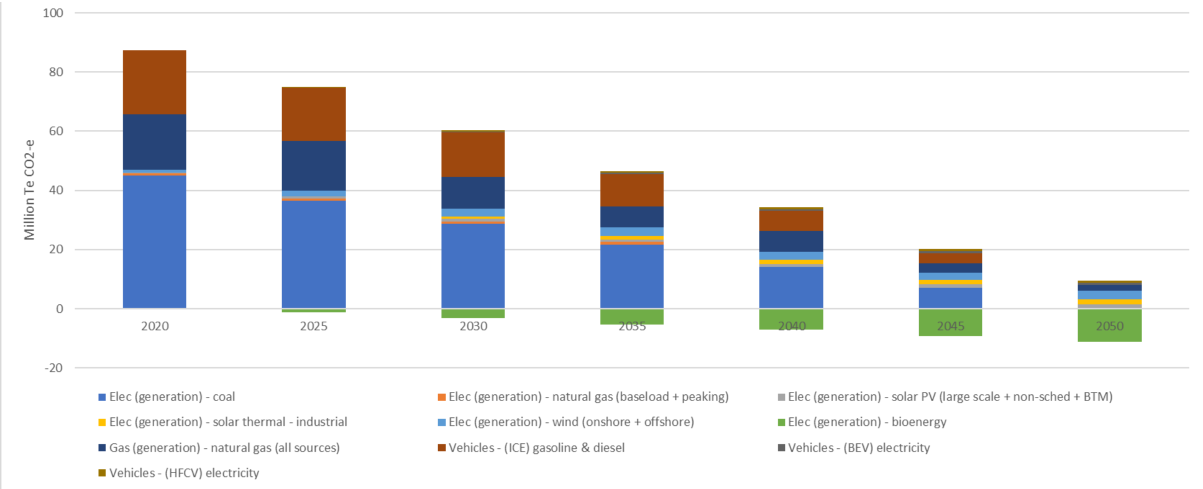


Table 5 in Section 1.6.4 documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for the Low Probability Technology case is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be:

- 2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and
- 2030 interim emissions target: up to 13 Million Te CO_2-e to cover out of scope emissions.

Figure 64: Contribution to Emissions by Source for the Low Probability Technology Case



Unlike both the Mid and High Probability Technology cases, the Low Probability Technology case requires no Carbon offsets to achieve net zero emissions by 2050.

7.3 Gas Spatial Analysis

7.3.1 Work Description

The proposed energy mix from the global modelling tool for the low probability case is used as an input into the spatial modelling tool. The spatial distribution of the energy gas demand has been kept in same proportion as the 2020 demand.

7.3.2 Results

Table 76 shows the gas demand by region from 2020 to 2050 for the Low Probability case. It can be seen that the overall energy gas demand reduces from 209 PJ/yr in 2020 to 66 PJ/yr, a reduction of around two thirds.

Table 76: Total energy gas demand by region for the Low Probability Technology case from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	129	121	78	56	65	42	41
North East	6	5	4	3	3	2	2
Loddon Mallee	21	19	13	9	10	7	6
Grampians Central West	19	17	12	9	9	6	6
Barwon South West	25	23	15	10	12	8	9
Gippsland	5	4	3	2	2	1	1
Goulburn Valley	5	4	3	2	2	1	1
Total (PJ/yr)	**209**	**193**	**127**	**91**	**104**	**66**	**66**

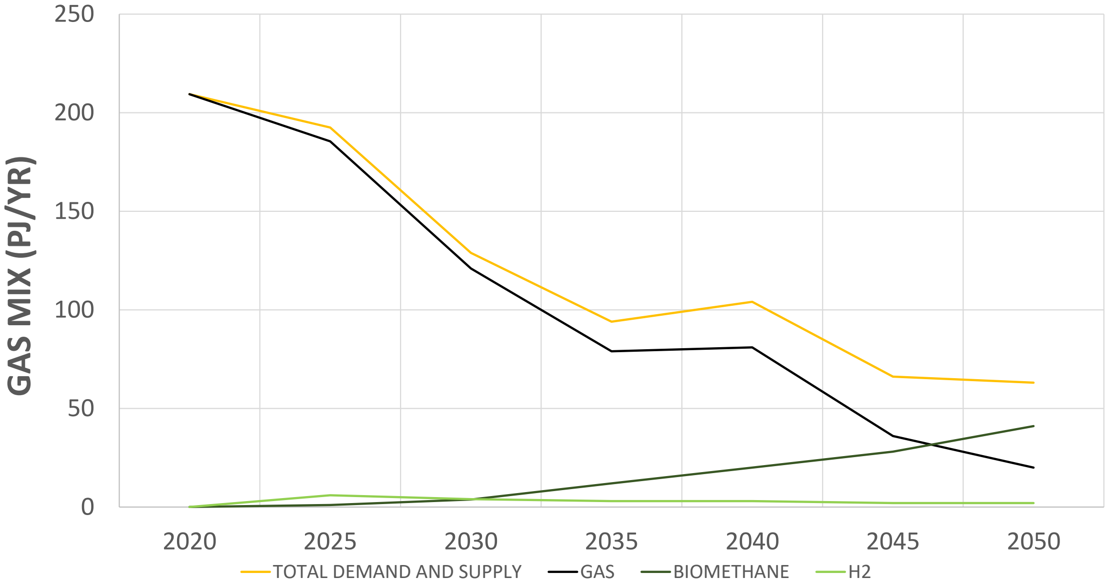
In the Low Probability Technology case the overall demand declines and the gas supply is supplemented by renewable biomethane and hydrogen (up to 10% by volume) as the natural gas supply from Victoria declines. The overall demand for biomethane and hydrogen is almost identical to the High Probability Technology case, while the total demand for natural gas is significantly lower. Table 77 shows the distribution of gas supply by type from 2020 to 2050. Biomethane production ramps up from 1 PJ/yr in 2025 to 42 PJ/yr in 2050.

Table 77: Energy gas supply by type for the Low Probability Technology case from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	197	170	117	77	81	36	21
New Victorian natural gas production or imports	12	16	0	0	0	0	0
Biomethane	0	1	4	11	20	28	42
H2 (green)	0	6	4	3	3	2	2
Total (PJ/yr)	**209**	**193**	**129**	**94**	**103**	**65**	**63**

Green hydrogen supply is relatively low ranging from 2 PJ/yr to 6 PJ/yr over the period and reduces after 2030 in order to limit the volume in the gas blend to a maximum of 10% H_2 by volume. Figure 65 shows the gas mix in the transmission system for the Low Probability Technology case from 2020 to 2050.

Figure 65: Energy gas mix in the transmission system for the Low Probability Technology case from 2020 to 2050.



The consequences for the Low Probability Technology case are similar to the High Probability case with an additional reduction of the gas in the system from 98 to 63 PJ/yr. The changes in the demand and supply are shown in the following table. In the Low Probability Technology case, by 2050, the demand and supply situation has become more even and distributed. Biomethane in Melbourne can supply 8 PJ/yr reducing the gas transmitted to the Melbourne region from 129 PJ/yr in 2020 to only 31 PJ/yr in 2050. The Loddon Mallee region becomes self-sufficient in renewable gas and the Grampians Central West region has excess renewable gas capacity to supply to other regions. The Goulburn Valley region and Barwon South West region also become self-sufficient and have excess renewable gas capacity.

Table 78: Regional demand and supply for energy gas in 2020 and 2050 for the Low Probability Technology case. Positive transmission rates mean gas is transmitted to the region, while negative transmission rates mean gas is transmitted from the region.

	2020			2050		
Region	**Demand**	**Supply**	**Transmitted To**	**Demand**	**Supply**	**Transmitted To**
Melbourne	129	0	129	41	8	33
North East	6	0	6	2	0	2
Loddon Mallee	21	0	21	6	6	0
Grampians Central West	19	0	19	6	14	-9
Barwon South West	25	39	-14	9	10	-1
Gippsland	5	158	-153	1	18	-17
Goulburn Valley	5	0	5	1	6	-5
From outside Victoria	0	12	-12	0	0	0

Figure 66 shows the biomethane production for the Low Probability Technology case. This is essentially the same as the solution for the High Probability Technology case.

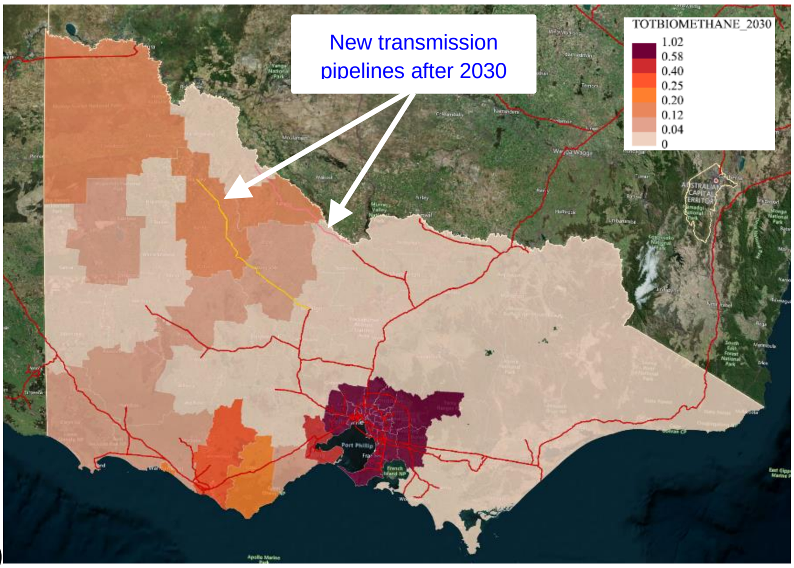
As with the High Probability Technology case, two new pipelines are proposed to be built by 2035:

1. Echuca to Swan Hill, 150 kilometres long, capacity 15 PJ/yr
2. Bendigo to Sea Lake, 210 kilometres long, capacity 15 PJ/yr

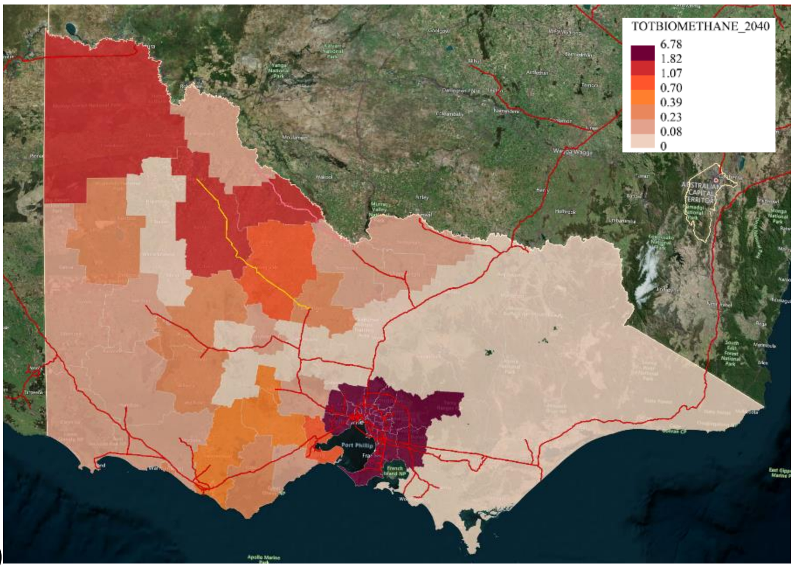
The location of green hydrogen generation for the high probability case is shown in Figure 67. Hydrogen generation has been located close to electrical transmission infrastructure and natural gas pipeline infrastructure as well as in areas where there is significant relatively flat land available. Hydrogen production is located in Latrobe Valley, Goulburn Valley around Shepparton, around Stawell and Ararat, and in the Barwon South West in the vicinity of Warrnambool. The exact locations for hydrogen production can be further optimised in future as there are many potential options for siting hydrogen production and injection. The proposed solution provided here distributes the relatively modest hydrogen production throughout the state in regions where electrical and transmission infrastructure is available.

As with the High and Mid Probability Technology cases, water consumption for hydrogen production is not significant at less than 1 GL/yr. In 2025, when there is a peak demand of 6 PJ/yr of hydrogen, the associated water consumption is approximately: 0.08 GL/yr in Barwon South West, 0.3 GL/yr in Gippsland, 0.15 GL/yr in Grampians Central West, 0.33 GL/yr in Goulburn Valley and 0.05 GL/yr in Melbourne.

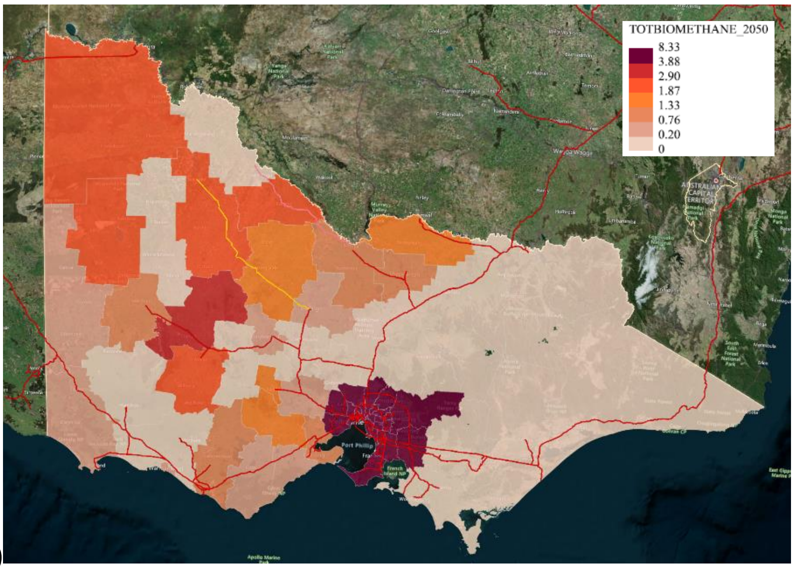
Figure 66: Biomethane production in (a) 2030, (b) 2040 and (c) 2050.



(a)



(b)



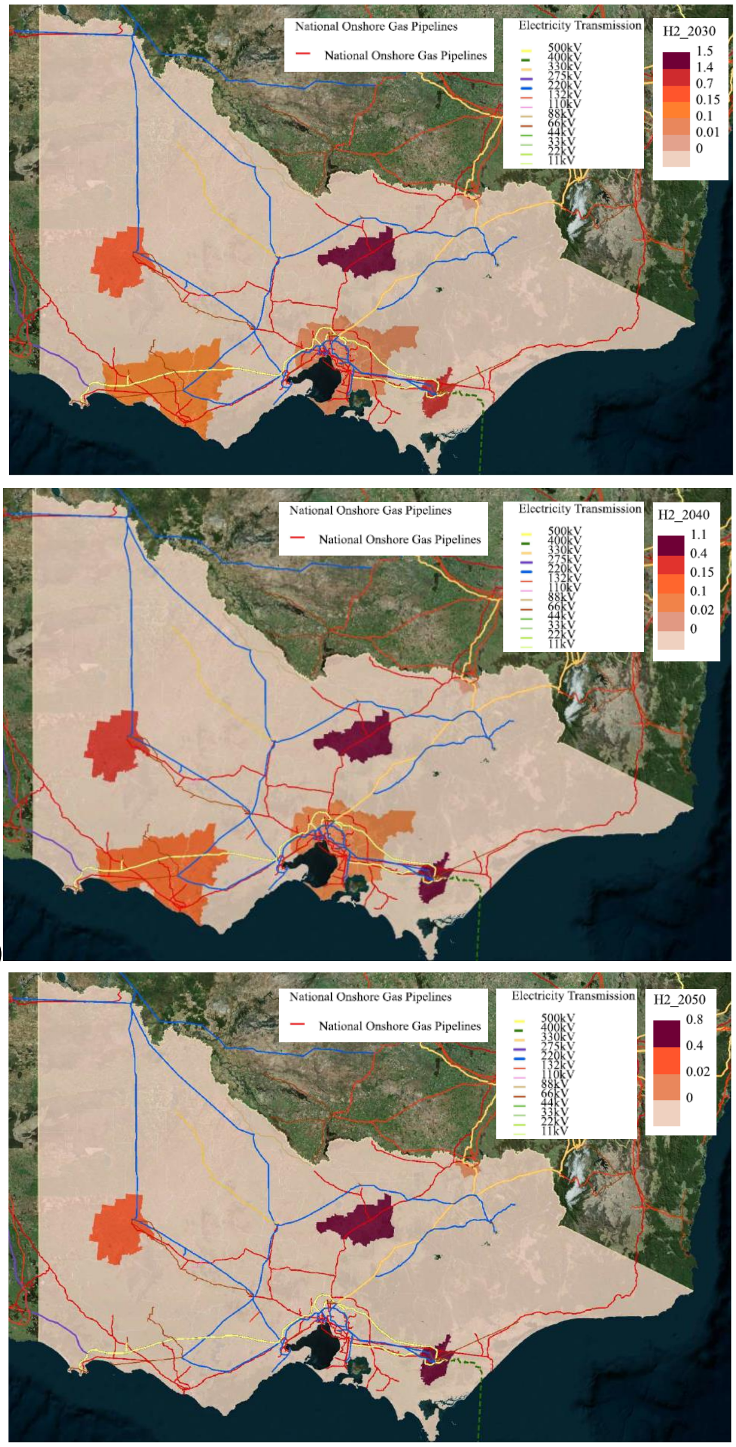
(c)

Figure 67: Hydrogen generation locations in (a) 2030, (b) 2040 and (c) 2050.

(a)

(b)

(c)



7.3.3 Discussion

- The Low Probability Technology case has a similar quantity of biomethane and green hydrogen in the energy mix as the High Probability Technology case. The main difference is lower quantity of fossil derived natural gas in the system. Therefore, the proposed spatial solution for the biomethane and green hydrogen production will be very similar as the High Probability Technology case.
- Total biomethane production ramps up from 1 PJ/yr in 2025 to 42 PJ/yr in 2050, with the contribution in 2050 from anaerobic digestion being 20 PJ/yr and biomass gasification being 22 PJ/yr.
- While biogas production for electricity production and combined heat and power projects is already being practiced at a small scale in Victoria, it is generally accepted that upgrading biogas to biomethane has a total cost of gas production in the range of 10 to 40 $/GJ, with the final cost sensitive to a range of factors such as: feedstock pricing, biomethane yield, transport costs, digester size etc. Therefore, to stimulate the modelled supply it is expected that appropriate policy settings will be required.
- Biomethane from biomass gasification is deployed commencing in 2030 in the Loddon Mallee and Grampians Central West regions of the state converting wheat straw residues producing at a relatively low rate of < 1 PJ/y and ramping up to 22 PJ/yr by 2050. To get this gas to the dominant demand centre in Melbourne, two new pipelines are proposed to be built by 2035.
- The proposed pipeline routes are indicative and further work is required to establish the economic viability and finalise the optimum route and required extent of the pipelines.
- Like biomethane production from anaerobic digestion, biomethane from biomass gasification will also need policy support in order to stimulate demand. While biomass gasification is a proven technology, its application to produce biomethane is not yet commercially practiced. Therefore, in order to improve the commercial readiness index of this technology, additional support for demonstration and first of a kind commercial projects will need to be encouraged in the next five years, with initial projects constructed in the period 2025 to 2030.
- In regard to biomethane production, the proposed solution leverages the most appropriate bioenergy conversion technology for each resource and considers the commercial readiness of each technology.
- Hydrogen production is relatively modest as it has been limited to 10% volume in the transmission system. Additional hydrogen production directly into the distribution system could also be considered in Melbourne and some regional centres and this would reduce overall demand of fossil derived natural gas even further.
- Hydrogen production has been located in areas with good pipeline access and good electrical infrastructure, however the locations are indicative and further work on optimal siting is required. However, selecting different locations will not affect the overall solution.

7.3.4 Gas pipeline network changes

For the Low Probability Technology case, the major changes in the gas transmission network can be summarised as:

- Addition of minor transmission pipeline from Swan Hill to Echuca by 2035.
- Addition of minor transmission pipeline from Sea Lake to Bendigo by 2035.
- Transmission of biomethane/hydrogen gas mixtures from Echuca/Shepparton/Bendigo and Ballarat towards Melbourne from 2035.
- Decommissioning of the Eastern Gas Pipeline from Longford to NSW.
- Decommissioning of the pipeline infrastructure in the Barwon South West region, around Port Campbell and Warrnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia.
- For the Low Probability Technology case, the major changes in the gas distribution networks can be summarised as:
- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland from 2030.
- Biomethane and hydrogen from the Loddon Mallee and Grampians production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat from 2030.
- Potential decommissioning of up to 30% of the distribution network.

7.4 Electrical Spatial Analysis

7.4.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

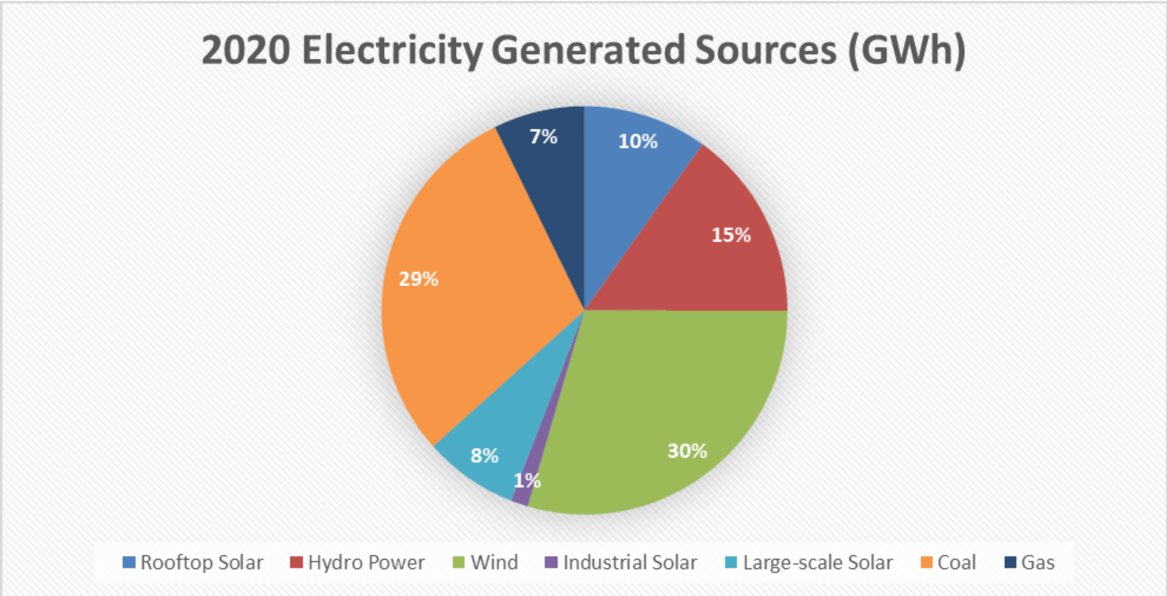
Assumptions are provided in Section 3.6.

7.4.2 Work Description

For the Low Probability Technology Case, the main electrical generation infrastructures are wind (onshore + offshore), solar (PV + thermal), fuel cells and bioenergy and the main electrical storage technologies are the Li-ion batteries (large-scale, industrial and behind the meter), and the molten salt storage associated with solar thermal generation.

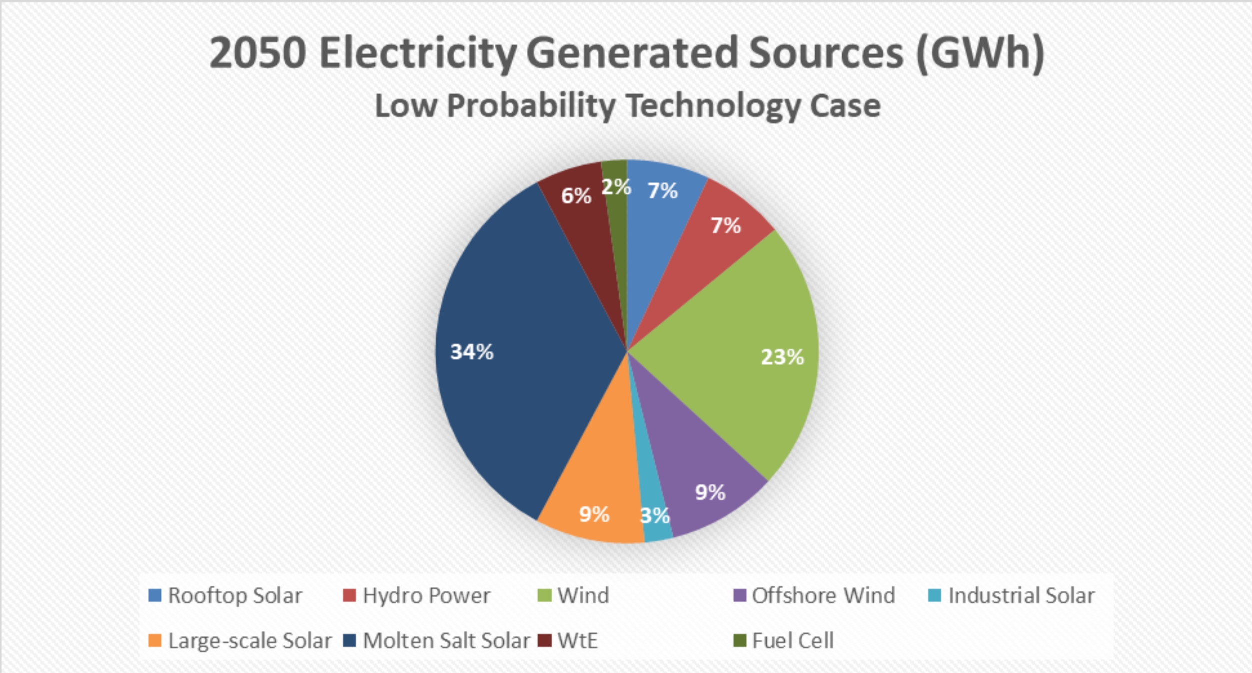
REMINDER: **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

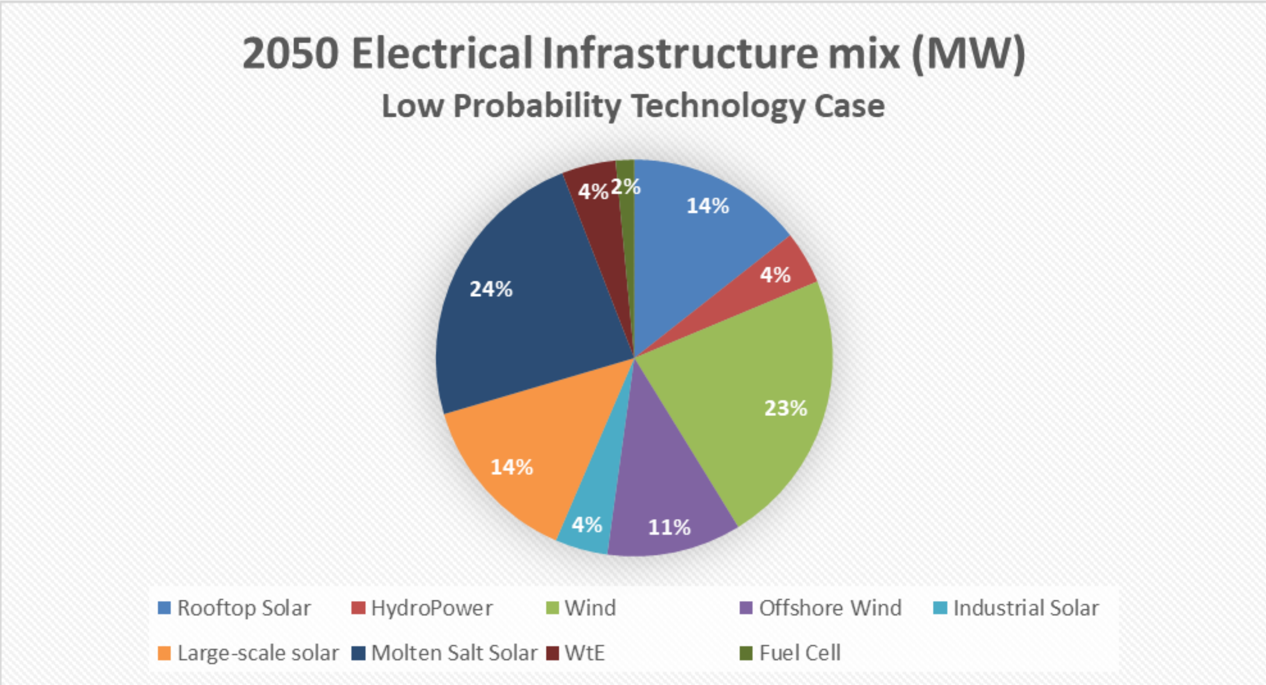
Electrical Generation Mix in 2020:



Electrical Mix in 2050:

(Note Reference in figures to “waste-to-energy” shall be read as “bioenergy”)





The electrical infrastructure capacity (MW) was found to increase by a factor of 3.5 over 30 years (2020 to 2050), whilst the electrical generation (GWh or PJ) increased by a factor of 2.2. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

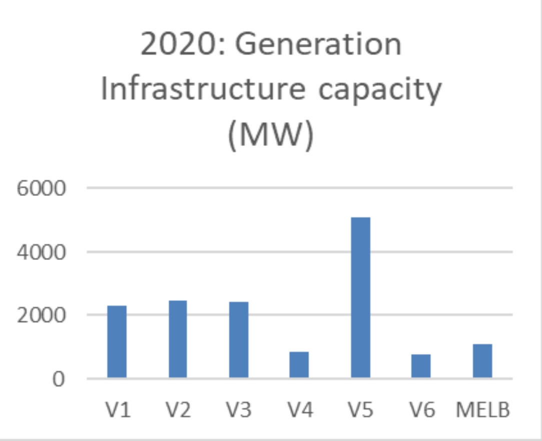
The Low Probability Technology Case was based on a breakthrough of the solar thermal technology (efficiency and cost), and the use of fuel cells is also considered.

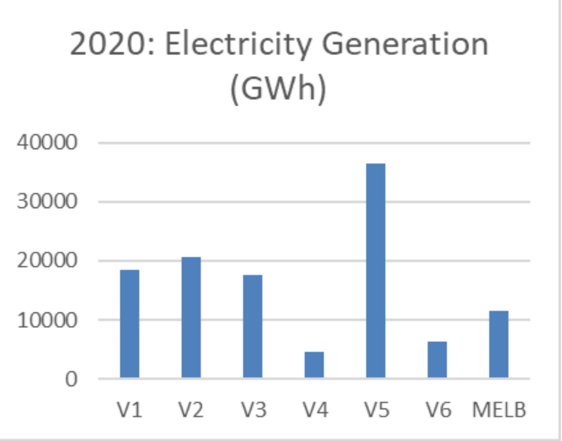
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	249 978	51 742

7.4.3 Results

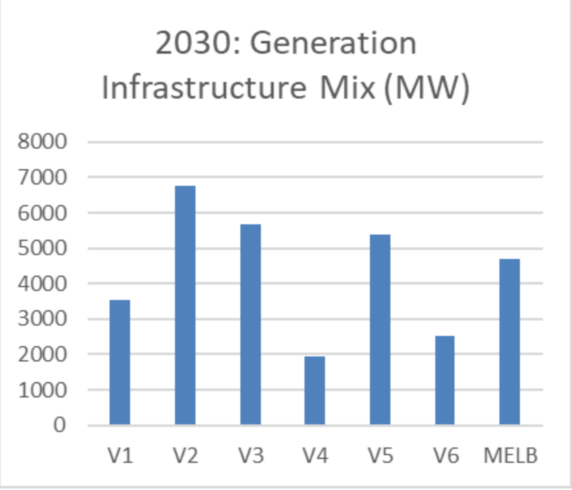
7.4.3.1 Overall Generation

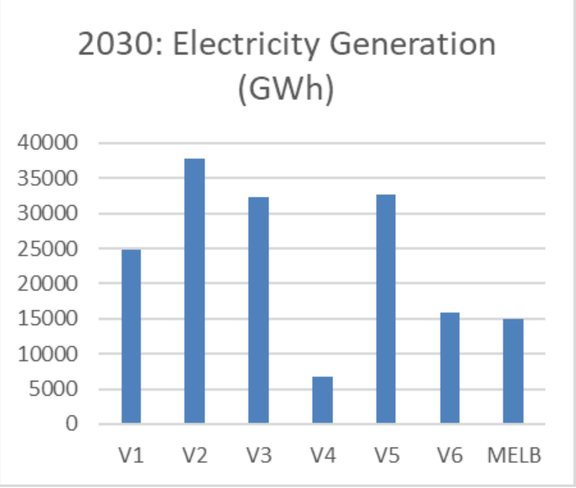
2020 generation infrastructure capacity (MW) and electricity generation (GWh):



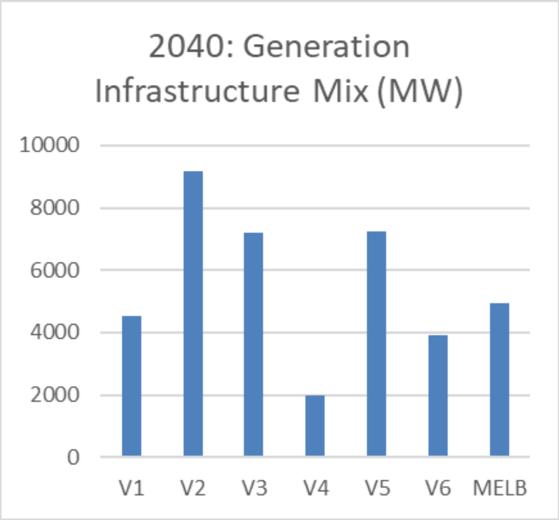


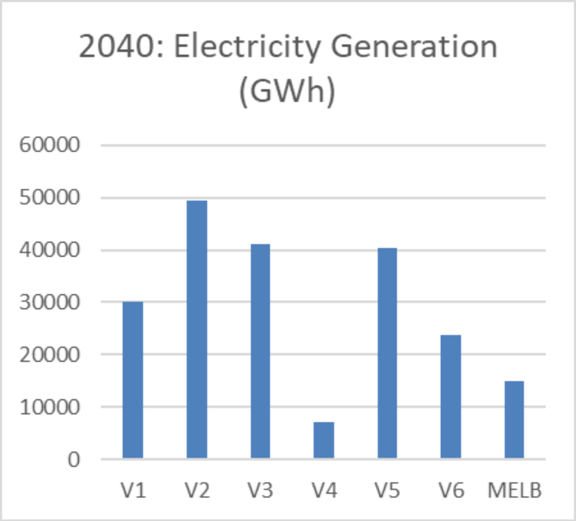
2030 generation infrastructure capacity (MW) and electricity generation (GWh):



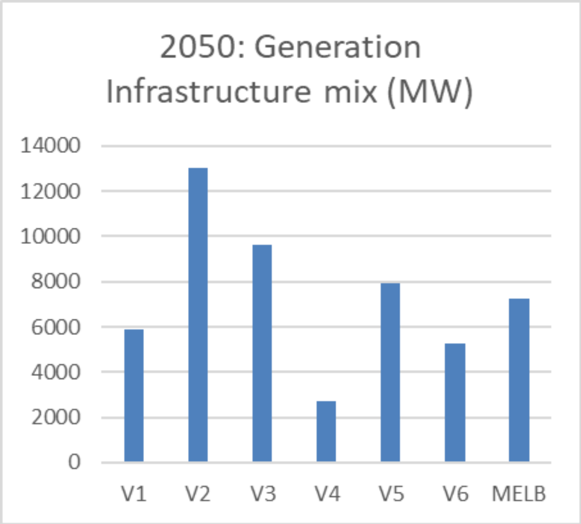


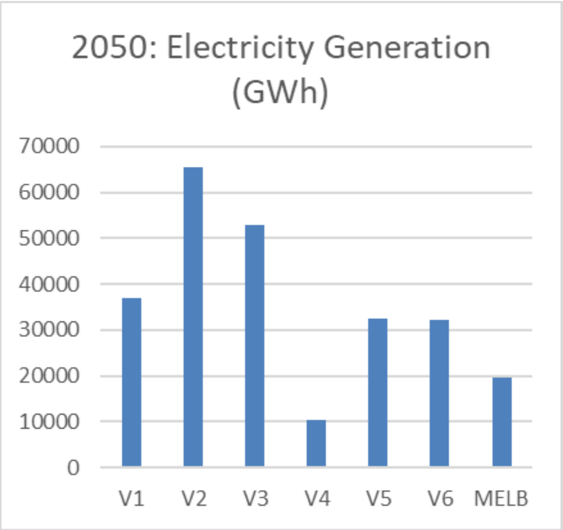
2040 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity for each REZ.
- Ovens Murray (V1), Gippsland (V5), Central North (V6) and Melbourne (MELB) have an averaged generation capacity.
- South West (V4) have a low generation capacity compared to other REZs.
- Murray River (V2) and Western Victoria (V3) have a high generation capacity.

The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

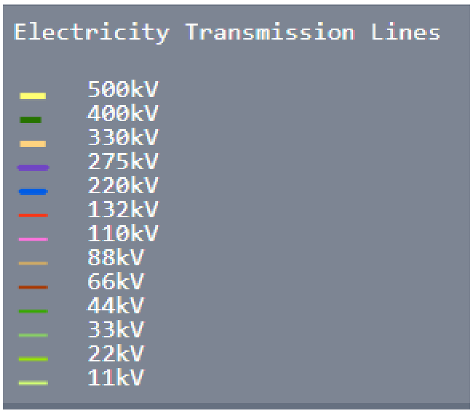
REMINDER: The assumptions used here are based on AEMO's ISP inputs and assumptions workbook which was used as "relied upon information".

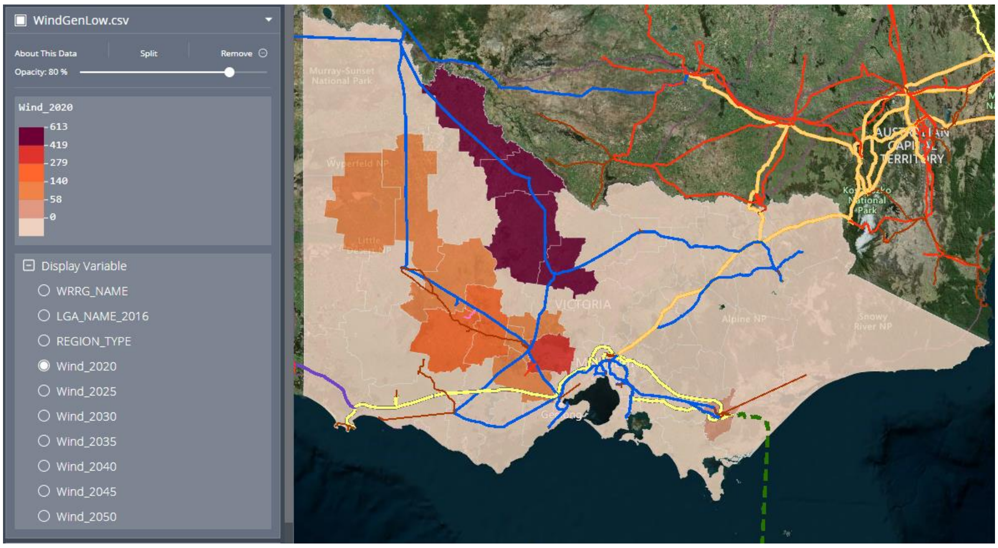
The demand is located mainly in the Melbourne metropolitan region (around 60%), with approximately 10% in each of V2, V3 and V4 (representing the entire West side of Victoria) with the last 10% being split between V1, V5 and V6.

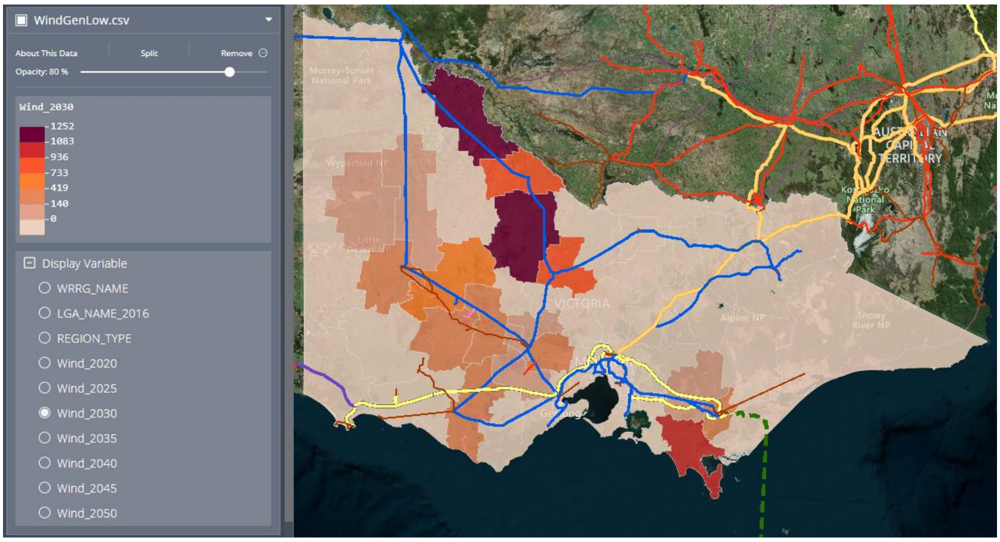
Comparing generation location and demand location, the transmission lines between all the regions and Melbourne and between East and West will need to be upgraded as both demand and electrical generation grow.

7.4.3.2 Wind

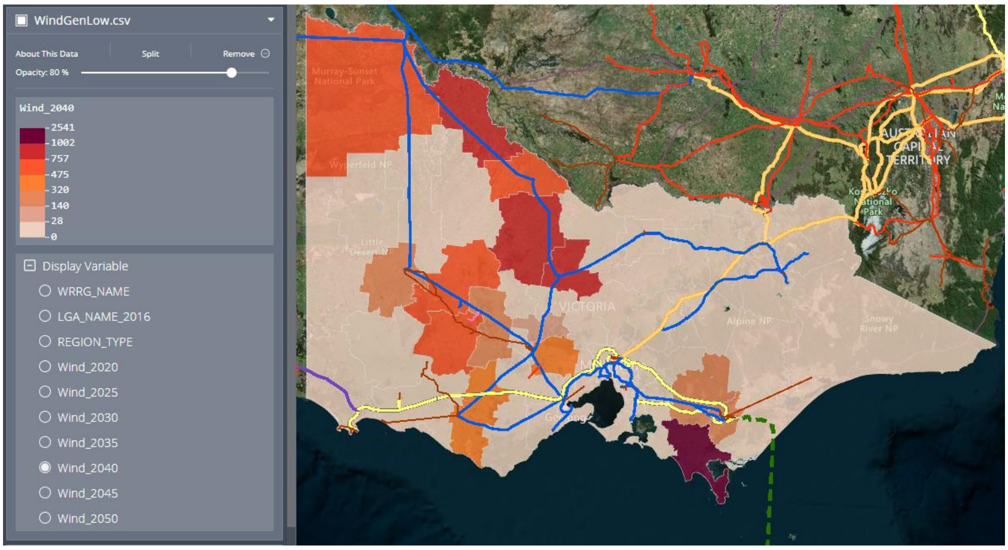
Only the transmission lines existing in 2020 are indicated on the following maps, for all time periods, and the scale (in MW) was fixed to provide consistency. The values shown on the scale represent electrical generation infrastructure in sub regions. Loddon Mallee, for example, has eight subregions.



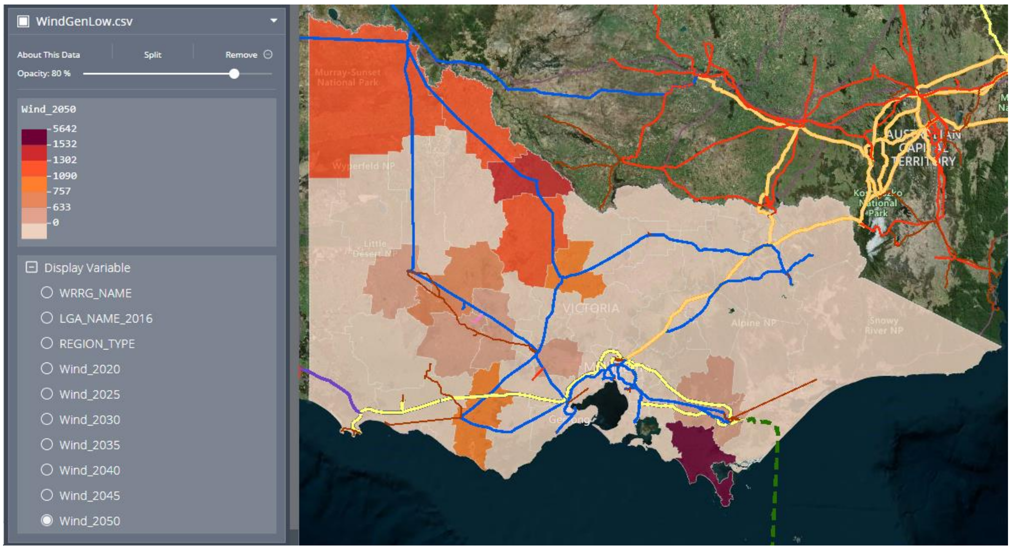
(2020) 



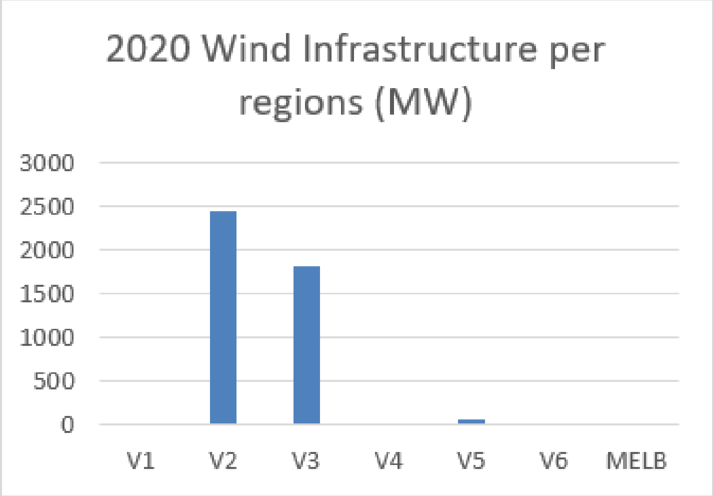
(2030)

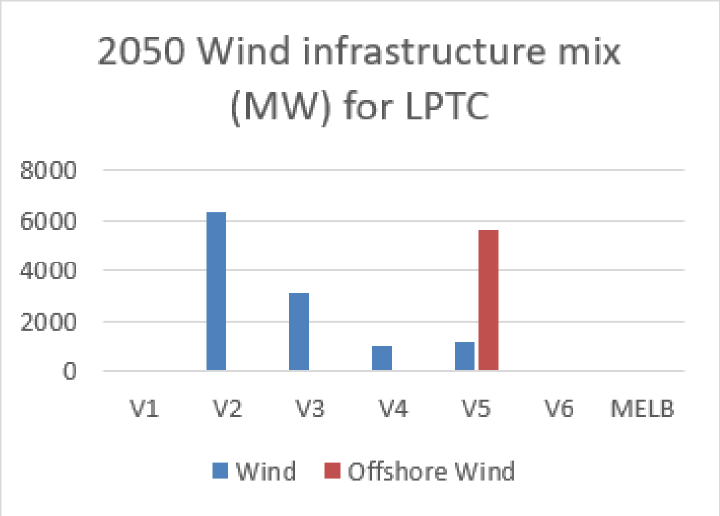


(2040)



(2050)





LPTC: Low Probability Technology Case

Note: All the locations of existing and committed asset for 2020 wind generation have been taken from AEMO's ISP input & assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zones alongside the existing transmission lines. The location is based on available open land and associated wind rows.

Further work may consider wind generation infrastructure being more balanced between V2, V3 and V4.

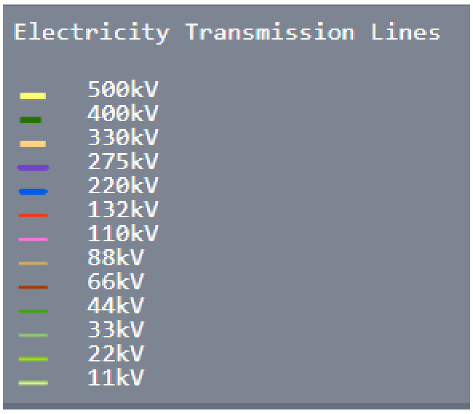
It is possible to consider V3 and V4 having more wind given the wind potential in these zones is around 40%.

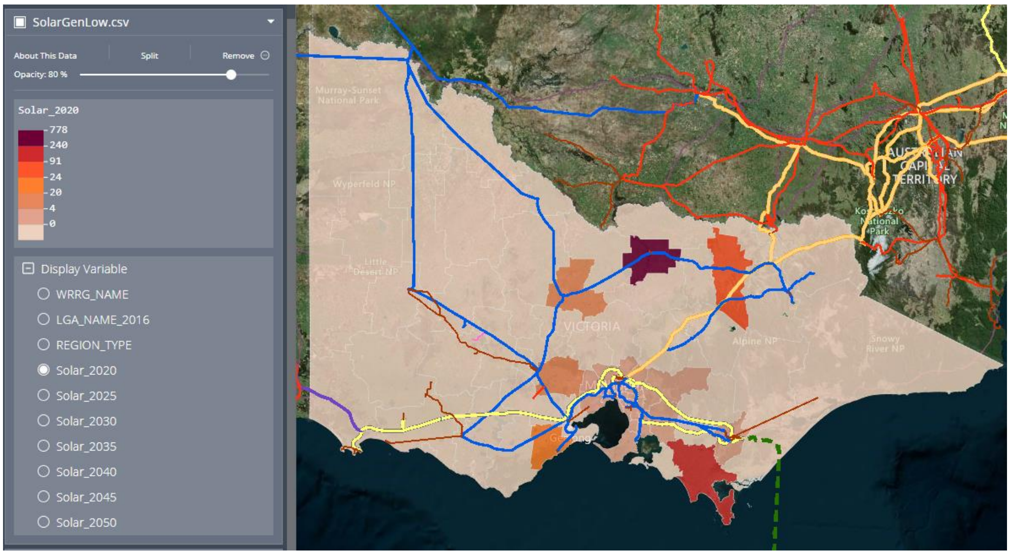
Offshore Wind has been allocated only to V5 in this case. Both South West (V4 and Gippsland (V5) can accommodate offshore wind, as they both have a good capacity factor.

By 2050, onshore wind represents 23% of the generated electricity with 11,585 MW of infrastructure capacity, and offshore wind represents 9% with 5,640 MW.

