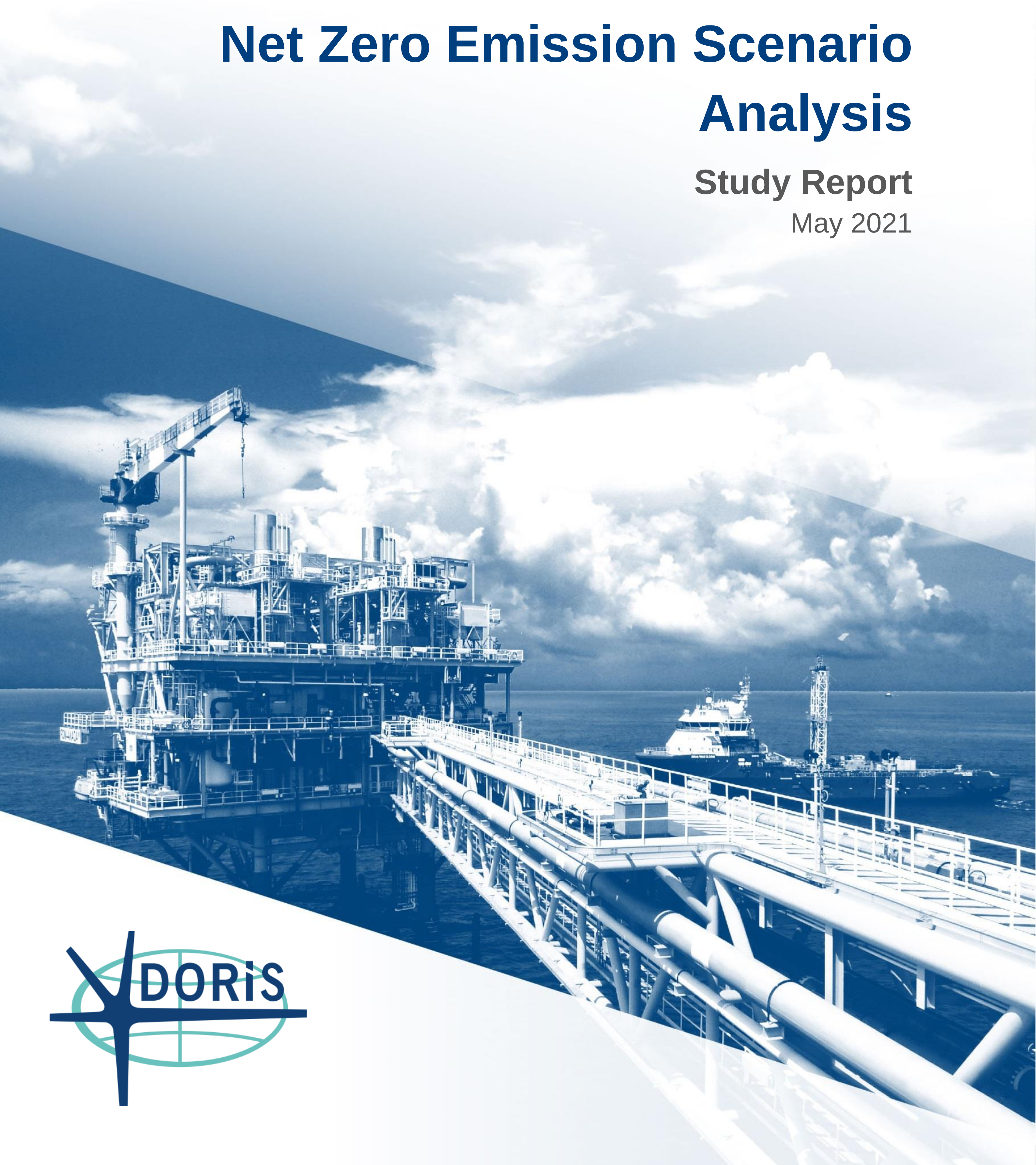
INFRASTRUCTURE VICTORIA

Net Zero Emission Scenario Analysis

Study Report

May 2021



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REVISION

Rev.	Date	Issued By	Checked By	Approved By	Reason for Revision
Rev 1	28-May-21	A LOANE	B LAMOUREUX	E MCNAMARA	Revised Final
Rev 0	19-May-21	A LOANE	B LAMOUREUX		Final Issue
Rev A	06-May-21	A LOANE	B LAMOUREUX		Draft Issue

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EXECUTIVE SUMMARY

Infrastructure Victoria has commissioned DORIS Engineering Australia to undertake a high-level technical analysis and screening of four “net zero gas sector scenarios” for the Australian State of Victoria which are designed to provide input into a “Gas Roadmap” by end of 2021, and guide State Government Policy for achieving “Net Zero Carbon Emissions” by 2050. The four scenarios were developed by Infrastructure Victoria and represented key input to the study providing guidance in the development of the scenario technical models. As the analysis progressed, opportunities for refinement of the scenarios were identified and, as results and outcomes became available, elements of a potential “hybrid scenario” were identified that may deliver improvements over the base scenarios in affordability and reliability of energy whilst achieving a Net Zero Emissions position by 2050. The analysis of the “hybrid scenario” was beyond the scope of the study.

A brief overview of the four scenarios is provided below, with comprehensive descriptions provided in the body of the report. Common to all scenarios is a gradual decline over time in the consumption of hydrocarbon fuels for energy generation, notably brown coal (primarily electricity), natural gas (primarily space and water heating), diesel and gasoline (primarily vehicular transport). Each scenario represents a proposed model of the gradual replacement of hydrocarbon fuels by specific combinations of renewable, and non-carbon energy sources, energy storage, and Carbon offsets to cover the entire energy-emissions-offset supply chain.

Scenario A is summarised as "full electrification / no natural gas (in 2050) / no CCS". The key feature of this scenario is its focus on solar, wind and hydro renewable electricity to replace hydrocarbon fuels by 2050. Its inherent advantage is reduced Carbon emissions for electricity generation meaning no requirement for Carbon capture and storage (CCS). Scenario A proposes energy gas demand will be met through production of Biogas and Hydrogen (green). Moderate uptake of energy efficiency measures are included for residential and commercial buildings through measures including insulation, ground source heat pumps and installation of smart grid systems. By 2050, hydrocarbon fuelled road vehicles (both light and heavy) are replaced primarily by Battery Electric Vehicles and, to a lesser extent, Hydrocarbon Fuel Cell Vehicles.