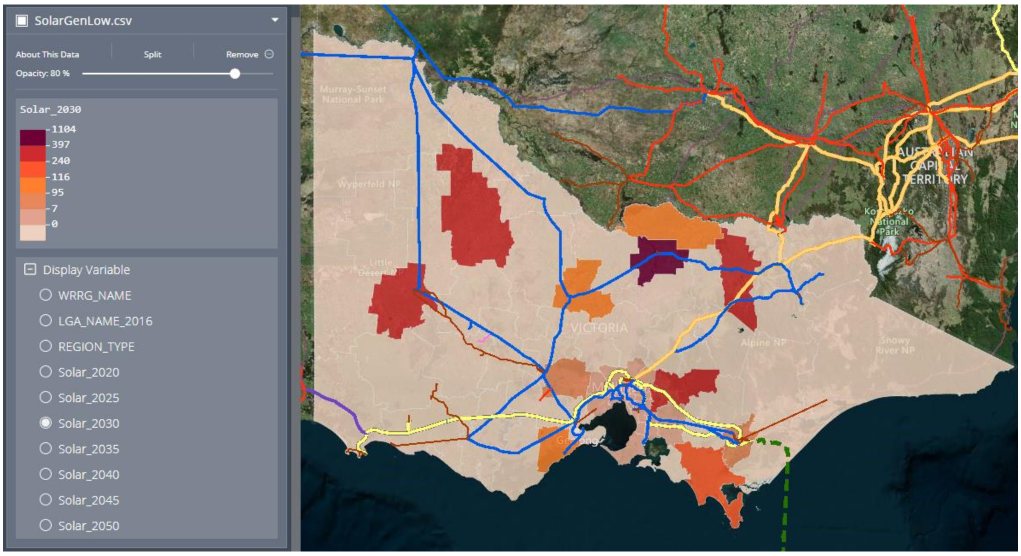
7.4.3.3 Solar

Only the transmission lines existing in 2020 are indicated on the following maps, for all time periods, and the scale (in MW) was fixed to provide consistency. The values shown on the scale represent electrical generation infrastructure in sub regions. Loddon Mallee, for example, has eight subregions.

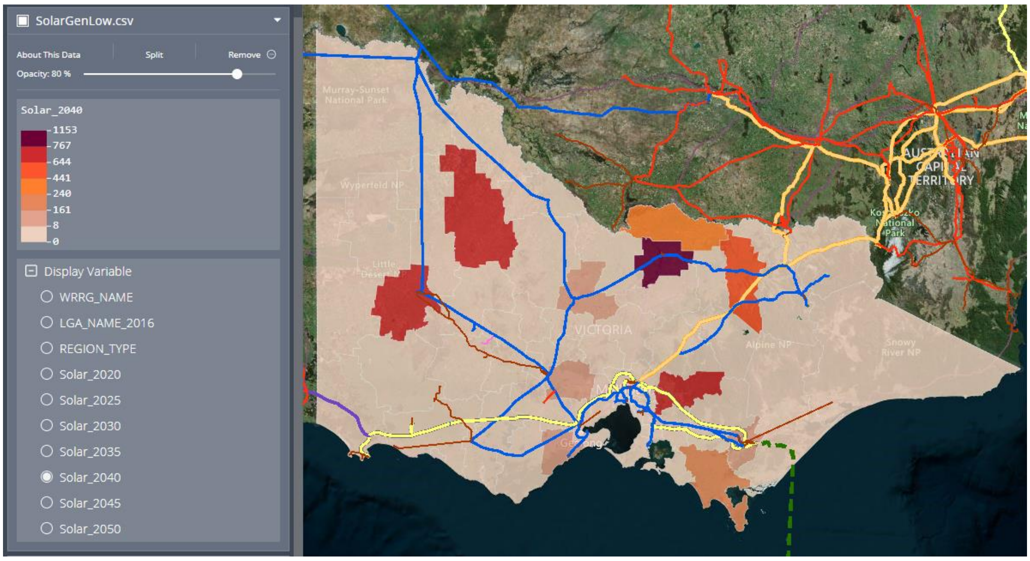




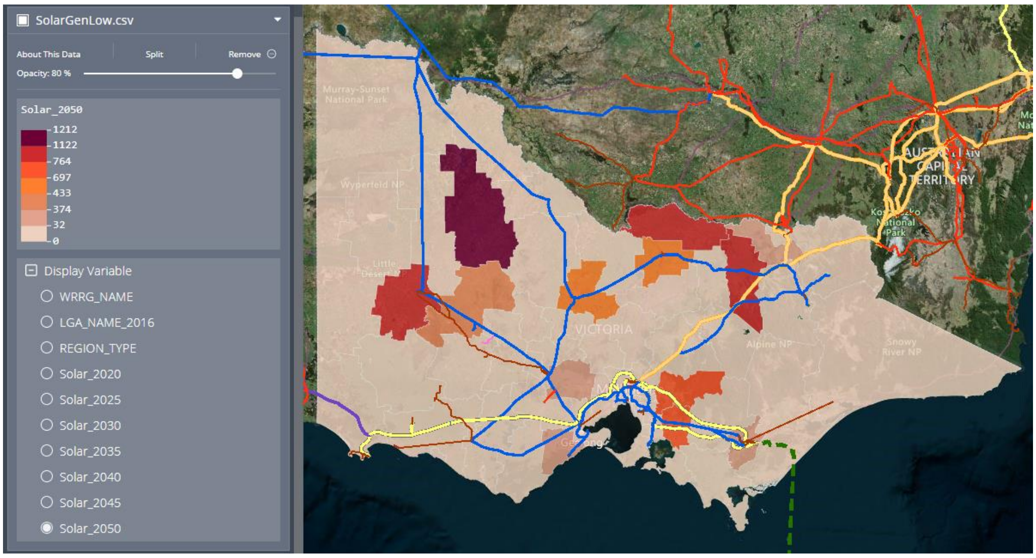
(2020)



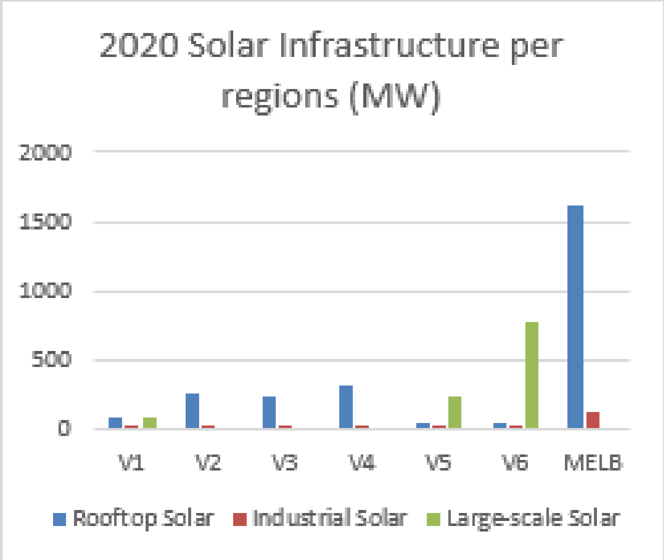
(2030)

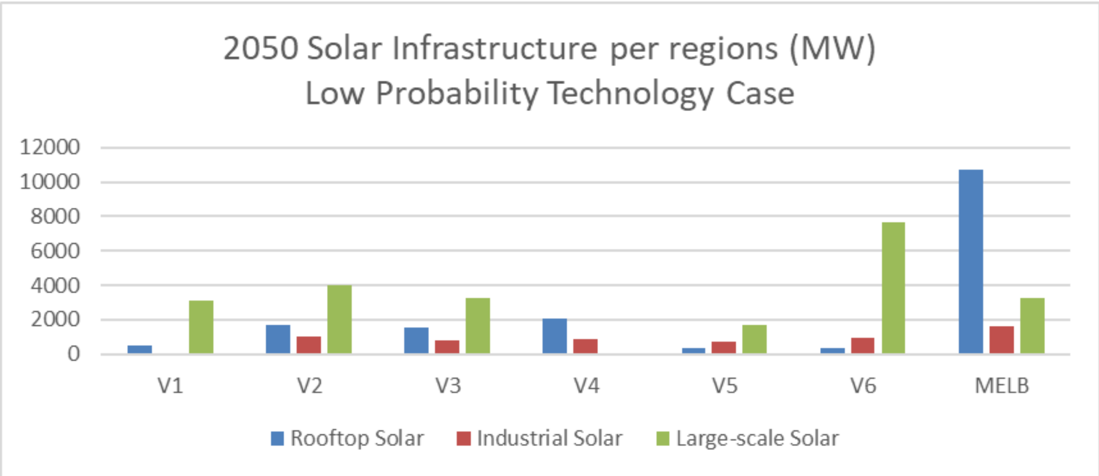


(2040)



(2050)





As for the High Probability Technology Case, solar PV will expand in all the regions in which it has a high potential: V1, V2, V3 and V6. Once again, the locations follow the transmission lines.

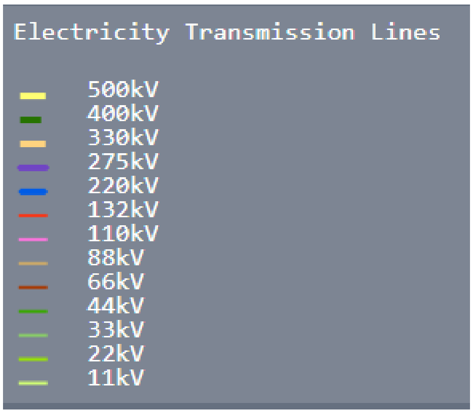
In 2050, Victoria will have:

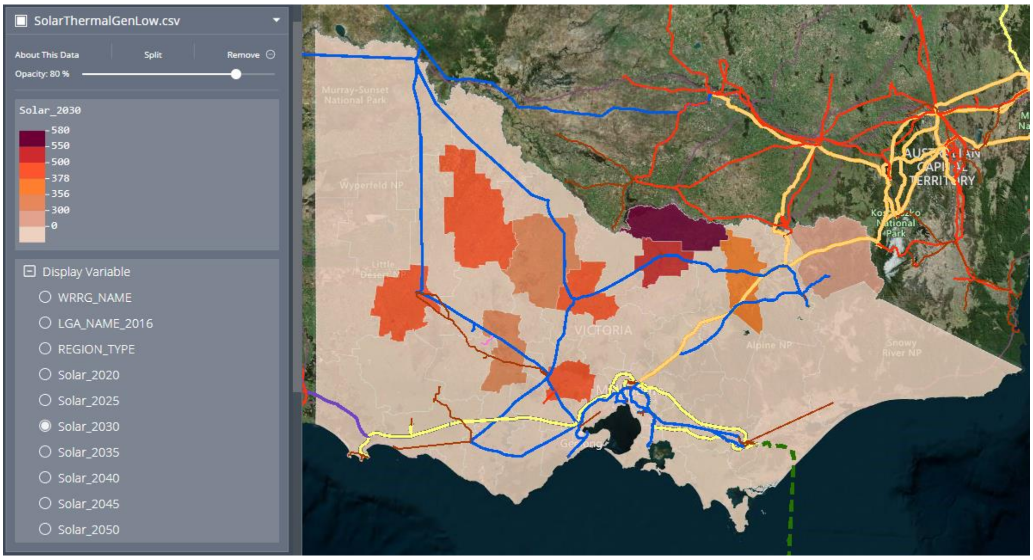
- 7,394 MW of rooftop solar PV generation, representing 6.8% of electrical mix
- 1,657 MW of industrial solar PV generation, representing 2.4% of electrical mix
- 12,663 MW of large-scale solar PV generation, representing 9.2% of electrical mix

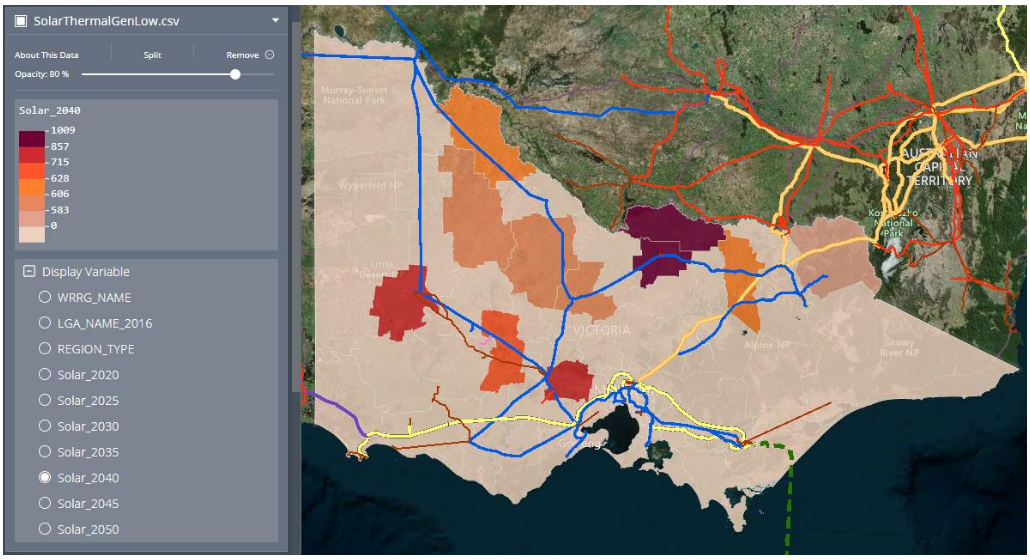
In the Low Probability Technology Case solar PV represents a smaller part of the mix compared to High and Mid Probability Technology Cases because of the assumed breakthrough in solar thermal technology.

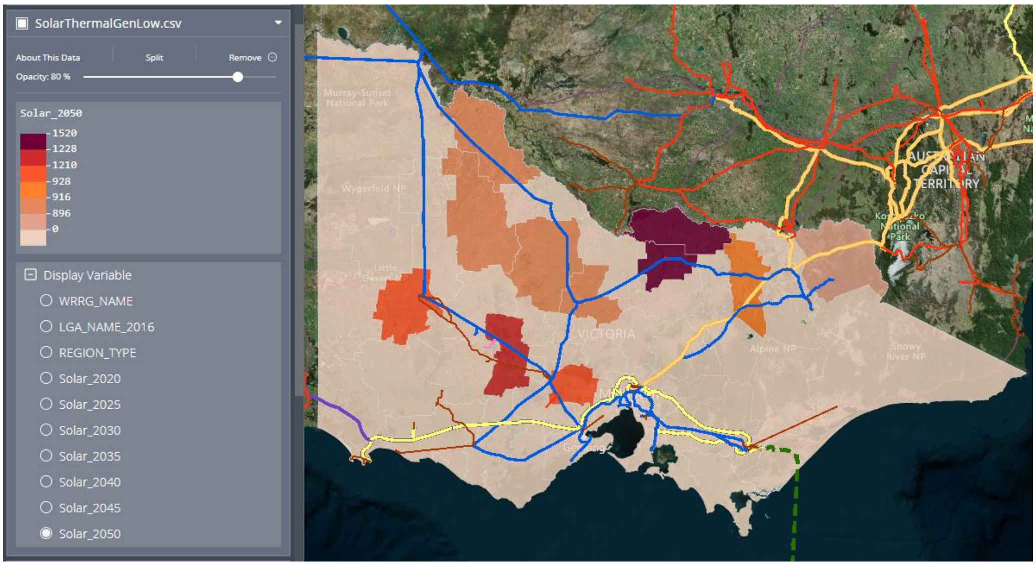
As solar thermal has inherent storage associated with it, it is prioritized over solar PV. The storage was assumed to be approximately 20 to 30% of the total installed capacity and can be called on as and when required.

7.4.3.4 Solar Thermal

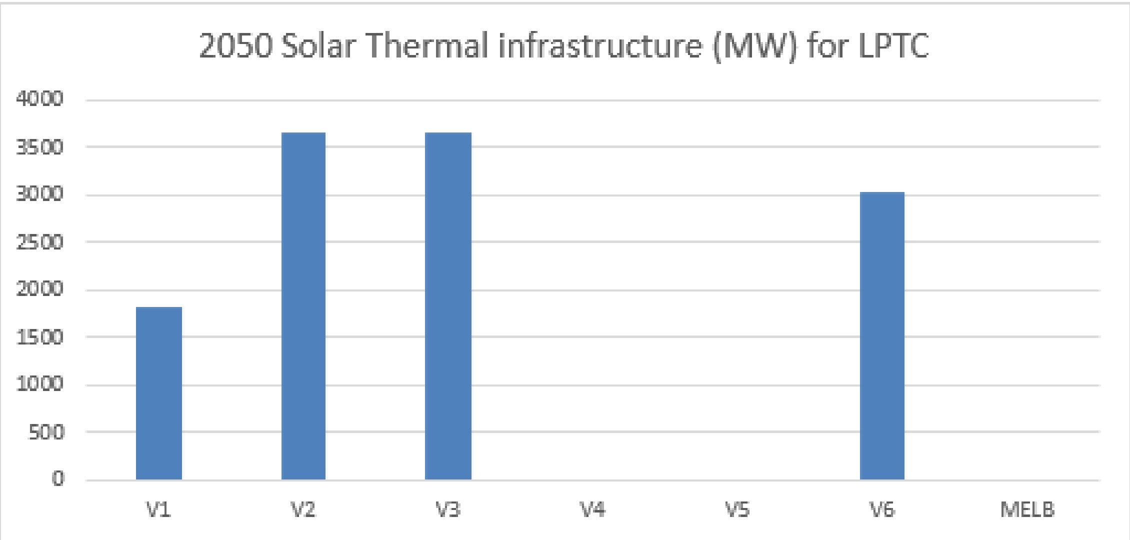


(2030) 

(2040) 

(2050) 

There is no solar thermal in 2020 in Victoria.



In 2050, solar thermal generates 34% of the electricity with 12,161 MW of infrastructure capacity.

The use of solar thermal is combined with molten salt storage which was estimated to store 43% of the production and located proximal to the solar thermal facility. Molten salt storage represents an advantage for solar thermal because it is much cheaper than li-ion batteries and stores 10 times more than the largest li-ion battery systems installed for renewable sources.

7.4.3.5 Focus on Bioenergy

By 2050, Bioenergy provides 6% of the electrical demand with 2,270 MW of installed capacity.

7.4.3.6 Infrastructure to be Installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period.

The values in 2020 are the existing and committed assets, then for each subsequent time period the values represent the additional generation infrastructure that has to be added for the specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	1	0	0	0	0	14	0	0	0	0	0	35	0	30	3	2	0	0	0
2030	57	0	0	0	0	95	0	0	0	678	0	55	0	910	50	124	20666	0	30
2035	3	0	0	0	0	131	0	0	0	329	0	64	0	413	14	7	10036	0	14
2040	13	0	0	0	0	136	0	0	0	204	0	59	0	710	28	28	6202	0	30
2045	13	0	0	0	0	215	0	0	0	206	0	58	0	752	56	28	6286	0	11
2050	46	0	0	0	0	320	0	0	0	407	0	70	0	1992	134	134	12391	0	31
	MW												GWh						MW

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	4	0	42	0	4	18	0	0	0	0	0	35	0	93	9	6	0	0	0
2030	191	0	1239	0	53	132	0	0	0	1356	0	55	0	2779	152	414	41332	0	30
2035	11	0	343	0	15	182	0	0	0	659	0	64	0	1260	42	23	20072	0	14
2040	44	0	708	0	30	188	0	0	0	407	0	59	0	2168	87	95	12403	0	30
2045	43	0	701	0	60	298	0	0	0	413	0	58	0	2298	172	94	12571	0	11
2050	155	0	2508	0	142	445	0	0	0	813	0	70	0	6086	410	447	24783	0	31
	MW												GWh						MW

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0	0
2025	3	0	20	0	2	16	0	0	0	0	0	35	0	63	6	5	0	0	0
2030	172	0	593	0	48	128	0	0	0	1356	0	55	0	2224	122	373	41332	0	30
2035	10	0	164	0	13	177	0	0	0	659	0	64	0	1008	34	21	20072	0	14
2040	39	0	338	0	27	183	0	0	0	407	0	59	0	1734	69	85	12403	0	30
2045	39	0	335	0	54	290	0	0	0	413	0	58	0	1838	137	84	12571	0	11
2050	139	0	1199	0	130	433	0	0	0	813	0	70	0	4868	328	402	24783	0	31
	MW												GWh						MW

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0	0
2025	5	0	7	0	3	0	0	0	0	0	0	35	0	41	4	7	0	0	0
2030	230	0	202	0	56	0	0	0	0	0	0	55	0	1364	75	497	0	0	30
2035	13	0	56	0	15	0	0	0	0	0	0	64	0	619	21	28	0	0	14
2040	52	0	115	0	32	0	0	0	0	0	0	59	0	1064	43	114	0	0	30
2045	52	0	114	0	63	0	0	0	0	0	0	58	0	1128	84	112	0	0	11
2050	186	0	408	0	150	0	0	0	0	0	0	70	0	2987	201	536	0	0	31
	MW												GWh						MW

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0	0
2025	1	0	8	0	3	3	0	0	0	0	0	35	0	26	3	1	0	0	0
2030	38	0	237	1083	56	0	0	0	0	0	0	55	0	859	47	83	0	0	30
2035	2	0	66	476	15	0	0	0	0	0	0	64	0	390	13	5	0	0	14
2040	9	0	135	982	32	0	0	0	0	0	0	59	0	670	27	19	0	0	30
2045	9	0	134	851	63	0	0	0	0	0	0	58	0	710	53	19	0	0	11
2050	31	0	480	2250	150	0	0	0	0	0	0	70	0	1881	127	89	0	0	31
	MW												GWh						MW

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	1	0	0	0	4	20	0	0	0	0	0	23	0	78	8	1	0	0	0
2030	38	0	0	0	58	116	0	0	0	1130	0	37	0	2122	116	83	34443	0	20
2035	2	0	0	0	16	160	0	0	0	549	0	42	0	963	32	5	16727	0	9
2040	9	0	0	0	33	165	0	0	0	339	0	39	0	1656	66	19	10336	0	20
2045	9	0	0	0	66	262	0	0	0	344	0	39	0	1755	131	19	10476	0	8
2050	31	0	0	0	156	391	0	0	0	678	0	46	0	4647	313	89	20652	0	20
	MW												GWh						MW

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	Molten Salt Solar	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Flywheel	Iron-air Batteries	Fuel Cell
2020	1617	0	0	0	125	0	0	982	0	0	0	0	0	0	0	0	0	0	0
2025	24	0	0	0	7	33	0	0	0	0	0	35	0	227	23	35	0	0	0
2030	1187	0	0	0	48	129	0	0	0	0	0	55	0	4902	268	2568	0	0	30
2035	66	0	0	0	13	178	0	0	0	0	0	64	0	2223	74	142	0	0	14
2040	271	0	0	0	28	184	0	0	0	0	0	59	0	3824	153	587	0	0	30
2045	268	0	0	0	55	291	0	0	0	0	0	58	0	4053	303	581	0	0	11
2050	961	0	0	0	130	434	0	0	0	0	0	70	0	10733	723	2772	0	0	31
	MW												GWh						MW

Note Reference in table to "waste-to-energy" shall be read as "bioenergy"

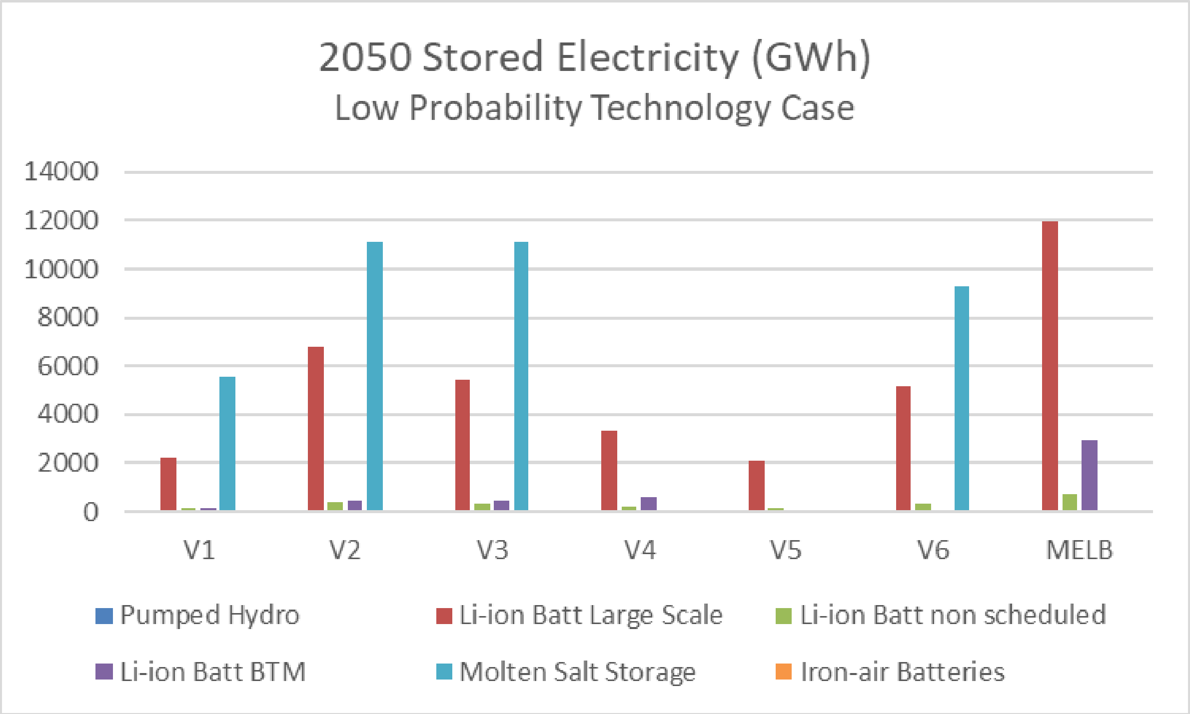
7.4.4 Discussion

The Low Probability Technology Case was observed to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (behind the meter, industrial and large scale)
  - Wind Offshore (starting 2030)
  - Solar thermal (starting 2030) + Molten Salt Storage
  - Fuel cells (starting 2030)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar and wind represents between 75 and 80% of the electrical mix creating grid instability that requires compensation by additional generation and storage facilities. Starting in 2035 all wind, solar PV and battery infrastructure is multiplied by 1.5.
- The share of wind and solar PV in 2050 is 59% solar and 41% wind.
- New transmission lines are needed as the grid will have to support a lot more electricity. Upgrades on the following lines are considered to be likely (same as High Probability Technology Case):
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers representing approximately 25% more infrastructure than exists today.
- All the connections between the facilities and the grid have been taken into account in the cost analysis, but are not shown on the maps.
- The storage is calculated depending on the quantity of solar PV and wind.



7.5 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

7.6 Environmental & Social Analysis

7.6.1 Work Description

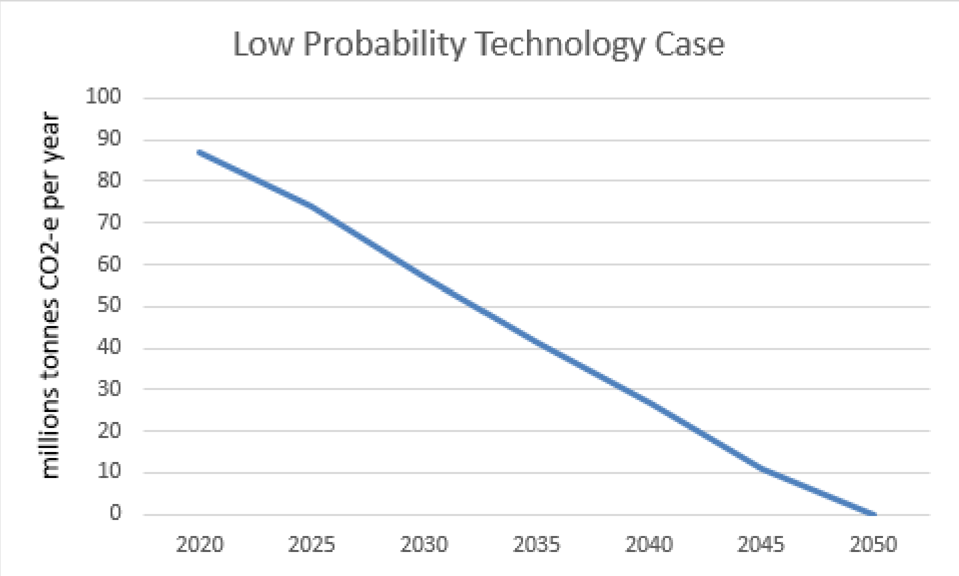
The environmental and social components of the Low Probability Technology Case have been assessed via a desk-top study using key aspects from environmental and social perspectives and presented in Table 51.

7.6.2 Results

In the Low Probability Technology Case, emissions reductions are achieved by utilising prototype energy technologies, solar thermal electricity generation, green hydrogen and offshore wind.

Figure 68 shows the modelled emissions reduction profiled for this case with a linear decline in greenhouse gas emissions zero in 2050. The assumed technologies achieve zero emissions from the studies sectors several years before 2050.

Figure 68: Emissions Reduction Profile – Low Probability Technology Case



- Unlike the Mid case, electricity generation from coal is still the highest source of emissions up until 2045. Natural gas and Vehicles - (ICE) gasoline & diesel remains the equal second highest emissions up until 2045.
- The low probability technology case utilises solar thermal electrical power generation technology combined with molten salt storage to provide dispatchable power generation technology.

7.6.3 Discussion

Relative to the high probability technology case, this case makes significant use of solar thermal technology with molten salt storage to supply approximately 177PJ of energy in 2050. This results in a reduction in the need for wind and solar PV generation and the corresponding battery storage required for those technologies. Noting the combined level of molten salt and battery storage is comparable to the high probability technology case.

The low probability technology case can be considered as similar to the mid probability technology case, but the use of ammonia is replaced with the use of solar thermal. Unlike the high and mid cases, the low probability technology case achieves net zero by 2050 without the need for greenhouse gas offsets.

The proposed low probability case has the following environmental and social considerations:

- Key investments to achieve the net zero emission target by 2050 include:
  - compared to 2020; 7.8 times more solar PV, 4.5 times more wind capacity, and roughly 100 time more battery storage
  - the role out of substantial solar thermal capacity and associated molten salt storage. In 2050 the amount of energy supplied by solar thermal is substantially greater than solar PV (150%) or wind (140%)

    - significant investment in biomethane, bioenergy and hydrogen production
    - strengthening the electricity grid.
- The low probability technology case offers comparable employment opportunities to the mid probability technology case, which are both significantly higher than the high probability technology case. In this case the main driver of employment is associated with the operation of solar thermal technology with around 55% of all jobs. Other major employment contributors are:
    - wind (11%)
    - energy efficiency (9%)
    - rooftop solar PV (9%)
    - battery storage (7%)

The deployment of solar thermal electrical generation combined with molten salt storge has fewer environmental and social risks requiring management compared with the use of ammonia in the mid probability technology case. Risks are likely to focus on community concerns over the industrialisation of previous rural areas and risks posed to birds entering the area of concentrated thermal radiation. Unlike wind power where birds may be able to avoid rotating turbine blades, birds may not be able to detect areas of concentrated solar energy before being exposed to potential injury. Careful monitoring of solar thermal bird losses will likely be required to assess if this is a significant issue and requires further management action.

7.7 Cost Analysis

7.7.1 Key References & Assumptions

Refer to Section 3.8.5.

7.7.2 Work Description

Refer to Section 3.8 for details of the work description.

7.7.3 Results

The figure below present the net difference between the Low Probability Technology Case and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Figure 69 demonstrates that:

- The Low Probability Technology Case projects a material reduction in fuel, FOM and VOM costs, as a result of the reduction of fossil fuel generation and expanded development and sharing of new variable renewable electricity resources, providing a net annualised benefit of approximately $0.5 billion in 2050.
- The Low Probability Technology Case projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $8 billion in 2050 transitioning to a net zero outcome. It is important to

note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the Low Probability Technology Case is represented by the purple line in Figure 69.

By 2050, the Low Probability Technology Case is forecast to provide a net cost increase of around $7.5 billion by 2050.

For the Low Probability Technology Case, the net costs show a gradual negative trend due to the increased annual CAPEX costs for new generation to meet the increased energy demand which returns a net cost increase.

Figure 69: Net Costs of the Control Scenario relative to the Low Probability Technology Case

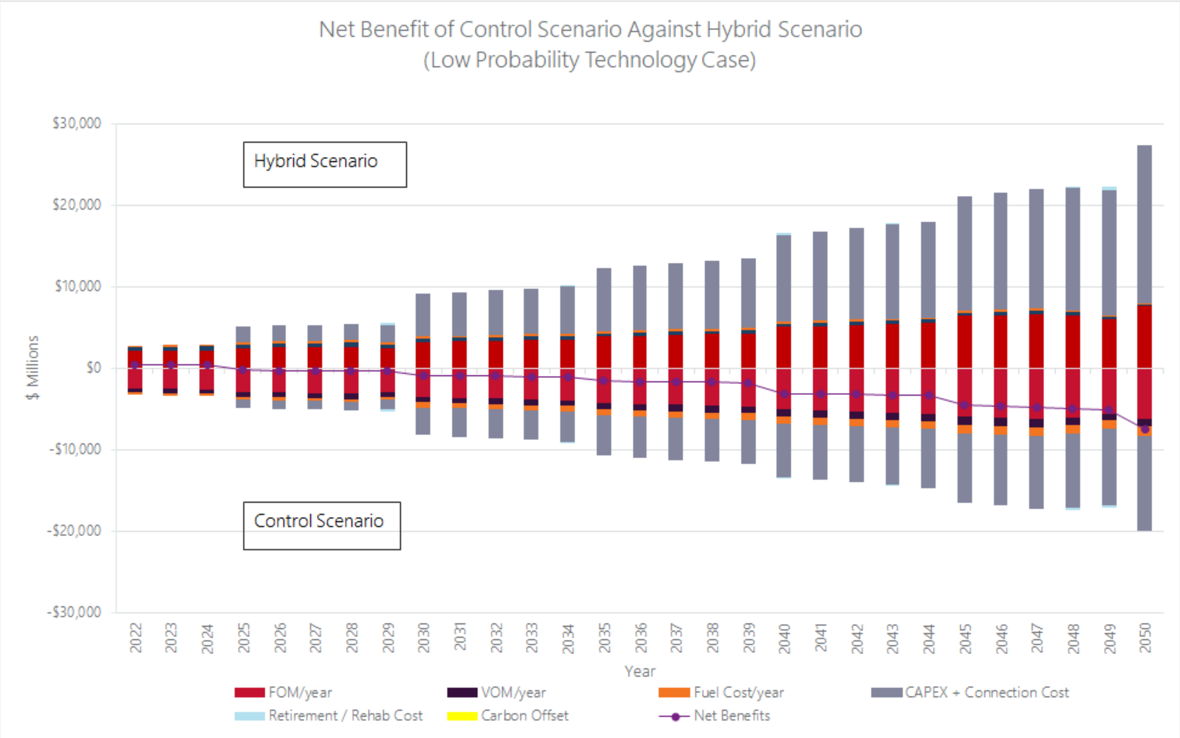


Table 79 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Low Probability Technology Case, in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the Low Probability Technology Case, discounted back to present value, is $8 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$1.9 billion (NPC).

The estimated cost of CO_2 abatement is $93/te CO_2.

Table 79: Net Costs of the Control Scenario relative to the Low Probability Technology Case

Cost Category[2]	**Net Benefit of Control Against Technology Case (Low Probability)**		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$4,907	-$2,156
FOM	$2,475	$2,633	-$158
VOM	$435	$256	$179
Fuel	$419	$176	$243
Retirement / Rehab	$48	$51	-$3
Agro-forestry (Land Area, Hectare)	$0	$0	$0
Gross Cost	$6,127	$8,024	-$1,896
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement[3] ($/tonne)	583	93	490

Notes:
1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

7.7.4 Discussion

The increased CAPEX combined with the overall energy mix for the Low Probability Technology Case compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity.

OPEX and fuel costs savings for the Low Probability Technology Case compared to the Control Scenario are also expected due to the reduction in fossil fuel generation and expanded development and sharing of new variable renewable electricity resources but are not sufficient to offset the CAPEX increase.

Retirement costs are marginally higher in the Low Probability Technology Case as this includes decommissioning of gas transmission and distribution lines and the existing, anticipated and committed generation being retired by 2050. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Low Probability Technology Case cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

7.8 Risk & Opportunity Analysis

7.8.1 Key References & Assumptions

The preceding Scenario Analysis Stage 1 (*Net Zero Emission Scenario Analysis Study Report May 2021*) study was used as the key reference for this study and informed the framing of the Hybrid Scenario to be studied.

Existing, proven, commercially viable and commercial scale technologies supplemented by emerging technologies have primarily been assumed for the Low Probability Technology Case. Energy production and power generation technologies and costs are based on the AEMO Inputs & Assumptions Workbook used to support the 2020 Integrated System Plan.

Additional technologies from CSIRO's GenCost 2020 report were also considered.

The key assumptions for this Low Probability Technology Case are:

- Green hydrogen (electrolysis using renewable energy) at large scale becomes technically viable and commercially competitive by 2025;
- Hydrogen blending into the existing natural gas transmission and distribution system is possible and limited to 10% by volume;
- One or more large scale offshore wind projects are developed and operational by 2030;
- Industrial scale solar thermal projects become commercially competitive by 2030;

7.8.2 Work Description

This study presents a hybrid scenario with a more balanced energy mix which also attempts to retain and utilise existing natural gas transmission and distribution infrastructure as far as possible.

The Low Probability Technology Case introduces the following emerging technologies which were not considered in the High Probability Technology Case, as described below.

- Offshore wind to utilise Victoria's high quality offshore wind resource;
- Concentrated solar thermal (with thermal storage) to provide and grid firming electricity supply;

These low carbon technologies reduce the reliance on natural gas for peak period electricity generation and direct heating, also allowing the use of natural gas to be phased out by 2040. The use of coal for power generation can also be phased out by 2040 whist utilising the existing electricity transmission infrastructure.

The study team reviewed the risks and opportunities identified in the Stage 1 study and assessed the key risks associated with this Hybrid Scenario, focussing on the implementation risks and rather than the inherent risks since a risk and opportunities comparison between scenarios was not contemplated in this study. Implementation risks are the risk of the technology not being adopted in the timeframe given for the Analysis Case, due to either cost or technology development or both, whereas inherent risks are those associated with the technology once implemented.

7.8.3 Results

The Low Probability Technology Case possesses a moderate implementation risk as it relies on the scale up of electrolysers and moderate cost reduction of green hydrogen production by 2025.

The ability of the existing natural gas transmission and distribution network to handle a blend of 10% hydrogen with 90% natural gas and biogas by 2025 is considered feasible, with a low implementation risk.

Offshore wind technology is well proven in other parts of the world, but there is a minor risk that offshore wind will not be cost competitive in Victoria, or a project may not be approved by 2030. The regulatory framework will also need to be established for such projects.

Concentrated solar thermal technology is well proven, but it is not currently cost competitive with other forms of renewable energy. There is a moderate risk that ongoing cost reductions in this technology will not reach a level for it to be commercialised in Australia by 2030.

Carbon offsets are not required to achieve net zero in this Low Probability Technology case, however opportunity exists to achieve negative net emissions.

7.8.4 Discussion

As discussed in Section 5.4.4, achieving a breakthrough with green hydrogen to make it commercially competitive with other energy sources by 2025 will be challenging, but it not outside of the realms of possibility. A blend of 10% hydrogen with 90% natural gas and biogas in the existing gas transmission and distribution system is likely to be possible by 2025 although the timing of 2025 may be ambitious unless implementation commences in the near future. However, a slight delay to this implementation will not have a material impact on the meeting net zero targets or renewable energy targets, but adjustments to the energy mix, and offsets, will be required to accommodate this.

Offshore wind for renewable power generation is a commercially proven technology in other parts of the world. The Star of the South offshore wind project is currently in feasibility phase and could potentially become Australia’s first offshore wind project. Located offshore Gippsland, this project has the advantage of tying into existing electricity transmission infrastructure in the Latrobe Valley. While high quality wind resources are available in Bass Strait, the commercial viability of offshore wind in an Australian context has yet to be demonstrated.

Australia is currently developing an offshore clean energy framework which will enable the exploration, construction, operation and decommissioning of offshore wind and other clean energy technologies and this framework legislation will need to pass before any offshore wind projects can proceed.

Industrial scale concentrated solar thermal technology (with thermal storage) is currently relatively expensive but has the potential to provide firm, grid scale electricity, if the costs continue to fall and uptake increases around the world.

Both of these “new” industries will require skilled workforce for the construction, operations and maintenance of the equipment due to the complexity of the equipment involved, in comparison with onshore wind and PV solar. The existing services capability for supporting the offshore oil and gas sector can be deployed to support the construction, operations and maintenance of offshore wind and this risk should be manageable.

Reliance on a single gigawatt scale offshore wind project is a substantial risk which will have to be mitigated to ensure security of supply by the provision of system redundancy and local capability to quickly repair critical failures, both onshore and offshore.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

8 SENSITIVITY CASE 1 "ACCELERATED NET ZERO"

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

8.1 Objective

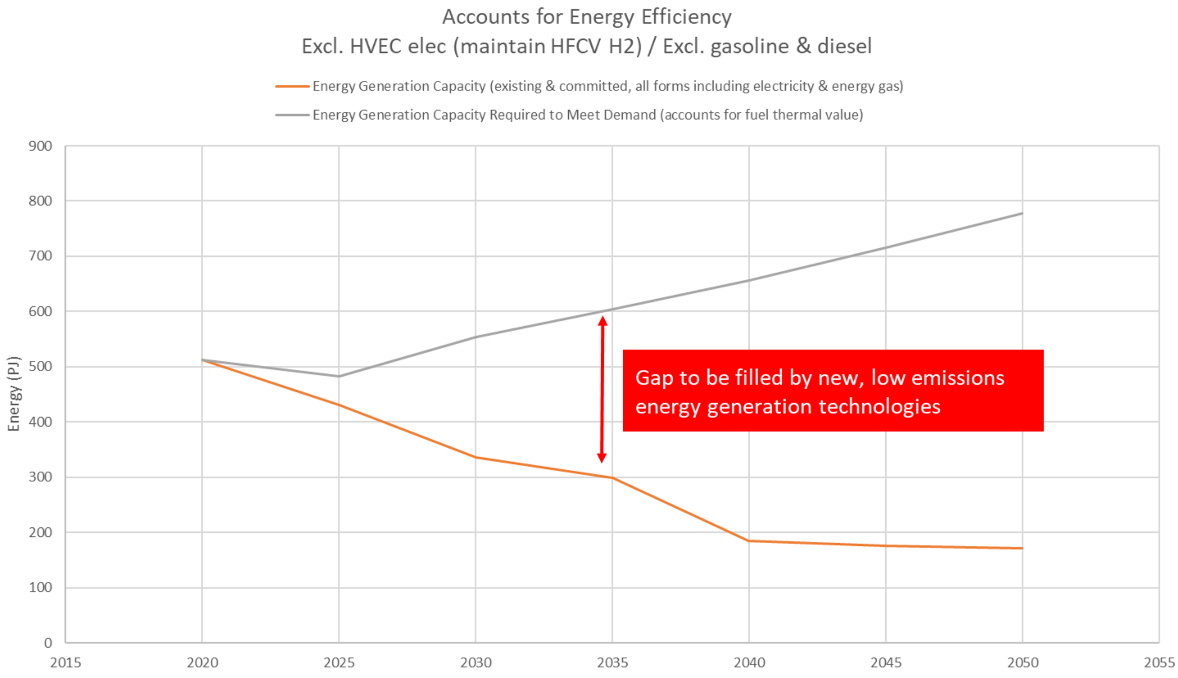
The objective of running Sensitivity Case 1 was to investigate the potential of achieving net zero significantly earlier than 2050, and along with an understanding of the associated cost implication.

8.2 Case Description

The objective of running Sensitivity Case 1 was to investigate the potential and cost of achieving net zero significantly earlier than 2050. Sensitivity Case 1 was constructed by combining the technology breakthroughs from both the Low and Mid Probability Technology Cases.

Figure 70: Forecast Energy Demand vs Generation Capacity (Sensitivity Case 1)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))



The energy generation capacity required to meet forecast demand (grey line in Figure 70) is:

- Limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles
- Determined by subtracting the fossil fuel thermal value from the overall energy demand.

As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

To accommodate the new energy technologies identified for Sensitivity Case 1, modifications were made to the existing & committed energy generation capacity scheduled by AEMO (Table 81) and the fossil fuel decline profile assumed for the prior *Net Zero Emission Scenario Analysis Study Report May 2021* (see Table 14 Section 3.2). The modifications closely match those made for the Mid Probability Technology Case, with a summary provided in Section 6.2.

The energy technology breakthroughs identified for Sensitivity Case 1 are summarized in Table 80. These technology breakthroughs are a combination of those identified for both the Low and Mid Probability Technology Cases, with descriptions provided in Section 6 and Section 7.

Table 80: Energy Technologies Used to Deliver Additional Capacity for Sensitivity Case 1

Energy Type	Description
elec gen	solar PV
elec gen	wind onshore
elec gen	hydropower
elec gen	bioenergy
elec gen	**WIND OFFSHORE (LOW)**
elec gen & stg	**SOLAR-THERMAL (LOW)**
elec gen	**FUEL CELLS (MID)**
elec gen	**NH3 (MID)**
elec stg	pumped hydro (storage)
elec stg	batteries (storage)
elec stg	**IRON-AIR BATTERY (MID)**
gas	biomethane
gas	**GREEN HYDROGEN (LOW & MID)**
gas	**NH3 (MID)**

Table 81: Existing & Committed Energy Production Capacity Assumed for Supplying Demand Sensitivity 1)

ELECTRICITY	2020		2030		2040		2050	
	Total Capacity		Total Capacity		Total Capacity		Total Capacity	
	MW	PJ	MW	PJ	MW	PJ	MW	PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	3,325	85
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**24,993**	**171**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	0	71	0
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	0	1,100	0
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to balance demand)	170	12	170	12	170	0	170	0
	1,360	**319**	**1,993**	**153**	**1,782**	**0**	**1,691**	**0**

8.3 Energy Emissions Offsets

8.3.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

8.3.2 Results & Discussion

In Sensitivity Case 1, net zero emissions was achieved prior to 2050 as a result of utilising low emissions energy technologies only, without the need for greenhouse gas offsets or geo-sequestration (CCS).

Table 82: Mean Demand Energy Mix for Sensitivity Case 1

	2020	2025	2030	2035	2040	2045	2050
	Impact of Energy Efficiency on Energy Generation Capacity (PJ)						
Energy Generation to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	585	650	693	738	793	850
	Cumulative Energy Consumed accounting for Energy Efficiency (PJ)						
Elec (generation) - coal	144	116	90	67	0	0	0
Elec (generation) - natural gas (baseload + peaking)	5	5	5	4	0	0	0
Elec (generation) - NH3	0	0	0	0	75	75	75
Elec (generation) - hydropower	10	10	11	10	10	10	10
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	47	74	87	87	87	90
Elec (generation) - solar thermal - industrial	0	0	41	65	103	103	114
Elec (generation) - wind (onshore + offshore)	28	58	81	96	97	96	98
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	31	35	42
Elec (generation) - fuel cells	0	0	5	5	13	13	16
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	3	3	3	3	3
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	1	15	56	78	121	126	144
Gas (generation) - natural gas (all sources)	209	189	174	150	0	0	0
Gas (generation) - biomethane [distribution system)	0	1	4	11	19	24	36
Gas (generation) - H2 (green) [incl HFCV fuel]	0	18	29	29	29	29	36
Gas (generation) - NH3 (green) [industrial use + conversion to H2 for distributiuon eg res	0	0	0	0	77	98	131
Vehicles - (ICE) gasoline & diesel	318	266	218	158	99	43	0
Vehicles - (BEV) electricity	0	10	20	36	52	51	58
Vehicles - (HFCV) electricity [GENERATION]	0	21	42	44	47	50	60
TOTAL ENERGY (PJ)	732	759	867	866	862	844	914

Table 82 reveals that:

- In 2020 as per the High Probability Technology Case, gasoline & diesel (ICE vehicles) is the single biggest energy source at approximately 320 PJ-thermal, or approximately 45% of the total, with natural gas in second position at approximately 210 PJ-thermal or approximately 30% of the total, and electricity from coal in third position at approximately 145 PJ-electricity or approximately 20% of the total.
- In 2030, as per the Low Probability Technology case, technology breakthroughs and subsequent introduction of offshore wind, solar thermal, fuel cells and green Hydrogen occurs. Gasoline & diesel (ICE vehicles) is the single biggest energy source at approximately 220 PJ-thermal, or approximately 25% of the total, natural gas also remains in second position with approximately 175 PJ-thermal or just approximately 20% of the total. Third position is, however, jointly occupied by coal,

wind and solar PV (approximately 90, 80 and 75 PJ-electricity respectively) each being approximately 10% of the total.

- In 2040, as per the Mid Probability Technology case, technology breakthroughs and subsequent introduction of Ammonia and Iron-Air batteries. Storage* represents the single biggest energy source at approximately 120 PJ-electricity or just under 15% of the total. Solar thermal is in second position with approximately 105 PJ-electricity or approximately 15% of the total. Third position is jointly occupied by both gasoline & diesel (ICE vehicles) with approximately 100 PJ-thermal and wind with approximately 95 PJ-electricity each representing approximately 10% of the total.
- In 2050, unlike the High Probability Technology case, no natural gas is present as a result of introducing green Ammonia. In this year, storage* represents the single biggest energy source at approximately 145 PJ-electricity or approximately 15% of the total. Green Ammonia gas is in second position with approximately 130 PJ-thermal representing just under 15% of the total. Solar thermal is in third position with approximately 115 PJ-electricity or approximately 12% of the total.

*For Sensitivity 1, storage includes molten salt (associated with solar thermal), Iron-air batteries and current technology batteries. Both the molten salt systems and Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

Also noteworthy from Table 82 is the increased diversity of energy sources resulting from the transition:

- In 2020, as per the High Probability Technology Case, the top three single energy sources (gasoline & diesel, natural gas & coal) represented approximately 90% of the total energy mix;
- In 2030 the top three remain as gasoline & diesel, natural gas & coal / wind / solar PV representing approximately 75% of the total;
- In 2040 the top three (storage*, solar thermal and gasoline & diesel / wind) represent approximately 50% of the total; and
- In 2050 the top three (storage*, green Ammonia gas and solar thermal) represent just over 40% of the total.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity), Figure 71 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In 2020, as per the High Probability Technology case, approximately 205 PJ-electricity is consumed, being approximately 50% of the total, and approximately 210 PJ-thermal energy gas is consumed being approximately 50% of the total.
- In 2030, there is a slight reduction in the level of electrification compared to the High Probability Technology case, with approximately 400 PJ-electricity consumed, being just over 65% of the total, and approximately 210 PJ-thermal energy gas consumed being just under 35% of the total.
- In 2040, there is a slight pivot towards a higher degree of electrification compared to the High Probability Technology case, with approximately 590 PJ-electricity

consumed, being approximately 80% of the total, and approximately 125 PJ-thermal energy gas consumed being approximately 20% of the total.

- In 2050, there is a significant pivot towards a higher degree of energy gas compared to the High Probability Technology case, with approximately 650 PJ-electricity consumed, being approximately 75% of the total, and approximately 200 PJ-thermal energy gas consumed being approximately 25% of the total.

Figure 71: Energy Mix Breakdown for Sensitivity Case 1 Covering only Electricity & Energy Gas

(excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

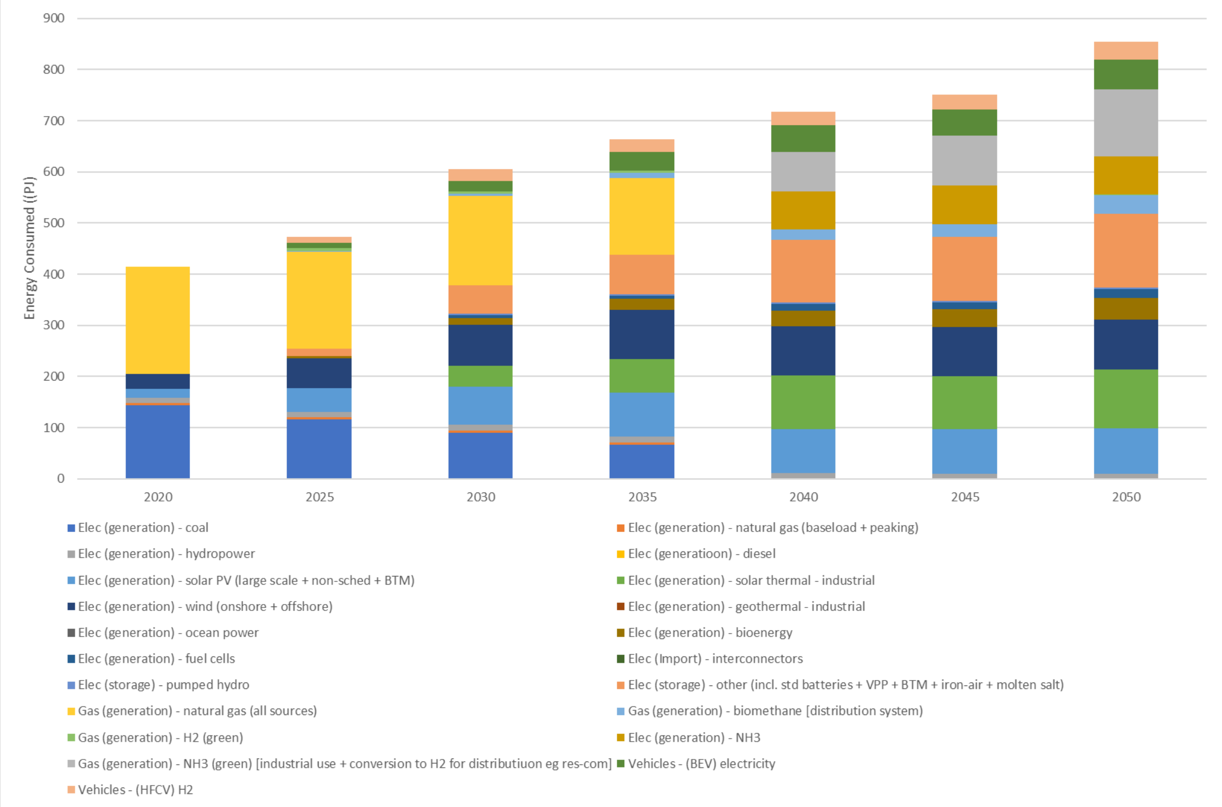


Table 83 and Figure 72 illustrate that Sensitivity 1 has a significantly different emissions decline profile over time compared to the High Probability Technology case, with a sharp decline occurring in 2040 due to the introduction of green Ammonia and Iron-air batteries resulting in stoppage of both natural gas and coal.

Additionally, with the introduction of offshore wind, solar thermal, fuel cells and green Hydrogen in 2030, there is a steeper decline of emissions in the latter phase of the transition leading to attainment of net zero prior to 2050. However, there is no significant difference observed when compared to the Low Probability Technology Case.

A more accelerated approach to net zero Carbon emissions may be achieved by speeding the uptake of low emissions vehicles to displace gasoline & diesel more quickly, particularly before 2040. Additionally, a significantly increase in the level of residential and commercial energy efficiency improvements before 2030 would assist by reducing demand resulting in less requirement for natural gas and coal.

As per the High Probability Technology case, bioenergy is noteworthy as the only technology with a negative emissions contribution, providing a dis-proportionately large contribution to reducing emissions (based on avoided emissions from agriculture and waste – refer ESE Methodology, Section 3.9.5). In 2050, despite its limited share of the energy mix (approximately 40 PJ-electricity or approximately 5%, set by supply chain constraints), it contributes approximately negative 10 Million Te CO2-e emissions leading to a net deficit of emissions.

As per the High Probability Technology case, coal represents a dis-proportionately large contribution to reducing emissions. In 2020, with approximately 145 PJ-elec or approximately 20% of the energy mix, coal contributes approximately 45 Million Te CO2-e emissions (approximately 50% of total). Sitting between bioenergy and coal are :

- Gasoline & diesel (ICE vehicles). In 2020, as per the High Probability Technology case, these fuels represent approximately 320 PJ-thermal consumed (approximately 45% of the total) and contribute approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Natural gas. In 2020, as per the High Probability Technology case, it represents approximately 210 PJ-thermal consumed (approximately 30% of the total) and contributes approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Low emissions electricity excluding bioenergy, but including electricity from Ammonia, solar thermal, fuel cells, hydroelectric, solar PV, wind, pumped hydro, molten-salt storage, Iron-air batteries and other storage*. In 2020, as per the High Probability Technology case, these low emissions technologies represent approximately 60 PJ-electricity consumption (almost 10% of the total), but contribute only 1 Million Te CO_2-e emissions (approximately 1% of the total positive emissions). In 2050 they provide approximately 670 PJ-electricity consumption – including electricity to charge BEVs and generate green Hydrogen for HFCVs - (almost 75% of the total) but contribute only approximately 10 Million Te CO_2-e emissions (all the positive emissions).

  *For Sensitivity 1, storage includes molten salt (associated with solar thermal), Iron-air batteries and current technology batteries. Both the molten salt systems and Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).
- Low emissions energy gases including biomethane, green Hydrogen and green Ammonia. In 2050 they provide approximately 200 PJ-thermal consumption – including fuel for HFCVs - (approximately 22% of the total) but have no emissions.

Table 83: Emissions for Sensitivity Case 1

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	36	28	21	0	0	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - NH3	0	0	0	0	2	2	2
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	1	1	1	1
Elec (generation) - solar thermal - industrial	0	0	0	1	1	1	1
Elec (generation) - wind (onshore + offshore)	1	2	3	3	3	3	3
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-7	-8	-10
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	16	13	0	0	0
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Gas (generation) - NH3 (green) [industrial = NH3 / res-com = convert to H2]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	15	11	7	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**61**	**46**	**9**	**4**	**-1**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NET EMISSIONS	**87**	**74**	**61**	**46**	**9**	**4**	**-1**

Figure 72: Emissions Profile for Sensitivity Case 1

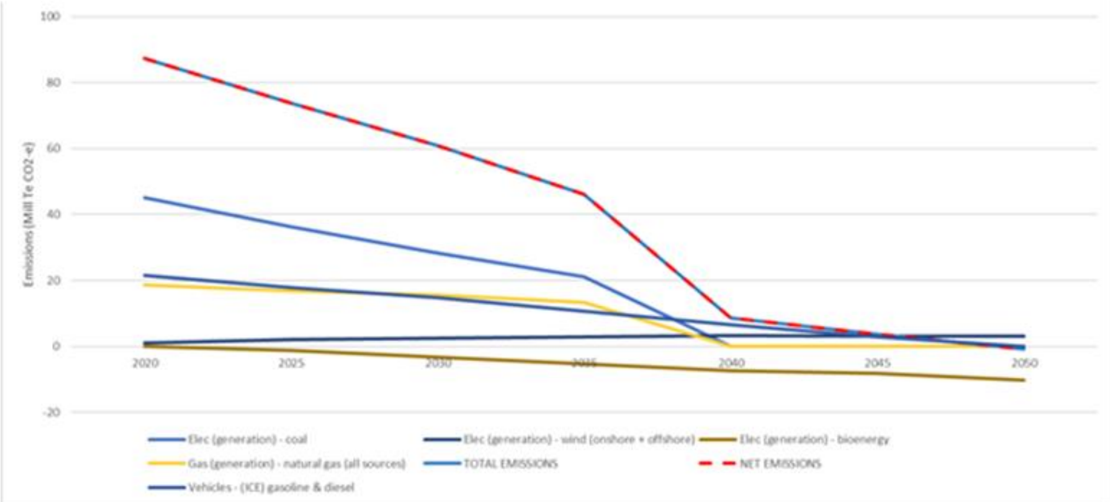
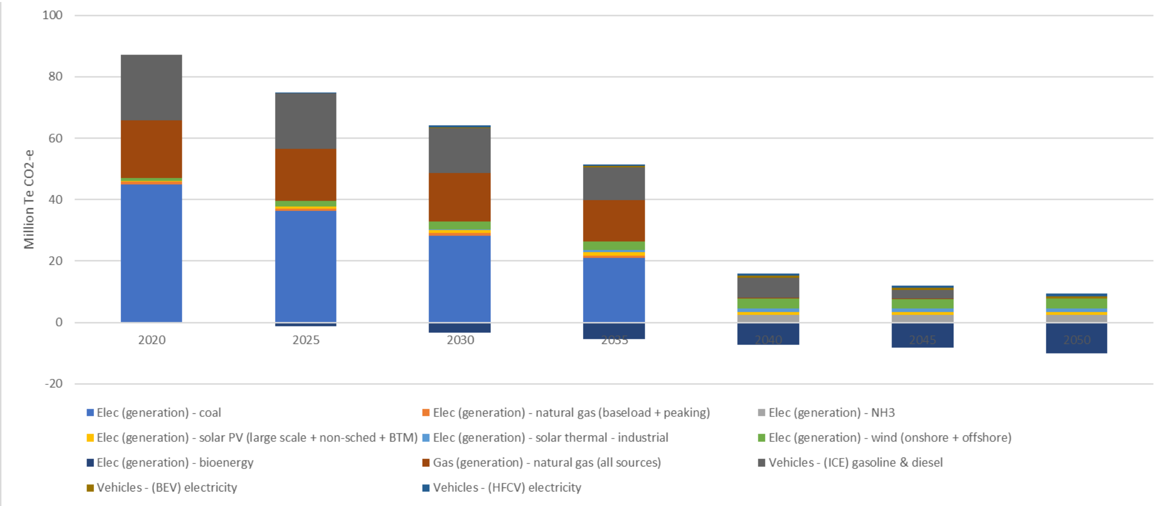


Table 5 (Section 1.6.4) documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for Sensitivity Case 1 is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be:

- <u>2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and</u>
- <u>2030 interim emissions target: up to 9 Million Te CO_2-e to cover out of scope emissions.</u>

Figure 73: Contribution to Emissions by Source for Sensitivity Case 1



Unlike the High Probability Technology case, Sensitivity 1 requires no Carbon offsets to achieve net zero emissions by 2050.

8.4 Gas Spatial Analysis

8.4.1 Work Description

The proposed energy mix from the global modelling tool for the low probability case is used as an input into the spatial modelling tool. The spatial distribution of the energy gas demand has been kept in same proportion as the 2020 demand.

8.4.2 Results

This Sensitivity Case is similar to the Mid Probability Technology case with lower energy gas supply and demand.

Table 84 shows the energy gas demand by region from 2020 to 2050 for the Sensitivity Case 1. It can be seen that the overall energy gas demand reduces from 209 PJ/yr in 2020 to 168 PJ/yr, a reduction of around 20%.

Table 84: Energy gas demand by region for the Sensitivity Case 1 from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	129	122	114	102	61	77	104
North East	6	5	6	5	3	4	5
Loddon Mallee	21	19	18	16	10	12	17
Grampians Central West	19	18	17	15	9	11	15
Barwon South West	25	24	22	20	11	15	20
Gippsland	5	4	4	3	2	2	3
Goulburn Valley	5	4	4	3	2	2	3
Total (PJ/yr)	**209**	**196**	**183**	**164**	**97**	**124**	**168**

In the Sensitivity Case 1 the overall demand declines and the gas supply is supplemented by renewable biomethane and hydrogen (up to 10% by volume) as the natural gas supply from Victoria declines and with renewable ammonia from 2040. Table 85 shows the distribution of energy gas supply by type from 2020 to 2050. Total biomethane production ramps up from 1 PJ/yr in 2025 to 36 PJ/yr in 2050.

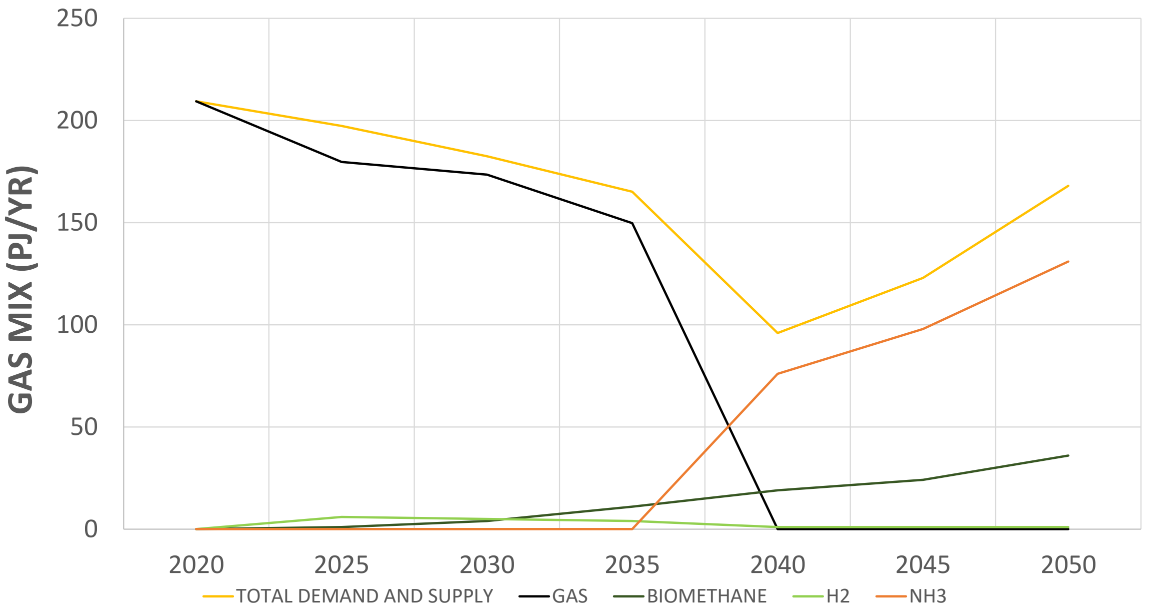
Table 85: Energy gas supply by type for the Sensitivity Case 1 from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	197	173	146	116	0	0	0
New Victorian natural gas production or imports	12	16	28	33	1	1	1
Biomethane	0	1	4	11	19	24	36
H2 (green)	0	6	5	4	1	1	1
Ammonia	0	0	0	0	76	98	131
Total (PJ/yr)	**209**	**196**	**183**	**164**	**97**	**124**	**168**

Compared with the Mid Probability Technology case the ammonia supply is reduced to 131 PJ/yr. Green hydrogen supply is relatively low ranging from 1 PJ/yr to 6 PJ/yr over the period and reduces after 2030 in order to limit the volume in the gas blend to a maximum of 10% H_2 by volume. A further opportunity that could be considered is to increase hydrogen injection into the local distribution networks as this could further reduce ammonia import requirements.

Figure 74 shows the gas mix for the Sensitivity Case 1 from 2020 to 2050.

Figure 74: Energy gas mix for the Sensitivity Case 1 from 2020 to 2050.



The consequences for the Sensitivity Case 1 are similar to the Mid Probability Technology case with the major infrastructure changes being: addition of ammonia import facilities, ammonia to hydrogen conversion facilities and modifications to the low-pressure gas distribution system to transport 100% hydrogen. The changes in the demand and supply are shown in Table 86.

In the Sensitivity Case 1, by 2050, the demand and supply situation has become more even and distributed with several regions become self-sufficient or close to it.

Table 86: Regional demand and supply for energy gas in 2020 and 2050 for the Sensitivity Case. Positive transmission rates mean gas is transmitted to the region, while negative transmission rates mean gas is transmitted from the region.

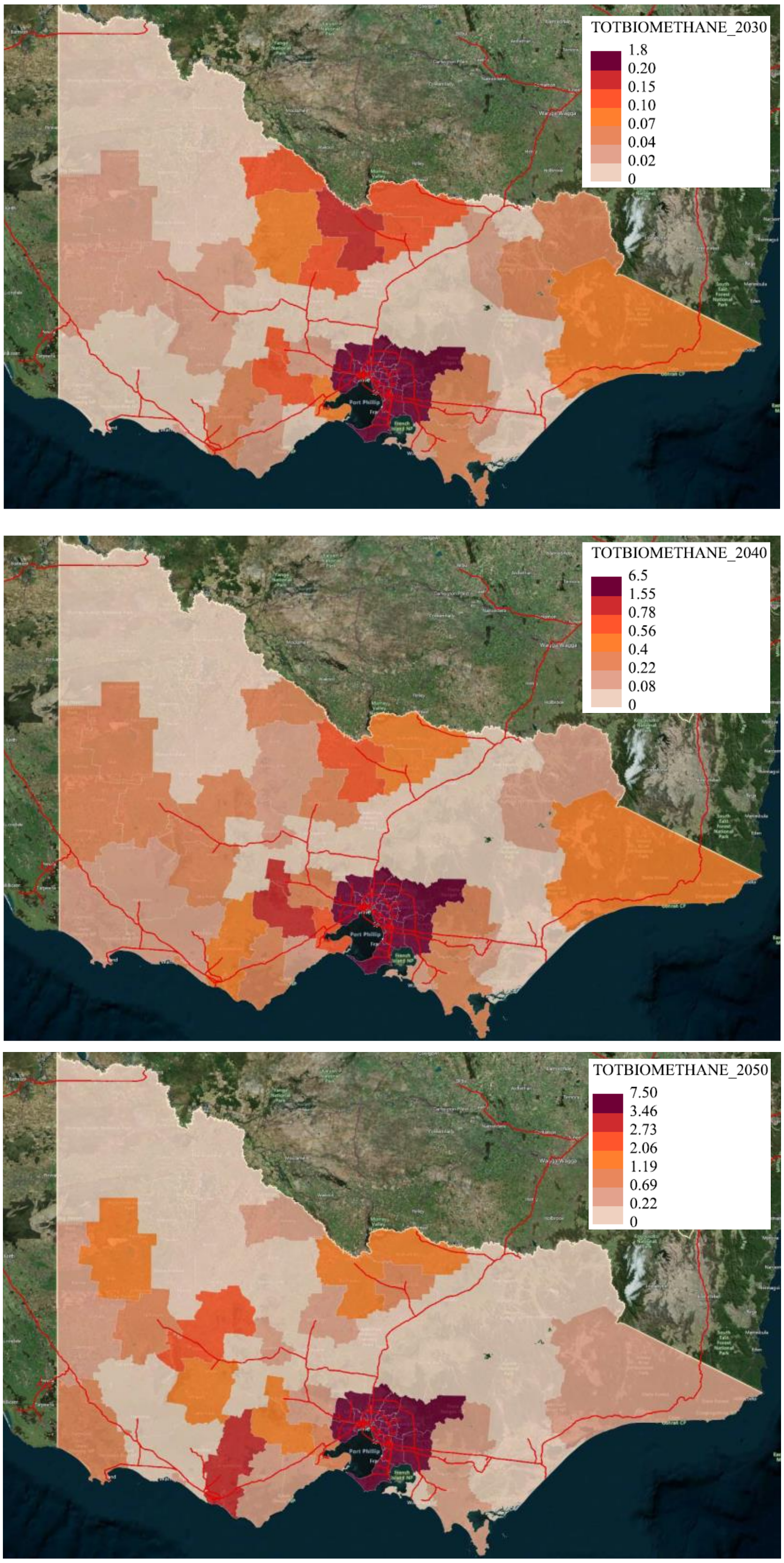
	2020			2050		
Region	**Demand**	**Supply**	**Transmitted To**	**Demand**	**Supply**	**Transmitted To**
Melbourne	129	0	129	105	140	-35
North East	6	0	6	5	1	4
Loddon Mallee	21	0	21	17	1	16
Grampians Central West	19	0	19	15	12	3
Barwon South West	25	39	-14	20	8	12
Gippsland	5	158	-153	3	2	1
Goulburn Valley	5	0	5	3	6	-3
Outside of Victoria	0	12	-12	0	0	0

Figure 75 shows the biomethane production for the Sensitivity Case 1. The main change between the High, Mid and Low Technology cases, is that biomethane demand is somewhat reduced by 2050 to 36 PJ/yr and will be supplied by biomethane from agricultural and domestic wastes in regions close to existing gas distribution networks. The use of biomass gasification to produce renewable natural gas is limited to 3 PJ/yr in 2045 and 14 PJ/yr in 2050 which is supplied predominately from the Grampians Central West and Barwon South West into existing distribution networks. The result of this combination of supply and demand means that there is not a need to produce biomethane from biomass gasification in the Loddon Mallee region which would need transmission to centres of demand. Therefore, the two pipelines proposed in the High, Mid and Low Technology Probably cases are not needed in this Sensitivity Case 1.

The location of green hydrogen generation for the Sensitivity Case 1 is shown in Figure 76. Hydrogen generation has been located close to electrical transmission infrastructure and natural gas distribution networks as well as in areas where there is significant relatively flat land available. Hydrogen production is located in Latrobe Valley, Goulburn Valley around Shepparton, around Stawell and Ararat, and in the Barwon South West in the vicinity of Warrnambool. As with the earlier cases the water demand for hydrogen production by electrolysis is less than 1 GL/yr and the exact locations for hydrogen production can be further optimised in future as there are many potential options for siting hydrogen production and injection.

The ammonia distribution would be undertaken similar to the Mid Probability Technology case and require similar investment in new infrastructure.

Figure 75: Biomethane production for Sensitivity Case 1 in (a) 2030, (b) 2040 and (c) 2050.

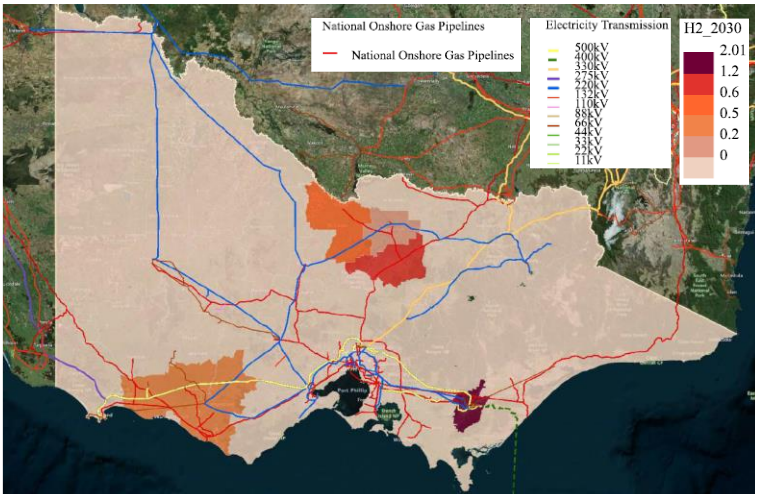


(a)

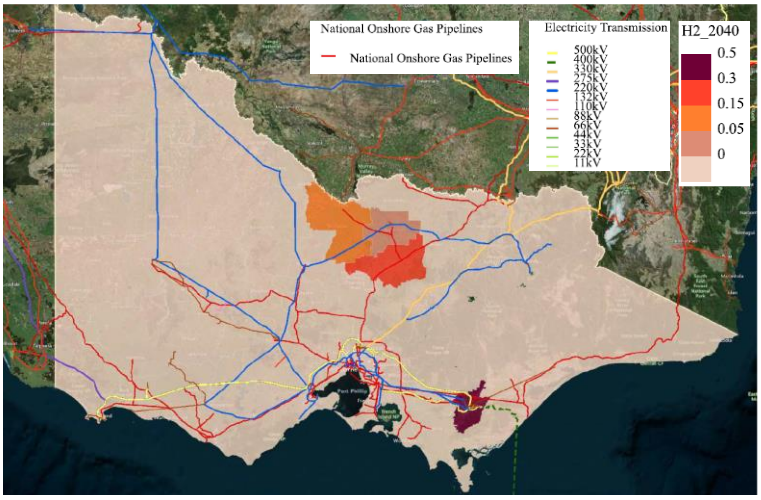
(b)

(c)

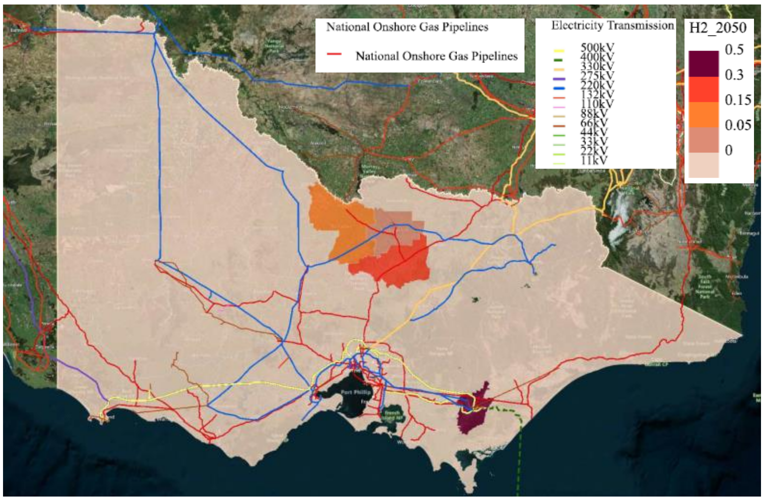
Figure 76: Hydrogen generation locations for Sensitivity Case 1 in (a) 2030, (b) 2040 and (c) 2050.



(a)



(b)



(c)

8.4.3 Discussion

- The Sensitivity Case 1 has a similar quantity of biomethane and green hydrogen in the energy mix as the Mid Probability Technology case. The main difference is lower quantity of fossil derived natural gas in the system and reduced ammonia as per the Mid case.
- Total biomethane production ramps from 1 PJ/yr in 2025 to 36 PJ/yr in 2050, with most of this being supplied from the anaerobic digestion of organics to produce biogas which is upgraded into biomethane.
- Biomethane production from anaerobic digestion ramps up to 11 PJ/yr by 2035 and 21 PJ/yr in 2050.
- Biomethane from biomass gasification is deployed commencing in 2045 in the Grampians Central West around Ararat and Bendigo. Production is increased to 14 PJ/yr by 2050 in the western parts of the state by converting wheat straw residues. This leads to a relatively good balance between supply and demand in the Grampians and Central West region, so that the gas is used locally in the population centres of Ararat and Bendigo.
- Hydrogen production is relatively modest as it has been limited to 10% volume of total energy gas demand. Hydrogen production has been located in areas with good gas distribution infrastructure and good electrical infrastructure, however the locations are indicative and further work on optimal siting is required. However, selecting different locations will not affect the overall solution.
- As with the Mid Probability Technology case, ammonia is imported into the state to supplement renewable gas from 2040. The amount of ammonia is reduced in comparison to the Mid case. The ammonia can be imported at several ports and converted back into hydrogen as per the Mid Probability Technology case. The ammonia would be utilised for power generation and for hydrogen generation for distribution in the local gas networks. Implications for ammonia import and distribution are the same as the Mid Probability Technology case.

8.4.4 Gas pipeline network changes

For the Sensitivity Case 1, the major changes in the gas transmission network can be summarised as:

- Addition of an ammonia import terminal at either Long Island Point, Crib Point or Geelong with associated facilities to store ammonia and inject it into the gas transmission network.
- Upgrading (if required) of transmission pipelines to handle ammonia. Mild carbon steel pipelines should not need upgrading; however this should be confirmed on a case by case basis in future work.
- Addition of a number of ammonia to hydrogen conversion facilities in metropolitan Melbourne. Estimates are that five to ten such facilities may be required.
- Decommissioning of the Eastern Gas Pipeline to NSW and the gas transmission pipelines between Seaspray and Longford, Longford and Morwell and Longford and Dandenong.
- Decommissioning of the Victorian Northern Interconnector (close to the border).

- Decommissioning of the pipeline infrastructure in the Barwon South West (V4) region, around Port Campbell and Warnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia.
- For the Sensitivity Case 1, the major changes in the gas distribution networks can be summarised as:
- Upgrading of gas distribution networks in Melbourne, Sunbury and Gippsland to handle 100% hydrogen by 2040.
- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland.
- Biomethane and hydrogen from the Loddon Mallee and Grampians production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat

8.5 Electrical Spatial Analysis

8.5.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

Assumptions are explained in Section 3.6.

8.5.2 Work Description

For the Sensitivity Case 1, the new electrical generation technologies are:

- Wind (onshore and offshore);
- Solar (PV and thermal solar)
- Bioenergy;
- Hydro Power;
- Fuel Cells; and
- Ammonia (NH3)

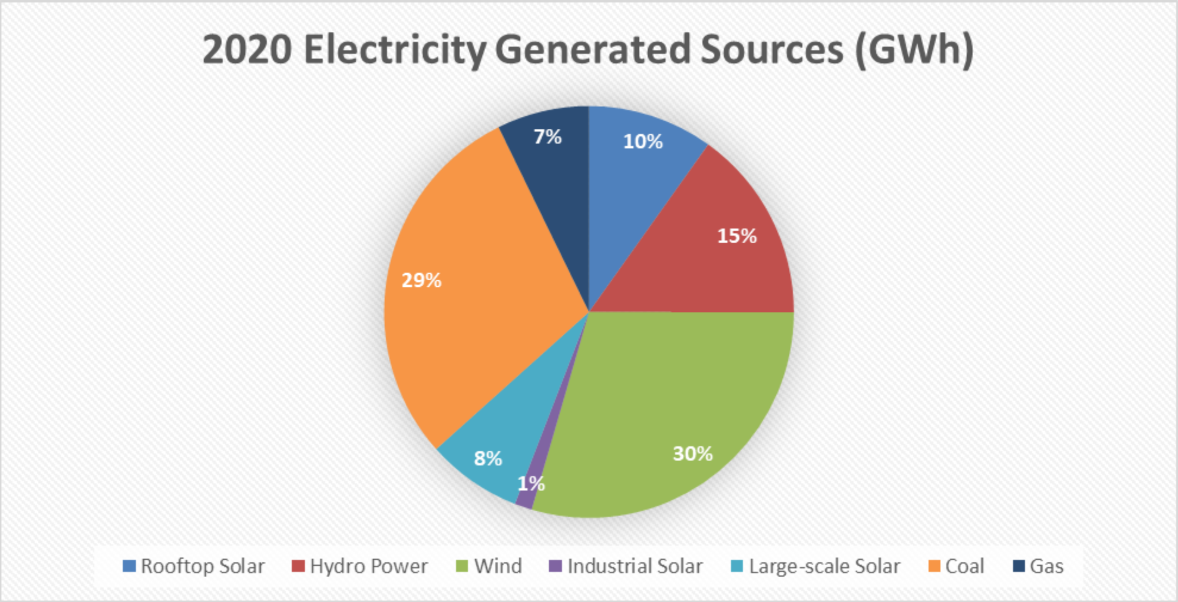
The electrical storage technologies include:

- Li-ion batteries (large-scale, industrial and behind the meter); and
- Molten salt storage associated with solar thermal generation.

- Iron-air batteries for wind and solar

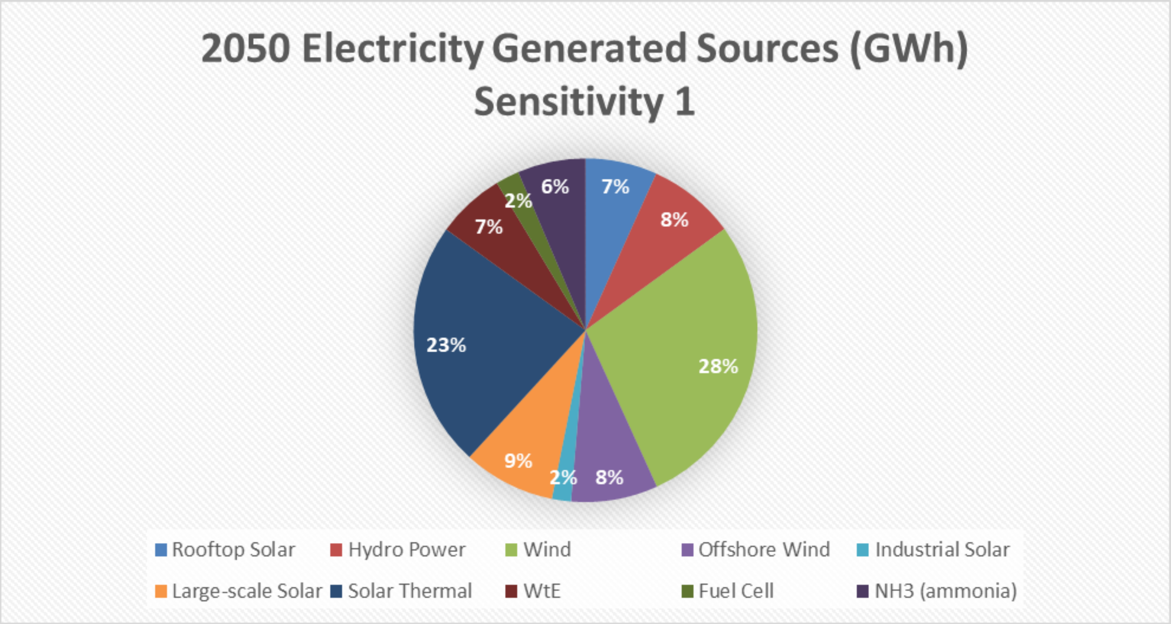
<u>REMINDER:</u> Electrical Generation infrastructure is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

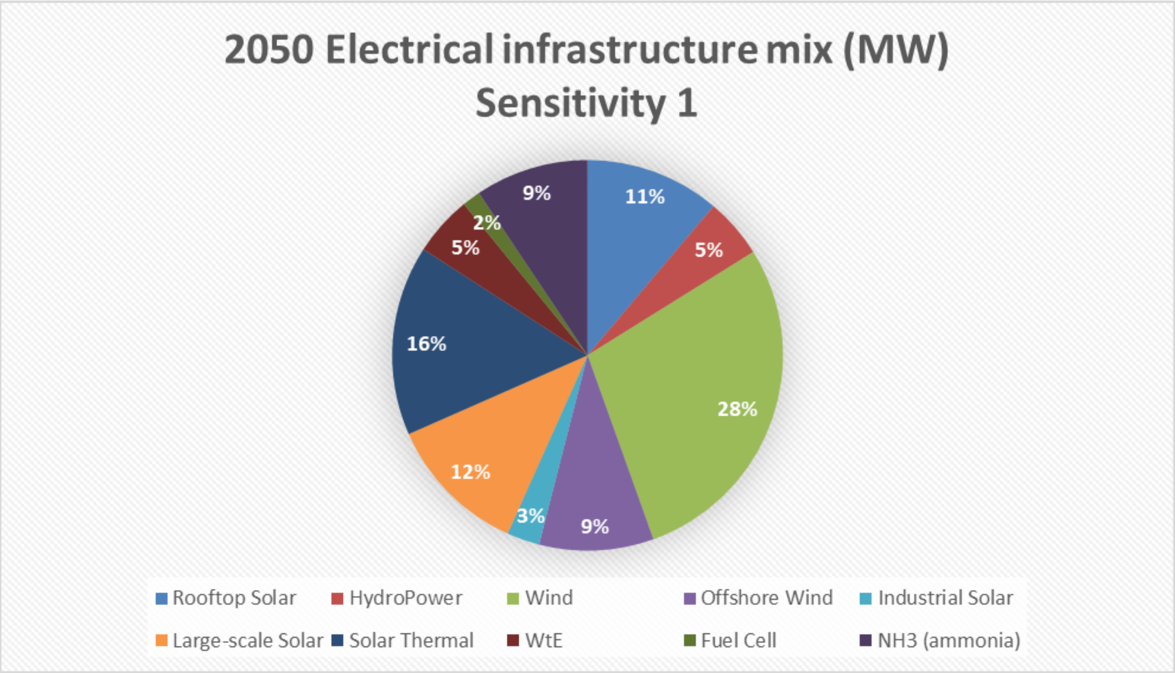
<u>Electrical Generation Mix in 2020:</u>



Electrical Mix in 2050:

(Note Reference in figures to “waste-to-energy” shall be read as “bioenergy”)





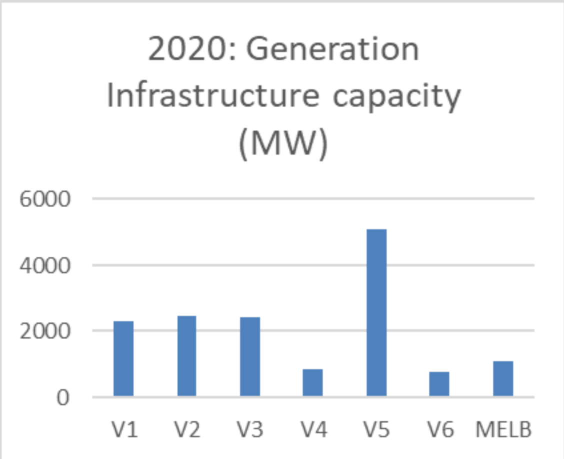
As seen in the charts above the electrical infrastructure capacity (MW) was found to increase by a factor of 3 over the 30 years (2020 to 2050), while the electrical generation (GWh or PJ) increased by a factor of 1.8. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

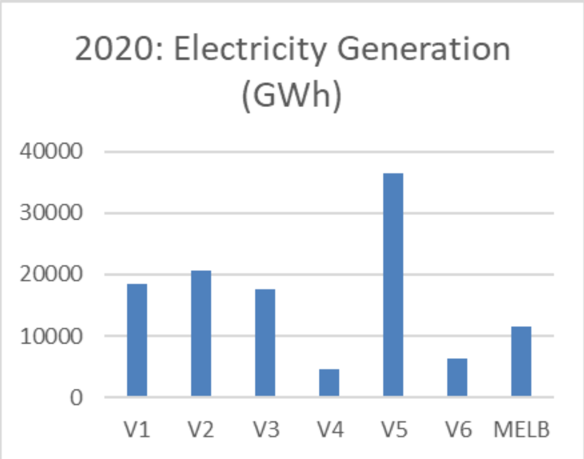
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	212 747	44 724

8.5.3 Results

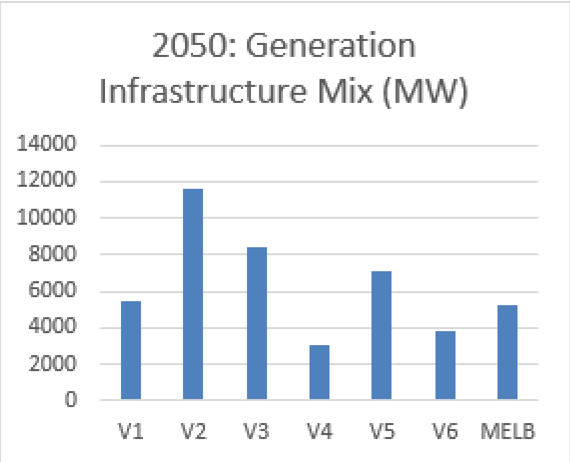
8.5.3.1 Overall Generation

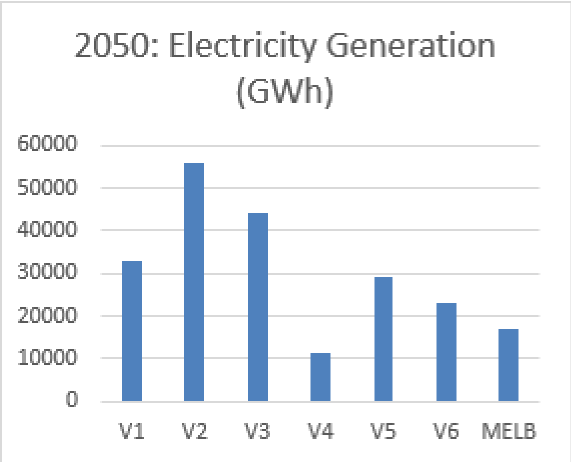
2020 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity for each REZ.
- Ovens Murray (V1), and Melbourne (MELB) have an averaged generation capacity
- South West (V4) and Central North (V6) have a low generation capacity compared to other REZs.

- Murray River (V2), Western Victoria (V3) and Gippsland (V5) have a high generation capacity.
- V5 has high capacity due to offshore wind.

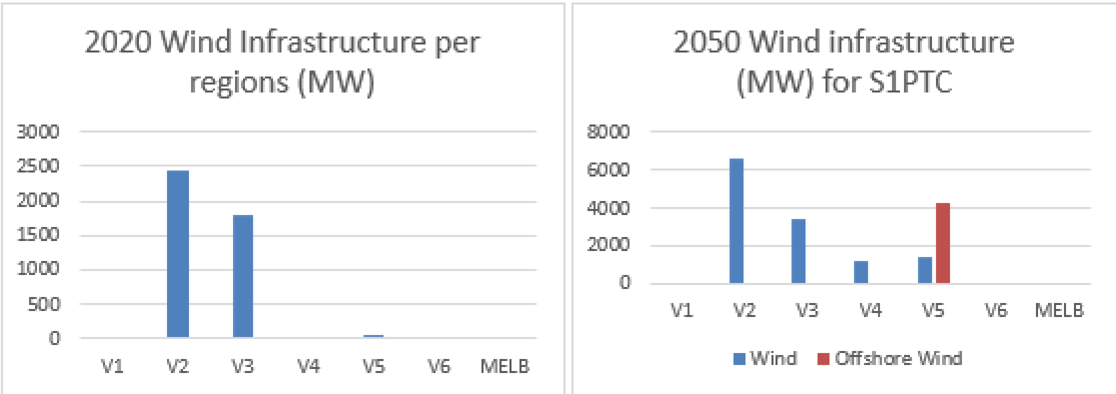
The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

REMINDER: The assumptions used here are based on the AEMO's ISP inputs and assumptions workbook which was used as "relied upon information".

The demand is located mainly in the Melbourne metropolitan region (around 60%), with approximately 10% demand in each of V2, V3 and V4 (representing the entire West side of Victoria), with the remaining 10% is split between V1, V5 and V6.

Comparing generation location and demand location, the transmission lines between all the regions and MEL and between East and West will need to be upgraded as both demand and electrical generation grows.

8.5.3.2 Wind



S1PTC: Sensitivity 1 Probability Technology Case

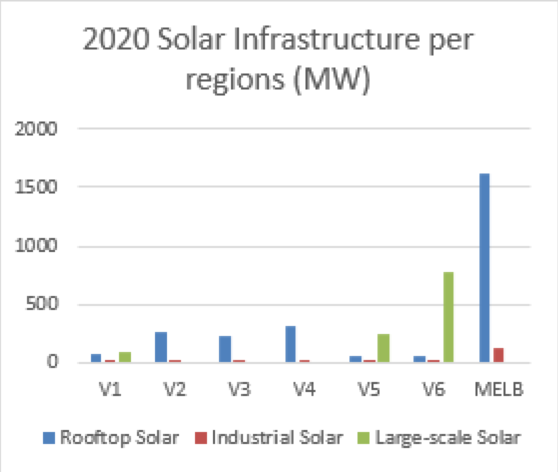
Note: All the locations of existing and committed assets for 2020 wind generation have been taken from AEMO's ISP inputs and assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

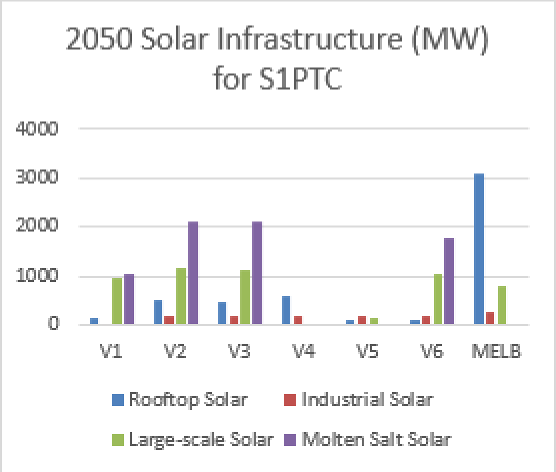
An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zones alongside the existing transmission lines. The location is based on available open land and associated wind rows.

Further work may consider wind generation infrastructures being more balanced between V2, V3 and V4. It is possible to consider V3 and V4 having much more wind as its wind potential is around 40%.

By 2050, onshore wind represents 28% of the generated electricity with 12,701 MW of infrastructure capacity and offshore wind 8% with 4,238 MW.

8.5.3.3 Solar





As for the High Probability Technology Case, solar PV will expand in all the regions in which it has a high potential: V1, V2, V3 and V6. Once again, the locations follow the transmission lines. Melbourne has a high capacity of rooftop solar PV as this region represent around 60% of Victorian households.

In 2050, Victoria is predicted to have:

- 4,993 MW of rooftop solar PV generation, representing 7% of electrical mix
- 1,211 MW of industrial solar PV generation, representing 2% of electrical mix
- 5,229 MW of large-scale solar PV generation, representing 8% of electrical mix
- 7,036 MW of solar thermal generation, representing 23% of electrical mix

The use of solar thermal is combined with molten salt storage, with the estimated storage level being 43% of the production. Molten salt storage represents an advantage for solar thermal because it is much cheaper than Li-ion batteries and stores 10 times more than the largest li-ion battery systems installed for renewable sources.

8.5.3.4 Bioenergy

By 2050, Bioenergy provides 6% of the electrical demand with 2,224 MW of installed capacity.

8.5.3.5 Infrastructure to be Installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period. The values in 2020 are the existing and committed assets, then for each subsequent period the values represent the additional generation infrastructure that has to be added for this specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3	Biomass Elec
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	10	0	0	0	0	191	0	0	0	0	0	35	0	450	30	15	0	0	0	0	0
2030	20	0	0	0	0	281	0	0	0	244	0	54	0	588	39	39	8333	0	30	347	0
2035	20	0	0	0	0	187	0	0	0	214	0	61	0	353	59	29	6250	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	357	0	61	0	118	59	88	10625	4250	48	129	0
2045	20	0	0	0	0	225	0	0	0	134	0	61	0	59	59	59	2500	3250	0	154	0
2050	0	0	0	0	0	0	0	0	0	107	0	61	0	0	59	59	2500	3000	24	0	0
	MW												GWh						MW		

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3	Biomass Elec
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	35	0	623	0	32	265	0	0	0	0	0	35	0	1375	92	50	0	0	0	0	0
2030	68	0	636	0	42	390	0	0	0	488	0	54	0	1797	120	131	16667	0	30	347	0
2035	68	0	733	0	62	234	0	0	0	428	0	61	0	1078	180	98	12500	0	0	0	0
2040	0	0	2420	0	0	0	0	0	0	713	0	61	0	359	180	294	21250	12986	48	129	0
2045	68	0	1760	0	31	281	0	0	0	268	0	61	0	180	180	196	5000	9931	0	154	0
2050	0	0	235	0	0	0	0	0	0	214	0	61	0	0	180	196	5000	9167	24	0	0
	MW												GWh						MW		

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3	Biomass Elec
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	31	0	298	0	29	258	0	0	0	0	0	35	0	1100	73	45	0	0	0	0	0
2030	61	0	304	0	38	380	0	0	0	488	0	54	0	1438	96	118	16667	0	30	347	0
2035	61	0	351	0	57	190	0	0	0	428	0	61	0	863	144	88	12500	0	0	0	0
2040	0	0	1157	0	0	0	0	0	0	713	0	61	0	288	144	265	21250	10389	48	129	0
2045	61	0	842	0	28	285	0	0	0	268	0	61	0	144	144	176	5000	7944	0	154	0
2050	0	0	374	0	0	0	0	0	0	214	0	61	0	0	144	176	5000	7333	24	0	0
	MW												GWh						MW		

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3	Biomass Elec
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	42	0	102	0	34	0	0	0	0	0	0	35	0	675	45	60	0	0	0	0	0
2030	82	0	103	0	44	0	0	0	0	0	0	54	0	882	59	157	0	0	30	347	0
2035	82	0	119	0	66	0	0	0	0	0	0	61	0	529	88	118	0	0	0	0	0
2040	0	0	394	0	0	0	0	0	0	0	0	61	0	176	88	353	0	6375	48	129	0
2045	82	0	287	0	33	0	0	0	0	0	0	61	0	88	88	235	0	4875	0	154	0
2050	0	0	191	0	0	0	0	0	0	0	0	61	0	0	88	235	0	4500	24	0	0
	MW												GWh						MW		

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	119	0	34	0	0	0	0	0	0	35	0	425	28	10	0	0	0	0
2030	14	0	122	678	44	0	0	0	0	0	0	54	0	556	37	26	0	0	30	347
2035	14	0	140	814	66	0	0	0	0	0	0	61	0	333	56	20	0	0	0	0
2040	0	0	463	1831	0	0	0	0	0	0	0	61	0	111	56	59	0	4014	48	129
2045	14	0	337	814	33	0	0	0	0	0	0	61	0	56	56	39	0	3069	0	154
2050	0	0	224	102	0	0	0	0	0	0	0	61	0	0	56	39	0	2833	24	0
	MW												GWh						MW	

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	0	0	35	233	0	0	0	0	0	23	0	1050	70	10	0	0	0	0
2030	14	0	0	0	46	343	0	0	0	406	0	36	0	1373	92	26	13889	0	20	231
2035	14	0	0	0	69	171	0	0	0	357	0	41	0	824	137	20	10417	0	0	0
2040	0	0	0	0	0	0	0	0	0	595	0	41	0	275	137	59	17708	9917	32	86
2045	14	0	0	0	34	206	0	0	0	223	0	41	0	137	137	39	4167	7583	0	103
2050	0	0	0	0	0	0	0	0	0	178	0	41	0	0	137	39	4167	7000	16	0
	MW												GWh						MW	

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	1617	0	0	0	125	0	0	982	0	0	0	0	0	0	0	0	0	0	0	0
2025	215	0	0	0	29	259	0	0	0	0	0	35	0	2425	162	310	0	0	0	0
2030	421	0	0	0	38	381	0	0	0	0	0	54	0	3170	211	810	0	0	30	347
2035	421	0	0	0	57	95	0	0	0	0	0	61	0	1902	317	608	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	61	0	634	317	1824	0	22903	48	129
2045	421	0	0	0	29	57	0	0	0	0	0	61	0	317	317	1216	0	17514	0	154
2050	0	0	0	0	0	0	0	0	0	0	0	61	0	0	317	1216	0	16167	24	0
	MW												GWh						MW	

Note Reference in table to “waste-to-energy” shall be read as “bioenergy”

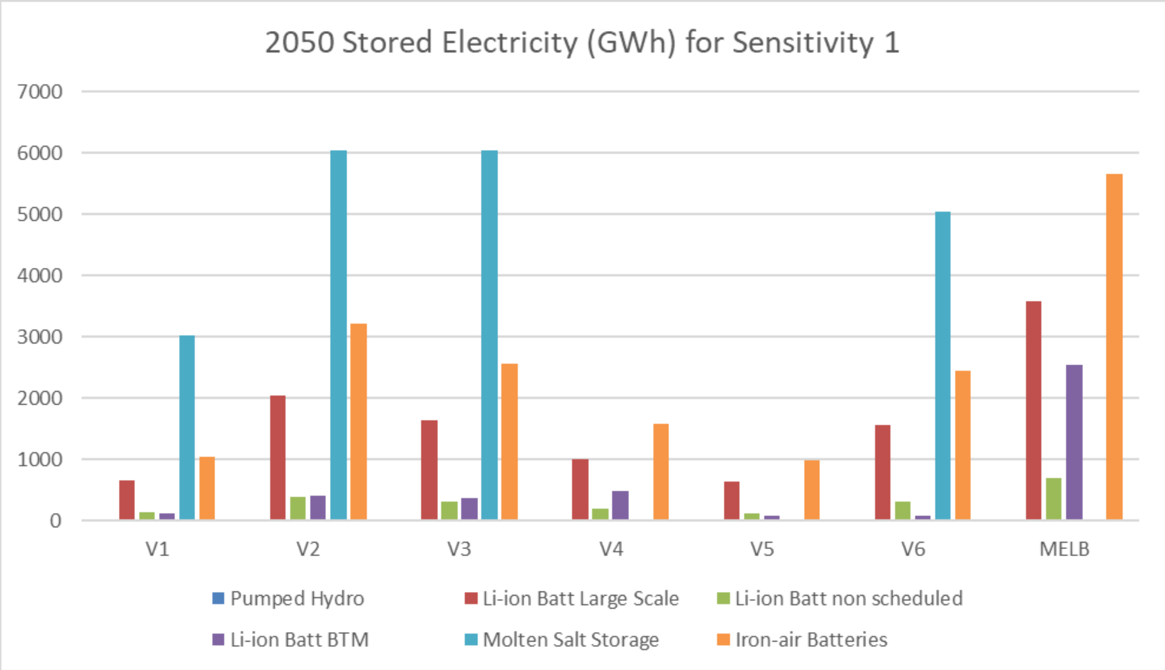
8.5.4 Discussion

Sensitivity Case 1 was observed to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (behind the meter, industrial and large scale)
  - Wind Offshore (starting 2030)
  - Solar thermal (starting 2030) + Molten Salt Storage
  - Fuel cells (starting 2030)
  - Ammonia (starting 2030)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar PV and wind represents between 75 and 80% of the electrical mix creating the potential for grid instability and requiring compensation through the addition of generation and storage facilities. Starting in 2035 all wind, solar PV and battery capacities levels are multiplied by 1.5.
- The share of wind and solar in 2050 is 41% solar PV (excluding behind the meter) and 59% wind.
- New transmission lines are needed as the grid will have to support a lot more electricity. Upgrade are considered likely for the following lines (same as High Probability Technology Case)
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers, representing approximately 25% more infrastructure than exists today.
- All the connections between the facilities and the grid have been taken into account in the cost analysis, but not shown on the maps.
- The storage is calculated depending on the quantity of solar and wind.