Scenario B is summarised as "partial electrification / limited gas / limited CCS”. A key differentiator with Scenario B is the continued consumption of a limited amount of natural gas right through to 2050 in order to support hard to abate manufacturing industries such as plastics and alumina production. No other scenario has any natural gas being consumed in 2050, and for this reason Scenario B maintains the greatest proportion of the current hydrocarbon energy supply chain of all scenarios. This aspect defines the key advantage of Scenario B being the high level of energy infrastructure efficiency achievable through use of natural gas to balance variable renewable loads and satisfy hard to abate feedstock demand, whilst also utilising pre-existing natural gas infrastructure. Scenario B is most closely aligned to Scenario A due to the relatively high proportion of renewable electricity rather than energy gas in the overall energy mix. In addition to a minimal loading of natural gas, Scenario B satisfies energy gas demand through a combination of Biogas and Hydrogen (green). Offsetting Carbon emissions can be achieved by a combination of Carbon capture and storage, and agro-forestry. A small uptake of energy efficiency measures are assumed for residential and commercial buildings through measures including insulation, ground source heat pumps and installation of smart grid systems. As per Scenario A, hydrocarbon fuelled road vehicles (both light and heavy) are replaced primarily by Battery Electric Vehicles and, to a lesser extent, Hydrocarbon Fuel Cell Vehicles.

Scenario C is summarised as "green & blue Hydrogen with offsets / electrification / no natural gas (in 2050) / no CCS". Scenario C distinguishes itself by proposing the most comprehensive energy mix of all scenarios, in other words the least focus on any particular one type of low Carbon energy source. This feature represents the primary advantage of this scenario by de-risking application of newer technologies through moderated levels of production scale. Scenario C is more closely aligned to Scenario D due to the relatively high proportion of energy gas rather than renewable electricity in the overall energy mix. Scenario C satisfies energy gas demand primarily through production of green Hydrogen, with use of blue Hydrogen scaled to utilise Victorian natural gas production through its natural decline. Offsetting Carbon emissions can be achieved by a combination of agro-forestry and Carbon trading certificates. A moderate uptake of energy efficiency measures are assumed for residential and commercial buildings through measures including insulation, ground source heat pumps and installation of smart grid systems. Hydrocarbon fuelled road vehicles (both light and heavy) are replaced by a balanced mix of Battery Electric Vehicles and Hydrocarbon Fuel Cell Vehicles.

Scenario D is summarised as "large brown Hydrogen / large CCS / no natural gas (by 2050)". Compared to the other scenarios: Scenario D proposes the highest proportion of energy gas, and its advantage is the economic growth through export of by brown Hydrogen produced by gasification of the large brown coal reserves in Victoria. Compared to other scenarios, Scenario D is more closely aligned to Scenario C due to the relatively high proportion of energy gas rather than renewable electricity in the overall energy mix. Scenario D satisfies energy gas demand primarily through production of brown Hydrogen (gasification of brown coal), with some contribution from biogas and green H2. Offsetting Carbon emissions is achieved through extremely large scale Carbon capture and storage. A small uptake of energy efficiency measures are assumed for residential and commercial buildings through measures including insulation, ground source heat pumps and installation of smart grid systems. Hydrocarbon fuelled road vehicles (both light and heavy) are replaced by a balanced mix of Battery Electric Vehicles and Hydrocarbon Fuel Cell Vehicles.

Figure 1: Energy-Emissions-Offset Supply Chain

The work was undertaken in three distinct phases to manage the flow of information, and provide decision gates where required. A staged approach was adopted with the analysis and costing of Scenario A undertaken first to develop an efficient work process, then applying that process to the work through the remaining Scenarios. The level of detail developed was calibrated to the limited study duration, with high level analysis undertaken and “order of magnitude” results generated for the purpose of comparing the scenarios to identify trends and drivers in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050.

Numerous simplifications were made to model Victoria’s energy system and generate useable data, including the use of a static, single point analysis method. A critical implication of this simplified approach is to over-estimate the level of new energy infrastructure required to reach Net Zero. The overestimate stems partly from the requirement to use a single design point to calculate the required size of plant & facilities, and also from not being able to access the transient excess energy from differentials in load and demand cycles that will occur in a diverse, complex, inter-connected system. This specific simplification also aligns with the scope exclusions of this study, for example agriculture and aviation, whereby optimized energy generation data would require assessment of the entire energy system using a sophisticated dynamic, parametric analysis method. An example of the simplified approach for electricity was to treat renewable firming capacity such as batteries or pumped hydro as being stranded from inter-state grid connections. A similar example for energy gas was treatment of the renewable electricity demand for green Hydrogen being delivered by a stand-alone renewable electricity generator dedicated to a specific green Hydrogen production plant. No advantage was taken of the availability of green electricity in the grid, or other potentially interconnected systems such as rooftop solar.

When applied in the same way to each scenario, use of this (and other) simplifying assumptions and approaches will yield equivalent levels of infrastructure outcomes, albeit non-optimised, which can nevertheless be considered “useful comparative data”, but not “useable absolute data”. Applying a comparative analysis method to screen the scenarios using the “useful comparative data” is therefore considered credible, and a justified approach for such early stage, non-engineered assessments.

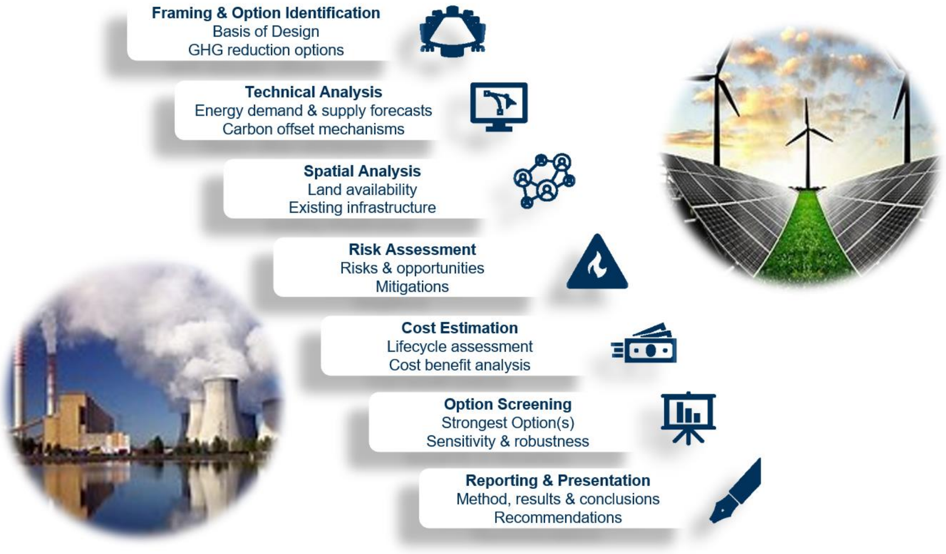
To emphasis the classification of results as being “useful comparative data” rather than “useable absolute data”, the cost estimate for each scenario is presented as a “cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The example of the “comparative cost index” illustrates the general intent and mandate of this study being a comparative analysis of scenarios to identify trends, drivers, risks and opportunities in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050. The comparative cost index was calculated by dividing the cost estimate for each scenario by the cost estimate for the lowest cost scenario, by way of example for Scenario A :

$$\textbf{Cost Index}_{\textbf{Scenario A}} = \textbf{Cost Estimate}_{\textbf{Scenario A}} \,/\, \textbf{Cost Estimate}_{\textbf{Lowest Cost Scenario}}$$

Using this system the Cost Index for the lowest cost scenario will equal 1.