8.6 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

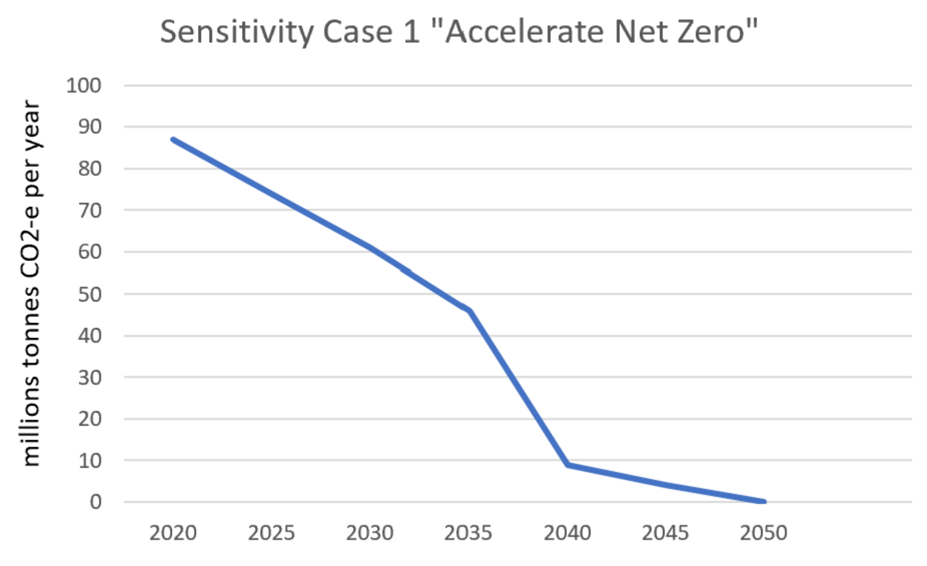
8.7 Environmental & Social Analysis

The environmental and social components of the Sensitivity Case 1 “Accelerated Net Zero” have been assessed via a desk-top study using key aspects from environmental and social perspectives and presented in Table 51.

8.7.1 Results

In the Accelerate Net Zero Sensitivity Case, the base technologies in the high probability technology case, the ammonia and solar thermal technologies in the mid and low probability technology cases are all brought forward accelerate emissions reduction post 2040 and achieve the net zero emissions goal earlier. Figure 77 shows the modelled emissions reduction profile for the accelerate net zero sensitivity. It shows a similar but more pronounced reduction in emissions from the covered sectors between 2035 and 2040 as the mid probability technology case and similarly to the low probability technology case delivers net zero emissions several years before 2050.

Figure 77 : Emissions Reduction Profile – Sensitivity Case 1 "Accelerated Net Zero"



The accelerated net zero scenario does not represent any additional environmental and social risks not addressed in the three reference cases. As the timing is brought forward, the formal assessment processes will also need to be accelerated. For example, the role of solar thermal between 2025 and 2030 requires detailed planning and strategic level environmental assessments to commence within the next few years.

As a consequence of the early and diverse use of low emissions technologies, greenhouse gas offsets and geo-sequestration are not required to achieve net zero emissions by 2050.

The environmental and social implications around implementation of this scenario are summarised in Section 4.6.

8.7.2 Discussion

Relative to the high probability technology case this case makes greater use of ammonia, both to generate electricity and as a source of hydrogen for distribution in the gas networks, and solar thermal generation technology with integrated molten salt storage. The roll out of these technologies occurs earlier than in the base references' cases. Compared to the high probability technology case, this results in a reduction in the use of solar PV and wind energy generation and corresponding battery backup.

The proposed Sensitivity Case 1 "Accelerated Net Zero" has the following environmental and social considerations:

- Key investments to achieve the net zero emissions target include:
  - Compared to 2020; six times more solar PV, three and one half times as much wind capacity, and approximately 100 times more battery storage.
  - The roll out of solar thermal capacity and associated molten salt storage. In 2050 the amount of energy supplied by solar thermal is substantially greater

than solar PV (130%) or wind (120%) – most of the solar thermal capacity is deployed by before 2040.
  - A modest amount of electrical generation from ammonia
  - The import of significant volumes of ammonia and the construction of new pipelines to transport the imported ammonia to the Melbourne gas distribution grid and the Latrobe Valley.
  - Investment in bioenergy, hydrogen and ammonia production.
  - Strengthening the electricity grid.

The accelerated net zero sensitivity does not result in any environmental and social impacts in addition to those identified in the three technology probability cases. Implementation of the sensitivity will require the formal planning and environmental impact assessments to be brought forward. For some technologies, for example solar thermal this work may need to commence withing the next few years.

- The accelerated net zero sensitivity offers the highest opportunity for employment of all the cases considered in this study. This is driven by employment opportunities to operate the ammonia fired (32%) and solar thermal (32%) electrical generation. Other main employment contributors are:
  - Energy efficiency (9%)
  - Wind (7.5%)
  - Rooftop solar PV (5.7%)
  - Battery storage (4.6%)
- An approximately 50% reduction in fossil energy sources (from 2020 consumption figures) occurs within 15 years for both coal and gasoline and diesel vehicles. A 100% reduction is achieved by 2040 for coal and 2050 for gasoline and diesel vehicles. This will have significant benefit to environmental quality and population health as the amount of noxious pollutants and airborne toxins, such as of volatile organic compounds and carbon monoxide from vehicular emissions and mercury, lead, sulphur dioxide, nitrogen oxides and particulates from coal, are reduced.
- The reduction in usage of transportable energy sources (for example coal, natural gas, gasoline and diesel) not only reduce the emissions profile of the state, but also contribute to a larger reduction in emissions outside the scope of this report through reducing the emissions outputs from transporting these commodities (e.g., trucking gasoline and diesel, transport of coal from source to point of energy generation).
- The construction of two new pipelines to meet proposed increases in biomethane production (150 km and 210 km in length) will result in the potential impact to environmentally sensitive terrestrial areas. There is the possibility that these construction projects may traverse national parks, wildlife management areas, rivers or wetlands. There may be opportunities to reduce the clearing required for these energy production methods if existing infrastructure corridors, such as transmission lines, are used.
- Along with these upgrades to existing gas pipelines, infrastructure will be required to enable compatibility with the use of green ammonia and green hydrogen.
- Land use impacts (environmental and socio-economic) are to be expected through the steady uptake of solar (PV and Thermal) given there is less opportunity for solar projects to share land with agricultural uses. However, land impacts from utility-scale

solar systems can be minimized by siting them at lower-quality locations such as brownfields, abandoned mining land, or existing transportation and transmission corridors.

- The uptake of thermal solar and reduction in solar PV (when compared with the high and mid probability technology cases) will put less pressure on the availability of batteries and storage (and products required for battery production). In addition, thermal solar requires less area for operation, therefore the environmental footprint and potential associated impacts are reduced.
- Uptake of onshore wind power generation may result in impacts to sensitive environments (such as habitat loss, noise etc.) depending on the locations and methods for construction. There may also be a reduction in visual amenity for locations where wind farm infrastructure is developed.
- Land use impacts may be minimised for onshore wind generation through opportunities for utilising existing agricultural land for wind infrastructure.
- The uptake of offshore wind power generation may result in impacts to sensitive marine environments (such has electromagnetic radiation, underwater noise, bird strikes, loss of visual amenity etc.) depending on the locations and methods of construction. Stand-alone environmental impact assessments will need to be undertaken for the marine and coastal environmental developments in accordance with the regulatory framework at the time.
- Given the requirement for construction and land-clearing, there may be the potential for cultural heritage risks or impacts. These will need to be further analysed on a case-by-case assessment during planning phases and should include community and stakeholder consultation.
- Construction works associated with new energy technologies (namely green hydrogen, green ammonia, biogas, wind, bioenergy, solar thermal and solar PV) may also increase the risk of environmental impacts (such as spills, fires etc.).
- As less commercial scale tested energy technology is utilised in this case, any potential hazardous waste streams are less known and understood.
- Unlike the high probability technology case, it is proposed that coal fired power stations are converted to ammonia and continue operation in 2050 and beyond. This reduces the impact on local employment impacts in the Latrobe Valley (assuming works can be re-tasked into this new energy technology sectors) and reduces the environmental impact and footprint of the new energy technology by utilising current coal infrastructure and land use.

8.8 Cost Analysis

8.8.1 Key References & Assumptions

Refer to Section 3.8.5.

8.8.2 Work Description

Refer to Section 3.8 for details of the work description.

8.8.3 Results

The figure below present the net difference between the Sensitivity Case 1 “Accelerated Net Zero” and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Figure 78 demonstrates that:

- The Sensitivity Case 1 “Accelerated Net Zero” projects a material increase in fuel, FOM and VOM costs as a result of the increase in fuel cost for the expanded development and sharing of new variable renewable electricity resources in particular green hydrogen / ammonia, providing a net annualised cost increase of approximately $4.5 billion in 2050.
- The Sensitivity Case 1 “Accelerated Net Zero” projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $8.5 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the Sensitivity Case 1 “Accelerated Net Zero” is represented by the purple line in Figure 78. By 2050, the Sensitivity Case 1 “Accelerated Net Zero” is forecast to provide a net cost increase of around $12.5 billion by 2050.

For the Sensitivity Case 1 “Accelerated Net Zero”, the net costs show a gradual negative trend until 2040 where coal fired generation is retired and the introduction of new generation increasing annual CAPEX and fuel costs to meet the energy demand which returns a net cost increase.

Figure 78: Net Costs of the Control Scenario relative to the Sensitivity Case 1 “Accelerated Net Zero”

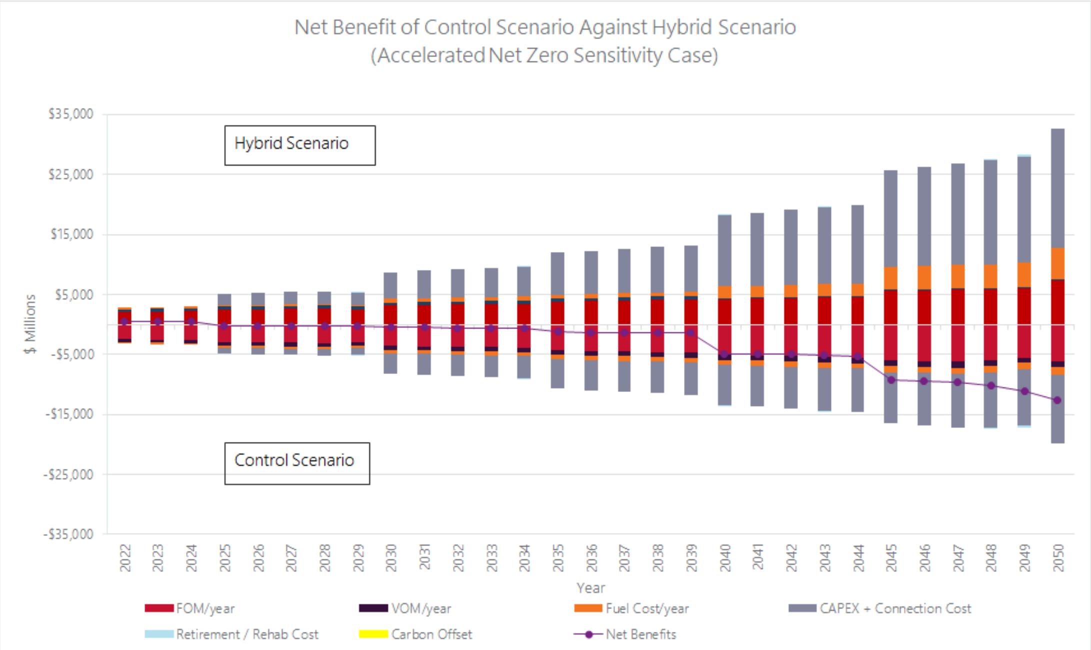


Table 87 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Sensitivity Case 1 "Accelerated Net Zero", in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the Sensitivity Case 1 "Accelerated Net Zero", discounted back to present value, is $11.4 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$5.3 billion (NPC).

The estimated cost of CO_2 abatement is $132/te CO_2.

Table 87: Net Costs of the Control Scenario relative to the Sensitivity Case 1 "Accelerated Net Zero"

Cost Category[2]	Net Cost of Control Against Technology Case (Accelerated Net Zero Sensitivity)		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$5,624	-$2,873
FOM	$2,475	$2,996	-$521
VOM	$435	$292	$143
Fuel	$419	$2,435	-$2,016
Retirement / Rehab	$48	$61	-$13
Agro-forestry (Land Area, Hectare)	$0	$0	$0
Gross Cost	$6,127	$11,408	-$5,280
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement t[3] ($/tonne)	583	132	451

Notes:

1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

8.8.4 Discussion

The increased CAPEX combined with the overall energy mix for the Sensitivity Case 1 “Accelerated Net Zero” compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity.

OPEX and fuel costs increase for the Sensitivity Case 1 “Accelerated Net Zero” compared to the Control Scenario are also expected due to the replacement of coal fired generation with green hydrogen / ammonia and expanded development and sharing of new variable renewable electricity resources.

Retirement costs increase in the Sensitivity Case 1 “Accelerated Net Zero” as the existing coal fired generation is retired early by 2040 plus decommissioning of gas transmission and distribution lines. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Sensitivity Case 1 “Accelerated Net Zero” cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

8.9 Risk & Opportunity Analysis

8.9.1 Key References & Assumptions

Four Sensitivity Cases were developed based on one of the three Base Analysis Cases previously described in this report. The modifications to the key assumptions are summarised in Table 88.

Table 88: Sensitivity Modifications to Key Assumptions

Sensitivity Case No.	Description	Reference Case	Modifications to Key Assumptions
1	Accelerated Net Zero	Mid Technical Probability	Include offshore wind from 2030 and solar thermal from 2030

8.9.2 Work Description

The Accelerated Net Zero sensitivity case introduces the following emerging technologies which were not considered in the Mid Technical Probability case, as described below.

- Large scale offshore wind projects;
- Industrial scale concentrated solar thermal projects incorporating thermal energy storage and steam turbines for power generation;

The study team reviewed the risks and opportunities identified in the Mid and Low Probability Technology Cases and assessed the key additional risks and opportunities unique to Sensitivity Case 1 “Accelerated Net Zero”, focussing on the implementation risks rather than the inherent risks. Implementation risks are those risks that relate to the successful uptake of the selected technologies within the stated timeframes, whereas inherent risks ae those associated with the technology once implemented.

8.9.3 Results

Sensitivity Case 1 “Accelerated Net Zero” is essentially a combination of the Mid and Low Probability Technology Cases and is susceptible to the technology risks within those cases. The key risks involve the failure of any of the key technologies to become commercially competitive at large scale within the indicated timeframes.

- Green hydrogen, initial incremental cost reduction breakthrough by 2025;
- Offshore wind projects by 2030;
- Industrial scale solar thermal projects by 2030;
- Hydrogen fuel cells become cost competitive with standard batteries by 2030;
- Green ammonia supply by 2040;
- Iron-air battery by 2040.

Carbon offsets are not required to achieve net zero in this Sensitivity 1 case, however opportunity exists to achieve negative net emissions.

8.9.4 Discussion

While it is likely that one or more of these technologies may not become technically proven and commercially competitive within the timeframes assumed in this sensitivity case, the accelerated net zero outcome does not rely on these technologies alone, nor the assumed timings. Therefore, the opportunity remains to accelerate using other combinations of technologies and implementation dates as such technologies are commercialised. Some examples of other technologies include novel battery technologies, compressed air storage, ammonia fuel cells, and direct solar-to-hydrogen (photo electrocatalysis).

To provide the greatest chance of accelerating net zero, a flexible stance should be taken to allow the energy system to pivot as new technologies are developed. Long duration grid scale energy storage technologies which will allow a greater share of variable renewable electricity into the energy mix will be critical in this regard.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

9 SENSITIVITY CASE 2 "REDUCED AMMONIA"

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

9.1 Objective

The objective of running Sensitivity Case 2 was to calibrate Ammonia demand to identified supply prospects e.g., Western Green Energy Hub (WA).

9.2 Case Description

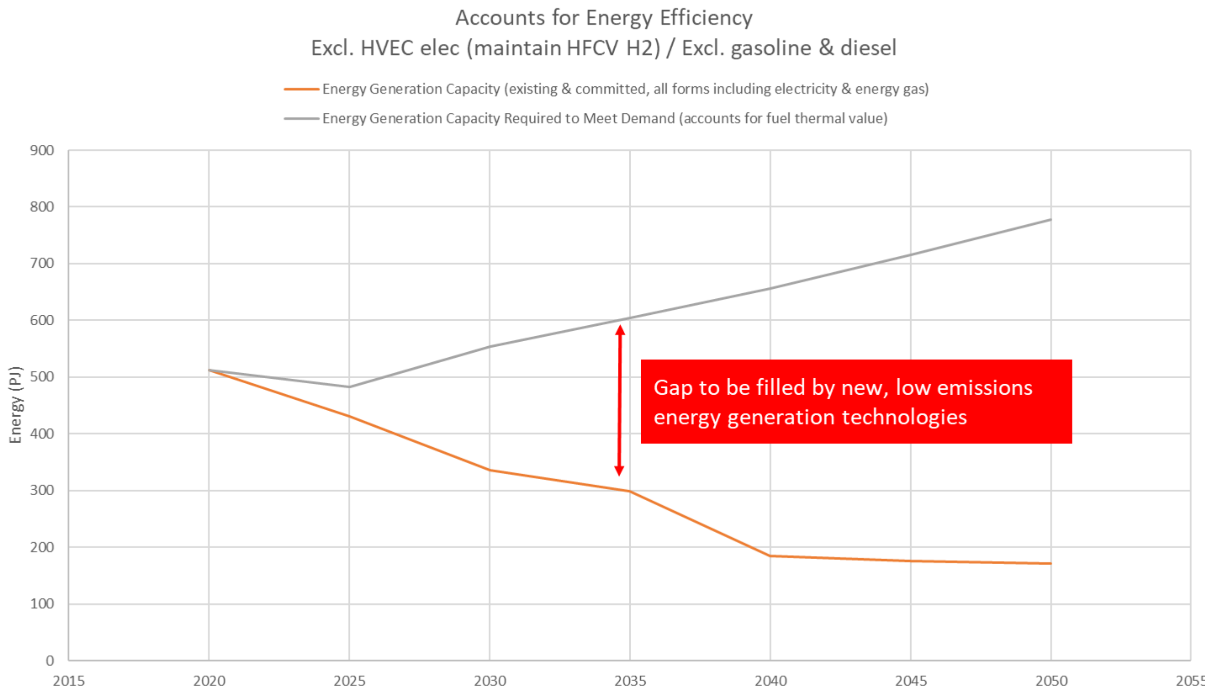
The Mid Probability Technology Case was used as the basis for Sensitivity Case 2, with green Ammonia demand reduced by approximately 20% in 2050 for "Ammonia to Power", and over 50% Ammonia energy gas. In contrast to the Mid Probability Technology case, Sensitivity Case 2 maintains natural gas through to 2050.

To offset the reduced Ammonia levels, the energy mean demand was met by increasing the supply of energy from the following technologies :

- (Electricity) Onshore Wind
- (Electricity Storage) Batteries
- (Gas) LNG Import
- (Gas) VNI Interconnector

Figure 79: Forecast Energy Demand vs Generation Capacity (Sensitivity Case 2)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))



The energy generation capacity required to meet forecast demand (grey line in Figure 79) is:

- Limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles
- Determined by subtracting the fossil fuel thermal value from the overall energy demand.

As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

To accommodate the new energy technologies identified for Sensitivity Case 2, modifications were made to the existing & committed energy generation capacity scheduled by AEMO (Table 89) and the fossil fuel decline profile assumed for the prior Net Zero Emission Scenario Analysis Study Report May 2021 (see Table 14 Section 3.2). The modifications closely match those made for the Mid Probability Technology Case.

The energy technology breakthroughs identified for Sensitivity Case 2 are as per the Mid Probability Technology Case, with descriptions provided in Section 6.

Table 89: Existing & Committed Energy Production Capacity Assumed for Supplying Demand Sensitivity 2)

ELECTRICITY	2020		2030		2040		2050	
	Total Capacity		Total Capacity		Total Capacity		Total Capacity	
	MW	PJ	MW	PJ	MW	PJ	MW	PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	3,325	85
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
Elec (storage) - "behind the meter" non-aggregated small scale batteries (dis-connected from grid)	94	1	551	3	1,527	10	2,034	13
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**24,993**	**171**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	0	71	0
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	0	1,100	0
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to balance demand)	170	12	170	12	170	0	170	0
Gas (import) - EGP (Eastern gas Pipeline) (to balance demand)	350	0	350	0	350	0	350	0
	1,360	**319**	**1,993**	**153**	**1,782**	**0**	**1,691**	**0**

9.3 Energy Emissions Offsets

9.3.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6, and also Section 6.2.1.

9.3.2 Results & Discussion

In Sensitivity Case 2, net zero emissions was achieved in 2050 through a combination of utilising low emissions energy technologies and carbon offsets. No Carbon sequestration was required.

Table 90: Mean Demand Energy Mix for Sensitivity Case 2

	2020	2025	2030	2035	2040	2045	2050
	Impact of Energy Efficiency on Energy Generation Capacity (PJ)						
Energy Required to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Required to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	585	650	693	738	793	850
	Cumulative Energy Demand accounting for Energy Efficiency (PJ)						
Elec (generation) - coal	144	116	89	66	0	0	0
Elec (generation) - natural gas (baseload + peaking)	5	5	4	4	0	0	0
Elec (generation) - NH3	0	0	0	0	88	88	89
Elec (generation) - hydropower	10	10	10	10	10	9	9
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	47	115	145	159	160	168
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	28	58	89	104	112	118	132
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	31	34	43
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	2	3	3	3	3
Elec (storage) - batteries (incl. standard + VPP + BTM + iron-air)	1	15	65	91	125	128	148
Gas (generation) - natural gas (all sources)	209	189	171	147	22	22	22
Gas (generation) - biomethane [distribution system)	0	1	4	11	20	24	36
Gas (generation) - H2 (green) [incl HFCV fuel]	0	18	29	29	30	31	36
Gas (generation) - NH3 (green) [industrial use + conversion to H2 for distributiuon eg res	0	0	0	0	68	84	109
Vehicles - (ICE) gasoline & diesel	318	266	214	155	97	42	0
Vehicles - (BEV) electricity	0	10	19	35	51	51	58
Vehicles - (HFCV) electricity [GENERATION]	0	21	41	43	46	49	60
TOTAL ENERGY (PJ)	**732**	**759**	**867**	**866**	**862**	**844**	**914**

Table 90 reveals that:

- From 2020 to 2035, Sensitivity 2 has the same energy-emissions-offset profile as the Mid Probability Technology Case.
- In 2040, as per the Mid Probability Technology case, technology breakthroughs and subsequent introduction of green Ammonia and Iron-air batteries, electricity from solar thermal occur. However, Sensitivity Case 2 differs from the Mid Probability Case with a lower uptake rate of Ammonia both in gaseous form and also conversion to electricity. Solar PV represents the single biggest energy source at approximately 160 PJ-electricity or approximately 20% of the total. Storage* is in second position with approximately 125 PJ-electricity or approximately 15% of the total. Third position is occupied by wind with approximately 110 PJ-electricity representing just under 15% of the total. This differentiates from the Mid Probability Technology case where electricity from green Ammonia occupied second position.

- In 2050, solar PV again represents the single biggest energy source at approximately 170 PJ-electricity or approximately 20% of the total. Storage* is in second position with approximately 150 PJ-electricity representing approximately 15% of the total. Wind is in third position with approximately 130 PJ-electricity or approximately 15% of the total. This differentiates from the Mid Probability Technology case where green Ammonia gas occupied second position.

  *For Sensitivity 2, storage includes both Iron-air batteries and current technology batteries. The Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).

Also noteworthy from Table 90 is the increased diversity of energy sources resulting from the transition:

- From 2020 to 2035 Sensitivity Case 2 has the same level of energy mix diversity as the Mid Probability Technology Case.
- In 2040 the top three (solar PV, storage* and wind) represent approximately 45% of the total, representing a more diverse energy mix than the Mid Probability Technology case; and
- In 2050 the top three (solar PV, storage* and wind) represent approximately 50% of the total, once again representing a more diverse energy mix than the Mid Probability Technology case.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity). Figure 80 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In all years, Sensitivity 2 has a similar proportion of electricity and energy gas to the Mid Probability Technology case.

Figure 80: Energy Mix Breakdown for Sensitivity Case 2 Covering only Electricity & Energy Gas

(excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

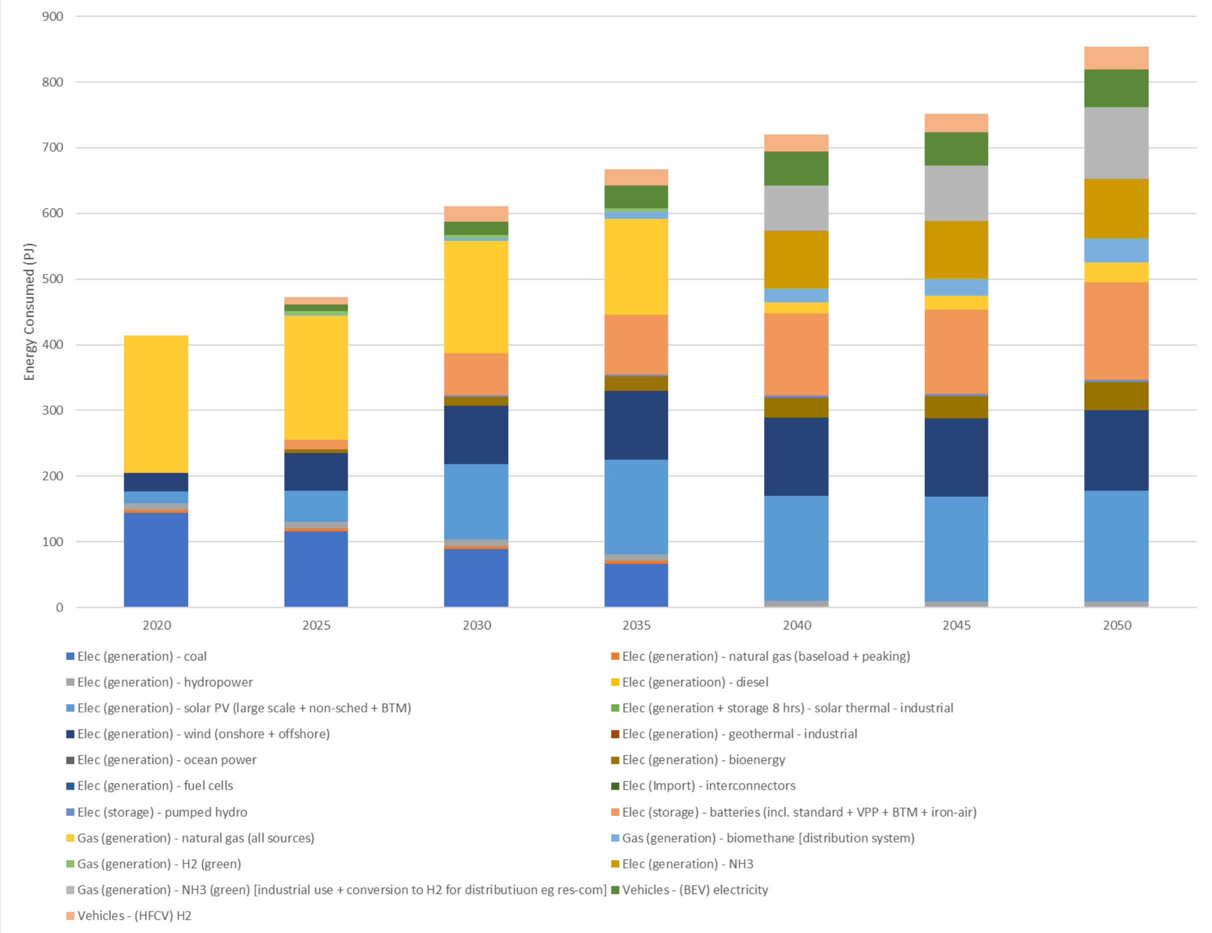


Table 91 and Figure 81 illustrate that Sensitivity 2 has a similar emissions decline profile to the Mid Probability Technology case, with a sharp decline occurring in 2040 due to the introduction of Ammonia and Iron-air batteries resulting in stoppage of both natural gas and coal.

Sensitivity Case 2 has a slightly higher uptake of bioenergy compared to the Mid Probability Technology case. Bioenergy is noteworthy as the only technology with a negative emissions contribution (based on avoided emissions from agriculture and waste – refer ESE Methodology, Section 3.9.5), providing a dis-proportionately large contribution to reducing emissions. In 2050, despite its limited share of the energy mix (approximately 45 PJ-electricity or approximately 5%, set by supply chain constraints), it contributes approximately negative 10 Million Te CO_2-e emissions leading to approximately 70% of the reduction of emissions to net zero, with the remainder (approximately 30%) provided by Carbon offsets.

On the contrary, as per the Mid Probability Technology case, coal represents a dis-proportionately large contribution to reducing emissions. In 2020, with approximately 145 PJ-elec or approximately 20% of the energy mix, coal contributes approximately 45 Million Te CO_2-e emissions (approximately 50% of total). Sitting between bioenergy and coal are:

- Gasoline & diesel (ICE vehicles). In 2020, as per the High Probability Technology case, these fuels represent approximately 320 PJ-thermal consumed (approximately 45% of the total) and contribute approximately 20 Million Te CO_2-e emissions (approximately 25% of the total).
- Natural gas. In 2020, as per the Mid Probability Technology case, it represents approximately 210 PJ-thermal consumed (approximately 30% of the total) and contributes approximately 20 Million Te CO_2-e emissions (approximately 20% of the total). In contrast to the Mid Probability Technology case, Sensitivity Case 2 maintains natural gas through to 2050.
- Low emissions electricity excluding bioenergy, but including electricity from Ammonia, hydroelectric, solar PV, wind, pumped hydro, Iron-air batteries and other storage*. In 2020, as per the Mid Probability Technology case, these low emissions technologies represent approximately 60 PJ-electricity consumption (almost 10% of the total), but contribute only 1 Million Te CO_2-e emissions (approximately 1% of the total positive emissions). In 2050 they provide approximately 670 PJ-electricity consumption – including electricity to charge BEVs and generate green Hydrogen for HFCVs - (approximately 75% of the total) but contribute only approximately 10 Million Te CO_2-e emissions (approximately 80% of all positive emissions).
  *For Sensitivity 2, storage includes both Iron-air batteries and current technology batteries. The Iron-air batteries are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).
- Low emissions energy gases including biomethane, Hydrogen (green) and Ammonia (green). In 2050 they provide approximately 180 PJ-thermal energy – including fuel for HFCVs - (approximately 20% of the total) but have no emissions.

Table 91: Emissions for Sensitivity Case 2

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	36	28	21	0	0	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - NH3	0	0	0	0	3	3	3
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	2	2	2	2
Elec (generation + storage 8 hrs) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	1	2	3	4	4	4	4
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-7	-8	-10
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - batteries (incl. standard + VPP + BTM + iron-air)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	17	15	13	2	2	3
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Gas (generation) - NH3 (green) [industrial = NH3 / res-com = convert to H2]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	18	15	10	7	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**61**	**46**	**11**	**7**	**3**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**-1**	**-1**	**-2**	**-2**	**-3**
NET EMISSIONS	**87**	**73**	**60**	**45**	**9**	**5**	**0**

Figure 81: Emissions Profile for Sensitivity Case 2

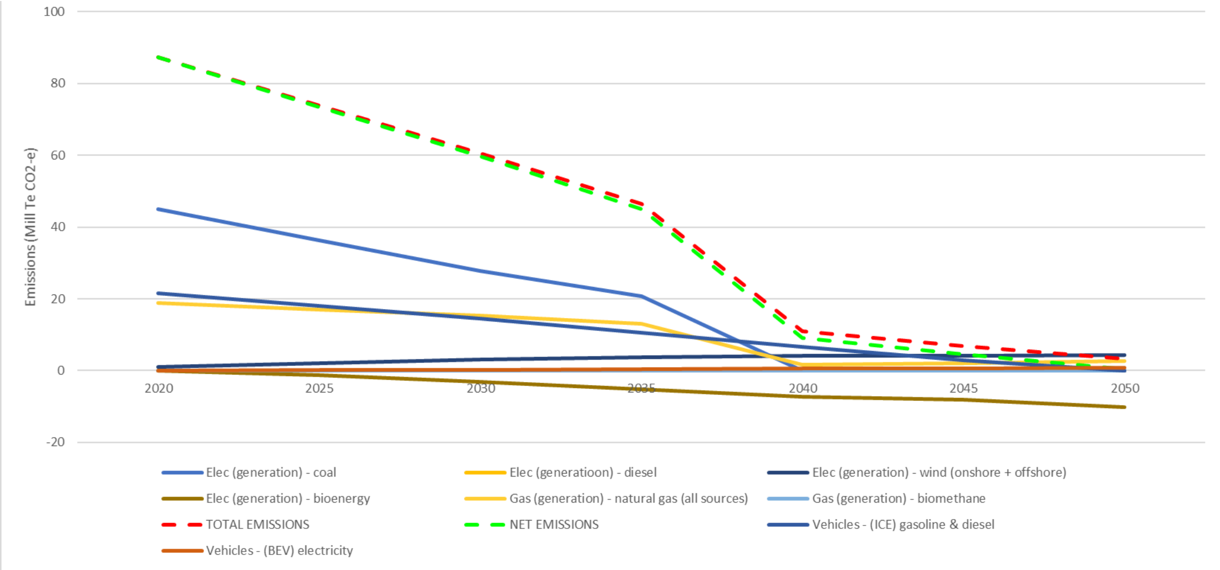


Table 5 in Section 1.6.4 documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for Sensitivity Case 2 is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be :

- 2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and
- 2030 interim emissions target: up to 9 Million Te CO_2-e to cover out of scope emissions.

Figure 82: Contribution to Emissions by Source for Sensitivity Case 2

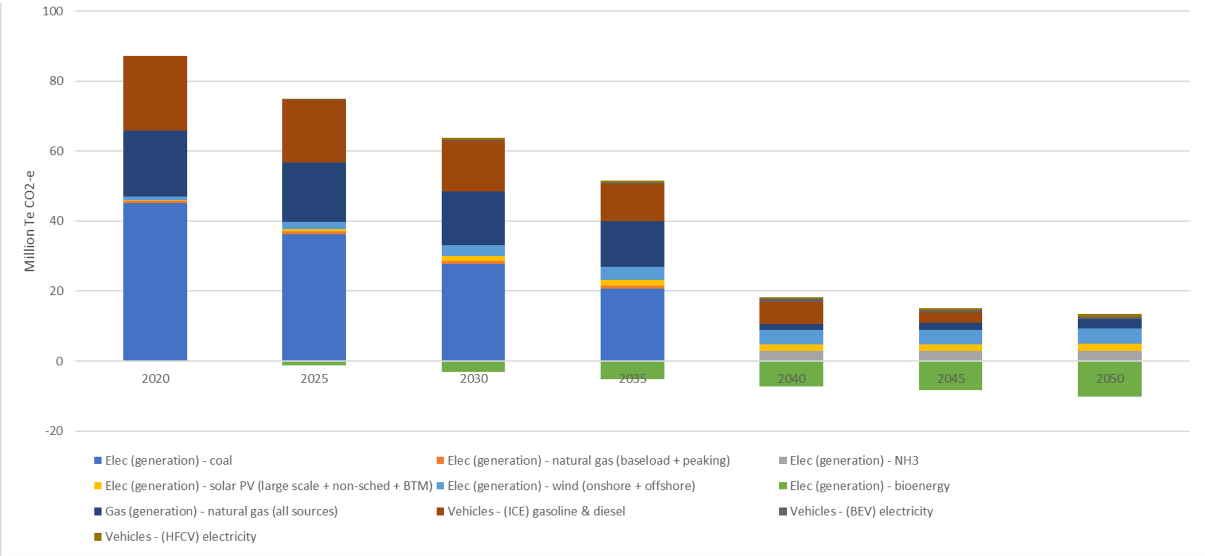


Figure 83: Agro-Forestry Offsets Utilised to Reach Net Zero Emissions for Sensitivity Case 2

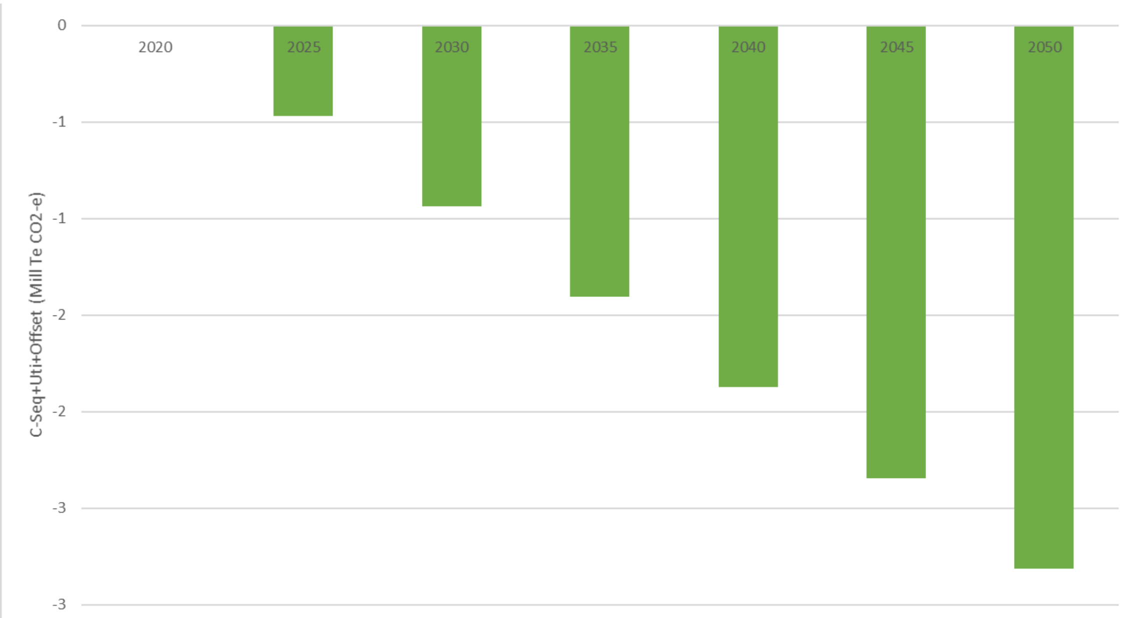
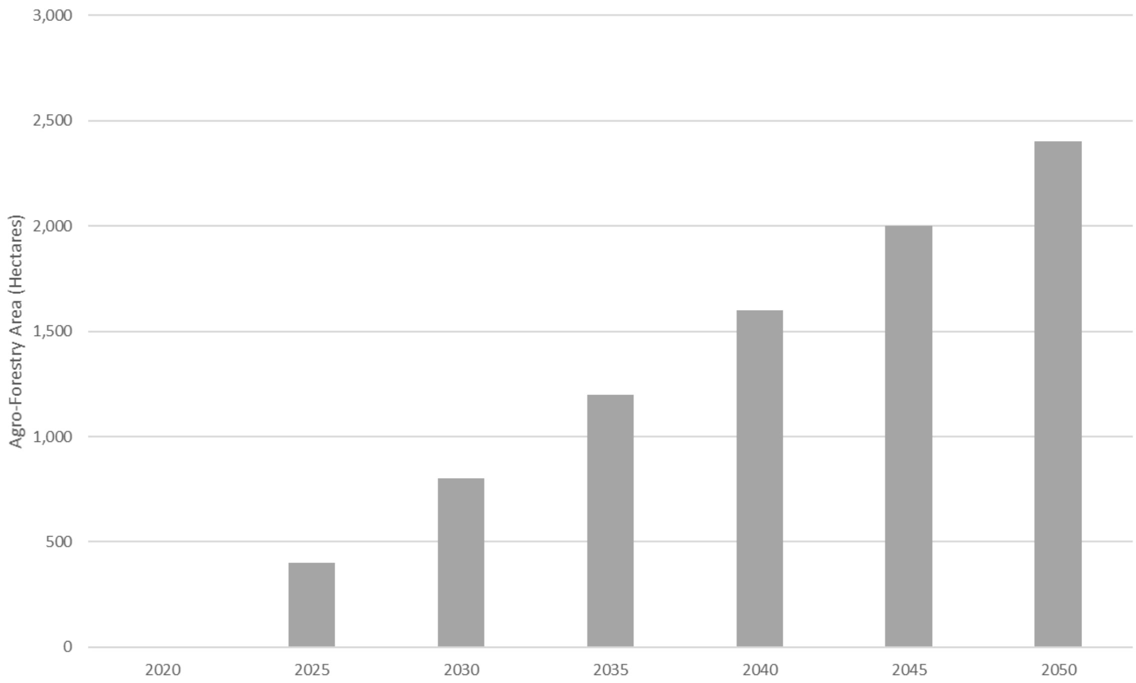


Figure 84: Area Required for Agro-Forestry Offsets in the Sensitivity Case 2



Sensitivity Case 2 requires slightly higher levels of Carbon offsets compared to the Mid Probability Technology case.

For the current study, offsets derived from soil farming projects have been assumed to illustrate how residual emissions could be managed, see Section 3.4 for an assessment of the options, and Section 9.8 for cost estimation.

Figure 83 and Figure 84 indicate that 800 hectares are required to be established every decade to achieve net zero emissions in 2050, commencing with 400 hectares in 2025, resulting in a cumulative total of 2,400 hectares in 2050, representing approximately 0.01% of Victoria's total land area.

9.4 Gas Spatial Analysis

9.4.1 Work Description

The proposed energy mix from the global modelling tool for the low probability case is used as an input into the spatial modelling tool. The spatial distribution of the energy gas demand has been kept in same proportion as the 2020 demand.

9.4.2 Results

This Sensitivity Case is similar to the Mid Probability Technology case and Sensitivity Case 1 with lower energy gas supply and demand.

Table 84 shows the energy gas demand by region from 2020 to 2050 for the Sensitivity Case 2. It can be seen that the overall energy gas demand reduces from 209 PJ/yr in 2020 to 177 PJ/yr.

Table 92: Energy gas demand by region for the Sensitivity Case 2 from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	129	123	111	100	68	81	105
North East	6	5	6	5	3	4	4
Loddon Mallee	21	19	18	16	12	13	17
Grampians Central West	19	17	16	15	110	12	15
Barwon South West	25	23	21	19	14	16	20
Gippsland	5	4	4	3	2	3	3
Goulburn Valley	5	4	4	3	2	3	3
Total (PJ/yr)	**209**	**196**	**180**	**162**	**112**	**131**	**169**

In the Sensitivity Case 2 the overall demand declines and the energy gas supply is supplemented by renewable biomethane and hydrogen (up to 10% by volume) and with renewable ammonia from 2040 as the natural gas supply from Victoria declines. Table 85 shows the distribution of energy gas supply by type from 2020 to 2050. Biomethane production ramps up from 1 PJ/yr in 2025 to 36 PJ/yr in 2050. Ammonia supply is reduced to 109 PJ/yr in 2050 compared to 131 PJ/yr in Sensitivity Case 1.

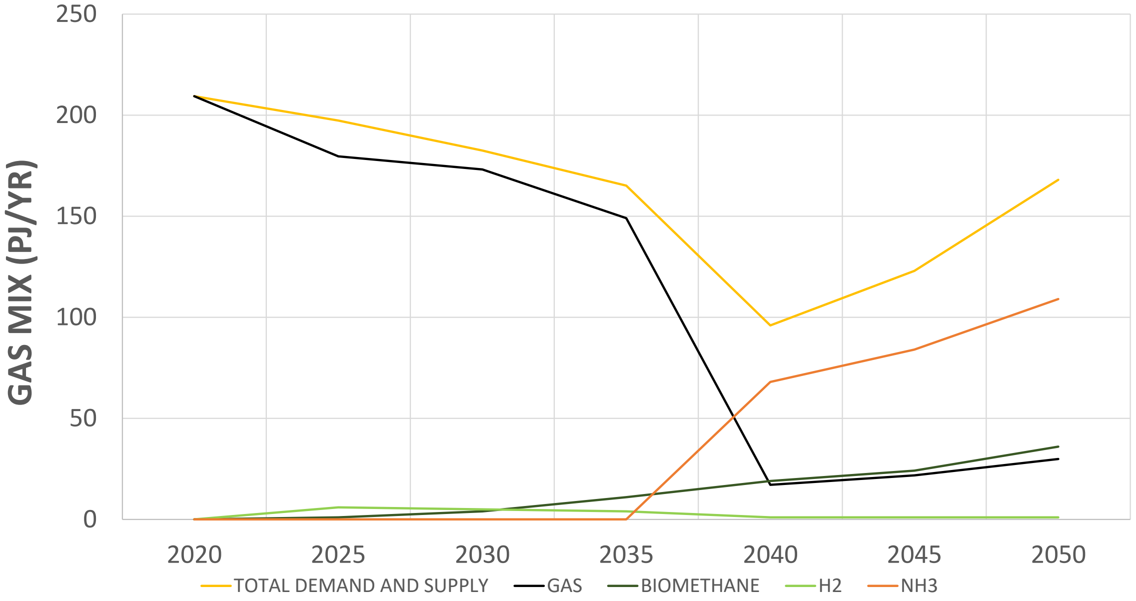
Table 93: Energy gas supply by type for the Sensitivity Case 2 from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	197	172	143	115	0	0	0
New Victorian natural gas production or imports	12	17	28	32	22	22	22
Biomethane	0	1	4	11	20	24	36
H2 (green)	0	6	5	4	2	1	2
Ammonia	0	0	0	0	68	84	109
Total (PJ/yr)	**209**	**196**	**180**	**162**	**112**	**131**	**169**

The total production of biomethane and green hydrogen are the same for Sensitivity Cases 1 and 2. Therefore, the spatial distribution of biomethane and green hydrogen production in Sensitivity Case 2 is kept identical to that proposed for Sensitivity Case 1.

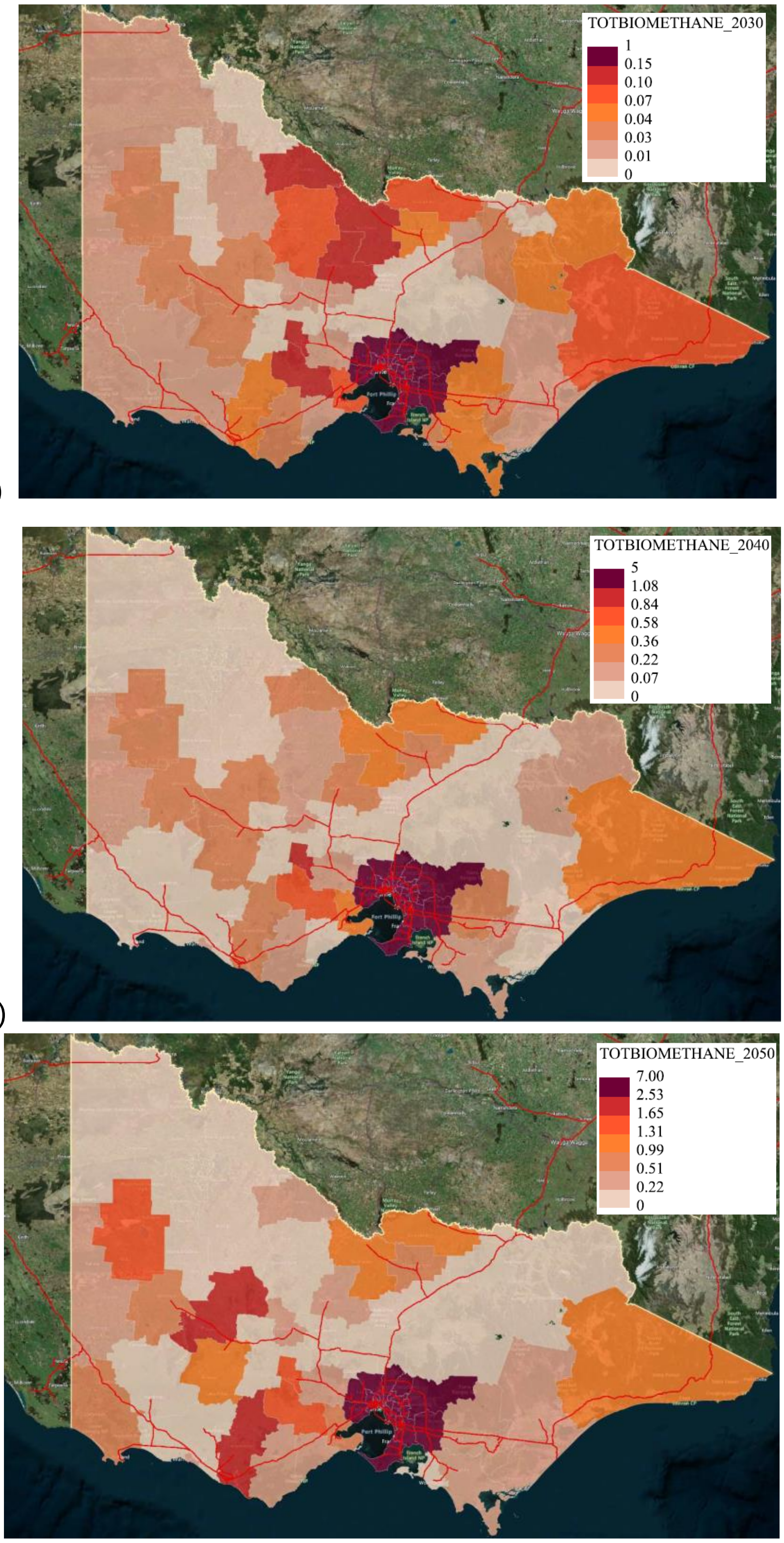
Figure 85 shows the gas mix for the Sensitivity Case 1 from 2020 to 2050.

Figure 85: Energy gas mix for the Sensitivity Case 2 from 2020 to 2050.



This Sensitivity Case is similar to the Mid Probability Technology case with lower ammonia demand. A combination of ammonia and natural gas will need to be managed in the transmission network. This could be achieved by segregating different parts of the network. For example, ammonia transmission and distribution are concentrated in the eastern part of the state – where ammonia is sent to Latrobe valley for power generation. While natural gas is distributed in the western and northern parts of the state. A consequence of this arrangement would likely be less flexibility to move gas between supply and demand centres. As in the Mid Probability Technology case the end customers will predominately use a mix of hydrogen and biomethane/natural gas.

Figure 86: Biomethane production for Sensitivity Case 2 in (a) 2030, (b) 2040 and (c) 2050.

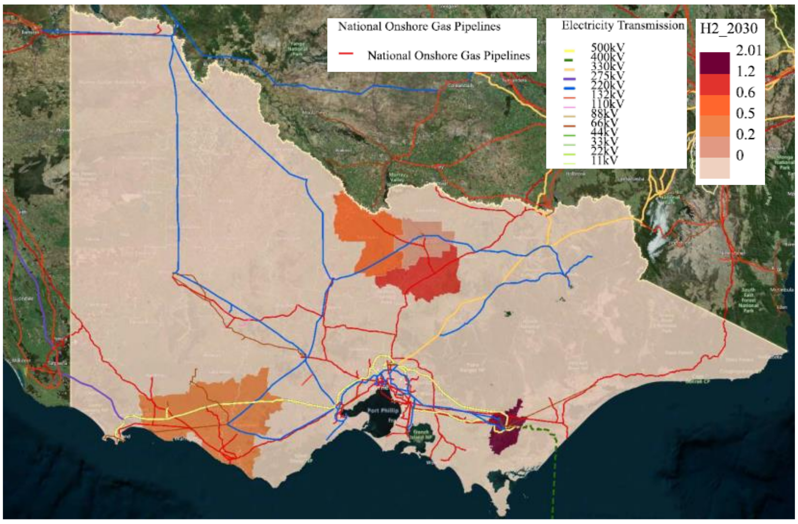


(a)

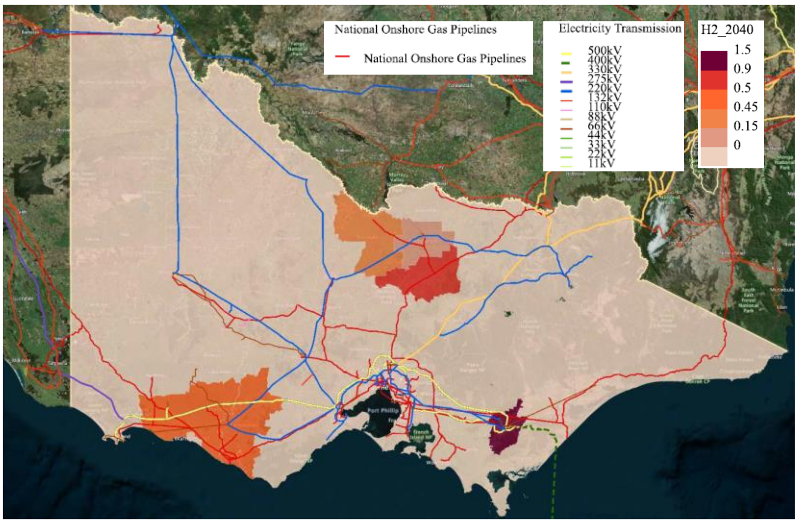
(b)

(c)

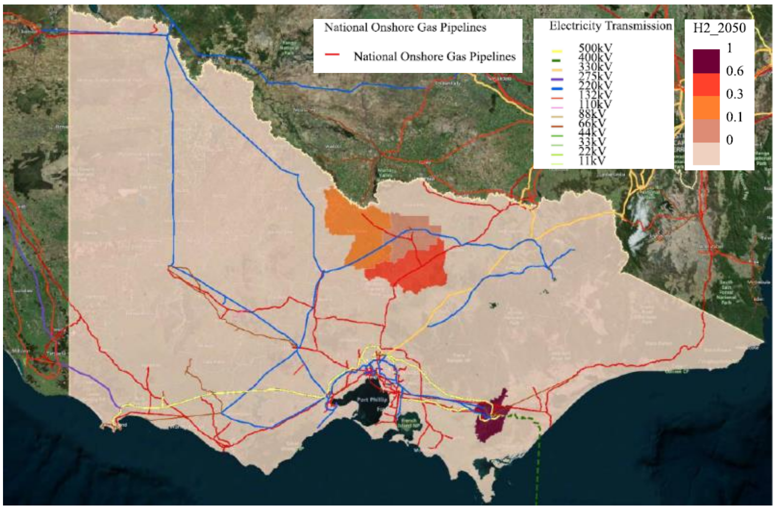
Figure 87: Hydrogen generation locations for Sensitivity Case 2 in (a) 2030, (b) 2040 and (c) 2050.



(a)



(b)



(c)

9.4.3 Discussion

- The Sensitivity Case 2 has the same quantity of biomethane and green hydrogen in the energy mix as Sensitivity Case 1 so the solution for these resources taken to be the same as Sensitivity Case 1.
- The Sensitivity Case 2 has ammonia import and transmission and conversion back into hydrogen for distribution to end customers like in the Mid Probability Technology Case. The solutions proposed for that case are retained in Sensitivity Case 2.
- The most significant change between Sensitivity Case 2 and the Mid Probability Technology case is that a mix of ammonia and natural gas/biomethane is being distributed by the high pressure gas transmission network. This can be achieved by segregating parts of the transmission network. For example, ammonia import could be achieved through an eastern port and ammonia distributed to Latrobe Valley for power generation and throughout Melbourne for conversion into hydrogen for distribution to end customers. Further studies are warranted to develop an optimised solution around this concept and ensure that it has sufficient flexibility to be viable.
- Additional hydrogen production and injection into the distribution network from 2040 onwards would help reduce ammonia and natural gas imports and may also be used to simplify the operation of the high pressure transmission network.

9.4.4 Gas Pipeline Network Changes

For the Sensitivity Case 2, the major changes in the gas transmission network can be summarised as:

- Addition of an ammonia import terminal at either Long Island Point or Crib Point with associated facilities to store ammonia and inject it into the gas transmission network.
- Upgrading (if required) of transmission pipelines to handle ammonia. Mild carbon steel pipelines should not need upgrading; however this should be confirmed on a case by case basis in future work.
- Addition of a number of ammonia to hydrogen conversion facilities in metropolitan Melbourne, mostly on eastern side. Estimates are that five to ten such facilities may be required.
- Decommissioning of the Eastern Gas Pipeline to NSW and the gas transmission pipelines between Seaspray and Longford, Longford and Morwell and Longford and Dandenong.
- The Victorian Northern Interconnector would be reversed enabling import of natural gas from NSW into northern regional areas to supplement biomethane production.
- Decommissioning of the pipeline infrastructure in the Barwon South West region, around Port Campbell and Warrnambool after 2040. This would include pipelines between the Otway Gas Plant and Mortlake Power Station; transmission pipelines to Hamilton and Cobden and transmission to Portland once the smelter shut down.
- Decommissioning of the SEA gas pipeline to South Australia after 2040.

For the Sensitivity Case 2, the major changes in the gas distribution networks can be summarised as:

- Upgrading of gas distribution networks in Melbourne, Sunbury and Gippsland to handle 100% hydrogen by 2040.
- Addition of local biomethane and hydrogen production in Barwon South West to serve Hamilton, Cobden and Portland.
- Biomethane and hydrogen from the Loddon Mallee and Grampians production serves Horsham, Ararat, Carisbrook, Bendigo and Ballarat

9.5 Electrical Spatial Analysis

9.5.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

Assumptions are explained in Section 3.6.

9.5.2 Work Description

For the Sensitivity Case 2, the electrical generation technologies include:

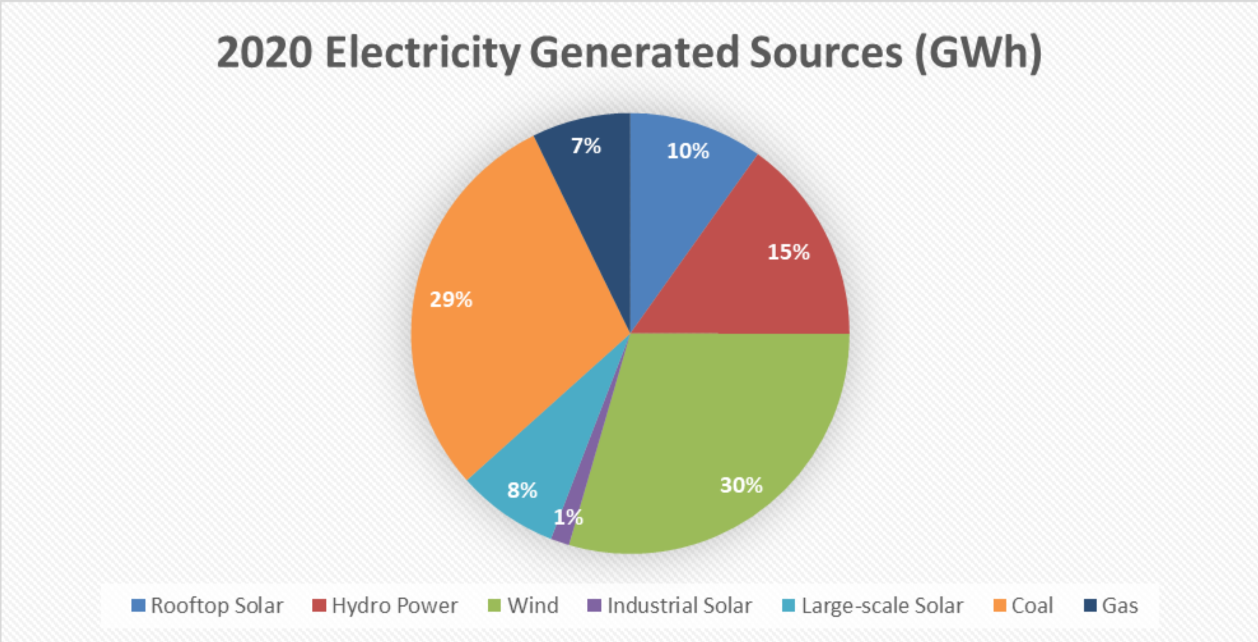
- Wind (onshore);
- Solar PV;
- Bioenergy;
- Hydro power; and
- Ammonia (NH3)

The electrical storage technologies include :

- Li-ion batteries (large-scale, industrial and behind the meter); and
- Iron-air batteries (for wind and solar).

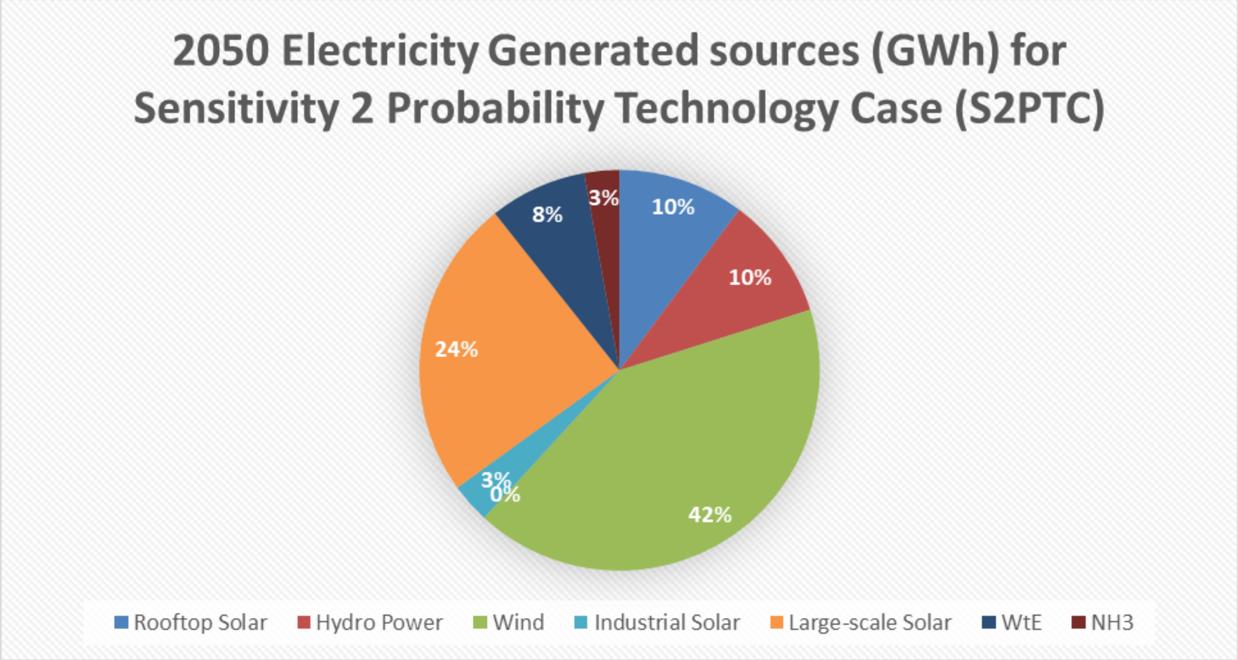
<u>**REMINDER:**</u> **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

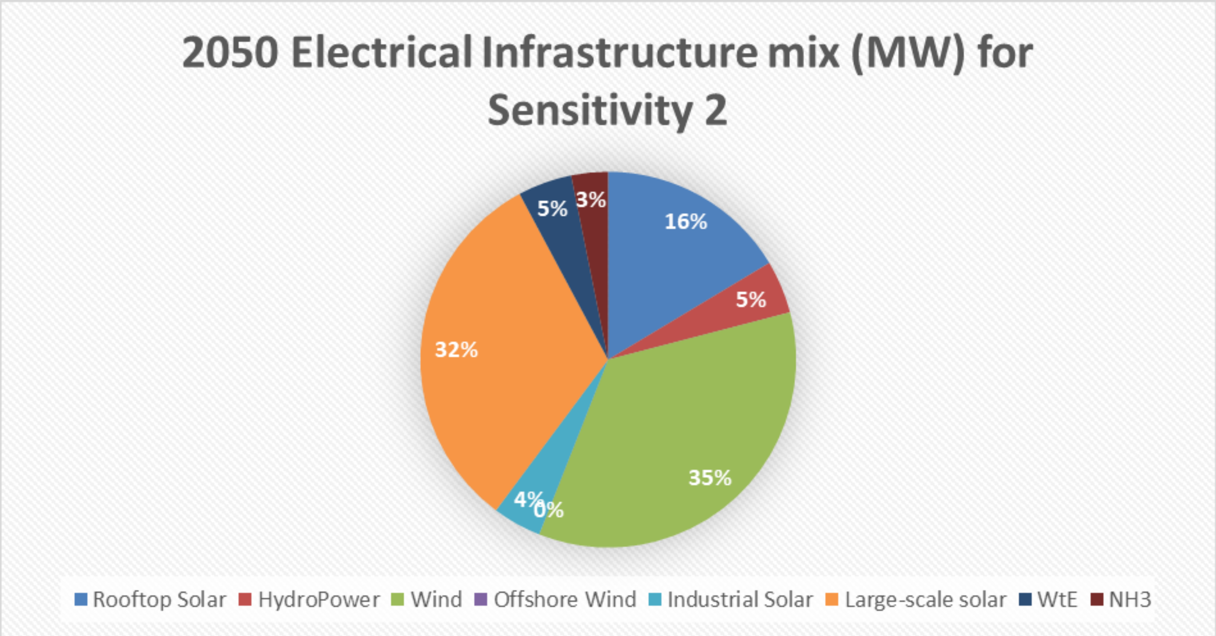
Electrical Generation Mix in 2020:



Electrical Mix in 2050:

(Note Reference in figures to "waste-to-energy" shall be read as "bioenergy")





The electrical infrastructure capacity (MW) was found to increase by a factor of 3.2 over the 30 years (2020 to 2050), whilst the electrical generation (GWh or PJ) increased by a factor of 1.5. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

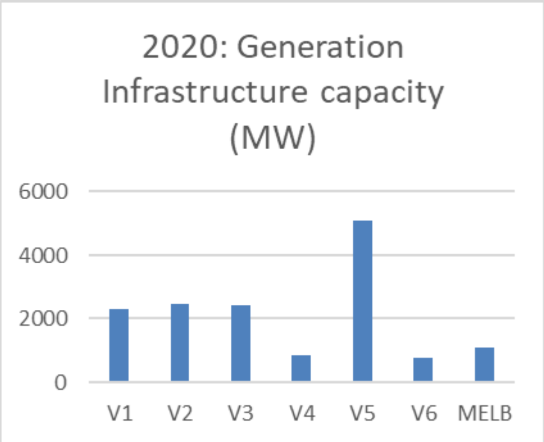
In this case technical analysis considered a lower increase in demand than the other cases, as summarised in the table below.

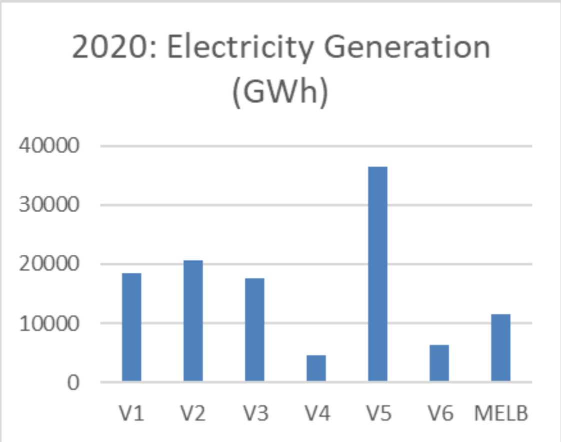
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	176 557	48 708

9.5.3 Results

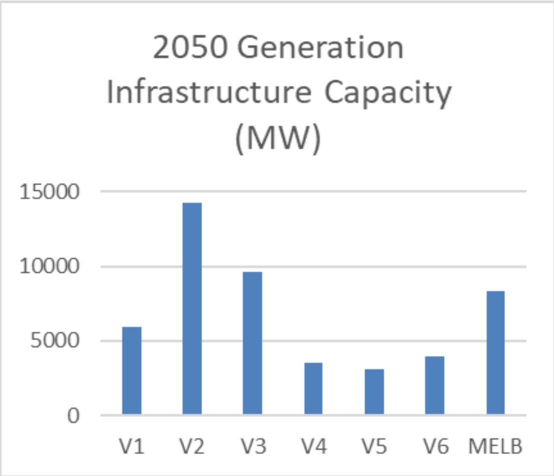
9.5.3.1 Overall Generation

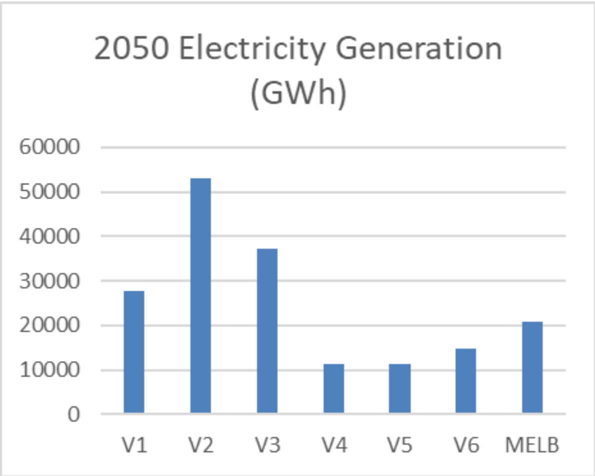
2020 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity for each REZ.
- Ovens Murray (V1), Central North (V6), South West (V4) and Gippsland (V5) have a low generation capacity.

- Melbourne (MELB), Murray River (V2) and Western Victoria (V3) have a high generation capacity.

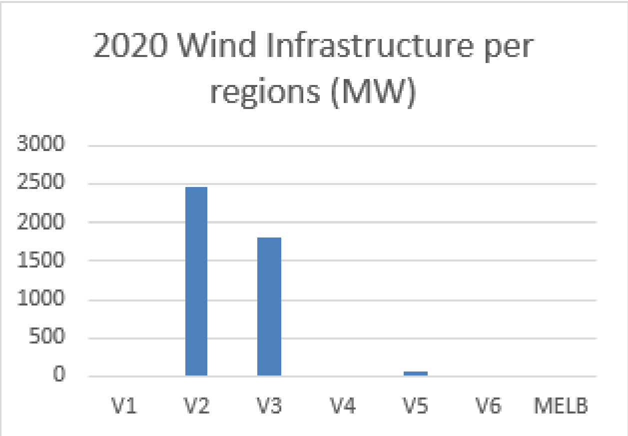
The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

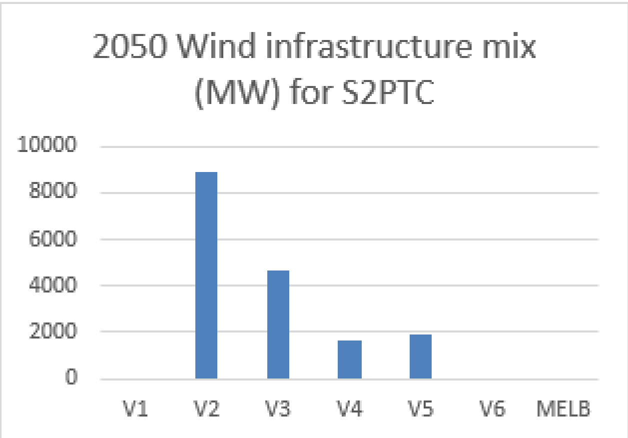
REMINDER: The assumptions used here are based on the AEMO's ISP inputs and assumptions workbook which has been used as "relied upon information". It has to be considered that V4 could have more capacity as it is a good location for wind.

The demand is located mainly in the Melbourne metropolitan region (around 60%), with around 10% demand for each of V2, V3 and V4 (representing the entire West side of Victoria) with the remaining 10% being split between V1, V5 and V6.

Comparing generation location and demand location, the transmission lines between all the regions and MEL and between East and West will need to be upgraded as both demand and electrical generation grow.

9.5.3.2 Wind





S2PTC: Sensitivity 2 Probability Technology Case

Note: All the locations of existing and committed asset for 2020 wind generation have been taken from AEMO's ISP inputs and assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

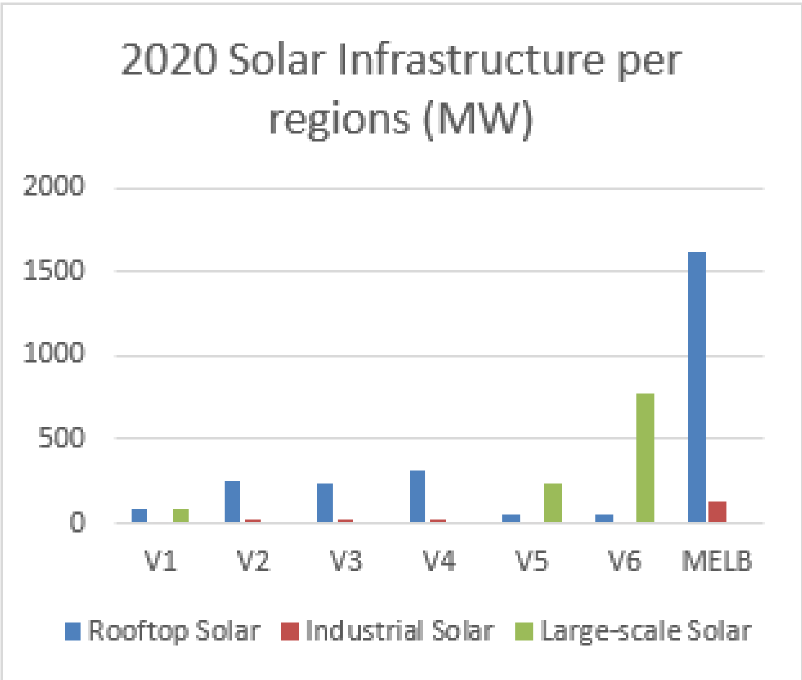
An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zones alongside the existing transmission lines. The location is based on available open land and associated wind rows.

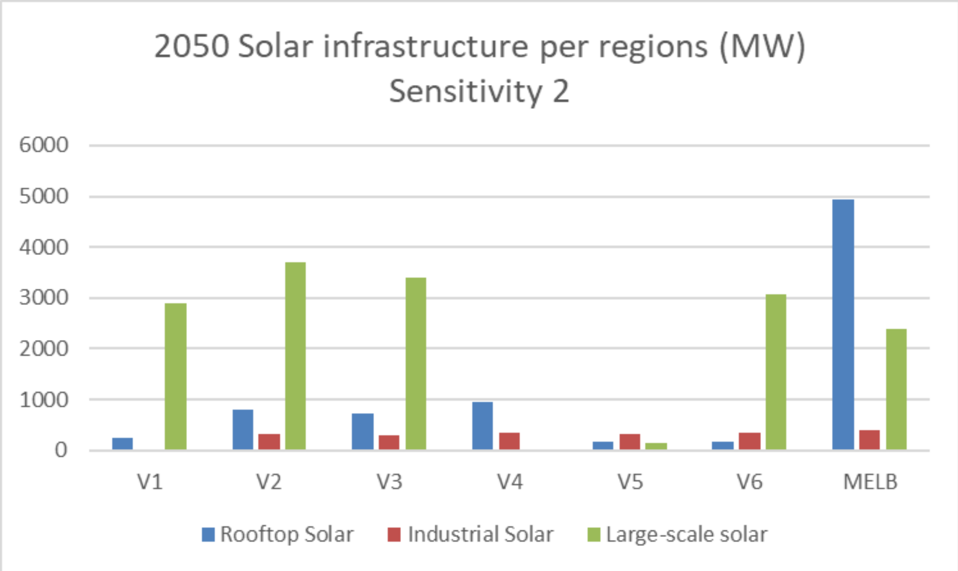
Further work may consider wind generation infrastructures being more balanced between V2, V3 and V4.

As for the other analysis cases, the charts above indicate an increasing capacity in wind infrastructure in V2, V3, V4 and V5 zones alongside the existing transmission lines. It is possible to consider V3 and V4 having much more wind as its wind potential is around 40%.

By 2050, wind represents 42% of the generated electricity with 17,071 MW of infrastructure capacity.

9.5.3.3 Solar





As for the High Probability Case, solar PV will expand in all the regions in which it has a high potential : V1, V2, V3 and V6. Once again, the locations follow the transmission lines.

In 2050, Victoria is predicted to have:

- 7,983 MW of rooftop solar PV generation, representing 10% of electrical mix
- 2,044 MW of industrial solar PV generation, representing 3% of electrical mix
- 15,585 MW of large-scale solar PV generation, representing 24% of electrical mix

9.5.3.4 Bioenergy

By 2050, bioenergy provides 8% of the electrical demand with 2,263 MW of installed capacity.

9.5.3.5 Infrastructure to be installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period.

The values in 2020 are the existing and committed assets, then for each subsequent time period the values represent the additional generation infrastructure that has to be added for the specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	10	0	0	0	0	191	0	0	0	0	0	35	0	450	30	15	0	0	0	0
2030	23	0	0	0	0	1077	0	0	0	0	0	57	0	1789	50	33	0	0	0	0
2035	19	0	0	0	0	951	0	0	0	0	0	64	0	1299	61	41	0	0	0	0
2040	34	0	0	0	0	187	0	0	0	0	0	61	0	118	59	88	0	6250	0	64
2045	48	0	0	0	0	412	0	0	0	0	0	61	0	59	59	59	0	3750	0	167
2050	27	0	0	0	0	0	0	0	0	0	0	61	0	0	59	59	0	4000	0	0
	MW												GWh						MW	

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	35	0	623	0	32	265	0	0	0	0	0	35	0	1375	92	50	0	0	0	0
2030	77	0	1652	0	53	1495	0	0	0	0	0	57	0	5468	152	110	0	0	0	0
2035	64	0	1379	0	65	1189	0	0	0	0	0	64	0	3970	186	138	0	0	0	0
2040	113	0	2200	0	62	234	0	0	0	0	0	61	0	359	180	294	0	19097	0	64
2045	159	0	2493	0	62	515	0	0	0	0	0	61	0	180	180	196	0	11458	0	167
2050	91	0	323	0	31	0	0	0	0	0	0	61	0	0	180	196	0	12222	0	0
	MW												GWh						MW	

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0	0	0
2025	31	0	298	0	29	258	0	0	0	0	0	35	0	1100	73	45	0	0	0	0
2030	69	0	790	0	48	1454	0	0	0	0	0	57	0	4374	122	99	0	0	0	0
2035	57	0	659	0	59	963	0	0	0	0	0	64	0	3176	149	124	0	0	0	0
2040	102	0	1052	0	57	190	0	0	0	0	0	61	0	288	144	265	0	15278	0	64
2045	143	0	1192	0	57	522	0	0	0	0	0	61	0	144	144	176	0	9167	0	167
2050	82	0	514	0	28	0	0	0	0	0	0	61	0	0	144	176	0	9778	0	0
	MW												GWh						MW	

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0	0	0
2025	42	0	102	0	34	0	0	0	0	0	0	35	0	675	45	60	0	0	0	0
2030	92	0	269	0	56	0	0	0	0	0	0	57	0	2684	75	133	0	0	0	0
2035	77	0	225	0	68	0	0	0	0	0	0	64	0	1949	91	166	0	0	0	0
2040	136	0	358	0	66	0	0	0	0	0	0	61	0	176	88	353	0	9375	0	64
2045	190	0	406	0	66	0	0	0	0	0	0	61	0	88	88	235	0	5625	0	167
2050	109	0	263	0	33	0	0	0	0	0	0	61	0	0	88	235	0	6000	0	0
	MW												GWh						MW	

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	119	0	34	0	0	0	0	0	0	35	0	425	28	10	0	0	0	0
2030	15	0	316	0	56	0	0	0	0	0	0	57	0	1690	47	22	0	0	0	0
2035	13	0	264	0	68	0	0	0	0	0	0	64	0	1227	57	28	0	0	0	0
2040	23	0	421	0	66	0	0	0	0	0	0	61	0	111	56	59	0	5903	0	64
2045	32	0	477	0	66	0	0	0	0	0	0	61	0	56	56	39	0	3542	0	167
2050	18	0	309	0	33	0	0	0	0	0	0	61	0	0	56	39	0	3778	0	0
	MW												GWh						MW	

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	7	0	0	0	35	233	0	0	0	0	0	23	0	1050	70	10	0	0	0	0
2030	15	0	0	0	58	1313	0	0	0	0	0	38	0	4175	116	22	0	0	0	0
2035	13	0	0	0	71	870	0	0	0	0	0	43	0	3032	142	28	0	0	0	0
2040	23	0	0	0	69	171	0	0	0	0	0	41	0	275	137	59	0	14583	0	43
2045	32	0	0	0	69	377	0	0	0	0	0	41	0	137	137	39	0	8750	0	111
2050	18	0	0	0	34	0	0	0	0	0	0	41	0	0	137	39	0	9333	0	0
	MW												GWh						MW	

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell	NH3
2020	1617	0	0	0	125	0	0	482	500	0	0	0	0	0	0	0	0	0	0	0
2025	215	0	0	0	29	259	0	0	0	0	0	35	0	2425	162	310	0	0	0	0
2030	475	0	0	0	48	1458	0	0	0	0	0	57	0	9643	268	685	0	0	0	0
2035	396	0	0	0	59	483	0	0	0	0	0	64	0	7002	328	857	0	0	0	0
2040	702	0	0	0	57	95	0	0	0	0	0	61	0	634	317	1824	0	33681	0	64
2045	983	0	0	0	57	105	0	0	0	0	0	61	0	317	317	1216	0	20208	0	167
2050	562	0	0	0	29	0	0	0	0	0	0	61	0	0	317	1216	0	21556	0	0
	MW												GWh						MW	

Note Reference in table to “waste-to-energy” shall be read as “bioenergy”

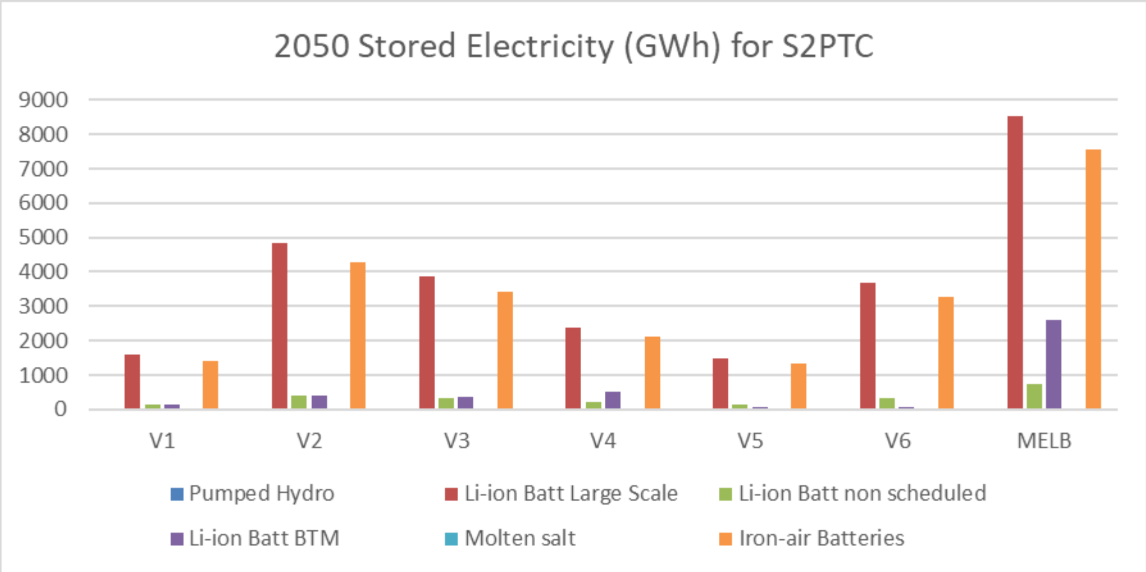
9.5.4 Discussion

Sensitivity Case 2 was observed to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (behind the meter, industrial and large scale)
  - Iron-air batteries (starting 2040)
  - Ammonia (starting 2040)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar and wind represents between 75 and 80% of the electrical mix with the potential to create grid instability requiring compensation through the addition of generation and storage facilities. Starting in 2035 all wind, solar PV and battery infrastructure levels are multiplied by 1.5.
- The share of wind and solar in 2050 is 40% solar PV (excluding behind the meter) and 60% wind. This resembles the South Australian mix with wind prioritised over solar.
- New transmission lines are needed as the grid will have to support a lot more electricity. Upgrades of the following lines are considered likely (same as High Probability Technology case)
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers, representing approximately 25% more infrastructure than exists today.
- All the connections between the facilities and the grid have been taken into account in the cost analysis, but not shown on the maps.
- The storage is calculated depending on the quantity of solar and wind.



9.6 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

9.7 Environmental & Social Analysis

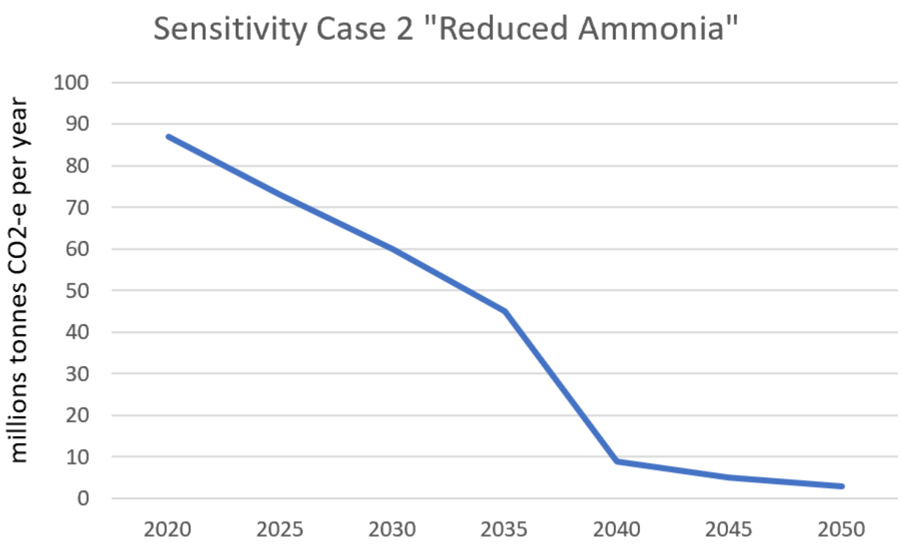
The environmental and social components of the Sensitivity Case 2 “Reduced Ammonia Share” have been assessed via a desk-top study using key aspects from environmental and social perspectives as presented in Section 4.6.

9.7.1 Results

The reduced ammonia sensitivity case builds on the mid probability technology scenario but assumes a modified energy mix to account for a 20% reduction in use of ammonia for electrical power generation and a 50% reduction in the use of ammonia and energy gas by 2050 when compared to the mid probability technology case.

Figure 88 shows the modelled emissions reduction profile for the reduced ammonia sensitivity. Similar to the mid probability technology case and accelerate net zero sensitivity, the profile shows a linear decline in emissions to 2035 and then an accelerated decline between 2035 and 2040. The technology mix in this sensitivity scenario has residual emissions of around 3 million tonne CO2-e per year in 2050 which are then assumed to be offset.

Figure 88: Emissions Reduction Profile – Sensitivity Case 2 "Reduced Ammonia"



- The Sensitivity Case 2 - Reduced Ammonia has as a similar emissions reduction profile to the Mid Probability Technology Case and Sensitivity Case 1 – Accelerate Net Zero in that emissions decline linearly until 2035 and then drop rapidly between 2035 and 2040.
- Conversely, given the implementation time for technology breakthroughs and the adoption of new technology, electricity generation from coal is still the highest source of emissions up until 2035, when coal and natural gas are phased out. Vehicles - (ICE) gasoline & diesel remains the third highest emissions up until 2035 before being the highest in 2040.
- Downscaling of coal represents the largest contribution to reducing emissions by 2050. Vehicles - (ICE) gasoline & diesel represent the second largest contribution to reducing emissions, after coal.
- The Sensitivity Case 2 relies heavily on solar PV, storage and wind as its largest energy generation by 2050. However, to achieve net zero emissions in 2050 this sensitivity makes use of greenhouse gas offsets more than the other cases/sensitivities modelled.

9.7.2 Discussion

Sensitivity Case 2 "Reduced Ammonia Share" has the following environmental and social considerations:

- Relative to the mid probability technology case:
    - Ammonia for electrical generation - reduced by 28%
    - Ammonia for conversion to hydrogen and blending into the gas network - reduced by 43%
    - Solar PV – increased by 14%
    - Wind – increased by 9%

  - bioenergy – increased by 16%
  - Battery storage - increased by 40%
- Relative to the mid probability technology case the reduced ammonia sensitivity is modelled to result in around 15% fewer few employment opportunities reflecting the lower use of ammonia. Ammonia however remains the most significant driver of employment. Employment estimates in this sensitivity are forecast to be double that of the high probability technology case. The main drivers of employment in this sensitivity are:
  - Ammonia for electricity generation (49%)
  - Wind (13%)
  - Rooftop solar PV (9.7%)
  - Energy efficiency (8.8%)
  - Battery storage (6.2%)
  - Large scale solar PV (5.3%)
- The environment and social risks are broadly comparable to those in the mid probability technology case, noting the detailed impacts will vary given the reduced use of ammonia and increased use of renewable energy.
- Interim emissions targets are met and exceeded with 10-15% greater reduction by 2025 and 3-8% greater reduction by 2030 modelled in the scenario.
- As per the mid probability technology case there is no requirement for commissioning geo-sequestration (CCS), although greenhouse gas offsets are required to achieve net zero emissions by 2050.
- As per the mid probability technology case, it is proposed that coal fired power stations are converted to ammonia and continue operation in 2050 and beyond, but with a lower uptake rate of ammonia both in gaseous form and also conversion to electricity. Although not as beneficial as the scenario described in the mid probability case, this still reduces the impact on employment in the Latrobe Valley (assuming workers can be retrained into these new energy technologies) and reduces the environmental impact and footprint of the new energy technology by utilising current coal infrastructure and land use.
- The reduction in coal energy production will both reduce the public health impacts of the community and those employed through the coal industry.

9.8 Cost Analysis

9.8.1 Key References & Assumptions

Refer to Section 3.8.5.

9.8.2 Work Description

Refer to Section 3.8 for details of the work description.

9.8.3 Results

The figure below present the net difference between the Sensitivity Case 2 "Reduced NH_3" and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Figure 78 demonstrates that:

- The Sensitivity Case 2 "Reduced NH_3" projects a material increase in fuel, FOM and VOM costs, as a result of the increase in fuel cost for the expanded development and sharing of new variable renewable electricity resources in particular green hydrogen / ammonia, providing a net annualised cost increase of approximately $3.5 billion in 2050.
- The Sensitivity Case 2 "Reduced NH_3" projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $4.7 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the Sensitivity Case 2 "Reduced NH_3" is represented by the purple line in Figure 78. By 2050, the Reduced NH_3 Sensitivity Case is forecast to provide a net cost increase of around $8 billion by 2050.

For the Sensitivity Case 2 "Reduced NH_3", the net costs show a gradual negative trend until 2040 when coal fired generation is retired and increased annual CAPEX and fuel costs for new generation which returns a net cost increase.

Figure 89: Net Costs of the Control Scenario relative to the Sensitivity Case 2 "Reduced NH_3" Sensitivity Case

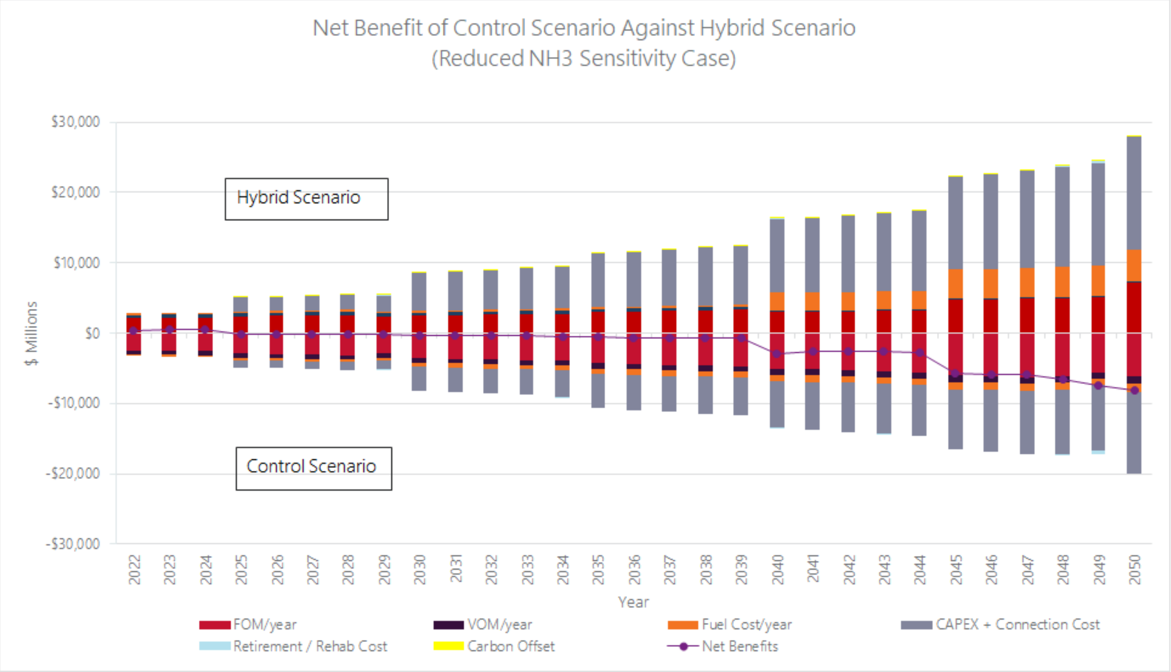


Table 87 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Sensitivity Case 2 “Reduced NH_3”, in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the Sensitivity Case 2 “Reduced NH_3”, discounted back to present value, is $8.8 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$2.7 billion (NPC).

The estimated cost of CO_2 abatement is $102/te CO_2.

Table 94: Net Costs of the Control Scenario relative to the Sensitivity Case 2 “Reduced NH_3”

Cost Category[2]	Net Cost of Control Against Technology Case (Reduced NH_3 Sensitivity)		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$4,616	-$1,866
FOM	$2,475	$2,385	$90
VOM	$435	$284	$151
Fuel	$419	$1,460	-$1,041
Retirement / Rehab	$48	$61	-$13
Agro-forestry (Land Area, Hectare)	$0	$0.14	-$0.14
Gross Cost	$6,127	$8,807	-$2,679
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement[3] ($/tonne)	583	102	481

Notes:
1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

9.8.4 Discussion

The increased CAPEX combined with the overall energy mix for the Sensitivity Case 2 “Reduced NH_3” compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity. For cost estimating purposes this assumes all coal fired generation is retired and replaced with new ammonia fired generation (gas turbine) in 2040. This approach is likely more costly than life extension, conversion plus OPEX for the existing coal fired generation but the risks and uncertainties of continuing with the existing generation in regard to life extension suggests this is the correct assumption to make. Note that there is an opportunity for cost reduction if conversion and life extension is possible, but this involves a greater technology risk.

OPEX and fuel costs savings for the Sensitivity Case 2 “Reduced NH_3” compared to the Control Scenario are also expected due to the replacement of coal fired generation with green hydrogen / ammonia and expanded development and sharing of new variable renewable electricity resources.

Retirement costs increase in the Sensitivity Case 2 “Reduced NH_3” as the existing coal fired generation is retired early by 2040 plus decommissioning of gas transmission and distribution lines. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Sensitivity Case 2 “Reduced NH_3” cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

9.9 Risk & Opportunity Analysis

9.9.1 Key References & Assumptions

Four Sensitivity Cases were developed based on one of the three Base Analysis Cases previously described in this report. The modifications to the key assumptions are summarised in Table 95.

Table 95: Modifications to Key Assumptions

Sensitivity Case No.	Description	Reference Case	Modifications to Key Assumptions
2	Reduced Ammonia Share	Mid Technical Probability	Reduced ammonia demand by approx. 20% for power generation and over 50% for use as energy gas

9.9.2 Work Description

Sensitivity Case 2 “Reduced Ammonia” does not introduce any technologies which were not considered in the Mid Probability Technology Case, as described below. However, with the modified the energy mix contained within this sensitivity case, the study team reviewed the risks and opportunities identified in the Mid Probability Technology Case and assessed the any additional risks and opportunities unique to Sensitivity Case 2 “Reduced Ammonia”, focussing on the implementation risks rather than the inherent risks.

9.9.3 Results

Sensitivity Case 2 “Reduced Ammonia” is essentially a modification of the Mid Probability Technology Case and is susceptible to the technology risks within those cases. The key risks remain as the failure of any of the key technologies to become commercially competitive at large scale within the indicated timeframes.

- Green hydrogen, initial incremental cost reduction breakthrough by 2025;
- Green ammonia supply by 2040;
- Green hydrogen from ammonia supply and distribution chain;
- Iron-air battery by 2040.

Sensitivity Case 2 “Reduced Ammonia” carries the following increased risk, compared with the Mid Probability Technology Case;

- Increased natural gas supply risk, but this risk is still less than that in the High Probability Technology Case and is considered to be manageable given the range of potential future gas sources that are available.

Whilst the quantity of carbon offsets required to achieve net zero is modest there is a risk to reliance on offsets to reach net zero, especially with competition for such offsets from hard to abate energy sectors.

9.9.4 Discussion

The Mid Probability Technology Case was used as the basis for Sensitivity Case 2 “Reduced Ammonia”, with ammonia demand reduced by approximately 20% for ammonia used for power generation, and over 50% ammonia used as energy gas in 2050.

To offset the reduced ammonia levels, the supply of energy from the following sources was increased:

- Onshore wind.
- Batteries of various forms.
- LNG import.
- Natural gas imports from interconnectors.

Once offshore wind is shown to be commercially viable, then scaling up a project or adding a further project to supply additional power is not considered a significant additional risk.

Likewise, if various types of battery and LNG imports are shown to be feasible, then scaling up to provide additional supply is not considered a significant additional risk.

The delivery of additional natural gas from interconnector pipelines is much less certain, as the available supply will depend on additional interstate gas production coming on stream, being diverted from LNG exports or being sourced from interstate LNG imports. However, the natural gas requirement is less than that in the High Probability Technology Case and a wide range of potential sources of gas are expected to be available in the future.

In this Analysis Case, the use of offsets is preferred over CCS implementation to achieve net zero, as it provides a more flexible approach with the ability to adjust the scale and timing of the offsets depending on the emissions reduction results actually being achieved. CCS projects involve a long lead time and significant capital expenditure and therefore greater certainty before an investment decision can be made.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

10 SENSITIVITY CASE 3 “ENERGY EFFICIENCY”

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

10.1 Objective

The objective of running Sensitivity Case 3 was to investigate the influence of energy efficiency on the transition cost benefit.