The development of classed cost estimates for each scenario is beyond the scope of this study.

Figure 2: Study Approach



Key Results

Time to Net Zero

Table 1: Estimated Timeframe to Achieve Net Zero Carbon Emissions for each Scenario

Scenario	Estimated Timeframe to Achieve Net Zero
A	Slightly prior to 2050
B	Slightly prior to 2050
C	Slightly prior to 2040
D	2050

Cost of Achieving Net Zero

The primary driver for Scenario D’s cost being significantly higher than the other Scenarios is the cost of offsetting the very high level of emissions (CCS and Carbon Trading Certificates).

Table 2: Estimated Comparative Cost Indices for each Scenario

Scenario	Comparative Cost Index
A	1.1
B	1.1
C	1.0
D	4.3

Hydrogen Export

Table 3: Estimated Hydrogen Export for each Scenario

Scenario	Hydrogen Export (PJ per Annum)		
	2030	2040	2050
A	No export allocated		
B	No export allocated		
C	Undefined	Undefined	>125
D	>50	>300	>470

Absolute Carbon Emissions

Table 4: Estimated Absolute Carbon Emissions for each Scenario

Scenario	Carbon Emissions (Mill Te CO_2 equiv per Annum)		
	2030	2040	2050
A	59	20	-8
B	59	23	-5
C	28	-6	-56
D	366	565	715

Carbon Capture and Storage Loadings

Table 5: Estimated Carbon Capture and Storage Loadings for each Scenario

*(*Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was calculated to assess manageability if it were utilised)*

Scenario	Carbon Capture and Storage Level (Mill Te CO_2 per Annum)		
	2030	2040	2050
A	*Not Applicable*		
B	0	1	1
C*	1	2	0
D	297	523	698

Potential Jobs Creation

Table 6: Potential Jobs Creation for each Scenario

Scenario	2030	2040	2050
A	3,880	6,750	8,767
B	3,878	6,698	8,826
C	7,203	9,616	13,013
D	10,098	16,057	17,477

Gas Infrastructure Upgrades

Table 7: Estimated Extent of Demolition of Existing Gas Transmission Pipelines for each Scenario

(4,694 kms installed transmission pipelines)

Scenario	2030	2040	2050
A	0%	40%	80%
B	0%	50%	90%
C	0%	75%	100%
D	0%	75%	100%

Table 8: Estimated Extent of Demolition of Existing Gas Distribution Pipelines for each Scenario

(26,249 kms total installed infrastructure for the 4 network suppliers)

Scenario	2030	2040	2050
A	20%	40%	80%
B	20%	60%	90%
C	20%	75%	100%
D	20%	75%	100%

Table 9: Installation of Hydrogen Infrastructure

(Refer separate capacity table for relative size of the infrastructure undertaken on a like for like basis)

Scenario	2030	2040	2050
A	0 kms	0 kms	0 kms
B	0 kms	50%	100%
C	25%	75%	100%
D	25%	75%	100%

Table 10: Relative Average Diameter of Hydrogen Pipeline Network Compared to Existing Natural Gas Infrastructure

(Hydrogen requires larger pipe diameters to transport the same amount of energy as natural gas)

Scenario	Capacity of Hydrogen Infrastructure
A	NA – no new hydrogen infrastructure
B	0.4 of current gas infrastructure
C	2 x current infrastructure
D	6 x current infrastructure

Electrical Infrastructure Upgrades

Data in the table below defines the extent of new or upgraded electrical infrastructure required for each scenario over and above existing electrical infrastructure. The values are presented as a "relative index" and, by way of example for Scenario A, calculated as follows:

$$\textbf{Relative Electrical Infrastructure Index}_{\textbf{Scenario A}} = \textbf{Electrical Infrastructure Estimate}_{\textbf{Scenario A}} / \textbf{Electrical Infrastructure Estimate}_{\textbf{Scenario with Lowest Level of Electrical Infrastructure}}$$

Using this "relative index" system the scenario having the lowest level of electrical infrastructure required will equal 1, in this case being Scenarios C and D in 2030. Other values indicate the extent of additional electrical infrastructure compared to Scenarios C and D in 2030 for example Scenarios A and B in 2030 each requires twice as much electrical infrastructure than Scenarios C and D in 2030.

Table 11: Relative Extent of Upgrades to Electrical Infrastructure for each Scenario

Scenario	2030	2040	2050
A	2	4	5
B	2	4	5
C	1	3	3
D	1	2	2

Road Vehicle Fuel Consumption

Table 12: Scenarios A & B – Total Fuel Consumption by Road Vehicle Type

Year	All Road Hydrocarbon Vehicles	All Road BEVs	All Road HFCVs
	Gasoline & Diesel (PJ / yr)	Electricity (PJ / yr)	Hydrogen (PJ / yr)
2030	217	20	23
2040	99	53	27

2050	0	66	40

Table 13: Scenarios C & D – Total Fuel Consumption by Road Vehicle Type

Year	**All Road Hydrocarbon Vehicles**	**All Road BEVs**	**All Road HFCVs**
	Gasoline & Diesel (PJ / yr)	**Electricity (PJ / yr)**	**Hydrogen (PJ / yr)**
2030	163	13	53
2040	69	30	71
2050	0	37	86

Key Risks & Opportunities

Table 14: Key Risks & Opportunities for each Scenario

Scenario	**Key Risk**	**Key Benefit**
A	Significant increase in electrical infrastructure, with sheer number of connections required and increased risk of power dropouts if peak demand not adequately managed, no participation in the ‘hydrogen economy’	Known technology with fully renewable sources and no CCS reliance
B	Significant increase in electrical infrastructure, with sheer number of connections required, limited CCS use.	Known technology, current technology for peak shaving
C	Significant increase in electrical infrastructure, with sheer number of connections required	Flexibility of approach, can pivot to more hydrogen or all electrical depending upon technological advances & global consensus
D	Use of brown coal to produce H2 and reliance upon undiscovered resources for CCS	H2 export potential
ALL	Sheer level of infrastructure spend required in the next few decades, with commensurate regulatory and planning load to ensure roll out minimises environmental and societal impacts	The degree of infrastructure required will provide many job opportunities