10.2 Case Description

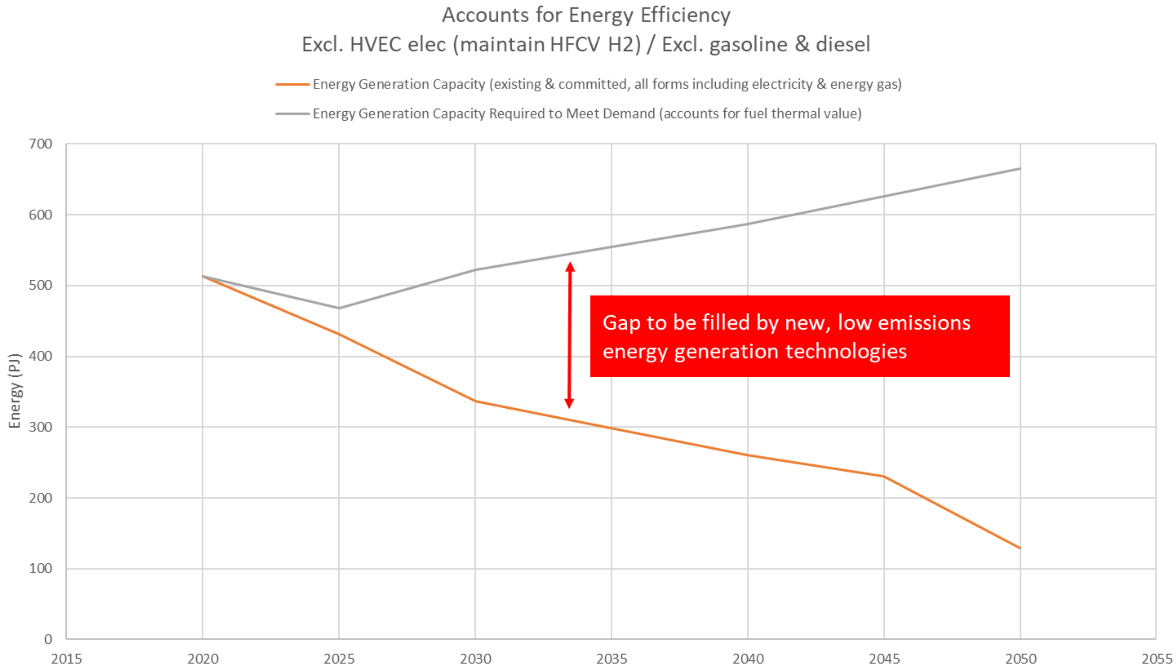
The High Probability Technology Case was used as the basis for Sensitivity Case 3 given it included no technology breakthroughs, and the impact of varying energy efficiency could be more clearly identified. The energy efficiency improvement rate was increased to 20% per decade for both electricity and energy gas (in comparison to the 5% rate included in the High Probability Technology Case).

Energy efficiency relates only to the mean energy demand, and is calculated as part of the energy-emissions-offsets analysis.

Demand side participation is represented by the capacity margin over the mean demand and was not varied in Sensitivity Case 3. Adjustments to the level of demand side participation will impact the specification of rated capacity of installed energy infrastructure. From a modelling perspective, increasing the level of demand side participation will result in the same outcome as increasing the energy efficiency improvement rate: a reduction in the extent of energy generation required.

Figure 90: Forecast Energy Demand vs Generation Capacity (Sensitivity Case 3)

(The difference between generation capacity and demand is covered by fuel thermal value, which relates primarily to ICE vehicle fuel (gasoline & diesel))



The energy generation capacity required to meet forecast demand (grey line in Figure 90) is:

- Limited to the study scope. namely electricity, energy gas and low emissions road vehicles. Notably excluded from the study scope are agriculture, and non-road vehicles
- Determined by subtracting the fossil fuel thermal value from the overall energy demand.

As noted in Section 3.2, one of the drivers for additional generation capacity increasing over time is the replacement of ICE fuel (gasoline & diesel) with electricity (BEVs) and Hydrogen (HFCVs).

Sensitivity Case 3 is based on the existing & committed energy generation capacity scheduled by AEMO (Table 96) which remains the same as for the High Probability Technology Case, and adopts a fossil fuel decline profile in line with the High Probability Case (see Table 14 Section 3.2).

The energy technologies identified for Sensitivity Case 3 are as per the High Probability Technology Case, see Section 5.

Table 96: Existing & Committed Energy Production Capacity Assumed for Supplying Demand Sensitivity 3)

ELECTRICITY	2020		2030		2040		2050	
	Total Capacity MW	PJ	Total Capacity MW	PJ	Total Capacity MW	PJ	Total Capacity MW	PJ
Elec (generation) - coal	4,775	133	3,325	85	3,325	85	0	0
Elec (generation) - natural gas - baseload	500	4	500	4	0	0	0	0
Elec (generation) - natural gas - peaking	1,900	1	1,900	1	1,196	0	612	0
Elec (generation) - hydropower - industrial	2,219	10	2,219	10	2,219	10	2,219	10
Elec (generation) - solar PV - large scale - variable - industrial	657	4	995	6	995	6	217	1
Elec (generation) - solar PV - non-sched ie small scale gen typ 5 - 30 MW - variable - industrial	202	1	600	4	1,081	7	1,591	11
Elec (generation) - solar PV - "Behind the Meter" rooftop - variable - residential / commercial	2,608	12	6,720	25	8,338	32	10,205	39
Elec (generation) - wind onshore - variable - industrial	2,784	28	4,014	41	2,754	28	209	2
Elec (storage) - pumped hydro	0	0	400	3	400	3	400	4
Elec (storage) - "Virtual Power Plant" (aggregated small scale batteries)	5	0	130	1	531	3	953	6
Elec (storage) - "behind the meter" non-aggregated small scale batteries (dis-connected from grid)	94	1	551	3	1,527	10	2,034	13
	17,472	**194**	**24,658**	**184**	**25,614**	**185**	**21,668**	**86**

GAS	2020		2030		2040		2050	
	Total		Total		Total		Total	
	Capacity		Capacity		Capacity		Capacity	
	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ	TJ/d	PJ
Gas (generation) - natural gas - industrial (total incl exports)	840	307	373	136	162	59	71	26
Gas (import) - LNG import (to balance demand)	0	0	1,100	4	1,100	4	1,100	4
Gas (import) - VNI Pipeline (Victoria Northern Interconnector) (to balance demand)	170	12	170	12	170	12	170	12
	1,360	**319**	**1,993**	**153**	**1,782**	**76**	**1,691**	**42**

10.3 Energy Emissions Offsets

10.3.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

10.3.2 Results & Discussion

As evidenced by Table 97 and Figure 91, the energy mix for Sensitivity Case 3 is very closely aligned to that of the High Probability Technology Case, with all figures reduced due to the increase in energy efficiency levels with the exception of coal power, natural gas power (peaking) and hydro-power which were intentionally retained at similar levels to the High Probability Case in order to maximise existing and committed energy generation capacity.

Table 97: Mean Demand Energy Mix for Sensitivity Case 3

	2020	2025	2030	2035	2040	2045	2050
Impact of Energy Efficiency on Energy Generation Capacity (PJ)							
Energy Generation to Meet Base Demand (Total VIC)	513	590	661	710	762	823	887
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	570	618	643	669	702	737
Cumulative Energy Consumed accounting for Energy Efficiency (PJ)							
Elec (generation) - coal	144	120	91	68	45	22	0
Elec (generation) - natural gas (baseload + peaking)	5	5	5	5	0	0	0
Elec (generation) - hydropower	10	11	11	11	10	10	10
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	44	107	132	161	189	239
Elec (generation) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	28	54	84	96	97	98	106
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	4	11	18	24	32	39
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	3	3	3	3	4
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	1	12	58	81	105	120	167
Gas (generation) - natural gas (all sources)	209	184	162	137	118	77	47
Gas (generation) - biomethane	0	1	3	9	14	20	32
Gas (generation) - H2 (green) [incl HFCV fuel]	0	17	28	28	28	32	35
Vehicles - (ICE) gasoline & diesel	318	258	203	143	87	42	0
Vehicles - (BEV) electricity	0	9	18	33	46	51	55
Vehicles - (HFCV) electricity [GENERATION]	0	20	39	40	41	49	57
TOTAL (PJ)	**732**	**738**	**823**	**803**	**780**	**747**	**792**

Figure 91: Energy Mix Breakdown for Sensitivity Case 3 Covering only Electricity & Energy Gas

(excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

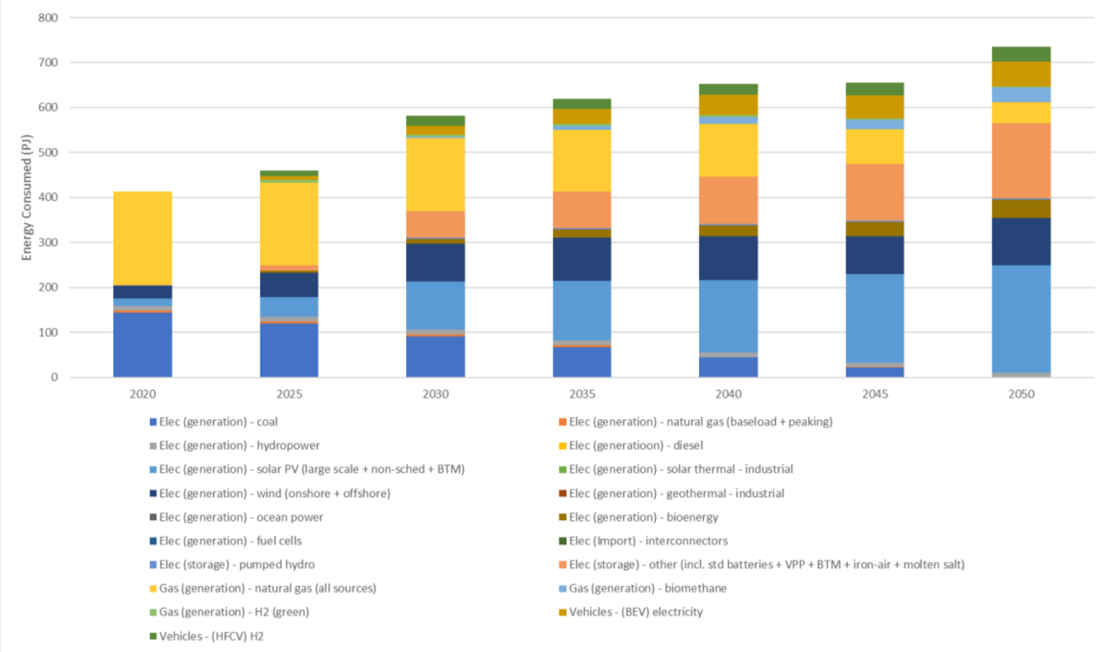


Table 98 and Figure 92 illustrate that Sensitivity 3 has a similar emissions decline profile to the High Probability Technology case, with a gradual decline to net zero emissions in 2050. Due to increased uptake of energy efficiency Sensitivity Case 3 has slightly lower emissions levels compared to the High Probability Technology case (refer Section 5.2), with proportionally the same contributions from the same energy technologies.

Table 98: Emissions for Sensitivity Case 3

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	37	28	21	14	7	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	2	2	2	3
Elec (generation) - solar thermal - industrial	0	0	0	0	0	0	0
Elec (generation) - wind (onshore + offshore)	1	2	3	3	3	3	4
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-4	-6	-8	-9
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	16	15	12	11	7	4
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	22	17	14	10	6	3	0
Vehicles - (BEV) electricity	0	0	0	0	1	1	1
Vehicles - (HFCV) electricity	0	0	0	1	1	1	1
TOTAL EMISSIONS	**87**	**74**	**60**	**46**	**31**	**16**	**3**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**-1**	**-1**	**-2**	**-2**	**-3**
NET EMISSIONS	**87**	**74**	**59**	**44**	**29**	**14**	**0**

Figure 92: Emissions Profile for Sensitivity Case 3

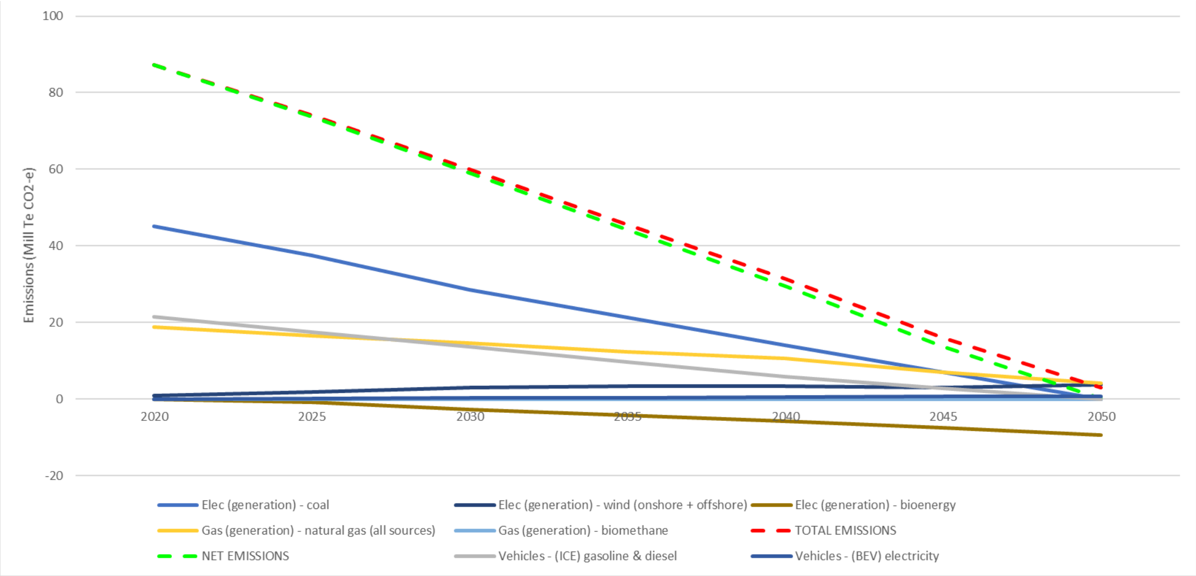


Table 5 in Section 1.6.4 documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for Sensitivity Case 3 is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be :

- 2025 interim emissions target: up to 18 Million Te CO_2-e to cover out of scope emissions; and
- 2030 interim emissions target: up to 10 Million Te CO_2-e to cover out of scope emissions.

Figure 93: Agro-Forestry Offsets Utilised to Reach Net Zero Emissions for Sensitivity Case 3

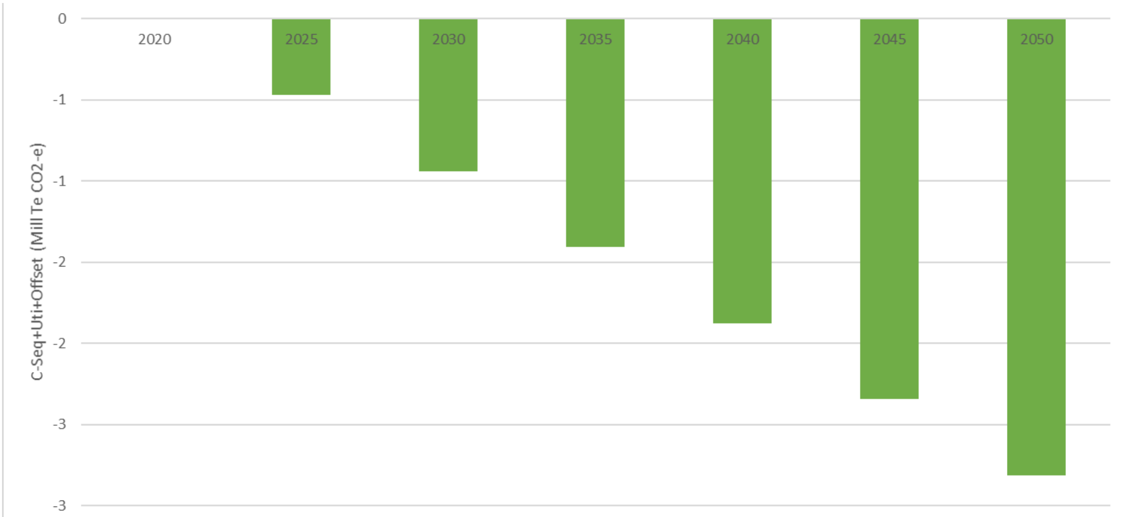


Figure 94: Area Required for Agro-Forestry Offsets in the Sensitivity Case 3

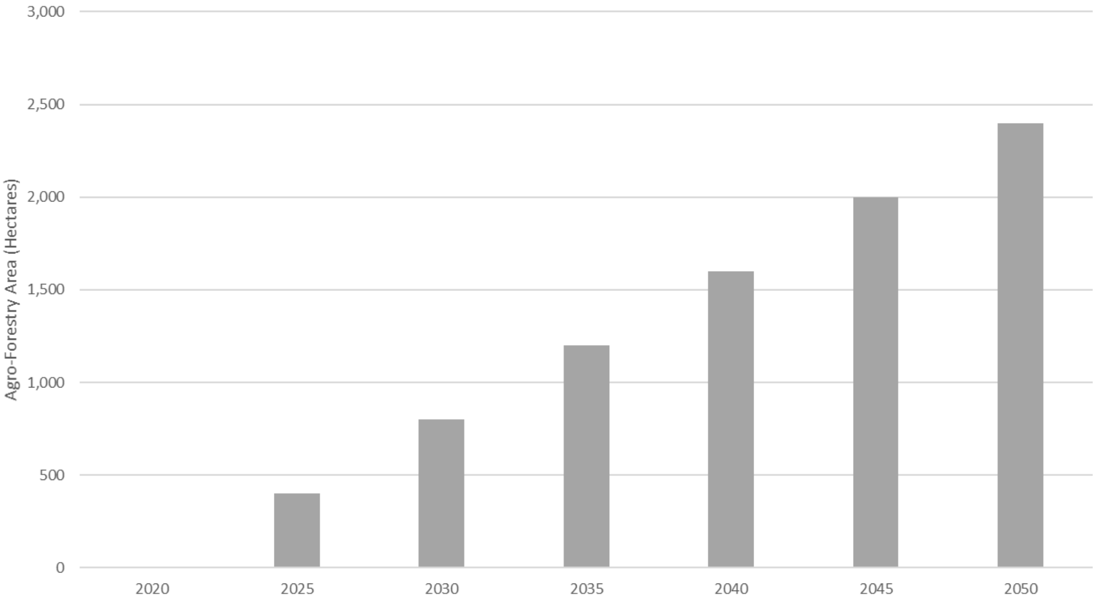
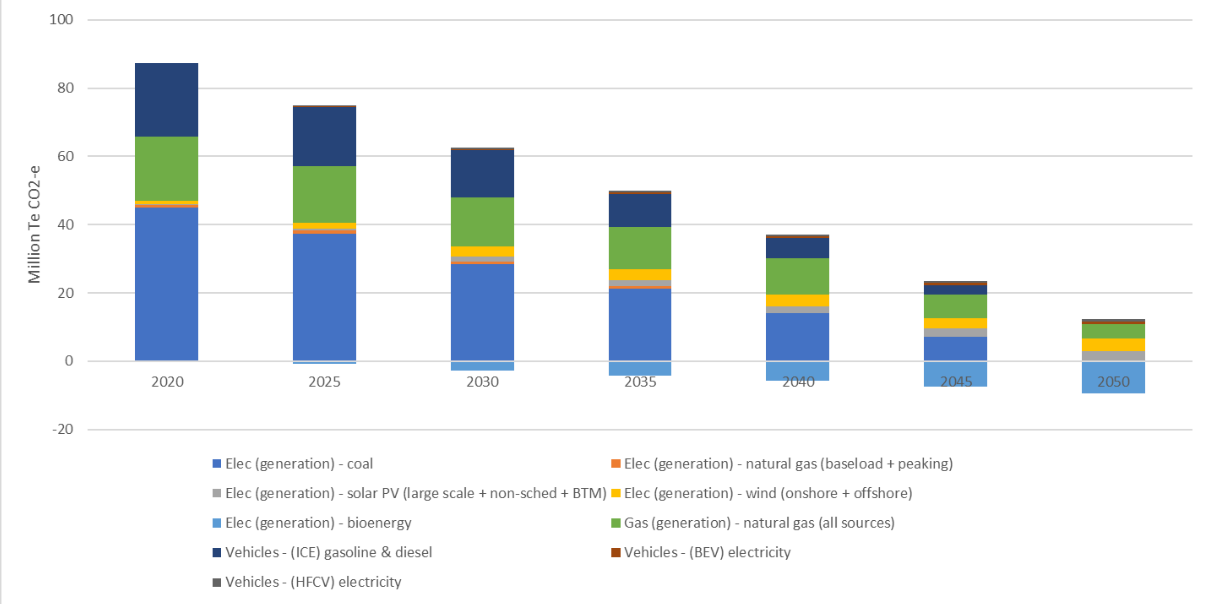


Figure 95: Contribution to Emissions by Source for Sensitivity Case 3



Sensitivity Case 3 requires slightly lower levels of Carbon offsets compared to the High Probability Technology case. It is noted that improving energy efficiency has little impact on reducing emissions because the largest sources of emissions tail off as the energy efficiency improvements become significant. The outcomes of Sensitivity Case 3 imply that a significant increase in residential-commercial energy efficiency improvement before 2030, combined with a much greater uptake of low emissions vehicles (also before 2030) would deliver a greater impact on emissions reduction.

For the current study, offsets derived from soil farming projects have been assumed to illustrate how residual emissions could be managed, see Section 3.4 for an assessment of the options, and Section 10.8 for cost estimation.

Figure 93 and Figure 94 indicate that 400 hectares would be required to be established every decade to achieve net zero emissions in 2050, commencing with 400 hectares in 2025, resulting in a cumulative total of 2,400 hectares in 2050, representing approximately 0.01% of Victoria's total land area.

10.4 Gas Spatial Analysis

10.4.1 Work Description

The proposed energy mix from the global modelling tool for the low probability case is used as an input into the spatial modelling tool. The spatial distribution of the energy gas demand has been kept in same proportion as the 2020 demand.

10.4.2 Results

This Sensitivity Case is based on the High Probability Technology case and has biomethane and hydrogen production rates with are somewhat lower than Sensitivity Case 1. Table 99 shows the energy gas demand by region from 2020 to 2050 for the Sensitivity Case 3. It can be seen that the overall energy gas demand reduces from 209 PJ/yr in 2020 to just 81 PJ/yr in 2050.

Table 99: Energy gas demand by region for the Sensitivity Case 3 from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	128	118	106	93	85	64	51
North East	6	5	6	5	4	3	2
Loddon Mallee	21	19	17	15	13	10	8
Grampians Central West	19	17	15	14	12	9	7
Barwon South West	25	23	20	18	16	12	9
Gippsland	5	4	4	3	3	2	1
Goulburn Valley	5	4	4	3	3	2	1
Total (PJ/yr)	**209**	**190**	**171**	**150**	**137**	**101**	**81**

In the Sensitivity Case 3 the overall energy gas demand declines due to increased energy efficiency. Table 100 shows the distribution of energy gas supply by type from 2020 to 2050. Biomethane production ramps up from 1 PJ/yr in 2025 to 32 PJ/yr in 2050. Green hydrogen in the gas network is limited to a maximum of 6 PJ/yr, with the remainder used for fuelling heavy fuel cell vehicles. Note the mean demand energy mix tables include green hydrogen for HFCV which represents 33 PJ/yr of demand in 2050.

Table 100: Energy gas supply by type for the Sensitivity Case 3 from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Victorian natural gas production	209	184	162	137	119	77	47
Biomethane	0	1	3	9	15	20	32
H2 (green)	0	6	6	5	4	3	2
Total (PJ/yr)	**209**	**190**	**171**	**150**	**137**	**101**	**81**

Figure 96 shows the gas mix for the Sensitivity Case 3 from 2020 to 2050.

Figure 96: Energy gas mix for the Sensitivity Case 3 from 2020 to 2050.

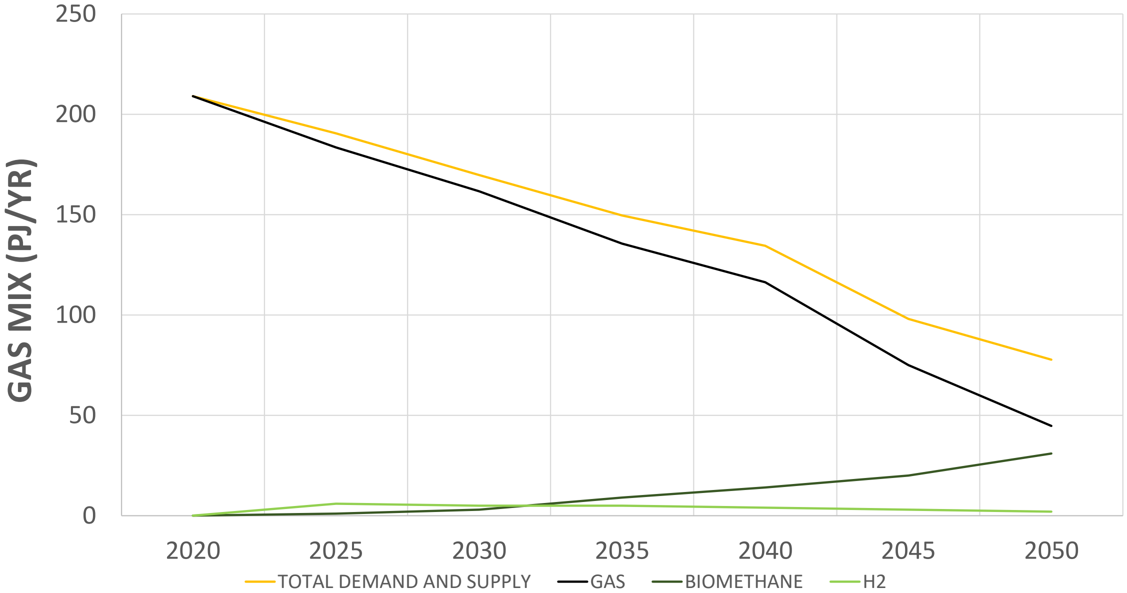
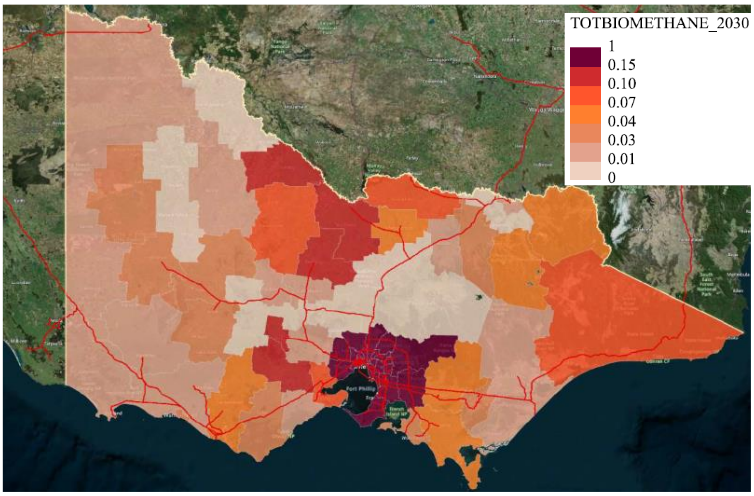


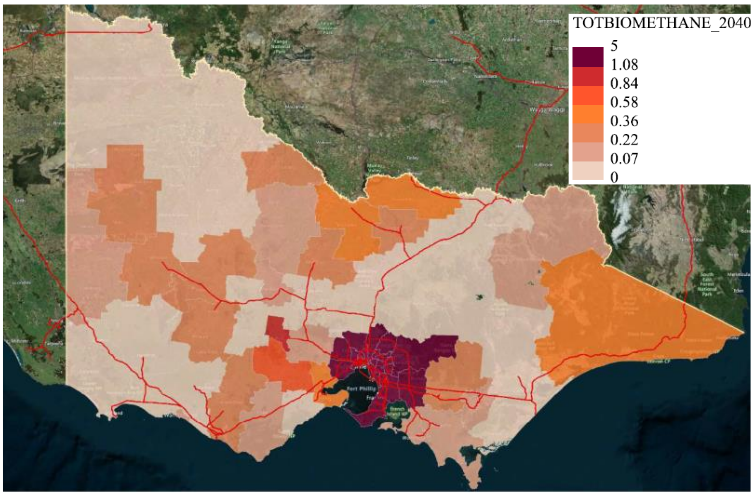
Figure 97 shows the biomethane production for Sensitivity Case 3, which is very similar to the results for Sensitivity Case 2.

Figure 97: Biomethane production for Sensitivity Case3 in (a) 2030, (b) 2040 and (c) 2050.

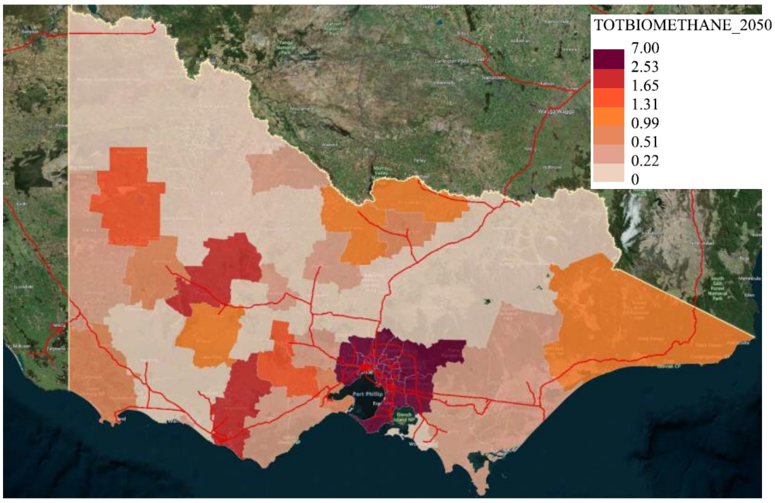
(a)



(b)



(c)



10.4.3 Discussion

- The Sensitivity Case 3 has the similar quantity of biomethane and green hydrogen in the energy mix as Sensitivity case 2.
- The major difference between this case and the High Probability Technology case is the lower demand for natural gas due to better energy efficiency. By 2050, biomethane will represent about 41% of the natural gas demand.

10.4.4 Gas pipeline network changes

For the Sensitivity Case 3, the major changes in the gas transmission network can be summarised as:

- Transmission of biomethane/hydrogen gas mixtures from Echuca/Shepparton/Bendigo and Ballarat towards Melbourne.
- Decommissioning of the Eastern Gas Pipeline from Longford to NSW after 2040.
- Decommissioning of the SEA gas pipeline to South Australia after 2040.

For the Sensitivity Case 3, the major changes in the gas distribution networks can be summarised as:

- Upgraded for 100% hydrogen use by 2030.

10.5 Electrical Spatial Analysis

10.5.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

Assumptions are explained in Section 3.6.

10.5.2 Work Description

For the Sensitivity Case 3, the electrical generation technologies include:

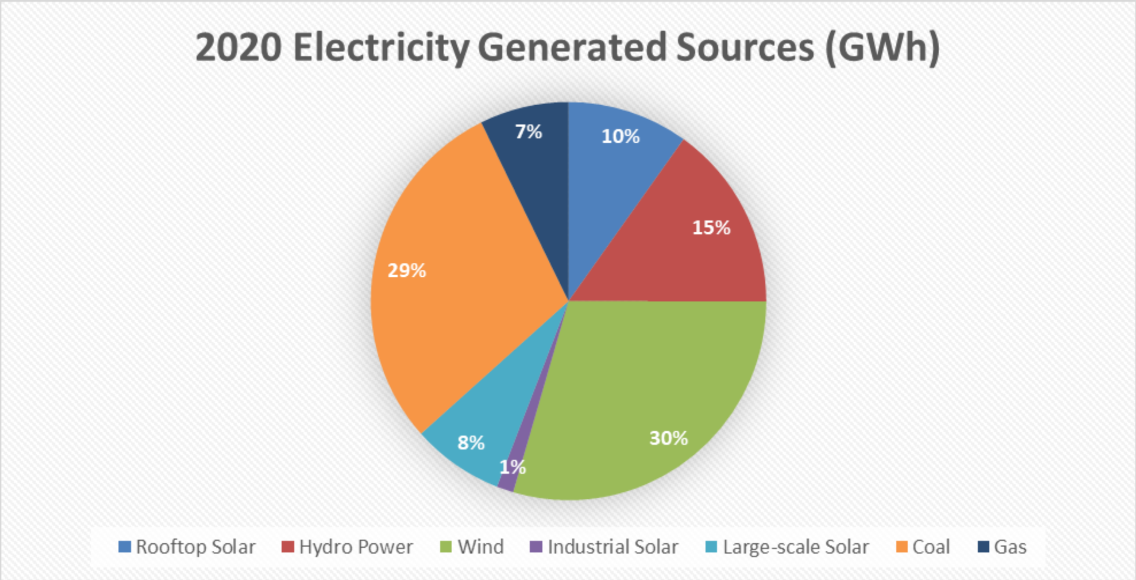
- Wind (onshore);
- Solar PV;
- Bioenergy; and
- Hydro power.

The electrical storage technologies include:

- Li-ion batteries (large-scale, industrial and behind the meter).

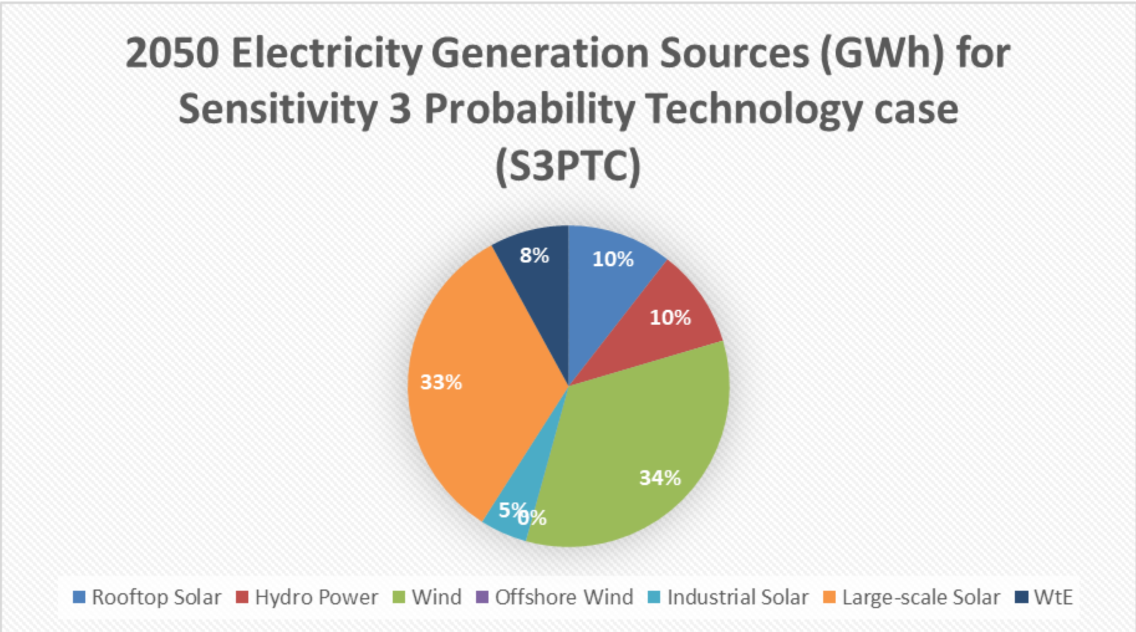
REMINDER: **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

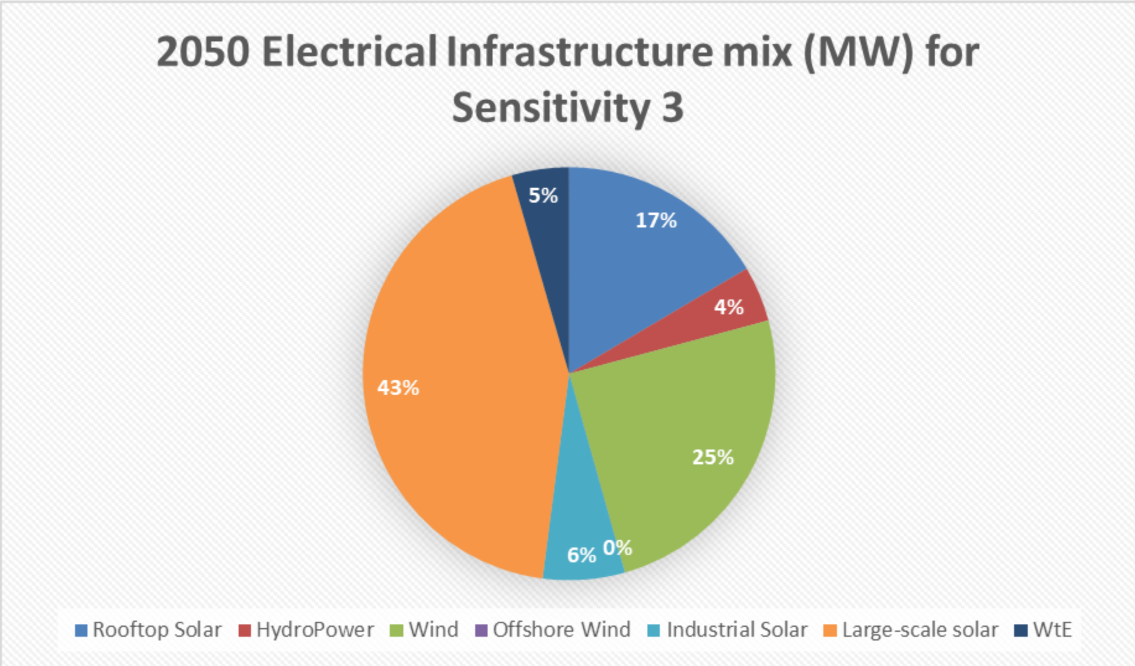
Electrical Generation Mix in 2020:



Electrical Mix in 2050:

(Note Reference in figures to "waste-to-energy" shall be read as "bioenergy")





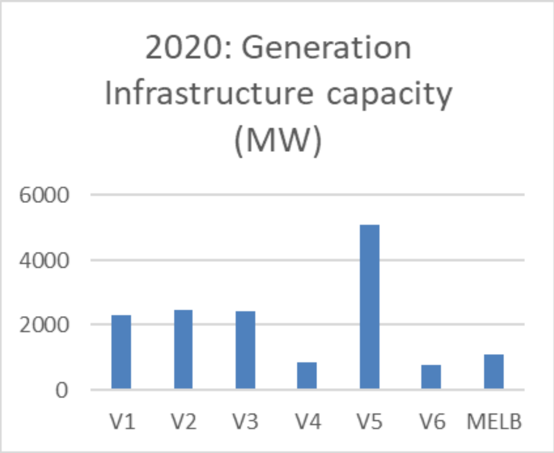
As observed in the charts above the electrical infrastructure capacity (MW) was found to increase by a factor of 3.6 over 30 years (2020 to 2050), while the electrical generation (GWh or PJ) increased by a factor of 1.6. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

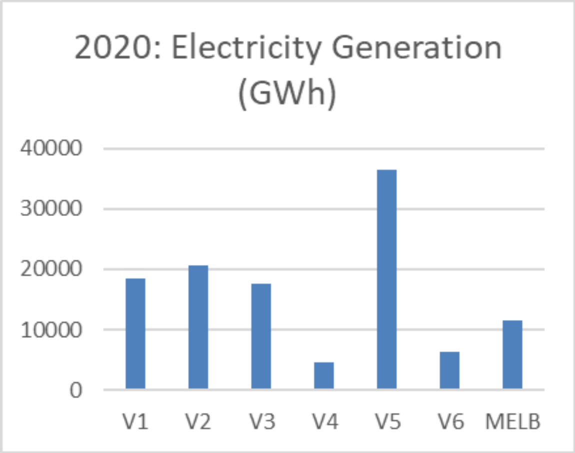
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	176 576	51 117

10.5.3 Results

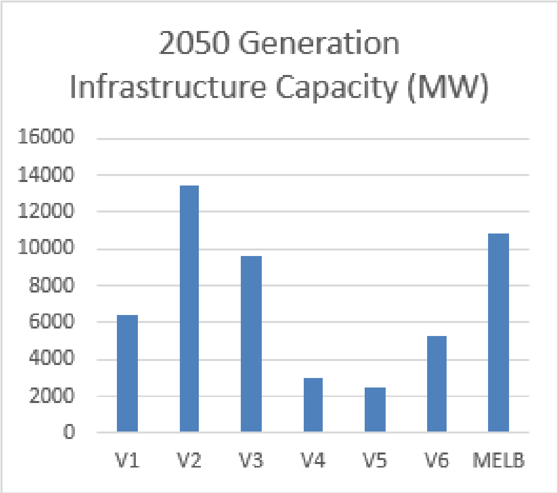
10.5.3.1 Overall Generation

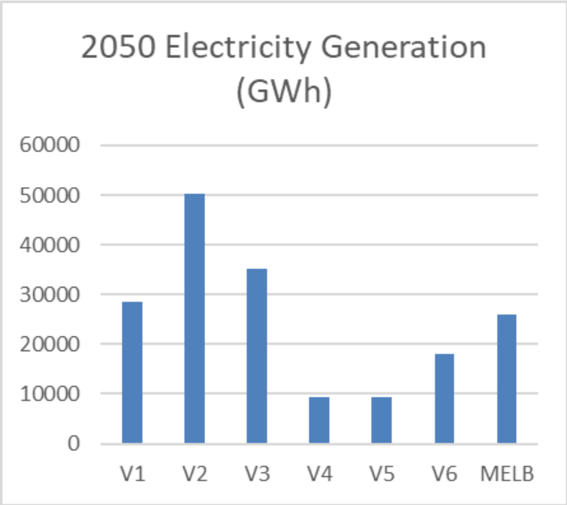
2020 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise of capacity for each REZ.
- South West (V4) and Gippsland (V5) have a low generation capacity.
- Ovens Murray (V1), Central North (V6) have an averaged generation capacity.
- Melbourne (MELB), Murray River (V2) and Western Victoria (V3) have a high generation capacity.

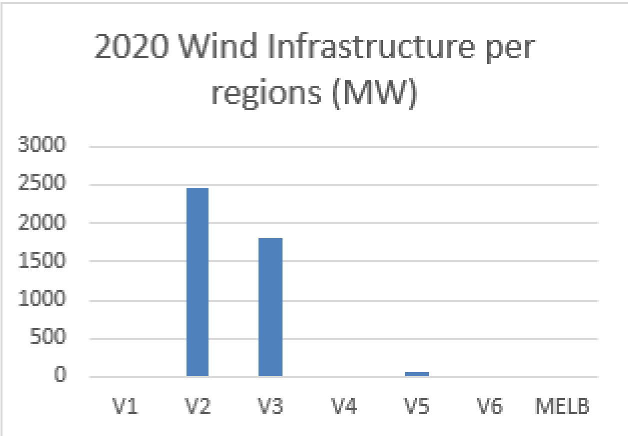
The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

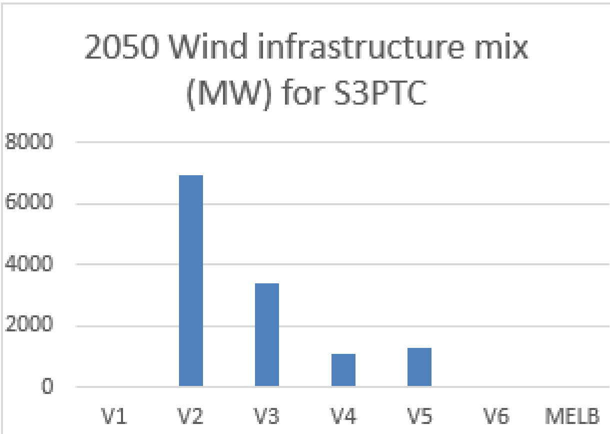
REMINDER: The assumptions used here are based on the AEMO's ISP inputs and assumptions workbook which has been used as "relied upon information".

The demand is located mainly in the Melbourne metropolitan region (around 60%), with around 10% demand in each of V2, V3 and V4 (representing the entire West side of Victoria) with the remaining 10% being split between V1, V5 and V6.

Comparing generation and demand locations, the transmission lines between all the regions, Melbourne and between East and West will need to be upgraded as both demand and electrical generation grows.

10.5.3.2 Wind





S3PTC: Sensitivity 3 Probability Technology Case

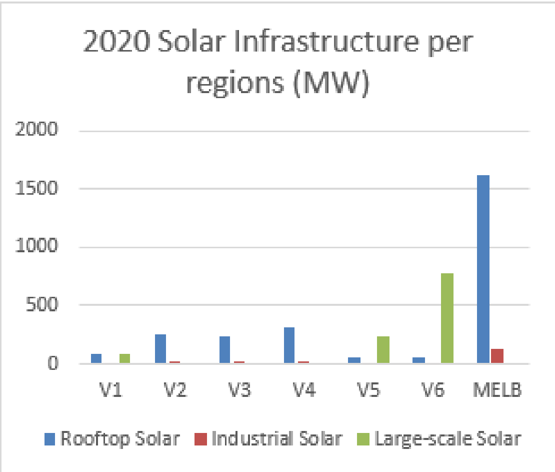
Note: All the locations of existing and committed assets for 2020 wind generation have been taken from AEMO's ISP inputs and assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched, in which case, consider (for wind only) that V2 and V4 values might need to be exchanged in the graphics and tables presented.

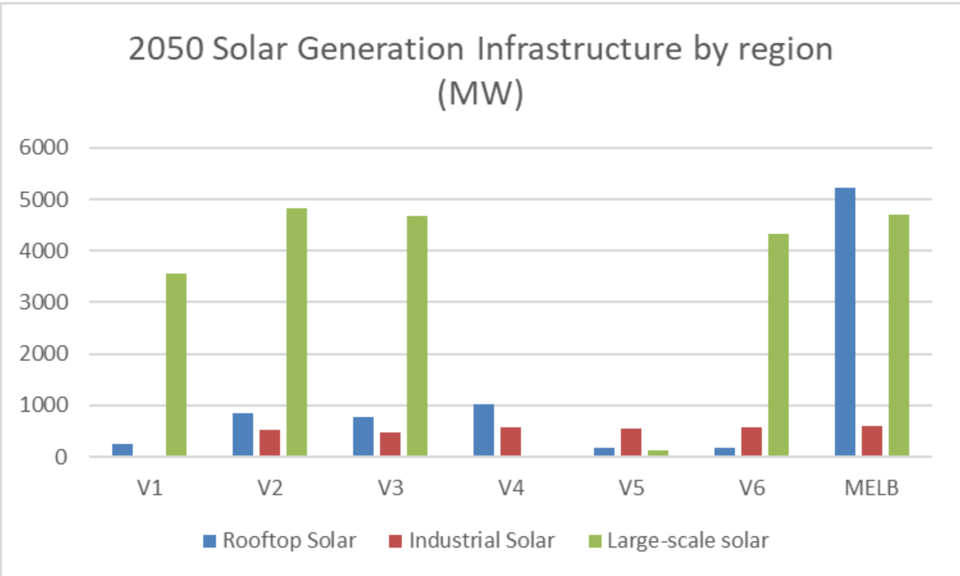
An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zone alongside the existing transmission lines. The location is based on available open land and associated wind rows.

Further work may consider wind generation infrastructure being more balanced between V2, V3 and V4. It is possible to consider V3 and V4 having much more wind as its wind potential is around 40%.

By 2050, wind represents 34% of the generated electricity with 12,672 MW of infrastructure capacity.

10.5.3.3 Solar PV





As for the High Probability Technology Case, solar PV will expand in all the regions in which it has a high potential: V1, V2, V3 and V6. Once again, the locations follow the transmission lines.

In 2050, Victoria is predicted to have:

- 8,437 MW of rooftop solar PV generation, representing 11% of electrical mix.

- 3,281 MW of industrial solar PV generation, representing 5% of electrical mix.
- 22,211 MW of large-scale solar PV generation, representing 33% of electrical mix.

10.5.3.4 Bioenergy

By 2050, Bioenergy provides 8% of the electrical demand with 2,295 MW of installed capacity.

10.5.3.5 Infrastructure to be Installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period.

The values in 2020 are the existing and committed assets, then for each subsequent time period the values represent the additional generation infrastructure that has to be added for the specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0
2025	7	0	0	0	0	117	0	0	0	0	0	37	0	280	22	11
2030	20	0	0	0	0	951	0	0	0	0	0	51	0	1580	44	29
2035	14	0	0	0	0	492	0	0	0	0	0	62	0	926	45	31
2040	10	0	0	0	0	597	0	0	0	0	0	58	0	1025	42	21
2045	46	0	0	0	0	517	0	0	0	0	0	69	0	701	120	100
2050	77	0	0	0	0	796	0	0	0	0	0	67	0	1812	208	167
	MW												GWh			

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0
2025	25	0	394	0	23	162	0	0	0	0	0	37	0	856	66	36
2030	68	0	1459	0	47	1320	0	0	0	0	0	51	0	4827	134	98
2035	48	0	1026	0	48	683	0	0	0	0	0	62	0	2830	138	103
2040	32	0	997	0	44	829	0	0	0	0	0	58	0	3130	127	69
2045	154	0	399	0	128	717	0	0	0	0	0	69	0	2141	367	334
2050	257	0	2441	0	221	1105	0	0	0	0	0	67	0	5536	636	555
	MW												GWh			

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0
2025	22	0	188	0	21	158	0	0	0	0	0	37	0	684	53	32	0	0
2030	61	0	698	0	42	1284	0	0	0	0	0	51	0	3861	107	88	0	0
2035	43	0	491	0	44	664	0	0	0	0	0	62	0	2264	111	93	0	0
2040	29	0	477	0	40	806	0	0	0	0	0	58	0	2504	102	62	0	0
2045	139	0	191	0	116	698	0	0	0	0	0	69	0	1713	294	300	0	0
2050	231	0	1167	0	202	1075	0	0	0	0	0	67	0	4429	509	500	0	0
	MW												GWh					

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0
2025	30	0	64	0	24	0	0	0	0	0	0	37	0	420	32	43	0	0
2030	81	0	238	0	49	0	0	0	0	0	0	51	0	2369	66	117	0	0
2035	57	0	167	0	51	0	0	0	0	0	0	62	0	1389	68	124	0	0
2040	38	0	162	0	47	0	0	0	0	0	0	58	0	1537	62	83	0	0
2045	185	0	65	0	134	0	0	0	0	0	0	69	0	1051	180	400	0	0
2050	308	0	397	0	233	0	0	0	0	0	0	67	0	2718	312	666	0	0
	MW												GWh					

Note

Reference in table to "waste-to-energy" shall be read as "bioenergy"

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0
2025	5	0	75	0	24	0	0	0	0	0	0	37	0	264	20	7	0	0
2030	14	0	279	0	49	0	0	0	0	0	0	51	0	1492	41	20	0	0
2035	10	0	196	0	51	0	0	0	0	0	0	62	0	875	43	21	0	0
2040	6	0	191	0	47	0	0	0	0	0	0	58	0	968	39	14	0	0
2045	31	0	76	0	135	0	0	0	0	0	0	69	0	662	113	67	0	0
2050	51	0	467	0	233	0	0	0	0	0	0	67	0	1711	197	111	0	0
	MW												GWh					

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0
2025	5	0	0	0	25	142	0	0	0	0	0	25	0	653	50	7	0	0
2030	14	0	0	0	51	1159	0	0	0	0	0	34	0	3686	102	20	0	0
2035	10	0	0	0	53	600	0	0	0	0	0	41	0	2161	106	21	0	0
2040	6	0	0	0	49	728	0	0	0	0	0	38	0	2391	97	14	0	0
2045	31	0	0	0	140	630	0	0	0	0	0	46	0	1635	280	67	0	0
2050	51	0	0	0	243	971	0	0	0	0	0	45	0	4228	486	111	0	0
	MW												GWh					

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM
2020	1617	0	0	0	125	0	0	482	500	0	0	0	0	0	0	0
2025	154	0	0	0	21	158	0	0	0	0	0	37	0	1509	116	223
2030	419	0	0	0	43	1287	0	0	0	0	0	51	0	8512	236	605
2035	295	0	0	0	44	666	0	0	0	0	0	62	0	4991	244	638
2040	199	0	0	0	40	808	0	0	0	0	0	58	0	5521	224	430
2045	956	0	0	0	117	699	0	0	0	0	0	69	0	3776	647	2069
2050	1591	0	0	0	202	1078	0	0	0	0	0	67	0	9764	1122	3443
	MW												GWh			

Note Reference in table to “waste-to-energy” shall be read as “bioenergy”

10.5.4 Discussion

Sensitivity Case 3 was observed to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Wind onshore
  - Bioenergy
  - Standard batteries (behind the meter, industrial and large scale)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar PV and wind represents between 75 and 80% of the electrical mix creating the potential for grid instability requiring compensation by additional generation and storage facilities. Starting in 2035 all wind, solar PV and battery infrastructure is multiplied by 1.5.
- The share of wind and solar PV (excluding behind the meter) in 2050 is 53% solar and 47% wind.
- New transmission lines are needed as the grid will have to support a lot more electricity. Upgrades of the following lines are considered likely (same as High Probability Technology case):
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers, representing approximately 25% more infrastructure than exists today.
- All the connections between the facilities and the grid have been taken into account in the cost analysis, but not shown on the maps.
- The storage is calculated depending on the quantity of solar and wind.