Major Conclusions

Scenario screening (updated for final results)

Table 2 and Table 15 illustrate outcomes of the Scenario Screening which identifies Scenarios A, B and C as the strongest scenarios. A definition of the traffic light ranking colour options is provided in Table 16 and the screening parameter weightings are presented in Table 17. A Screening Tool calculates the weighted sum for each scenario by adding the product of the assigned rank number and the parameter weighting calculated for all parameters. Because the rank number increases as the comparative favourability decreases, the strongest option will have the lowest weighted sum and the weakest option will have the highest weighted sum.

The following conclusions can be drawn from the post processing analysis which was undertaken to test the general robustness of the screening outcomes to different weighting values and ranking assignments, as well as unexpected conditions or events that may change the value of parameters and rankings:

1. Whilst the consensus screening outcomes were found to be generally robust, there was a mild level of sensitivity to significant changes in the Environmental parameter (weighting and ranking).
2. Under all cases, Scenario B was always found to be amongst the strongest outcomes either on its own, or (in almost all cases) alongside Scenarios A and C.
3. Scenario D was always found to be the weakest scenario under all cases.

Table 15: Scenario Ranking with Logic Statements – Updated for Final Results

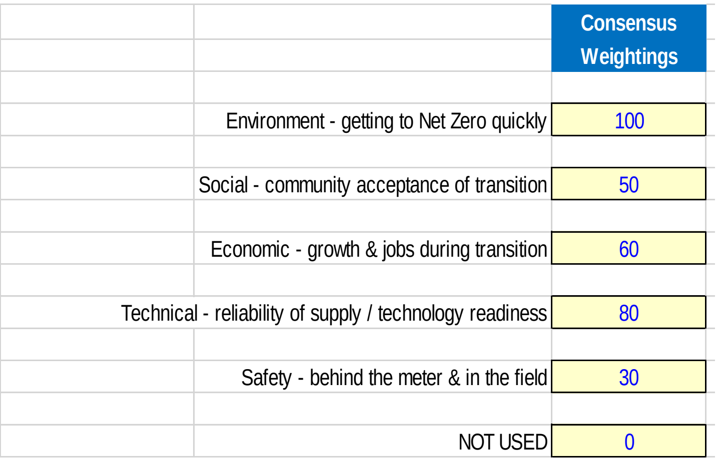
Parameter		**Ranking**			
		Sc. A	**Sc. B**	**Sc. C**	**Sc. D**
Environ.	Quicker to Net Zero	**REVISED FOR FINAL RESULTS** Achieves Net Zero Slightly before 2050	**REVISED FOR FINAL RESULTS** Achieves Net Zero Slightly before 2050	**REVISED FOR FINAL RESULTS** Achieves Net Zero well before 2050	**REVISED FOR FINAL RESULTS** equires v. large CCS to hieve Net Zero by 2050
	Risk / Opp Balance	Hydrocarbon use minimised	Risk of not capturing all CO2	Hydrocarbon use minimised	Risk of not capturing all CO2 (largest volumes)
Social	Community Acceptance	Comm. happy with solar & wind	Comm. happy with solar & wind	Concern of ongoing nat gas (blue H2)	Concern of ongoing coal (brown H2)
	Risk / Opp Balance	Public opposition to dams (hydro power)	Minimum change	ıblic opposition to dams (hydro power)	Brown coal and public opposition
Economic	rowth & Jobs	**REVISED FOR FINAL RESULTS** Lower jobs potential mpared to H2 scenarios	Lower jobs potential ompared to H2 scenarios	**REVISED FOR FINAL RESULTS** Higher jobs potential for H2 industry	Higher jobs potential for H2 industry
	CAPEX	**REVISED FOR FINAL RESULTS** Significantly lower cost than Sc D	Significantly lower cost than Sc D	**REVISED FOR FINAL RESULTS** Significantly lower cost than Sc D	**REVISED FOR FINAL RESULTS** Significantly higher st than other scenarios
	Risk / Opp Balance	as network stranded set – write off, miss out n H2 economy, cost of istributed power asset	Parts of gas network tranded asset – write off , niss out on H2 economy	ost of distributed power sset upgrade blow out. i/rare earth cost risks	CCS cost blowouts. pportunity LNG export.
Technical	Reliability of Supply	most complex power supply with “amateur anagement” (behind the meter)	Minimal change	H2 storage & distribution efficiency	H2 storage & distribution efficiency
	Technology Readiness	Solar, wind, hydro proven	Mixed bag	2 technology at scale	2 technology at scale
	Risk / Opp Balance	Concentrated solar opportunity	Less new technology	portunities concentrated solar, H2 production cost / scale red’n.	CCS and H2 ıbrittlement risks in high pressure lines

Safety	Behind the Meter / In Field	More complex behind the meter	Least change / most understood	H2	H2 (largest volume)
	Risk / Opp Balance	Household battery fire	Household battery fire	Household battery fire, ydrogen risks (storage / piping / cars)	Household battery fire, ydrogen risks (storage / piping / cars)

Table 16: Definition of Traffic Light Ranking Options

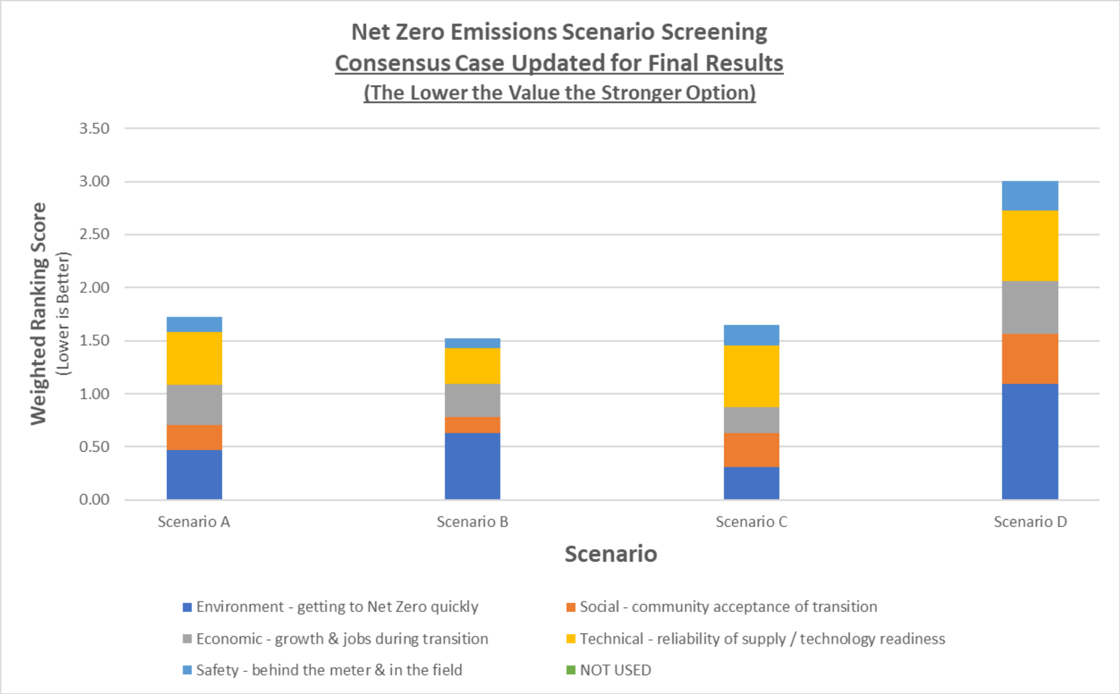
Colour & Rank Number	**Definition**
0	(Comparative) non differentiated / cannot be compared
🟩 1	(Comparative) Better / Good / Preferable
🟨 2	(Comparative) Mid-Range Low / Few Issues but Manageable
🟧 3	(Comparative) Mid-Range High / Numerous Issues but Manageable
🟥 4	(Comparative) Worse / Unacceptable / Not Preferable / Issues Unlikely Manageable

Table 17: Consensus Weightings used for Screening Parameters



	Consensus Weightings
Environment - getting to Net Zero quickly	100
Social - community acceptance of transition	50
Economic - growth & jobs during transition	60
Technical - reliability of supply / technology readiness	80
Safety - behind the meter & in the field	30
NOT USED	0

Figure 3: Scenario Screening Results – Updated for Final Results



Comparison of the scenarios against energy-emissions-offset results

- Scenario A
    - Achieves Net Zero slightly before 2050 given the relatively high proportion of zero emissions electricity generation in the energy mix.
    - Similar energy-emissions-offset profile to Scenario B.
    - Whilst the estimated Carbon emissions levels for Scenarios A and B are higher than Scenario C (approximately twice in 2030), they are an order of magnitude lower than Scenario D (six times less in 2030 and even more so as the transition continues).
- Scenario B
    - Achieves Net Zero slightly before 2050 given the relatively high proportion of zero emissions electricity generation in the energy mix.
    - Similar energy-emissions-offset profile to Scenario A.
    - Whilst the estimated Carbon emissions levels for Scenarios A and B are higher than Scenario C (approximately twice in 2030), they are an order of magnitude lower than Scenario D (six times less in 2030 and even more so as the transition continues).
    - Retains relatively small level of natural gas beyond transition (20 PJ in 2050) to provide electricity peaking coverage to firm variable renewable power, and support hard to abate manufacturing.
- Scenario C
    - Achieves Net Zero significantly earlier than 2050 given the relatively high proportion of zero and negative emissions electricity and gas in the energy mix (renewables and biogas).

  - For the reasons described in the prior point, the estimated Carbon emissions levels for Scenario C are much lower than Scenarios A and B (approximately half in 2030), and an order of magnitude lower than Scenario D (thirteen times less in 2030 and even more so as the transition continues).
  - Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was calculated to assess manageability if it were utilised. Based on these results the level of CCS that would be required (no more than 2 Mill Te CO_2 per annum) falls within that proposed by the CarbonNet project.
  - Most balanced mix of energy sources / least focused on one specific energy source to provide flexibility for adoption of new technologies that may reach competitive pricing in the future, in addition to providing a level of protection in the event that the necessary scale green Hydrogen production cannot be achieved.
- Scenario D
  - Very large scale Carbon emissions with estimated levels growing from 366 Mill Te CO_2 equiv. in 2030 to 715 Mill Te CO_2 equiv. in 2050.
  - Rapid installation of large scale Hydrogen transportation infrastructure given the specific location of the brown coal resource meaning this Scenario is constrained to a centralised energy production model.
  - Rapid installation of extremely large scale CCS required with estimated storage levels growing from 297 Mill Te CO_2 in 2030 to 698 Mill Te CO_2 in 2050. These large reservoir storage volumes are as yet unidentified.

Comparison of the scenarios against use of existing natural gas infrastructure

- Scenario A
  - The potential may exist for retaining a small proportion of the existing natural gas infrastructure, for example 20% by 2050, given it has a low proportion of energy gas in the mix.
  - Given the comparatively low levels of Hydrogen production (estimated 42 PJ in 2050) the extent of new Hydrogen pipeline infrastructure proposed for Scenario A is minimal given the potential for blending by adjusting the level of biogas production as natural gas production declines.
- Scenario B
  - The potential may exist for retaining a small proportion of the existing natural gas infrastructure, for example 10% by 2050, given it has a low proportion of energy gas in the mix. This estimate requires optimisation of the Hydrogen / natural gas / biogas phasing and blending schedule. Replacement of natural gas assets beyond design life, would require careful economic assessment considering the alternative of installing new Hydrogen infrastructure.