10.6 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

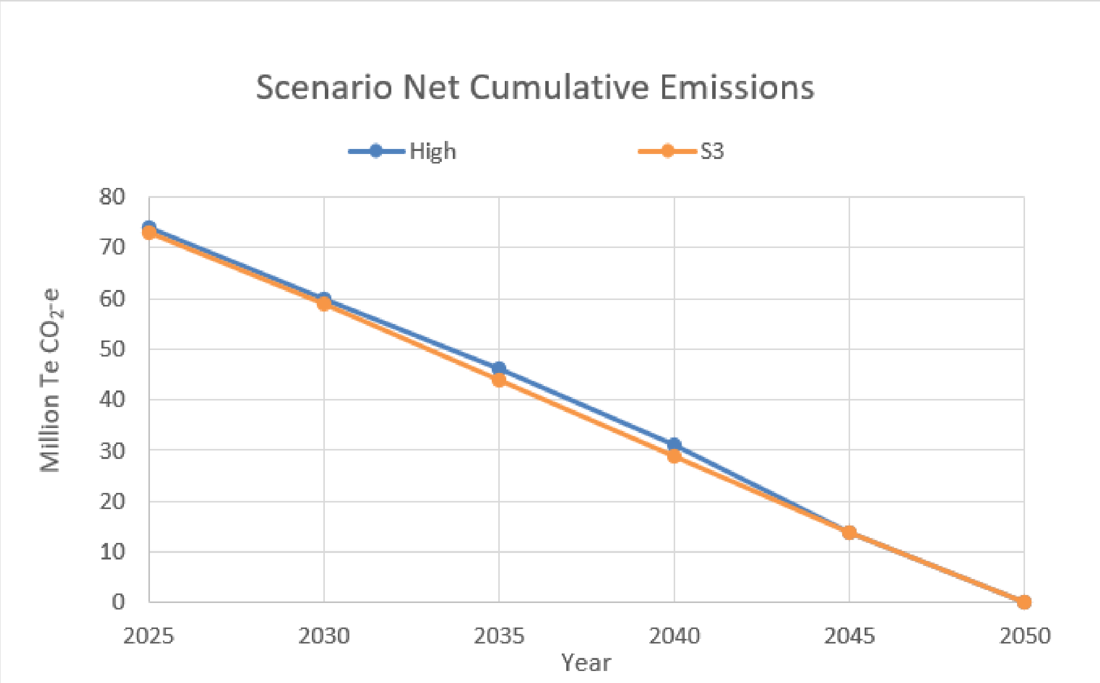
10.7 Environmental & Social Analysis

The environmental and social components of the Sensitivity Case 3 – Energy Efficiency have been assessed via a desk-top study using key aspects from environmental, social and economic perspectives and presented in Table 51.

10.7.1 Results

Sensitivity Case 3 – "Energy Efficiency" is based on the high probability technology Case with a higher rate of energy efficiency improvement being incorporated over the duration of the modelling. *Figure 99* shows the modelled emissions reduction profile for the energy efficiency sensitivity case and shows a linear decline in emissions to 2050. Prior to 2035 this sensitivity shows the lowest level of emissions of all the cases analyses. In 2050 the selected technologies have a residual emissions foot print of around 3 million tonnes CO2-e which are offset to achieve net zero emissions in 2050.

Figure 98: Comparison of High and Sensitivity 3 Case Scenario Emissions Reductions



- The Sensitivity Case 3 scenario profiles alongside High Probability Technology Case with slightly lower emission levels and proportionally the same contributions from the same energy technologies.

10.7.2 Discussion

The increased energy efficiency sensitivity takes the high probability technology case and assumes an increased rate of energy efficiency improvement to reduce energy demand and hence the need to invest in low emissions generation technology. Total energy demand in the sectors covered by this Study is reduced by around 15% compared with the high probability technology scenario. The need for large-scale solar PV is reduced by 13%, wind by 17%, battery storage by 13% and bioenergy by 20%.

Behavioural economic studies have identified a risk with attempting to reduce energy use through improvements to energy efficiency. Reducing energy demand can suppress energy prices relative to the counter factual, with lower energy prices serving to stimulate an increased demand for energy (IEAA Conference proceedings Energy Efficiency Policies and Rebound Effects in the Light of Radical Technical Change, and S, Borenstein, A Microeconomic Framework for Evaluating Energy Efficiency Rebound and Some Implications, The Energy Journal, 2015). Consequently, assumed energy saving may be eroded by this rebound effect. This has not been factored into this Study.

The proposed Sensitivity Case 3 "Increased Energy Efficiency" has the following environmental and social considerations:

- Key investments to achieve the net zero emissions target by 2050 include:
  - Compared to 2020; 16 times more solar PV, 3.8 times more wind capacity, and 160 times the level of battery support.
  - Significant investments in bioenergy and hydrogen production.
  - By 2050, 3.5 million tonnes per year of abatement being provided by greenhouse gas offsets.
  - Additional gas pipelines (to transport biogas).
  - Strengthened electricity grid.
- Total employment number for the sensitivity 3 ”Energy Efficiency” are slightly higher than the high probability technology case. There are slightly less people employed in the generation of renewable energy commensurate with the reduced amount of energy required in this case. This is more than compensated by the relatively large number of employees engaged in delivering the energy efficiency improvements. These include those engaged in undertaking energy efficiency assessments and implementing the resulting improvements. The main drivers of employment in this sensitivity are:
  - Energy efficiency (23%).
  - Rooftop solar PV (21%).
  - Wind (19.5%).
  - Battery storage (13%).
  - Large scale solar PV (12%).
- The construction of two new pipelines to meet proposed increases in biomethane production (150 km and 210 km in length) will result in the potential impact to environmentally sensitive terrestrial areas. There is the possibility that these construction projects may traverse national parks, wildlife management areas, rivers or wetlands. There may be opportunities to reduce the clearing required for these energy production methods if existing infrastructure corridors, such as transmission lines, are used.
- The increase in energy production from solar PV and wind (onshore) from 2020 to 2050 may require greater amounts of land clearing to support the infrastructure. There may be opportunities to reduce the clearing required for these energy production methods if existing cleared or infrastructure areas are used.
- It’s unlikely that there will be significant resistance from community for proposed increase in Solar PV with the Victorian public already having a high take up rate of roof top solar. Bioenergy and hydrogen developments will require careful management to avoid community concerns over rural industrialisation. Similarly, if offsets are sourced locally, care will be required to avoid community concerns over changed land use.
- The large reliance on solar PV to meet energy demand will require the attention to the management of end of life recycling.
- With the increase in renewable generation the numbers of batteries to support residential and commercial solar systems increases dramatically, requiring the management of fire risk, and end of life recycling.
- The increase in onshore wind power generation may result in impacts to sensitive environments (such has habitat loss, noise etc.) depending on the locations and

methods for construction. There may also be a reduction in visual amenity for locations where wind farm infrastructure is developed.

- Given the requirement for construction and land-clearing, there may be the potential for cultural heritage risks or impacts. These will need to be further analysed on a case-by-case assessment during planning phases and should include community and stakeholder consultation.
- Construction works associated with new infrastructure for renewable energy technologies (namely Biogas and Solar PV) may also increase the risk of environmental impacts (such as spills, fires etc.).

10.8 Cost Analysis

10.8.1Key References & Assumptions

Refer to Section 3.8.5.

10.8.2Work Description

Refer to Section 3.8 for details of the work description.

10.8.3Results

The figure below present the net difference between the Sensitivity Case 3 “Energy Efficiency” and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Note that energy efficiency is accounted for through avoided CAPEX due to reduced generation requirements to meet demand.

Figure 99 demonstrates that:

- The Sensitivity Case 3 “Energy Efficiency” projects a material reduction in fuel, FOM and VOM costs, as a result of the reduction of fossil fuel generation and expanded development and sharing of new variable renewable electricity resources, providing a net annualized cost benefit of approximately $3.6 billion in 2050.
- The Sensitivity Case 3 “Energy Efficiency” projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $5 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the Sensitivity Case 3 “Energy Efficiency” is represented by the purple line in Figure 99 By 2050, the Sensitivity Case 3 “Energy Efficiency” is forecast to provide a net cost increase of around $1.5 billion by 2050.

For the Sensitivity Case 3 “Energy Efficiency”, the net costs show a neutral trend until 2050 where there is an increased annual CAPEX spend to meet the energy demand in 2050 which returns a marginal net cost increase.

Figure 99: Net Costs of the Control Scenario relative to the Sensitivity Case 3 "Energy Efficiency"

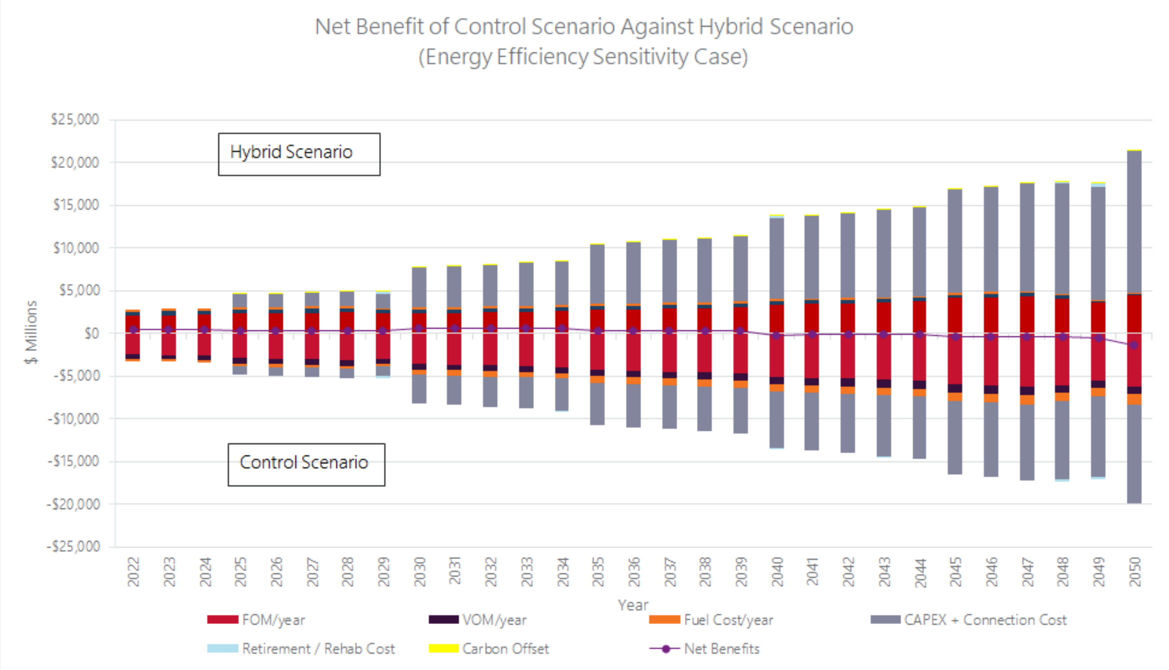


Table 101 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Sensitivity Case 3 "Energy Efficiency", in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of above, discounted back to present value, is $6.6 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$0.5 billion (NPC).

The estimated cost of CO2 abatement is $76/te CO2.

Table 101: Net Costs of the Control Scenario relative to the Sensitivity Case 3 "Energy Efficiency"

Cost Category[2]	**Net Cost of Control Against Technology Case (Energy Efficiency)**		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$4,410	-$1,659
FOM	$2,475	$1,745	$731
VOM	$435	$230	$205
Fuel	$419	$174	$245
Retirement / Rehab	$48	$52	-$4
Agro-forestry (Land Area, Hectare)	$0	$0.14	-$0.14
Gross Cost	$6,127	$6,610	-$482
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement t[3] ($/tonne)	583	76	507

Notes:
1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

10.8.4Discussion

The increased CAPEX combined with the overall energy mix for the Sensitivity Case 3 "Energy Efficiency" compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity but the reduced energy demand for this case improves the CAPEX compared to the other scenarios which is also expected.

OPEX and fuel costs savings for the Sensitivity Case 3 "Energy Efficiency" compared to the Control Scenario are also expected due to the reduction in fossil fuel generation and expanded development and sharing of new variable renewable electricity resources but are not sufficient to offset the CAPEX increase but improves the OPEX compared to the other scenarios which is also expected.

Retirement costs are marginally higher in the Sensitivity Case 3 "Energy Efficiency" as the existing, anticipated and committed generation is retired by 2050 plus decommissioning of gas transmission and distribution lines. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Sensitivity Case 3 "Energy Efficiency" cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

10.9 Risk & Opportunity Analysis

10.9.1 Key References & Assumptions

Four Sensitivity Cases were developed based on one of the three Base Analysis Cases previously described in this report. The modifications to the key assumptions are summarised in Table 102.

Table 102: Sensitivity Cases - Modifications to Key Assumptions

Sensitivity Case No.	Description	Reference Case	Modifications to Key Assumptions
3	Increased Energy Efficiency	High Probability Technology	Increased energy efficiency improvement rate from 5% to 20% per decade

10.9.2 Work Description

Sensitivity 2 "Energy Efficiency" incorporates a reduced energy demand reflective of the improvements in energy efficiency over the High Probability Technology Case.

Specific energy efficiency measures and their individual uptake rates were not assessed.

The study team reviewed the risks and opportunities identified in the High Probability Technology Case and assessed the key additional risks and opportunities unique to Sensitivity 2 "Energy Efficiency", focussing on the implementation risks rather than the inherent risks.

10.9.3 Results

Sensitivity 2 "Energy Efficiency" is based on the High Probability Technology Case and is susceptible to the technology and energy supply risks within that case. The key risks involve the failure of any of the key technologies to become commercially competitive at large scale within the indicated timeframes, but for the High Probability Technology Case this risk is minimal.

- Green hydrogen, initial incremental cost reduction breakthrough by 2025.

The supply of natural gas resources is a minor risk, but due to the reduction in overall energy demand, the requirement for any and all forms of energy may be reduced when compared with the High Probability Technology Case.

Increasing the adoption of energy efficiency measures may also assist in accelerating the achievement of net zero.

Whilst the quantity of carbon offsets required to achieve net zero is modest there is a risk to reliance on offsets to reach net zero, especially with competition for such offsets from hard to abate energy sectors.

10.9.4 Discussion

Specific energy efficiency measures and their individual uptake rates were not assessed during this Stage 2 study. An assumption of 5% energy efficiency per decade was used this study, apart from this sensitivity case which assumed 20%.

Various energy efficiency technologies were discussed briefly in the preceding Stage 1 (*Net Zero Emission Scenario Analysis Study Report May 2021*) study, but to fully understand and quantity the energy efficiency opportunity, including costs and benefits, a separate, detailed study would be required.

In this Analysis Case, the use of offsets is preferred over CCS implementation to achieve net zero, as it provides a more flexible approach with the ability to adjust the scale and timing of the offsets depending on the emissions reduction results actually being achieved. CCS projects involve a long lead time and significant capital expenditure and therefore greater certainty before an investment decision can be made.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

11 SENSITIVITY CASE 4 "MAXIMUM GREEN HYDROGEN"

Refer to Section 3.1 for a description of the technology breakthrough probability concept, and Section 1.5 for important guidance on the analysis methodology and related limitations.

11.1 Objective

The objective of running Sensitivity Case 4 was to investigate how a high proportion of green hydrogen in the energy mix would affect transition cost, emissions and use of existing energy infrastructure.

Sensitivity Case 4 provides a more complete understanding of the role of green Hydrogen in the transition. Combined with the Low Probability Technology case (limited green Hydrogen) it represents another "midpoint" Hydrogen case between the two extreme cases analysed in the prior Net Zero Emission Scenario Analysis Study Report May 2021: Scenario A (full electrification, with no Hydrogen); and Scenario D (full Hydrogen (brown)).

11.2 Case Description

A key assumption for Sensitivity Case 4 is that gas distribution systems in Victoria will be available for introduction of pure Hydrogen in 2035 (refer Section 2.6.2, item 16). On this basis, Sensitivity 4 proposes to segregate the gas transmission and distributions systems in 2035 as follows :

- Gas transmission system – transportation of biomethane and a "tail" of natural gas, along with a limited concentration of green Hydrogen limited to 10% due to materials of construction constraints; and
- Gas distribution system – transportation of successively elevated concentrations of green Hydrogen up to 2035, at which point pure green Hydrogen will be introduced.

The Low Probability Technology Case was used as the basis for Sensitivity Case 4, with green Hydrogen increased in two ways:

- Higher concentration of green Hydrogen in the gas distribution system. From 2020 to 2050 the concentration of green Hydrogen in the gas transmission system remains at 10% due to limitations in materials of construction.
  - 2025 : 20% green Hydrogen in the gas distribution system
  - 2030 : 30% green Hydrogen in the gas distribution system
  - 2035 – 2050 : 100% green Hydrogen in the gas distribution system
- Higher uptake of HFCVs compared to all other analysis cases. The higher uptake of HFCVs was offset by a reduction in the uptake of ICEs and BEVs
  - 2030 : approximately 250,000 HFCVs (approximately 33% light vehicles, and 66% heavy vehicles)
  - 2040 : approximately 330,000 HFCVs (approximately 35% light vehicles, and 65% heavy vehicles)
  - 2050 : approximately 450,000 HFCVs (approximately 50% light vehicles, and 50% heavy vehicles)

All new energy technologies used to “fill the gap” between existing / committed and additional energy generation capacity remain as per the Low Probability Technology Case, with the exception of green Hydrogen wherein the following improvements have been made by 2030 as a result of the breakthrough in this technology:

- **High Efficiency Electrolysis** - the amount of electrical power is significantly reduced compared to the current technology (therefore resulting in less VRE power required per kg Hydrogen).

2020 – 2030	58 kWh-e / kg H_2
2035	55 kWh-e / kg H_2
2040 - 2045	48 kWh-e / kg H_2
2050	42 kWh-e / kg H_2

- **High Pressure Electrolysis** - allows Hydrogen production at a pressure that can enter the pipelines without the need for compression (both HP transmission and LP distribution).

11.3 Energy Emissions Offsets

11.3.1 Key References & Assumptions

Refer Section 2.5 and Section 2.6.

11.3.2 Results and Discussion

Sensitivity Case 4 is in line with the Low Probability Technology Case, achieving net zero emissions by 2050 through low emissions energy technologies only, without the need for Carbon offsets or sequestration.

Table 103: Mean Demand Energy Mix for Sensitivity Case 4

	2020	2025	2030	2035	2040	2045	2050
Impact of Energy Efficiency on Energy Generation Capacity (PJ)							
Energy Generation to Meet Base Demand (Total VIC)	513	597	675	732	791	842	895
Energy Generation to Meet Reduced Demand due to Energy Efficiency (Total VIC)	513	592	664	715	768	811	857
Cumulative Energy Consumed accounting for Energy Efficiency (PJ)							
Elec (generation) - coal	144	113	89	60	37	17	0
Elec (generation) - natural gas (baseload + peaking)	5	4	4	4	0	0	0
Elec (generation) - hydropower	10	10	10	9	9	8	8
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	17	52	74	118	131	153	187
Elec (generation) - solar thermal - industrial	0	0	46	46	59	60	68
Elec (generation) - wind (onshore + offshore)	28	63	110	138	138	144	169
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	5	13	22	32	33	43
Elec (generation) - fuel cells	0	0	10	9	15	16	21
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	2	3	3	3	3
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	1	15	62	66	76	76	92
Gas (generation) - natural gas (all sources)	209	176	117	67	66	27	15
Gas (generation) - biomethane	0	1	4	10	16	21	32
Gas (generation) - H2 (green) [incl HFCV fuel]	0	27	45	96	112	155	169
Vehicles - (ICE) gasoline & diesel	318	258	212	138	80	37	0
Vehicles - (BEV) electricity	0	8	17	27	36	41	48
Vehicles - (HFCV) electricity [GENERATION]	0	26	52	55	55	56	59
TOTAL (PJ)	732	759	867	867	864	845	914

Compared to the Low Probability Technology Case, Table 103 reveals the large pivot from electricity demand in Sensitivity Case 4 with approximately 115 PJ additional energy gas, primarily green Hydrogen in 2050.

The higher uptake of HFCVs leads to a reduced uptake of BEVs and, when combined with the improvements assumed for green Hydrogen production technology, a lower level of electricity demand is required for low emissions vehicles.

- In 2020, as per the Low Probability Technology Case, gasoline & diesel (ICE vehicles) is the single biggest energy source at approximately 320 PJ-thermal, or approximately 45% of the total, with natural gas in second position at approximately 210 PJ-thermal or approximately 30% of the total, and electricity from coal in third position at approximately 145 PJ-electricity or approximately 20% of the total.
- In 2030, Sensitivity Case 4 begins to deviate significantly from the Low Probability Technology Case with approximately 30 PJ additional solar & wind power as the level of energy gas picks up with approximately 15 PJ additional green Hydrogen. Overall energy demand balance is maintained through reduced levels of solar thermal and associated molten salt storage*. The higher uptake of HFCVs compared to the Low Probability Case leads to reduced BEV and ICE road vehicles leading to reduced demand for diesel and gasoline plus electricity (for BEVs) of approximately 15 PJ.
- 2040 sees Sensitivity Case 4 continue to deviate from the Low Probability Technology Case with approximately 85 PJ additional solar & wind power as the level of energy gas picks up with approximately 80 PJ additional green Hydrogen. Overall energy demand balance is maintained through reduced levels of solar thermal and associated molten salt storage*. The higher uptake of HFCVs compared to the Low Probability Case leads to reduced BEV and ICE road vehicles leading to reduced demand for diesel and gasoline plus electricity (for BEVs) of approximately 35 PJ.
- In 2050 Sensitivity Case 4 continue to deviate from the Low Probability Technology Case with approximately 115 PJ additional solar & wind power as the level of energy

gas picks up with approximately 130 PJ additional green Hydrogen. Overall energy demand balance is maintained through reduced levels of solar thermal and associated molten salt storage*. The higher uptake of HFCVs compared to the Low Probability Case leads to reduced BEV and ICE road vehicles leading to reduced demand for diesel and gasoline plus electricity (for BEVs) of approximately 15 PJ.

**For Sensitivity Case 4, storage includes both molten salt (associated with solar thermal) and current technology batteries. The molten salt systems are configured as large-scale (industrial), whilst the current technology batterie have several configurations: large-scale (industrial), virtual power plants (aggregated / co-ordinated), and behind the meter (non-aggregated).*

Also noteworthy from Table 103 is the increased diversity of energy sources resulting from the transition:

- In 2020, as per the Low Probability Technology Case, the top three single energy sources (gasoline & diesel, natural gas & coal) represented approximately 90% of the total energy mix;
- In 2030 the top three energy sources are gasoline & diesel, natural gas (as per the Low Probability Technology Case), however wind is also in the top three (as opposed to coal) representing approximately 50% of the total;
- In 2040 the top three are wind, solar PV and green Hydrogen (as opposed to solar thermal / storage, wind and gasoline & diesel for the Low Probability Technology Case) representing approximately 45% of the total; and
- In 2050 the top three remain as wind, solar PV and green Hydrogen (as opposed to storage*, solar thermal and wind for the Low Probability Technology Case) representing approximately 60% of the total.

By excluding gasoline & diesel consumption (ICE fuel) and HFCV electricity (more relevant to generation capacity), Figure 100 allows a clear examination of only electricity and energy gas consumption indicating the proportion of electricity to gas over time.

- In 2020, in line with the Low Probability Technology case, approximately 205 PJ-electricity is consumed, being approximately 50% of the total, and approximately 210 PJ-thermal energy gas is consumed being approximately 50% of the total.
- In 2030, compared to the Low Probability Technology Case there is a pivot to energy gas (due to increased levels of green Hydrogen), though the overall split remains essentially the same.
- In 2040, the proportion of energy gas (due to increased levels of green Hydrogen) is now higher than the Low Probability Technology Case with approximately 25% energy gas and 75% electricity.
- In 2050, the proportion of energy gas (due to increased levels of green Hydrogen) is now significantly higher than the Low Probability Technology Case maintaining a split of approximately 25% energy gas and 75% electricity.

Figure 100: Energy Mix Breakdown for Sensitivity Case 4 Covering only Electricity & Energy Gas (excludes gasoline & diesel (ICE fuel) and HFCV electricity (more relevant to generation capacity))

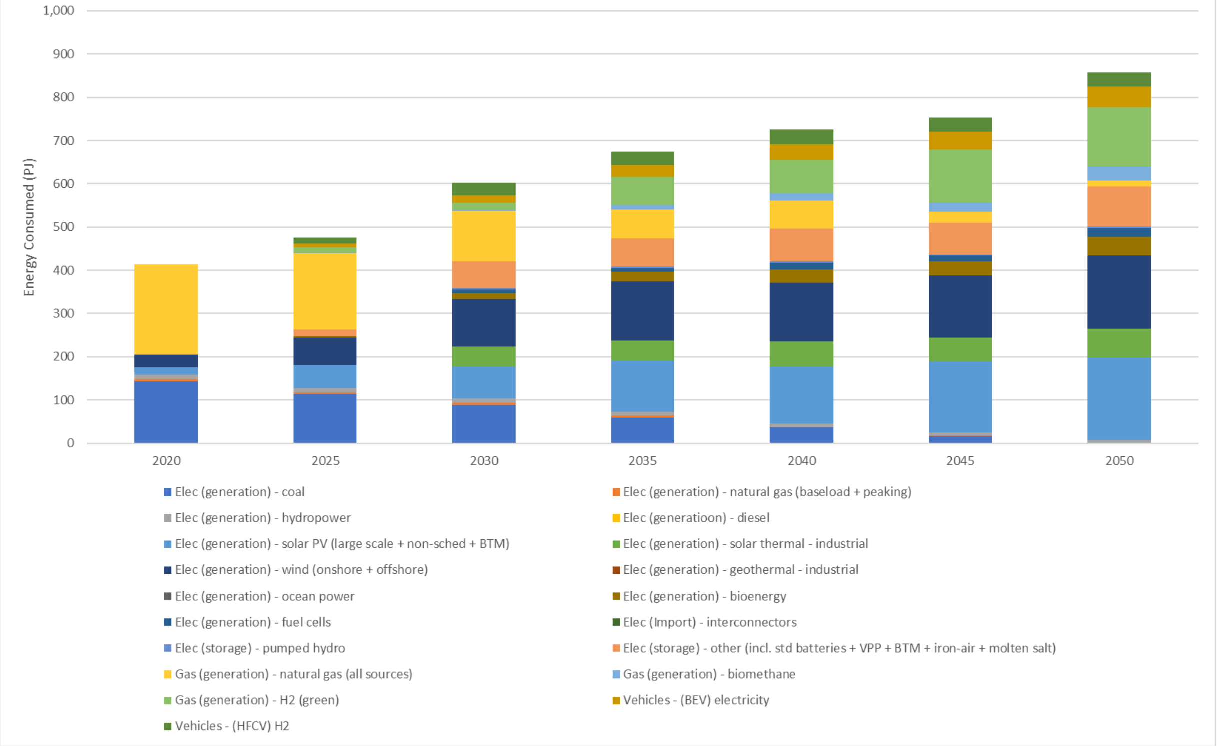


Table 104 and Figure 102 illustrate that Sensitivity 4 has a similar emissions decline profile to the Low Probability Technology case, with a gradual decline to net zero emissions in 2050. A slight deviation occurs around 2035 as green Hydrogen displaces coal and natural compared to the Low Probability Technology Case leading to a slightly lower level of overall emissions for Sensitivity Case 4.

Table 104: Emissions for Sensitivity Case 4

(rounding errors may lead to minor inconsistencies in reported total emissions)

	2020	2025	2030	2035	2040	2045	2050
Elec (generation) - coal	45	35	28	19	12	5	0
Elec (generation) - natural gas (baseload + peaking)	1	1	1	1	0	0	0
Elec (generation) - hydropower	0	0	0	0	0	0	0
Elec (generatioon) - diesel	0	0	0	0	0	0	0
Elec (generation) - solar PV (large scale + non-sched + BTM)	0	1	1	1	2	2	2
Elec (generation) - solar thermal - industrial	0	0	0	0	1	1	1
Elec (generation) - wind (onshore + offshore)	1	2	3	4	4	5	5
Elec (generation) - geothermal - industrial	0	0	0	0	0	0	0
Elec (generation) - ocean power	0	0	0	0	0	0	0
Elec (generation) - bioenergy	0	-1	-3	-5	-8	-8	-10
Elec (generation) - fuel cells	0	0	0	0	0	0	0
Elec (Import) - interconnectors	0	0	0	0	0	0	0
Elec (storage) - pumped hydro	0	0	0	0	0	0	0
Elec (storage) - other (incl. std batteries + VPP + BTM + iron-air + molten salt)	0	0	0	0	0	0	0
Gas (generation) - natural gas (all sources)	19	16	10	6	6	2	1
Gas (generation) - biomethane	0	0	0	0	0	0	0
Gas (generation) - H2 (green) [incl HFCV fuel]	0	0	0	0	0	0	0
Vehicles - (ICE) gasoline & diesel	21	17	14	9	5	2	0
Vehicles - (BEV) electricity	0	0	0	0	0	1	1
Vehicles - (HFCV) electricity	0	0	1	1	1	1	1
TOTAL EMISSIONS	**87**	**72**	**56**	**37**	**23**	**11**	**0**
TOTAL SEQUESTRATION & OFFSETS	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NET EMISSIONS	**87**	**72**	**56**	**37**	**23**	**11**	**0**

Figure 101: Emissions Profile for Sensitivity Case 4

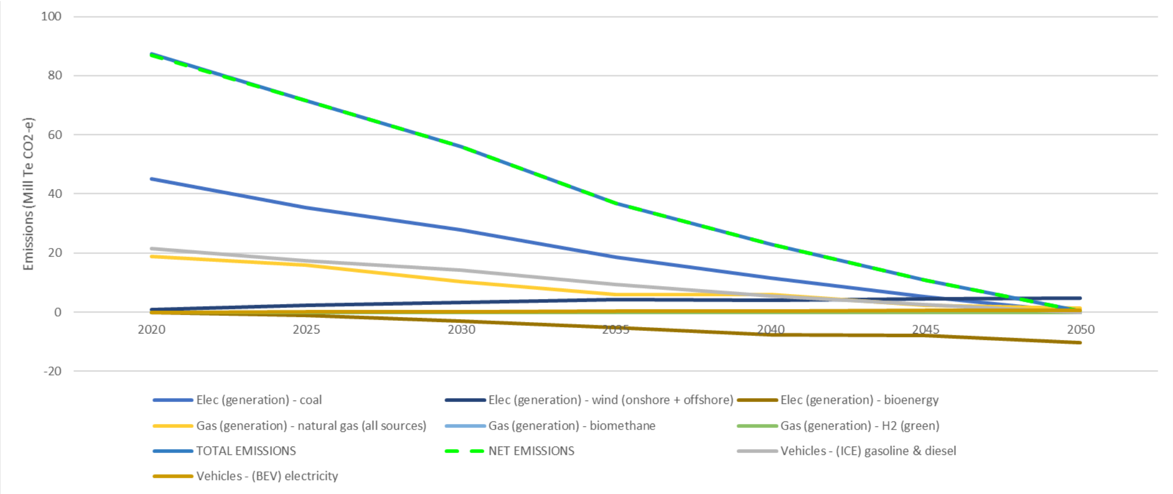
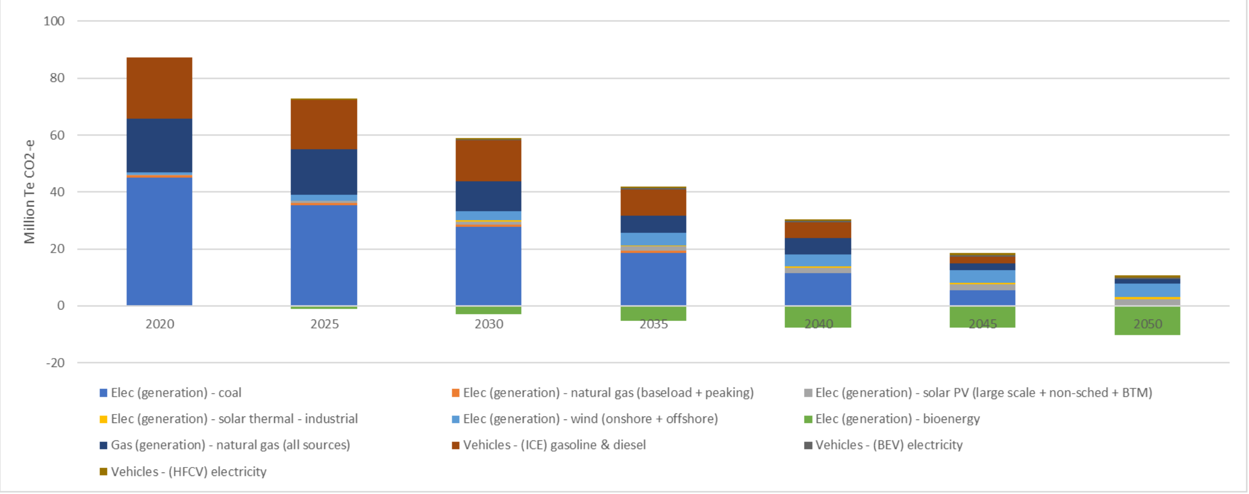


Table 5 in Section 1.6.4 documents the interim emissions targets covering all emissions sources in Victoria. It should be noted that the emissions profiles for the various Hybrid Scenario cases shown in the following figures relate only to the study scope (electricity, energy gas and road vehicles) and can therefore not be compared directly with the interim emissions targets which would cover emissions sources out of the study scope such as agriculture, non-road vehicles and fossil fuels other than coal, natural gas and gasoline diesel (other than for road vehicles).

What can be concluded from an indirect comparison of the interim emissions targets and the emissions profile for Sensitivity Case 4 is that a margin exists in the interim target to cover out of scope emissions, which is estimated to be:

- <u>2025 interim emissions target: up to 20 Million Te CO2-e to cover out of scope emissions; and</u>
- <u>2030 interim emissions target: up to 14 Million Te CO2-e to cover out of scope emissions.</u>

Figure 102: Contribution to Emissions by Source for Sensitivity Case 3



Sensitivity Case 4 requires no Carbon offsets to achieve net zero emissions by 2050, as per the Low Probability Technology Case.

11.4 Gas Spatial Analysis

11.4.1 Work Description

The proposed energy mix from the global modelling tool for the Sensitivity 4 case is used as an input into the spatial modelling tool. The spatial distribution of the energy gas demand has been kept in same proportion as the 2020 demand.

11.4.2 Results

Table 105 shows the energy gas demand by region from 2020 to 2050 for the Sensitivity 4 case. It can be seen that the overall gas demand stays roughly stable over the period at 150 – 200 PJ/yr with a dip down to 130 PJ/yr around 2030-2035.

Table 105: Energy gas demand by region for the Sensitivity 4 case from 2020 to 2050.

REGION	2020	2025	2030	2035	2040	2045	2050
Melbourne	128	109	80	85	97	104	112
North East	6	5	4	4	4	5	6
Loddon Mallee	21	17	13	14	16	17	19
Grampians Central West	19	16	12	13	14	15	16
Barwon South West	25	21	15	16	18	20	22
Gippsland	5	4	3	3	3	3	3
Goulburn Valley	5	4	3	3	3	3	3
Total (PJ/yr)	**209**	**176**	**129**	**137**	**156**	**167**	**181**

In the Sensitivity 4 case the natural gas supplies from Gippsland and Port Campbell are allowed to decline naturally. Additional natural gas is not imported into Victoria. Biomethane is ramped up so that collectively it supplies 31 PJ/yr by 2050. Green hydrogen production is used to supplement the supply of natural gas and biomethane and is injected into the low-pressure distribution networks in each region. The total green hydrogen production ramps from 12 PJ/yr in 2025 to 137 P/yr in 2050.

Table 106 shows the distribution of gas supply by type from 2020 to 2050.

Table 106: Energy gas supply by type for the Sensitivity 4 case from 2020 to 2050.

SUPPLY SOURCE	2020	2025	2030	2035	2040	2045	2050
Gippsland, Bass Strait	165	130	89	51	50	21	12
Port Campbell, Otway basin	44	33	22	13	13	5	3
Biomethane	0	1	4	10	16	21	31
Hydrogen in distribution network	0	12	15	65	78	123	137
Total (PJ/yr)	**209**	**176**	**130**	**139**	**157**	**170**	**183**

Figure 103 shows the gas mix in the complete system across Victoria for the Sensitivity 4 case from 2020 to 2050.

Figure 103: Energy gas mix in Victoria for the Sensitivity 4 case from 2020 to 2050.

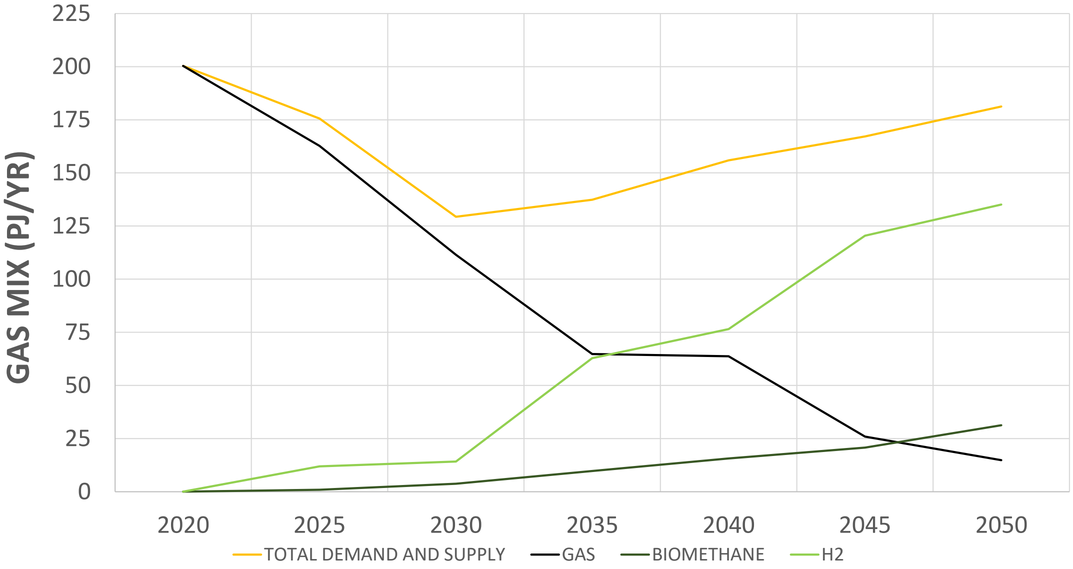
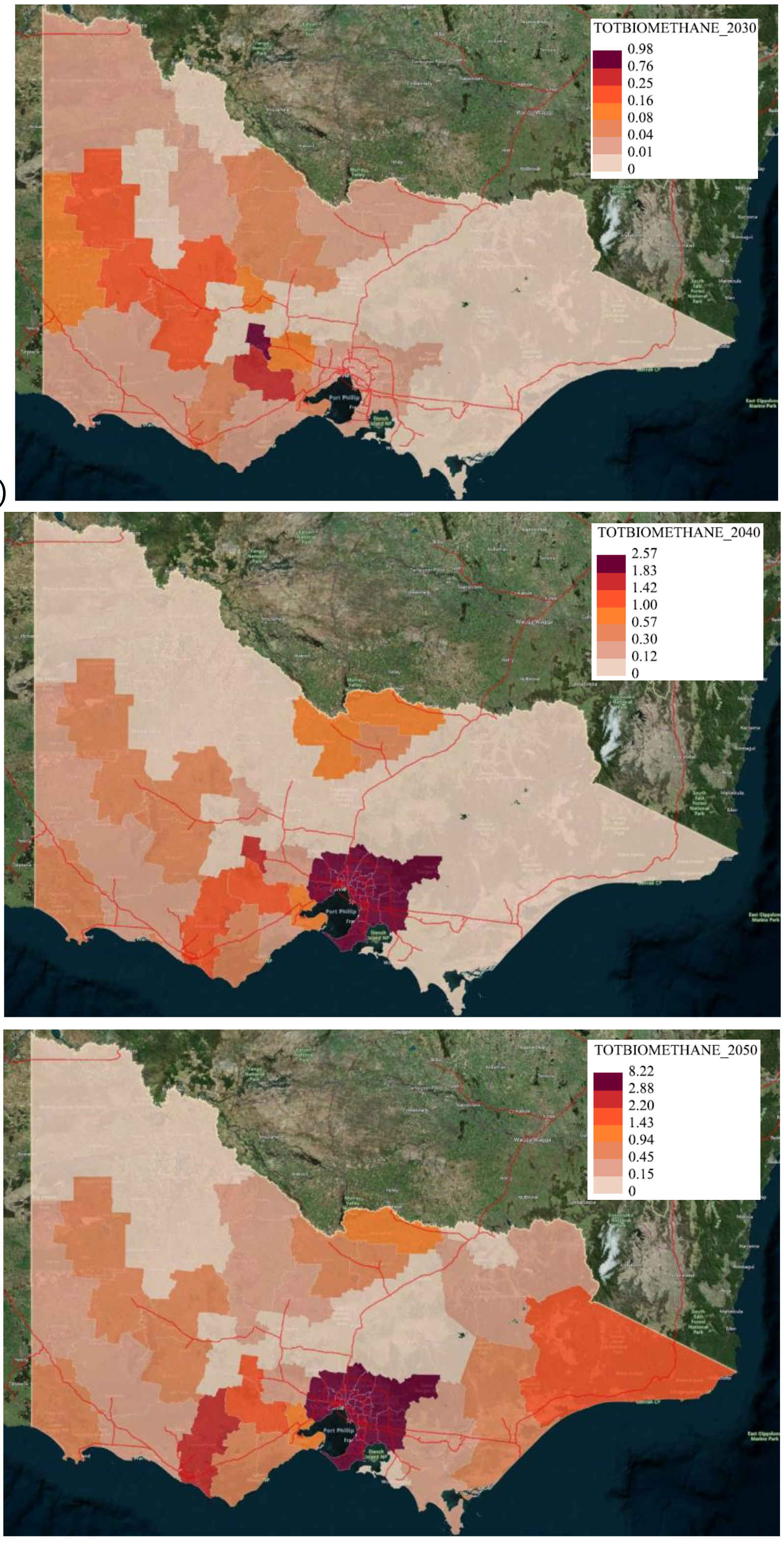


Figure 104 shows the biomethane production for the Sensitivity 4 case. In the Sensitivity 4 case the biomethane is used locally in the same region it is generated in. No new transmission lines are installed as in the Low, Mid and High Probability technology cases. Similarly, green hydrogen is produced close to where it will be consumed. Green hydrogen will be made from the electrolysis of water and injected into the low-pressure distribution systems. By 2030 it is assumed that all of these distribution systems will have been upgraded to handle 100% hydrogen. This aligns with existing plans to install high density polyethylene (HDPE) liners to enable 100% hydrogen and an increase in distribution pressure to enable the same or greater energy flows in the distribution systems.

Figure 104: Biomethane production in (a) 2030, (b) 2040 and (c) 2050.

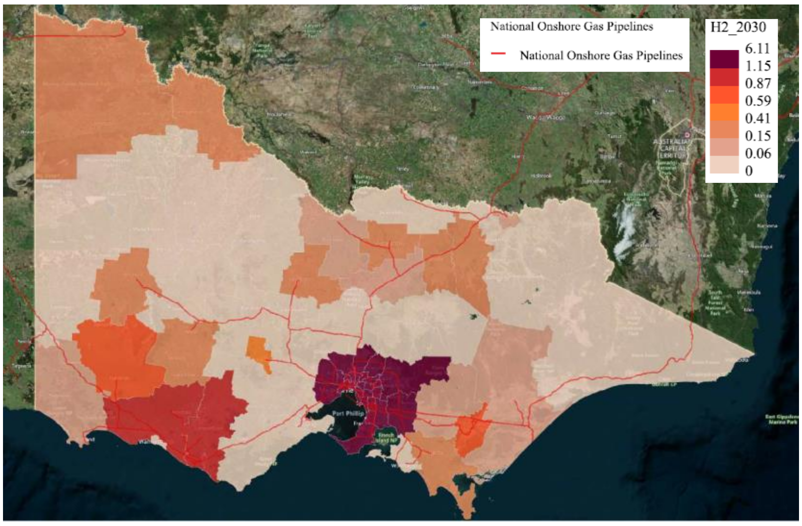


(a)

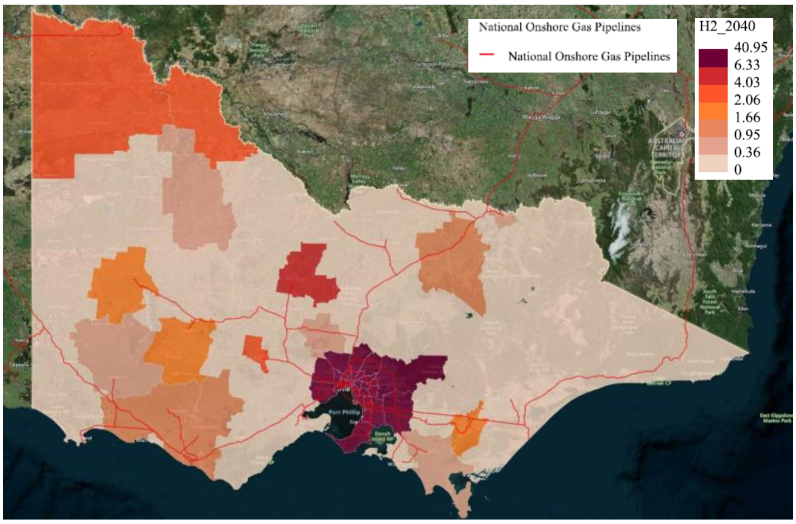
(b)

(c)

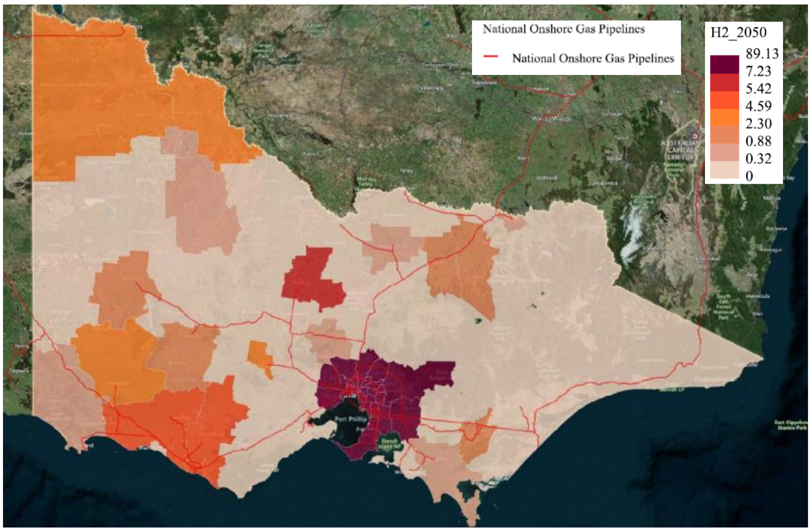
Figure 105: Hydrogen generation locations in (a) 2030, (b) 2040 and (c) 2050.



(a)



(b)



(c)

Figure 105 and Table 107 shows the distribution of green hydrogen production from 2030 to 2050. Around 50-65% of the state's green hydrogen is needed in Melbourne with the other major sources of demand being in Loddon Mallee, Grampians Central West and Barwon South West.

Table 107: Local green hydrogen production in PJ/yr from 2020 to 2050.

Region	2020	2025	2030	2035	2040	2045	2050
Melbourne	0	3	6	35	42	77	91
North East	0	1	1	3	4	5	4
Loddon Mallee	0	1	1	14	15	16	18
Grampians Central West	0	2	2	7	8	10	9
Barwon South West	0	2	3	4	4	9	15
Gippsland	0	2	2	0	3	3	0
Goulburn Valley	0	1	1	2	1	2	0
Total (PJ/yr)	0	12	15	65	78	123	137

Water consumption for green hydrogen production is around 0.15 GL/PJ-H_2. Therefore, in 2050, the water requirements will reach 21 GL/yr distributed as follows: 14 GL/yr in Melbourne, 0.6 GL/yr in North East, 2.7 GL/yr in Loddon Mallee, 1.4 GL/yr in Grampians Central West, 2.3 GL/yr in Barwon South West, up to 0.5 GL/yr in Gippsland and up to 0.3 GL/yr in Goulburn Valley. The supply and allocation of this water will need to be managed, but is small in comparison to the total state resource, which is estimated at over 15,000 GL/yr. Also of note: water not used by coal fired power generation in the Latrobe Valley - reported to be 140 GL/yr (Institute of Public Affairs, 2008)) – would be sufficient to supply water for hydrogen production several times over.

A consequence of allowing natural gas supply to decline naturally and to produce both biomethane and green hydrogen locally and into the low-pressure distribution systems is that the utilisation of the high-pressure transmission line system declines over time. Table 108 shows the flows in the main transmission line connections between the regions for the period 2020 to 2050. By 2035, the local production of green hydrogen and biomethane mean that there is no need for transmitting gas from Melbourne to the North East, Loddon Mallee, Grampians Central West and Goulburn Valley. From 2035 there is only a small residual flow of natural gas from Barwon South West, Port Campbell to Melbourne of less than 3 PJ/yr. The flow from Gippsland to Melbourne reduces from 49 PJ/yr in 2035 to 12 PJ/yr in 2050.

Therefore, by 2035, a large portion of the high-pressure transmission line can be decommissioned. The total kilometres of transmission line that could be decommissioned is potentially up to 4,000 kms (85%).