  - Phasing of new Hydrogen pipeline infrastructure is less aggressive for Scenario A than Scenarios C and D given the significantly lower levels of Hydrogen (estimated 90 PJ in 2050 compared to 470 PJ in 2050 for Scenario C and 1,486 PJ in 2050 for Scenario D).
  - The extent of new Hydrogen pipeline infrastructure required compared to the current natural gas infrastructure is less than half (on a relative equivalent diameter basis).
- Scenario C
  - By 2050, none of the current natural gas infrastructure is likely to be retained for Scenario C given the high level of Hydrogen production (estimated at 470 PJ in 2050) compared to biomethane (estimated at 112 PJ in 2050) thereby precluding the ability to blend on the basis of materials incompatibility.
  - The pace of phasing in new Hydrogen pipeline infrastructure for Scenario C is faster than that of Scenario B, but equivalent to Scenario D with estimated 25% of total new pipeline infrastructure installed in 2030 growing to 100% in 2050.
  - The extent of new Hydrogen pipeline infrastructure required for Scenario C compared to the current natural gas infrastructure is double (on a relative equivalent diameter basis). This level of infrastructure is five times greater than that required for Scenario B, but only one third of that required for Scenario D.
  - A notional quantity of brown Hydrogen export is allocated for Scenario C rising to level exceeding 125 PJ per annum in 2050.
- Scenario D
  - As for Scenario C: by 2050, none of the current natural gas infrastructure is likely to be retained for Scenario D given the high level of Hydrogen production (estimated at 1,486 PJ in 2050) compared to biomethane (estimated at 54 PJ in 2050) thereby precluding the ability to blend on the basis of materials incompatibility.
  - The pace of phasing in new Hydrogen pipeline infrastructure for Scenario D is faster than that of Scenario B, but equivalent to Scenario C with estimated 25% of total new pipeline infrastructure installed in 2030 growing to 100% in 2050.
  - The extent of new Hydrogen pipeline infrastructure required for Scenario D compared to the current natural gas infrastructure is six times (on a relative equivalent diameter basis). This level of infrastructure is far greater than that required for the other scenarios (estimated fifteen times greater than Scenario B, and three times that required for Scenario C).
  - A notional quantity of brown Hydrogen export is allocated for Scenario D rising to a level exceeding 470 PJ per annum in 2050.

Comparison of the scenarios against use of existing electrical infrastructure

- General

  - Identify specific locations where additional HV power transmission lines should be routed underground for safety reasons including bushfires.

- Scenario A
  - Scenarios A and B introduce approximately the same level of new renewable electricity into the energy mix reaching approximately 1,600 PJ in 2050, being approximately 15% more than Scenario C and approximately double that for Scenario D.
  - Scenarios A and B will require approximately twice the level of upgrades to the existing electrical transmission infrastructure compared to Scenarios C & D. Comparatively similar levels of additional storage infrastructure will also be required.
  - Scenario A has under-utilised renewable generation in North West regional zones and under-utilisation of high-capacity electrical infrastructure from Latrobe Valley.
  - In Scenario A, two key implications for residential and commercial consumers of transitioning to full renewable electricity are the requirement for extensive replacement of natural gas appliances for electrical units, and the need for energy “self reliance” with the high level of behind the meter solar and battery storage systems.
  - Industrial consumers will either continue to rely on grid supplied electricity or install their own renewable electricity generation and storage infrastructure or some combination of the two, particularly to cover the peak demand case.
- Scenario B
  - Scenarios A and B introduce approximately the same level of new renewable electricity into the energy mix reaching approximately 1,600 PJ in 2050, being approximately 15% more than Scenario C and approximately double that for Scenario D.
  - Scenarios A and B will require approximately twice the level of upgrades to the existing electrical transmission infrastructure compared to Scenarios C & D. Comparatively similar levels of additional storage infrastructure will also be required.
  - Scenario B has under-utilised renewable generation in North West regional zones but has better use of existing high-capacity electrical infrastructure through the Latrobe Valley due to increased use of offshore wind turbines.
  - In Scenario B, implications for each consumer type would be similar to those described above for Scenario A, though for residential and commercial consumers a small level of replacement of natural gas appliances with Hydrogen units would also be required. A lower level of energy self reliance would be required compared to Scenario A.
- Scenario C
  - By 2050, Scenario C introduces approximately 1,480 PJ of new renewable electricity into the energy mix, being approximately 15% less than Scenarios A and B and approximately 75% more than Scenario D.

  - By 2050, Scenario C will require approximately 40% less upgrades to the existing electrical transmission infrastructure compared to Scenarios A & B and approximately 50% more than Scenario D. Comparatively similar levels of additional storage infrastructure will also be required.
  - Scenario C still includes some under-utilisation of renewable generation in North West regional zones and under-utilisation of the electrical infrastructure throughout the Latrobe Valley.
  - In Scenario C, implications for each consumer type would be similar to those described for Scenario A, though for residential and commercial consumers a significant level of natural gas appliances would need to be replaced by Hydrogen units. A lower level of energy self reliance would be required compared to Scenario A.
- Scenario D
  - Scenario D requires the least upgrade of the existing electrical infrastructure compared to the other scenarios, for example in 2050 approximately 60% less than that required for Scenarios A and B, and 33% less than that required for Scenario C.
  - Most of the upgrades in Scenario D, are to support hydro energy storage.
  - In Scenario D, implications for all consumers of transitioning to a large proportion of Hydrogen in the energy mix would be extensive replacement of natural gas appliances for Hydrogen units.

Scenario refinements

- General
  - Define the basis for interstate electricity and gas import and export to reduce (optimise) the level of energy infrastructure estimated during the study as a result of the necessary time-constraint driven simplifications that were made for the analysis. The overestimate stems partly from the requirement to use a single design point to calculate the required size of plant & facilities, and also from not being able to access the transient excess energy from differentials in load and demand cycles that will occur in a diverse, complex, inter-connected system
  - Describe the uptake of large-scale offshore wind separately from onshore wind projects.
  - Identify the optimum level of residential & commercial energy efficiency improvements corresponding to the lowest overall cost of reliable electricity. The complex, dynamic and interconnected nature of behind the meter demand on firming grid electricity capacity would need to be considered to determine this optimum energy efficiency level which is beyond the scope of the study.
  - Include small scale geothermal for commercial and industrial consumers in all scenarios.

  - CCS by chemical sequestration such as methane pyrolysis should be considered, subject to technology readiness position.
- Scenario A
  - Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
    - Increase the utilisation of gas infrastructure
    - Reduce overall Carbon emissions
  - Include green hydrogen for heavy transportation and suitable commercial transportation.
- Scenario B
  - Confirm the source of natural gas to satisfy residual demand beyond the transition for hard to abate users and potentially also blue Hydrogen in the event it is introduced into Scenario B. Likely candidates may include Victorian natural gas production (based on new discoveries of economic reserves), LNG import (for example through the proposed Viva facility), or inter-state supply via the existing natural gas network.
  - Optimise the phasing and blending of Hydrogen / natural gas / biogas.
  - Optimise the location of biogas production facilities (including biomethane) versus demand (users) with due consideration of feedstock logistics and energy regionalisation objectives.
  - Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
    - Increase the utilisation of gas infrastructure
    - Reduce overall Carbon emissions
- Scenario C
  - Optimise the phasing and blending of biomethane and Hydrogen to maximise the use of existing natural gas infrastructure during the early phases of the transition. A blend of up to 20% Hydrogen in methane (actual value dependent on pipeline pressure) would allow use of existing natural gas infrastructure during the early phases of the transition, offsetting the requirement for purpose-built Hydrogen infrastructure.
  - Consider transferring blue Hydrogen production to Scenario B where the supply of natural gas is maintained beyond the transition. When specified in Scenario C the future of blue Hydrogen is tied to the availability of Victorian natural gas (assumed to cease prior to 2050), resulting in the cost of finance for the large capital outlay required to establish the blue Hydrogen industry would likely be significantly higher than that for an equivalent green Hydrogen industry given the uncertain long term outlook for Victorian natural gas production, and limited time horizon for return on investment.

  - Noting that the speed at which Net Zero Carbon emissions can be achieved in Scenario C is determined to a large degree by the uptake of biogas, it is proposed to increase the level of natural gas during the early phases of the transition to slow the deployment of biogas resulting in more time to introduce the logistics required for biogas (for example biomass supply chains) and thereby improve the economics of Scenario C whilst still achieving Net Zero Carbon Emissions prior to 2050.

- Scenario D

  - Define the brown Hydrogen export levels to match the scale and timing of international markets.

Optimum scenario

It is recommended to undertake dynamic, parametric analysis of Scenarios A, B and C to develop more detailed data allowing further differentiation between Scenarios A, B and C. Given the constraints of the static, single point analysis method adopted for this study, it is not considered possible to develop the necessary level of detail to differentiate Scenarios A, B and C. Identification of the “Optimum Scenario” should be based on the more detailed data.

1. INTRODUCTION

1.1 Purpose

The purpose of this document is to record the work undertaken during the Net Zero Emissions Scenario Analysis, including results, conclusions and recommendations.

1.2 Scope & Objectives

Infrastructure Victoria has commissioned DORIS Engineering Australia to undertake a high-level technical analysis and screening of four "net zero Gas sector scenarios" for the Australian State of Victoria which are designed to provide input into a "Gas Roadmap" by end of 2021, and guide State Government Policy for achieving "Net Zero Carbon Emissions" by 2050. Study outcomes include advice on key decisions in three-time horizons (near-, medium-, and long-term) related to maximising opportunities and minimising risks associated with existing and committed Victorian gas infrastructure required to achieve "Net Zero" by 2050.

The four scenarios, described in Appendix 1, were developed by Infrastructure Victoria and represented key input to the study providing guidance in the development of the scenario technical models. As the analysis progressed, opportunities for refinement of the scenarios were identified and, as results and outcomes became available, elements of a potential "hybrid scenario" were identified that may deliver improvements over the base scenarios in affordability and reliability of energy whilst achieving a Net Zero Emissions position by 2050. The analysis of the "hybrid scenario" was beyond the scope of the study.

The four scenarios each represent a specific blend of traditional, renewable, and non-carbon energy sources, energy storage, and carbon sequestration including:

- Natural gas (from traditional reservoirs, plus waste-to-energy / biogas)
- Renewable energy (solar, wind, hydro, etc.)
- Non-carbon energy (Hydrogen)

Analysis of each scenario will estimate the degree of pre-existing Victorian energy infrastructure that can be retained, including natural gas and electrical power distribution networks, and which new infrastructure will be required. Key areas of work undertaken during the study are summarised below.

Natural Gas Consumption - analysing Victorian industrial consumers of natural gas (for both energy and chemical feedstock), to understand the nature and quantity of natural gas use, which uses can be more/less easily displaced, and the implications.

Natural Gas Transition Risks - analysing the Victorian gas industry and consumers to understand the potential risks of transition to the developed scenarios, including security of supply, grid resilience, safety, and cost implications of network rationalisation

Emission Reduction - analysing the upstream, midstream, and downstream gas infrastructure within Victoria to review the potential emission reduction opportunities and identify constraints, opportunities, and risks. Identification of specific potential emission reduction opportunities or colocation/symbiotic opportunities that may assist to achieve a faster transition to net zero emissions and/or lower the cost of transition.

Electricity Infrastructure - analysing the scale of electricity generation, storage, transmission, distribution, and efficiency gains required to fulfil the scenarios, including the impact of renewable energy development, constraints, risks, and opportunities

Risks & Opportunities - identification of significant uncertainties, barriers, or enablers (economic, technological, social, environmental, regulatory or policy).

Cost Benefit Analysis - identification of likely cost bearers and beneficiaries and any instances where redistribution of costs and benefits may be required.

Energy Gas & Carbon Sequestration - investigating the potential for green/blue/brown hydrogen, Carbon Capture & Storage, geothermal and biogas to displace natural gas and repurpose existing gas infrastructure in order to achieve relevant scenario outcomes.

Sufficient techno-economic knowledge will be developed to undertake a qualitative “Scenario Screening” exercise using an in-house Option Screening Tool, with the aim of identifying the strongest scenario to take forward for more detailed analysis.

1.3 Definitions

IV	Infrastructure Victoria
DORIS	DORIS Group
Green Hydrogen	H_2 produced through electrolysis using renewable electricity
Blue Hydrogen	H_2 produced through steam reforming of natural gas, with CCS
Brown Hydrogen	H_2 produced through gasification of brown coal, with CCS

1.4 Abbreviations

Acronym	Definition
ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ATO	Australian Tax Office
BEV	Battery Electric Vehicle
CHP	Combined Heat & Power (biogas for heat and electricity generation)
CAPEX	Capital Expenditure

Acronym	Definition
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
COAG	Council of Australian Governments
COVID-19	Coronavirus 2019
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 (AEM0 publication)
GW	Giga Watt (10^9 Watts)
H_2	Hydrogen
HFCV	Hydrogen Fuel Cell Vehicle
IPPU	Industrial Process and Product Use
ISP	Integrated System Plan
kW	Kilo Watt (10^3 Watts)
LNG	Liquified Natural Gas
LMP	Longford Melbourne Pipeline
LULUCF	Land Use, Land Use Change and Forestry
Mt CO_2-e	Million Tonnes of Carbon Dioxide equivalent
Mt(pa)	Million Tonnes (per annum)
NEM	National Electricity Market
OPEX	Operating Expenditure
PJ	Peta Joules (10^{15} Joules)
PTS	Principal Transmission System
PV	Photo Voltaic (solar)
tpa	Tones per annum
REZ	Renewable Energy Zone
SDGs	Sustainable Development Goals
SWP	South West Pipeline
TRL	Technology Readiness Level
VNI	Victoria – New South Wales Interconnector

1.5 References

Ref.	Title
1	Technical Analysis of Energy Generation and Carbon Offsets
2	Spatial Analysis of Energy Infrastructure
3	(Infrastructure Victoria) Scenario Descriptions (Appendix 1)
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2 STUDY BASIS & ASSUMPTIONS

2.1 Study Basis

2.1.1 Energy Demand

The base line for the annual energy demand of 1,298 PJ for Victoria has been taken from the 2018 -2019 overall energy demand figures (DISER 2020 Ref 6, 7). The breakdown of usage per consumer type is based on DISER Table F. These are considered a representative usage and the mix is not distorted by the COVID-19 impact on 2020 demand.