Table 108: Energy gas transmissions between regions in PJ/yr from 2020 to 2050.

Region to Region Transmissions	2020	2025	2030	2035	2040	2045	2050
Melbourne to North East	6	4	4	0	0	0	0
Melbourne to Loddon Mallee	20	17	12	0	0	0	0
Melbourne to Grampians Central West	18	13	7	0	0	0	0
Barwon South West to Melbourne	16	15	10	3	2	0	0
Gippsland to Melbourne	159	130	88	49	51	21	12
Melbourne to Goulburn Valley	5	3	2	0	0	0	0

11.4.3 Discussion

The proposed solution for the Sensitivity 4 case has the following characteristics:

- No natural gas will be imported into the state via interconnectors or via LNG imports.
- Total biomethane production ramps up to 31 PJ/yr by 2050. The biomethane is produced locally and injected directly into the local low pressure distribution systems in each region.
- Biomethane from anaerobic digestion is deployed commencing at 1 PJ/yr in 2025 and ramping up to 23 PJ/yr by 2050.
- Biomethane production from domestic waste organics delivers around 8 PJ/yr of gas in Melbourne by 2050. Biomethane production from agricultural organics reaches 7 PJ/yr in the Grampians Central West and 3 PJ/yr in Barwon South West by 2050.
- Biomethane from biomass gasification is limited to 8 PJ/yr by 2050 and is concentrated in Barwon South West, Gippsland and North East.
- Green hydrogen production is ramped up very significantly from 12 PJ/yr in 2025 to 137 PJ/yr in 2050. The green hydrogen production is achieved primarily by electrolysis of water, which requires a very substantial addition of renewable electricity production across the state. The green hydrogen is injected into the low pressure distribution systems in each region.
- The end customers in each region will receive a gas mix that is a combination of natural gas from fossil sources, biomethane and green hydrogen. By 2050, the proportion of energy supplied by green hydrogen in each region will be: 80% in Melbourne; 80% in North East; 95% in Loddon Mallee; 57% in Grampians Central West; 67% in Barwon South West; 0% in Gippsland and 0% in Goulburn Valley. Gippsland will be supplied with 100% fossil derived natural gas and Goulburn Valley by 100% biomethane.
- The local production of biomethane and green hydrogen will mean that by 2035 over 80% of the high pressure transmission line system could be decommissioned. Only the lines transporting natural gas from the Otway Basin to Melbourne and from Bass

Strait, Gippsland to Melbourne are needed as the supply of natural gas in these regions exceeds demand and can be used by customers in Melbourne.

- Further work would be required to ensure that the proposed system without transmission lines is sufficiently resilient at both the regional and system levels. For example, major power outages would prevent production of green hydrogen, and this could have significant impacts on residents if it occurred during the winter months. However, it is expected that the distributed nature of renewable energy generation will make the electrical system more resilient than the centralised system we have today.

11.4.4 Gas Pipeline Network Changes

For the Sensitivity 4 case, the major changes in the gas infrastructure can be summarised as:

- Assumption that the low pressure distribution system is capable of handling 100% hydrogen by 2035. This assumption is compatible with existing plans the gas operators have to install HDPE linings where needed to ensure the capability to distribute 100% hydrogen at the same or higher flow rates than today.
- Addition of multiple local green hydrogen production plants in each region, producing green hydrogen into the local low pressure distribution systems. Each plant will require electrical connection and sufficient supply of high quality water.
- Decommissioning of the majority of the high pressure natural gas transmission system by 2035. Around 80-85% of the transmission system is not required after 2030.
- The transmission lines from Port Campbell to Melbourne and from Gippsland to Melbourne are used to transport excess natural gas to Melbourne after 2030. The transmission line from Port Campbell to Melbourne could be decommissioned by 2045.
- Gas storage facilities such as Iona and Dandenong LNG are probably not required after 2030 as local green hydrogen production can be readily ramped up and down in each region to meet seasonal demands.

11.5 Electrical Spatial Analysis

11.5.1 Key References & Assumptions

Victoria regional split:

- V1: Ovens Murray REZ: North East Victoria
- V2: Murray River REZ: Loddon Mallee
- V3: Western Victoria REZ: Grampians Central West
- V4: South West REZ: Barwon South West
- V5: Gippsland REZ: Gippsland
- V6: Central North REZ: Goulburn Valley
- MEL: Metropolitan (Melbourne and surroundings)

Assumptions are explained in Section 3.6.

11.5.2 Work Description

For the Sensitivity Case 4, the electrical generation technologies include:

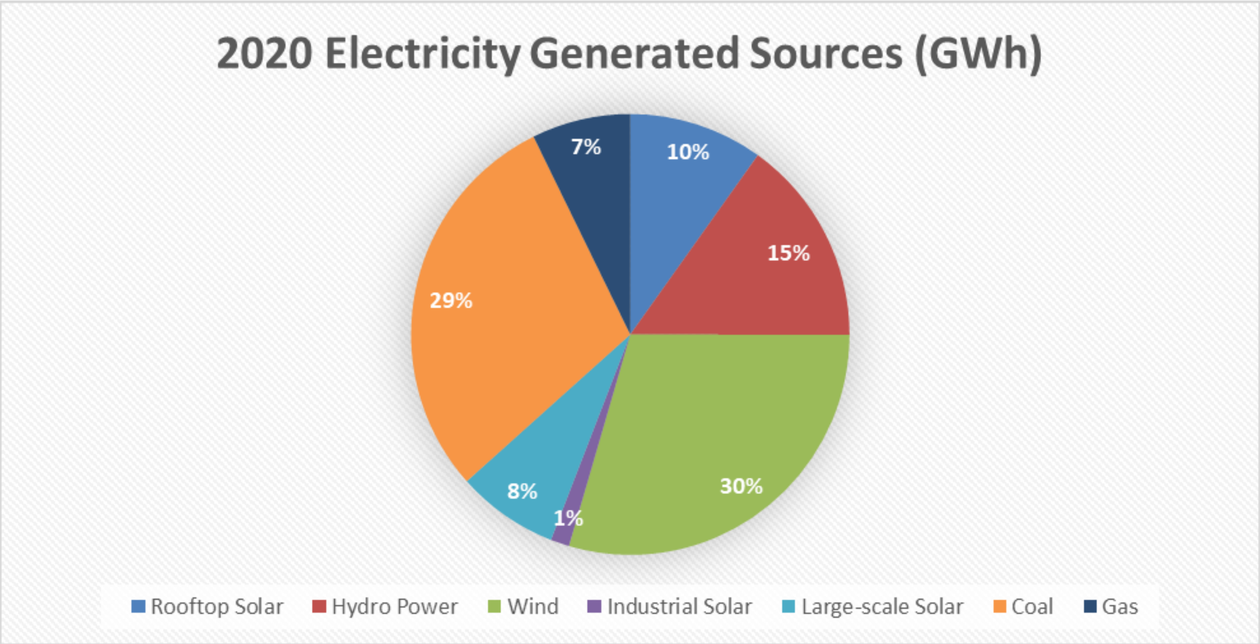
- Wind (onshore and offshore);
- Solar (PV and thermal);
- Bioenergy;
- Hydro power; and
- Fuel cells.

The electrical storage technologies include:

- Li-ion batteries (large-scale, industrial and behind the meter); and
- Molten salt storage (associated with solar thermal generation).

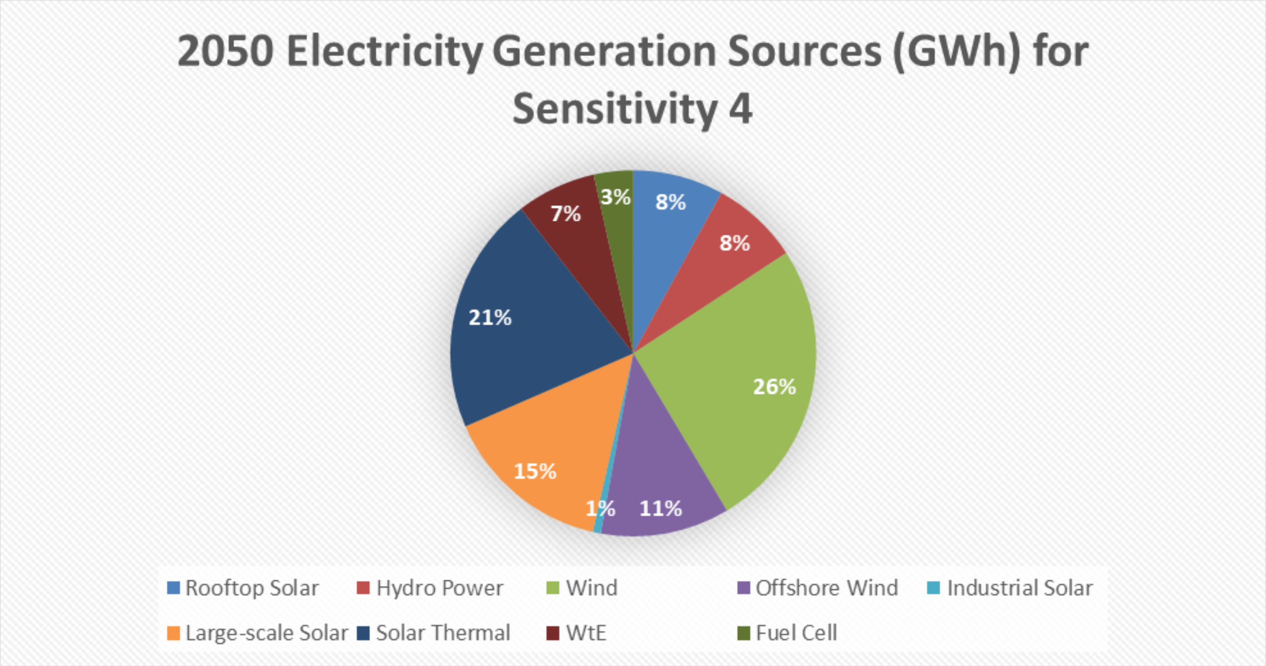
REMINDER: **Electrical Generation infrastructure** is measured in megawatts (MW) and represents the nominal capacity of an electrical asset. Whereas the **generated electricity** is measured in megawatts hours (MWh) and represents in average the quantity of energy that can be generated by an asset in time period (a year for example). The electrical generation depends on the asset capacity factor. A capacity factor is the percentage (%) of the working time of an asset over a time period (a year for example).

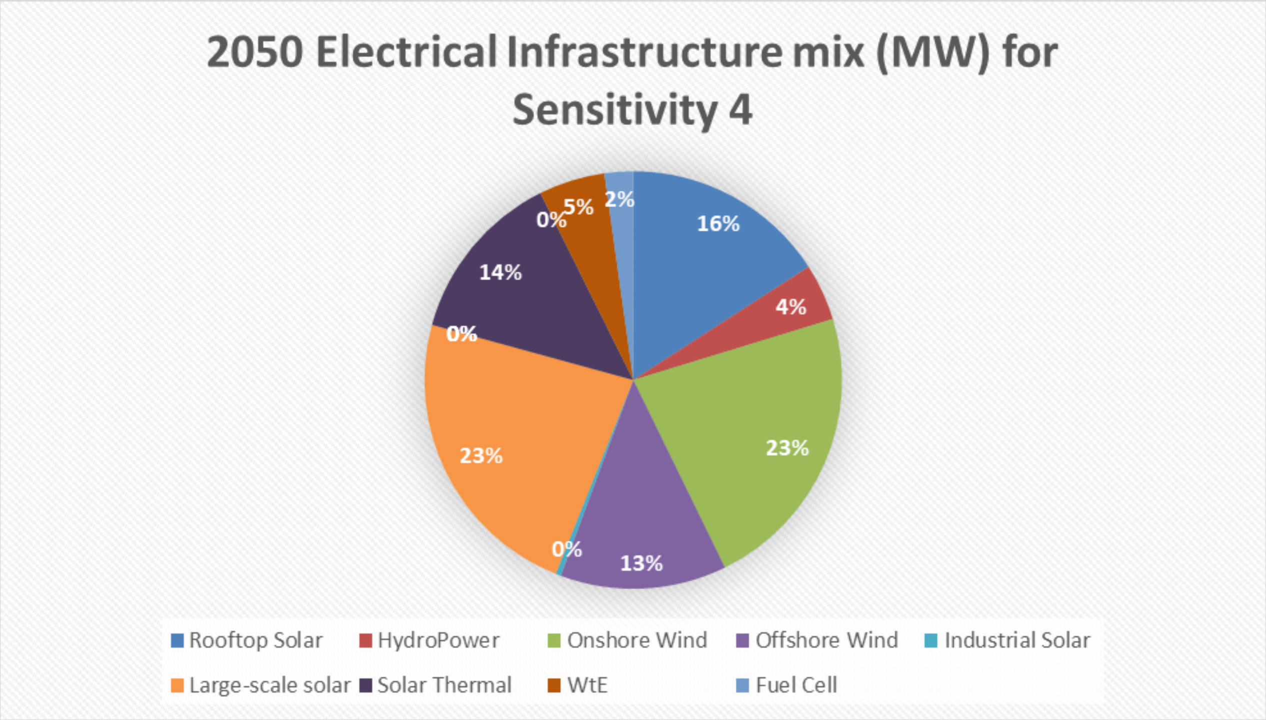
Electrical Generation Mix in 2020:



Electrical Mix in 2050:

(Note Reference in figures to “waste-to-energy” shall be read as “bioenergy”)





In the above charts it can be observed that the electrical infrastructure capacity (MW) increased by a factor of 3.4 over 30 years (2020 to 2050), while the electrical generation (GWh or PJ) increased by a factor of 2. The difference between the infrastructure factor and the generation factor is explained by the high presence of renewables in the mix.

Sensitivity Case 4 prioritises green Hydrogen which is generated by renewable energies:

- 55% solar PV
  - Large-scale solar generates 26% of the green Hydrogen by 2050.
  - Solar thermal generates 29% of the green Hydrogen by 2050.
- 45% wind.
  - Onshore wind generates 28% of the green Hydrogen by 2050.
  - Offshore wind generates 17% of the green Hydrogen by 2050.

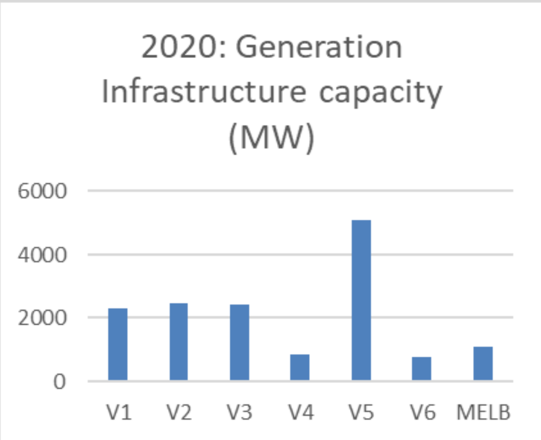
34% of the 2050 electrical mix is assigned to green Hydrogen generation, as shown in the table below.

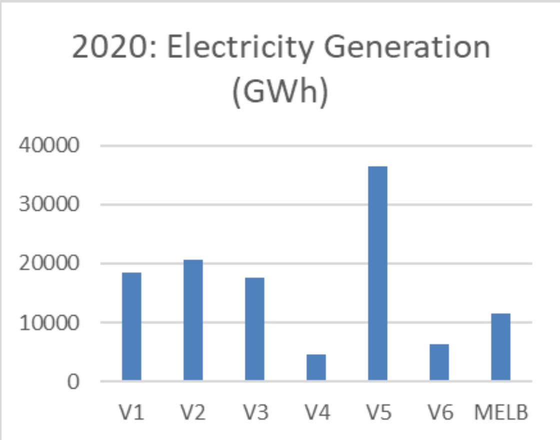
Year	Electricity Generated (GWh)	Electrical Generation Infrastructure (MW)
2020	115 544	15 017
2050	225 493	50 467

11.5.3 Results

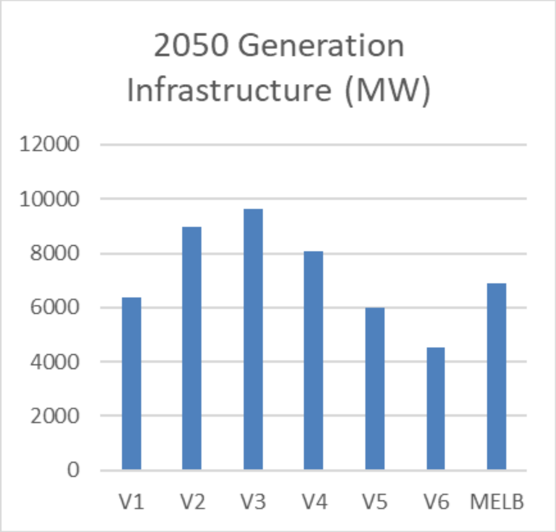
11.5.3.1 Overall Generation

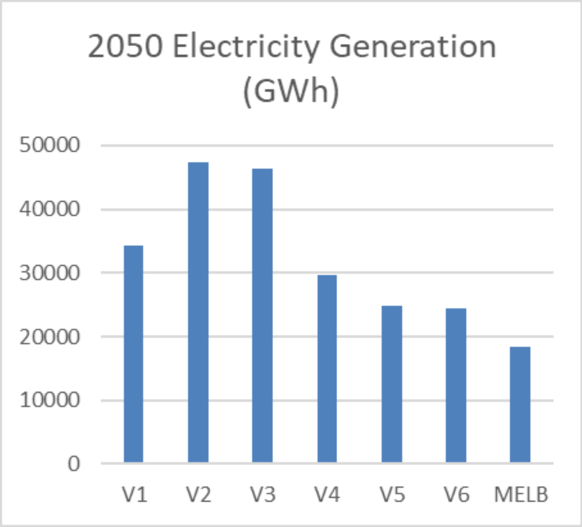
2020 generation infrastructure capacity (MW) and electricity generation (GWh):





2050 generation infrastructure capacity (MW) and electricity generation (GWh):





The main changes observed are summarised below.

- Global rise in capacity for each REZ.
- Generation infrastructure is well balanced over all regions.

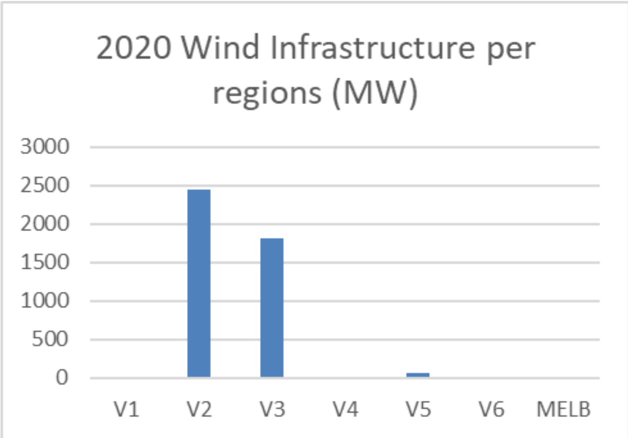
The trends are explained by the high wind potential in V3 (onshore), V4 (onshore and offshore) and V5 (offshore) (see table 1.c in Methodology) and high solar potential in V1, V2, V3 and V6.

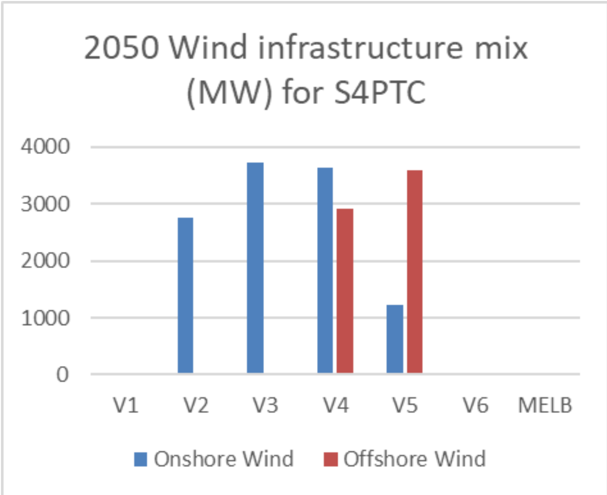
Sensitivity Case 4 considers V4 at it should have been: a high potential location for wind.

Demand is located mainly in the Melbourne metropolitan region (around 60%), with around 10% demand in each of V2, V3 and V4 (representing the entire West side of Victoria), with the remaining 10% being split between V1, V5 and V6.

Comparing generation and demand locations, the transmission lines between all the regions, Melbourne and between East and West will need to be upgraded as both demand and electrical generation grow.

11.5.3.2 Wind





S4PTC: Sensitivity 4 Probability Technology Case

Note: All the locations of existing and committed assets for 2020 wind generation have been taken from AEMO's ISP inputs and assumptions workbook. According to Infrastructure Victoria, Murray River (V2) and South West (V4) may have been switched.

An increasing capacity in wind infrastructure is observed in Murray River (V2), Western Australia (V3), South West (V4) and Gippsland (V5) zone alongside the existing transmission lines. The location is based on available open land and associated wind rows.

In this case, we considered that offshore wind could be divided in both V4 and V5.

As for the High Probability Technology Case, we can observe an increasing capacity in wind infrastructure in V2, V3, V4 and V5 zones alongside the existing transmission lines.

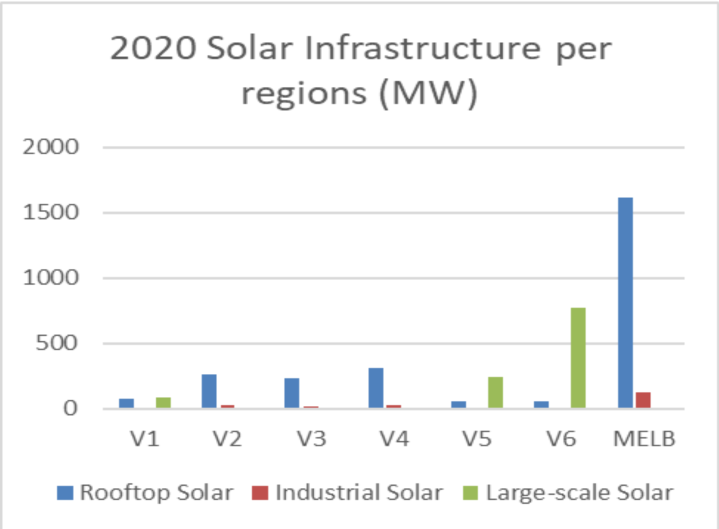
The table below defines the wind capacity factor per region:

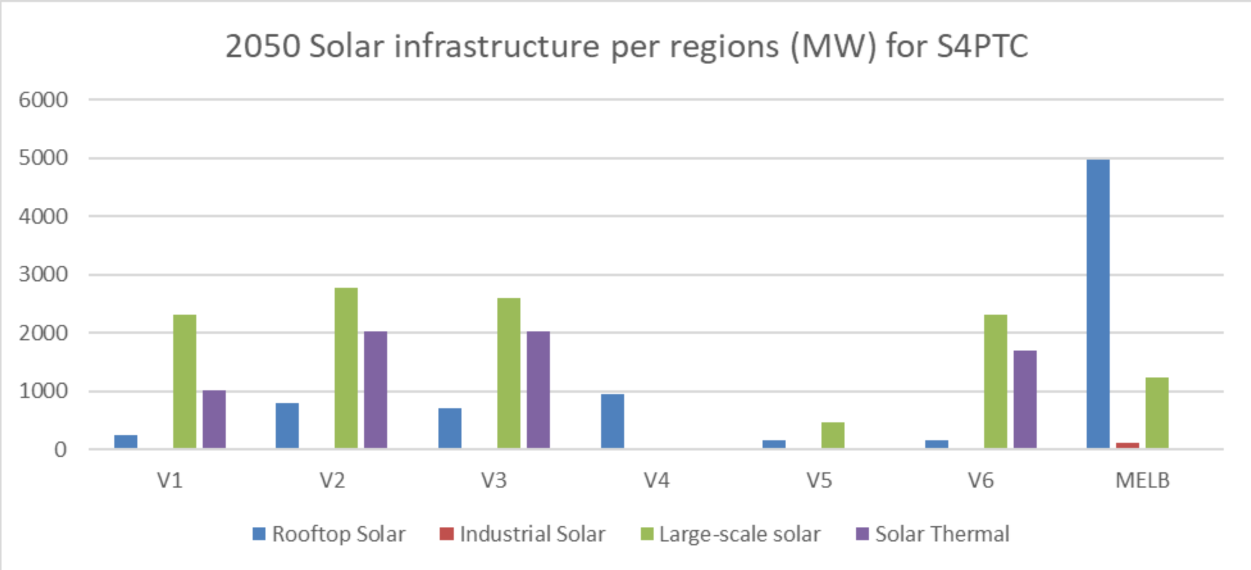
Zones	Wind	Offshore Wind
V1	36%	N/A
V2	32%	N/A
V3	41%	N/A
V4	40%	43%
V5	34%	47%
V6	33%	N/A
MELB	1%	N/A

By 2050,

- Onshore Wind represents 26% of the generated electricity (including electricity used for electrolysis) with 11,345 MW of infrastructure capacity.
- Offshore Wind represents 11% of the generated electricity (including electricity used for electrolysis) with 6,512 MW of infrastructure capacity.

11.5.3.3 Solar PV





As for the High Probability Technology Case, solar PV will expand in all the regions in which it has a high potential: V1, V2, V3 and V6. Once again, the locations follow the transmission lines.

Rooftop solar PV was installed according to the demand split per zone which is an indicator of the population per zone.

Industrial solar PV represents a minimal value, with green Hydrogen production being generated using large-scale solar PV.

In 2050, Victoria will have:

- 8,014 MW of rooftop solar PV generation, representing 8% of electrical mix
- 202 MW of industrial solar PV generation, representing 1% of electrical mix
- 11,707 MW of large-scale solar PV generation, representing 15% of electrical mix
- 6,765 MW of Solar Thermal generation, representing 21% of electrical mix

11.5.3.4 Bioenergy

By 2050, Bioenergy represents 7% of the electrical demand with 2,584 MW of installed capacity.

11.5.3.5 Infrastructure to be Installed

The following tables present all the new infrastructure needed by zone and per type of energy for each period.

It is important to note that 34% of the overall generation is dedicated to green Hydrogen production.

The values in 2020 are the existing and committed assets, then for each subsequent time period the values represent the additional generation infrastructure that has to be added for the specific period.

V1	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	78	2219	0	0	6	85	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	33	0	0	0	0	386	0	0	0	0	0	33	0	279	0	48	0	0	0
2030	29	0	0	0	0	149	0	0	0	276	0	55	0	596	0	42	8403	0	61
2035	6	0	0	0	0	480	0	0	0	238	0	83	0	18	0	6	1150	0	0
2040	25	0	0	0	0	237	0	0	0	166	0	95	0	51	0	24	3629	0	47
2045	0	0	0	0	0	602	0	0	0	172	0	27	0	0	0	0	0	0	0
2050	68	0	0	0	0	379	0	0	0	163	0	94	0	424	0	65	3348	0	60
	MW												GWh						MW

V2	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	261	0	2451	0	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	112	0	487	0	0	536	0	0	0	0	0	33	0	1163	0	161	0	0	0
2030	97	0	546	0	0	207	0	0	0	552	0	55	0	2484	0	140	16807	0	61
2035	21	0	376	0	0	600	0	0	0	475	0	83	0	63	0	20	2300	0	0
2040	84	0	204	0	0	296	0	0	0	332	0	95	0	179	0	81	7259	0	47
2045	0	0	660	0	0	753	0	0	0	344	0	27	0	0	0	0	0	0	0
2050	227	0	281	0	0	394	0	0	0	327	0	94	0	1384	0	218	6695	0	60
	MW												GWh						MW

Note
Reference in table to "waste-to-energy" shall be read as "bioenergy"

V3	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	235	0	1814	0	18	0	0	584	0	0	0	0	0	0	0	0	0	0	0
2025	100	0	679	0	0	521	0	0	0	0	0	33	0	1225	0	145	0	0	0
2030	88	0	762	0	0	201	0	0	0	552	0	55	0	2617	0	126	16807	0	61
2035	18	0	524	0	0	486	0	0	0	475	0	83	0	62	0	18	2300	0	0
2040	76	0	285	0	0	240	0	0	0	332	0	95	0	176	0	73	7259	0	47
2045	0	0	921	0	0	763	0	0	0	344	0	27	0	0	0	0	0	0	0
2050	204	0	392	0	0	383	0	0	0	327	0	94	0	1458	0	196	6695	0	60
	MW												GWh						MW

V4	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	313	0	0	0	24	0	0	834	0	0	0	0	0	0	0	0	0	0	0
2025	134	0	693	0	0	0	0	0	0	0	0	33	0	961	0	193	0	0	0
2030	117	0	778	0	0	0	0	0	0	0	0	55	0	2054	0	168	0	0	61
2035	25	0	535	0	0	0	0	0	0	0	0	83	0	49	0	24	0	0	0
2040	101	0	291	458	0	0	0	0	0	0	0	95	0	295	0	97	0	0	47
2045	0	0	941	605	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0
2050	272	0	401	1851	0	0	0	0	0	0	0	94	0	2712	0	262	0	0	60
	MW												GWh						MW

V5	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	52	0	58	0	4	240	4775	0	0	0	0	0	0	0	0	0	0	0	0
2025	22	0	233	0	0	0	0	0	0	0	0	33	0	1969	0	32	0	0	0
2030	19	0	261	1268	0	0	0	0	0	0	0	55	0	4207	0	28	0	0	61
2035	4	0	180	1751	0	0	0	0	0	0	0	83	0	100	0	4	0	0	0
2040	17	0	98	181	0	0	0	0	0	0	0	95	0	127	0	16	0	0	47
2045	0	0	316	98	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0
2050	45	0	135	300	0	333	0	0	0	0	0	94	0	1052	0	44	0	0	60
	MW												GWh						MW

V6	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	52	0	0	0	4	774	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	22	0	0	0	0	470	0	0	0	0	0	22	0	651	0	32	0	0	0
2030	19	0	0	0	0	182	0	0	0	460	0	37	0	1391	0	28	14006	0	41
2035	4	0	0	0	0	439	0	0	0	396	0	55	0	33	0	4	1917	0	0
2040	17	0	0	0	0	216	0	0	0	277	0	63	0	94	0	16	6049	0	31
2045	0	0	0	0	0	551	0	0	0	287	0	18	0	0	0	0	0	0	0
2050	45	0	0	0	0	346	0	0	0	272	0	63	0	775	0	44	5579	0	40
	MW												GWh						MW

MEL	Rooftop Solar	HydroPower	Wind	Offshore Wind	Industrial Solar	Solar	Coal	Gas OCGT	Gas-powered steam turbine	SOLAR Thermal	Geothermal	Waste to energy	Pumped Hydro	Li-ion Batt Large Scale	Li-ion Batt non scheduled	Li-ion Batt BTM	Molten salt (thermal)	Iron-air Batteries	Fuel Cell
2020	1617	0	0	0	125	0	0	482	500	0	0	0	0	0	0	0	0	0	0
2025	838	0	0	0	0	720	0	0	0	0	0	35	0	1986	0	1209	0	0	0
2030	516	0	0	0	0	307	0	0	0	0	0	56	0	3843	0	744	0	0	49
2035	249	0	0	0	0	244	0	0	0	0	0	54	0	84	0	239	0	0	0
2040	511	0	0	0	0	120	0	0	0	0	0	56	0	207	0	491	0	0	70
2045	0	0	0	0	0	153	0	0	0	0	0	0	0	0	0	0	0	0	0
2050	1474	0	0	0	0	0	0	0	0	0	0	66	0	1409	0	1418	0	0	58
	MW												GWh						MW

Note Reference in table to “waste-to-energy” shall be read as “bioenergy”

11.5.4 Discussion

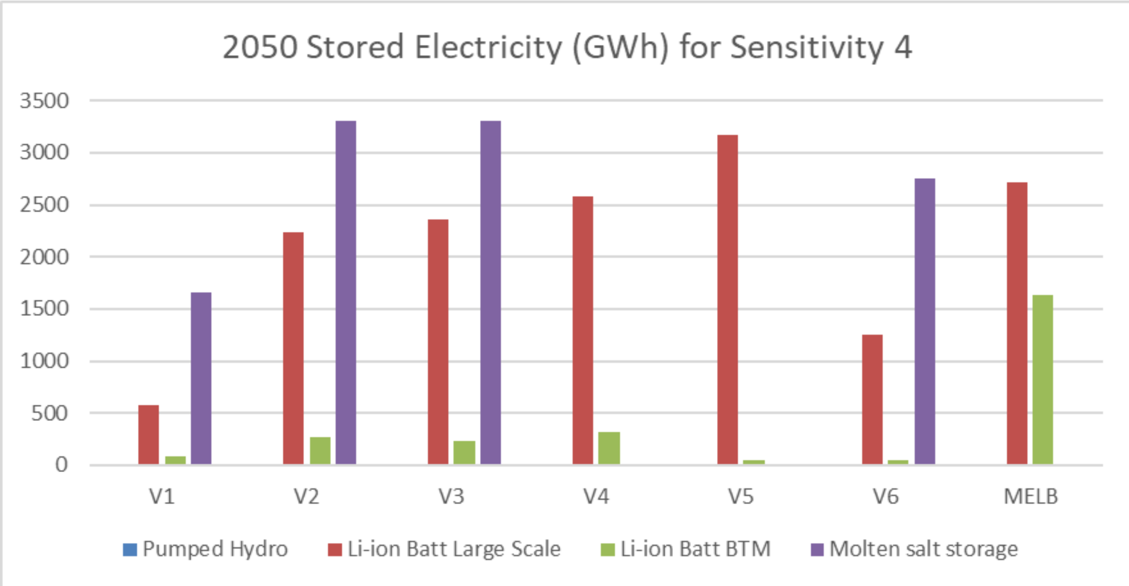
Sensitivity Case 4 was observed to have the following characteristics:

- Use of the following technologies in the mix:
  - Solar (behind the meter, industrial and large scale)
  - Solar Thermal
  - Wind Onshore
  - Wind Offshore
  - Bioenergy
  - Fuel Cells
  - Standard batteries (behind the meter, industrial and large scale)
  - Molten Salt Storage (dedicated to Solar Thermal production)
  - pumped hydro was included as a future new energy storage technology and included in the energy mix at relatively minor levels with 2 PJ available in 2030
- Existing technology in the mix with no change:
  - Hydro power
- In 2050, solar PV and wind represents 82% of the electrical generation mix if we include the solar PV and wind dedicated to green Hydrogen production. Without green Hydrogen, solar PV and wind represent 72% of the mix, creating grid instability requiring compensation by addition of generation and storage facilities.
- New/upgraded transmission lines are needed as the grid will have to support a lot more electricity. Upgrade are considered to be likely for the following lines:
  - Murray River (V2) – Melbourne
  - Western Victoria (V3) – Melbourne
  - Gippsland (V5) – Melbourne
  - Western Victoria (V3) – South West (V4)
  - Ovens Murray (V1) – Melbourne
  - Central North (V6) – Western Victoria (V3)
  - South West (V4) – Melbourne

  The report only considers a simplistic representation of the transmissions system assuming it to be possible to expand the system as required to meet the new generation requirements.

  Transmission systems likely to require upgrades represent more than 1,500 km of new lines along with new, associated transformers, representing approximately 25% more infrastructure than exists today.

  The distribution of power between the zones dictates the requirement for new lines. However if the overall power requirement for each case is the same it does not matter where the new lines will be placed, only the amount of power to be transmitted.
- All the connections between the facilities and the grid have been taken into account in the cost analysis.
- The storage is calculated depending on the quantity of solar and wind generation per regions and according to the demand.



11.6 Vehicle Analysis

Refer Section 4.4 for vehicle analysis results which was fixed for all analysis cases except Sensitivity Case 4.

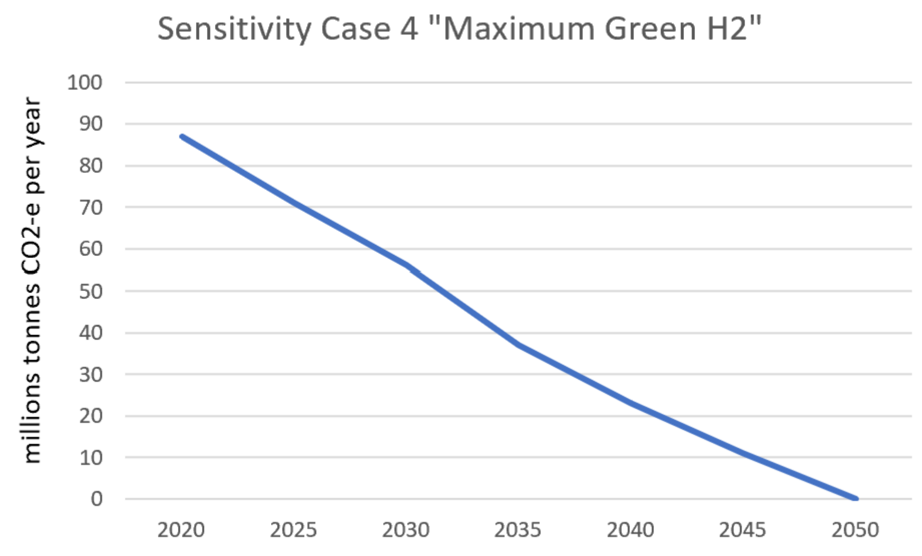
11.7 Environmental & Social Analysis

The environmental and social components of the Sensitivity 4 "Maximum Green Hydrogen" have been assessed via a desk-top study using key aspects from environmental and social perspectives and presented in Section 4.6.

11.7.1Results

Sensitivity 4 is based on the low probability technology case with a higher penetration of hydrogen in the energy mix. Figure 106 shows the modelled emissions profile for the maximum green hydrogen sensitivity, which shows a liner decline in emissions to 2050. The selected technologies deliver net zero emissions in 2050.

Figure 106: Emissions Reduction Profile – Sensitivity Case 4 "Maximum Green H2"



11.7.2 Discussion

Relative to the low probability technology case, sensitivity 4 "maximise green hydrogen" assumes significantly more large-scale solar PV (an increase of 70%), wind (37%) and a reduction in solar thermal electricity generation (a decrease of 60%). Battery storage is also reduced by half. Importantly hydrogen distributed through the gas distribution system is increased by four times compared to the low probability technology case. Only the mid probability technology case utilises a greater amount of distributed hydrogen. The increased reliance on distributed hydrogen requires careful attention to the management of hydrogen safety risk

The proposed Sensitivity Case 4 "maximise green hydrogen" has the following environmental and social considerations:

- Key investments to achieve net zero emissions target include:
  - Compared to 2020: 12.5 times more solar PV, six times more wind generation, and approximately 100 times more battery storage.
  - A large investment in hydrogen production for distribution in the gas networks.
  - Significant investment in solar thermal, bioenergy and biomethane production.
  - Significant volumes of solar PV and wind – 198 and 171 PJ of electricity supply in 2050.
  - Modifications the gas distribution system to accommodate the increase in use of hydrogen.
  - Strengthening of the electricity grid.
- Sensitivity 4 "maximise green hydrogen" shows only a modest increase in employment compared with the high probability technology reference case. Only the

high probability technology case and sensitivity 3 “energy efficiency” have a lower employment level. The main drivers of employment in this sensitivity are:

- Solar thermal (33%).
- Wind (23%).
- Rooftop solar (12%).
- Energy efficiency (9%).
- Large scale solar PV (8%).

- The significant increase in the distribution of hydrogen in this sensitivity is accompanied by an increase in the safety risks associated with hydrogen. These risks are manageable but will require a heightened focus in this sensitivity.
- This sensitivity is accompanied by a relatively large amount of renewable energy generation requiring the accompanying issues of fears of industrialisation, land use change and potentially impacts on rural water supplies.

11.8 Cost Analysis

11.8.1 Key References & Assumptions

Refer to Section 3.8.5.

11.8.2 Work Description

Refer to Section 3.8 for details of the work description.

11.8.3 Results

The figure below presents the net difference between the Sensitivity Case 4 “Maximum Green Hydrogen” and the Control Scenario. Additional generation commercial readiness technology breakthrough factors have been used to account for lower future CAPEX build costs.

Figure 107 demonstrates that:

- The Sensitivity Case 4 “Maximum Green Hydrogen” projects a material increase in fuel, FOM and VOM costs, as a result of the operating costs related to green hydrogen and expanded development and sharing of new variable renewable electricity resources, providing a net annualized cost increase of approximately $2.6 billion in 2050.
- The Sensitivity Case 4 “Maximum Green Hydrogen” projects a material increase in the combined capital costs due to the increased investment in new variable renewable electricity resources, providing a net annualised cost increase over the control scenario of approximately $10 billion in 2050 transitioning to a net zero outcome. It is important to note that this analysis has not included comparison to the costs on inaction on emissions reduction.

The annual net costs of the Sensitivity Case 4 “Maximum Green Hydrogen” is represented by the purple line in Figure 107 by 2050, the Sensitivity Case 4 “Maximum Green Hydrogen” is forecast to provide a net cost increase of around $12.7 billion by 2050.

For the Sensitivity Case 4 “Maximum Green Hydrogen”, the net costs show a neutral trend until 2030 where there is an increase in annual CAPEX spend to meet the energy demand due to phasing out of natural gas and costs related to green hydrogen and expanded development which returns a net cost increase going forward to 2050.

Figure 107: Net Costs of the Control Scenario relative to the Sensitivity Case 4 “Maximum Green Hydrogen”

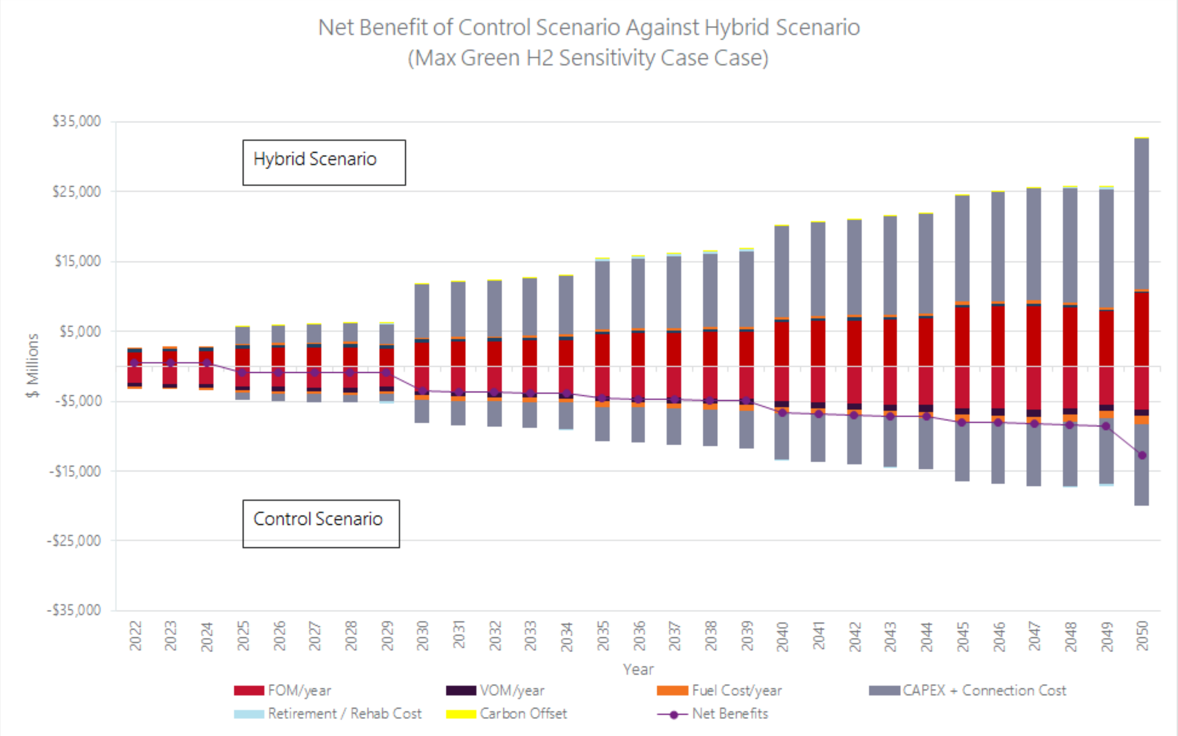


Table 109 provides a summary of the total costs for each cost category to 2050 of the Control Scenario and the Sensitivity Case 4 “Maximum Green Hydrogen”, in Net Present Cost (NPC) terms. The net cost compares the two scenarios, a positive value is considered a net benefit to the hybrid scenario, a negative value (red) is considered a disadvantage to the hybrid scenario.

This shows that the total of the annualised costs of the Sensitivity Case 4 “Maximum Green Hydrogen”, discounted back to present value, is $8.9 billion.

In contrast, for the Control Scenario, the total of the annualised costs discounted back to present value is $6.1 billion.

The estimated net cost of -$2.8 billion (NPC).

The estimated cost of CO_2 abatement is $103/te CO_2.

Table 109: Net Costs of the Control Scenario relative to the Sensitivity Case 4 "Maximum Green Hydrogen"

Cost Category[2]	**Net Cost of Control Against Technology Case (Maximum Green Hydrogen)**		
	Control	HYBRID	Net Cost
	($M)[1]	($M)[1]	($M)
Capex	$2,751	$5,394	-$2,643
FOM	$2,475	$2,994	-$519
VOM	$435	$234	$200
Fuel	$419	$227	$192
Retirement / Rehab	$48	$69	-$21
Agro-forestry (Land Area, Hectare)	$0	$0.17	-$0.17
Gross Cost	$6,127	$8,919	-$2,792
Estimated Annual Emissions (Mte CO_2 @ 2020)	87	87	
Estimated Annual Emissions (Mte CO_2 @ 2050)	76	0	
Cost of CO_{2e} Abatement[3] ($/tonne)	583	103	480

Notes:

1. Total of the annualised costs from 2021 to 2050 discounted to 2021.
2. Refer to the cost analysis and methodology section for details of costs included for Capex etc.
3. Gross cost divided by the emissions abated between 2020 and 2050.

11.8.4Discussion

The increased CAPEX combined with the overall energy mix for the Sensitivity Case 4 "Maximum Green Hydrogen" compared to the Control Scenario is expected due to the build and connection costs for the new variable renewable electricity due to the phasing out of natural gas with the higher capital expenditure and costs related to green hydrogen.

OPEX and fuel costs savings for the Sensitivity Case 4 "Maximum Green Hydrogen" compared to the Control Scenario are also expected due to the reduction in fossil fuel generation and expanded development and sharing of new variable renewable electricity resources but are not sufficient to offset the CAPEX increase.

Retirement costs are increased due to the decommissioning of natural gas supply and transmission lines as well as the existing, anticipated and committed generation being retired by 2050. All new generation is assumed still operational in 2050.

The Control Scenario has greater total emissions over the timeframe, and hence emissions cost, as the energy mix is relatively unchanged and therefore minimal emissions reduction from retired existing generation, noting that the Control Scenario purpose is not emissions reduction. The Sensitivity Case 4 "Maximum Green Hydrogen" cost for emissions is for the existing generation up to 2050 where net emissions are zero going forward.

The Cost of Carbon Abatement is effectively the gross cost divided by the emissions abated between 2020 and 2050 which provides a $/tonne cost.

11.9 Risk & Opportunity Analysis

11.9.1 Key References & Assumptions

Four Sensitivity Cases were developed based on one of the three Base Analysis Cases previously described in this report. The modifications to the key assumptions are summarised in Table 110.

Table 110: Sensitivity Cases - Modifications to Key Assumptions

Sensitivity Case No.	Description	Reference Case	Modifications to Key Assumptions
4	Maximum Green Hydrogen	Low Probability Technology	Substantial breakthrough in green hydrogen technology and costs

11.9.2 Work Description

Sensitivity Case 4 "Maximum Green Hydrogen" assumes a significantly greater amount of hydrogen is available than in the other cases that were limited by a 10% hydrogen blend in the gas transmission and distribution network.

The increased delivery of hydrogen is achieved by injecting additional hydrogen directly into the low-pressure gas distribution network while the high-pressure gas transmission system remains constrained to a 10% hydrogen blend. This requires the distribution network to be isolated from the transmission system at the start of this transition.

The study team reviewed the risks and opportunities identified in the Low Probability Technology case and assessed the key additional risks and opportunities unique to Sensitivity Case 4 "Maximum Green Hydrogen", focussing on the implementation risks rather than the inherent risks.

11.9.3 Results

Sensitivity Case 4 "Maximum Green Hydrogen" is based on the Low Probability Technology Case and is susceptible to the technology and energy supply risks within that case. The key risks involve the failure of any of the key technologies to become commercially competitive at large scale within the indicated timeframes.

- Green hydrogen, initial incremental cost reduction breakthrough by 2025.
- Green hydrogen, high pressure electrolysis technology breakthrough by 2030 and/or ongoing cost and efficiency improvements.
- Offshore wind projects by 2030.

- Industrial scale solar thermal projects by 2030.

High pressure electrolysis is still to be commercialised, whist the other technologies listed above are proven technologies, where cost reductions and scale-up are the main enablers. If high pressure electrolysis does not come to fruition, then enhancements in electrolysis cost reductions and efficiency gains will be needed in order for an equivalent outcome to be realised.

11.9.4 Discussion

This Sensitivity Case takes advantage of the opportunity to replace natural gas with green hydrogen in the gas distribution network therefore maximising the utilisation of the existing gas infrastructure whilst minimising emissions, in contrast to the High Probability Technology Case where a ‘tail” of natural gas persists beyond 2050.

It may be possible to achieve cost effective green hydrogen production and distribution by 2025 if supply and demand is able to be ramped up in a coordinated manner, under the prevailing market forces.

Injecting additional hydrogen into the low-pressure system allows the quantity of hydrogen to be increased beyond the 10% limit assumed to be retained for high pressure gas transmission system. To produce this hydrogen, additional renewable electricity generation and storage capacity is required, in comparison with the other cases that have been analysed, due to the energy losses incurred in the production of hydrogen by electrolysis which could otherwise be used in a fuller electrification scenario.

Therefore, a potential risk is that the amount of renewable electricity required to sustain this pathway is not able to be supplied.

A further opportunity realised by this sensitivity is the reduction is compression cost and renewable energy requirements for hydrogen gas compression via two contributing elements.

- Injection of hydrogen injection directly into the low pressure gas network.
- High pressure electrolysis.

Conventional electrolysis methods produce hydrogen at low pressure, and the hydrogen must be compressed for injection into the gas pipeline network. Since it requires more work to compress hydrogen to a given pressure than natural gas, the opportunity to inject gas directly into the low-pressure gas distribution system by siting the electrolysers close to the end users would minimise the compression cost. This also has the benefit of avoiding major upgrade of the high-pressure gas transmission pipelines to handle 100% hydrogen. Most of the Victorian gas distribution system is already compatible with 100% hydrogen and it is anticipated the remainder of the system will have been upgraded by 2035, and this is perceived as a low risk.

High pressure electrolysis is a potential technology breakthrough that would further reduce the hydrogen compression costs and associated energy requirements. Commercialisation of this breakthrough by 2030 is by no means certain and whilst it remains a risk for this Sensitivity Case, it is not a fatal risk if further electrolyser efficiency gains and energy cost improvements are able to offset the increased compression costs.