Table 18: Forecast Overall Energy Demand for the State of Victoria

2030	2040	2050
1,492 PJ	1,716 PJ	1,973 PJ

The assumed decline of hydrocarbon energy fuel demand during the transition is defined in Table 19.

Table 19: Hydrocarbon Energy Demand Decline Profile Assumed for the Analysis

(All values in PJ per year)

Hydrocarbon Energy	Scenario	2030	2040	2050
Natural Gas for Peaking Electricity, Heating and Manufacturing	A, C, D	233	70	0
	B	233	100	20
Brown Coal for Electricity Generation	All	300	150	0
Gasoline & Diesel for Road Vehicle Fuel	A, B	217	99	0
	C, D	163	69	0

A forecast increase of 15% in energy consumed per decade has been used to develop the overall energy demand over the three study time horizons refer Table 18. This is based on the Australian Energy Market Operator (AEMO) Integrated System Planning energy usage forecasts until 2050 and the associated 2020 modelling Inputs and Assumptions Workbook (Ref 36). AEMO has the role of managing the electricity and gas systems across Australia. They operate both the electricity systems in the National Electricity Market (NEM) and Victoria's gas transmission system as well as operating Australia's gas and electricity markets. As Australia energy landscape is rapidly changing there are increasing challenges particularly with increasing interdependencies between the gas and electricity markets. The Integrated System Plan (ISP) is a whole of system plan that provides an integrated roadmap for the efficient development of the NEM over the next 20 years and beyond. The ISP uses five scenarios to analyse the future with the middle three of these scenarios indicating the same percentage increase in energy demand. These scenarios are reflective of energy transitions led either by consumer behaviour or a technology led transition. Recovery of energy demand post COVID-19 is anticipated prior to 2030.

2.1.2 Time Horizons

The analysis considers three-time horizons – short, medium and long term (Ref 4). These are nominally 2030 to align with short term renewable energy targets, 2040 to identify scenarios that can achieve net zero earlier than 2050, and 2050 to align with the overall goal of net zero by 2050.

2.1.3 Geographical Boundaries

Numerous simplifications were made to model Victoria's energy system and generate useable data, including the use of a static, single point analysis method. A critical implication of this simplified approach is to over-estimate the level of new energy infrastructure required to reach Net Zero. The overestimate stems partly from the requirement to use a single design point to calculate the required size of plant & facilities, and also from not being able to access the transient excess energy from differentials in load and demand cycles that will occur in a diverse, complex, inter-connected system. This specific simplification also aligns with the scope exclusions of this study, for example agriculture and aviation, whereby optimized energy generation data would require assessment of the entire energy system using a sophisticated dynamic, parametric analysis method. An example of the simplified approach for electricity was to treat renewable firming capacity such as batteries or pumped hydro as being stranded from inter-state grid connections (Ref 4). A similar example for energy gas was treatment of the renewable electricity demand for green Hydrogen being delivered by a stand-alone renewable electricity generator dedicated to a specific green Hydrogen production plant. No advantage was taken of the availability of green electricity in the grid, or other potentially interconnected systems such as rooftop solar.

When applied in the same way to each scenario, use of this (and other) simplifying assumptions and approaches will yield equivalent levels of infrastructure outcomes, albeit non-optimised, which can nevertheless be considered "useful comparative data", but not "useable absolute data". Applying a comparative analysis method to screen the scenarios using the "useful comparative data" is therefore considered credible, and a justified approach for such early stage, non-engineered assessments.

2.1.4 Electricity Transmission Capacity

The AEMO website has been used to set a basis for the current capacity of the installed electrical infrastructure in Victoria. Historical data was reviewed and the data for a high demand day, where most electricity produced in Victoria was consumed in-state, was selected as the basis to estimate the maximum capacity through the installed infrastructure. The development of a simplified model for analysis of network congestion is detailed under Scenario A, Section 0.

2.1.5 Gas Production Capacity

The AEMO Gas Statement of opportunity (Ref 38), AEM0 website Gas Bulletin Board (GBB) interactive map and knowledge of current Victorian drilling and asset development projects has been used to predict the available gas production.

Table 20: Victorian Gas Plants and Storage Facilities

Location	Asset	Management	Pipeline	Capacity (TJ/d)	Annual Capacity (PJ)
Gippsland	Longford Gas Plant	Esso	LMP	850	310
	Lang Lang Gas Plant	Beach	LMP	27	10
	Orbost Gas Plant	APA	LMP	68	25
Otway (Port Campbell)	Otway Gas Plant	Beach	SWP	150	55
Otway (Port Campbell)	Iona Gas Plant and underground storage	Lochard (QIC)	SWP	570	208
Otway (Port Campbell)	Athena Gas Plant (previously Minerva Gas Plant)	Cooper	SWP	50	18
Melbourne (Dandenong)	LNG Storage Facility Dandenong	APA	LMP	237	87
Geelong	Proposed LNG Import Terminal (**Note 1**)	Viva	SWP	TBC	

Note 1 *: The capacity of the installed Gas Plants is more than sufficient to support the gas depletion profile used in the scenarios and the gas requirement assumed for the Scenarios post 2040 could be supplied just by the Otway assets. The Viva LNG Import Terminal (currently preparing the EIS stage and is at pre-FEED stage) could also provide an alternative source of gas for Victoria. Viva indicates on their website that the Terminal will have the capacity to provide half of the Victorian gas demand which would also provide another peaking energy source if the project is completed. This project has been considered in the analysis from an infrastructure removal perspective to ensure decommissioning plans allow for maximum facility life if project is implemented in line with current plans.*

It was assumed, based on publicly available information at the time of undertaking the study, that the following facilities will be operational in 2030:

- LNG Storage Facility Dandenong – storage capacity 680 TJ
- Iona Gas Plant Storage – storage capacity 24917 TJ (potential expansion by 2030) – it is assumed that once the Minerva cut-over project is complete the facility will no longer produce gas and act purely as a storage facility.

The existing infrastructure capacity, length. age and layout was taken from the AEMO GSO (Ref 38), the APA website, published maps (Ref 42) and the Australian Pipeline License Database (Ref 43).

Figure 4: Victorian Gas Production Facilities

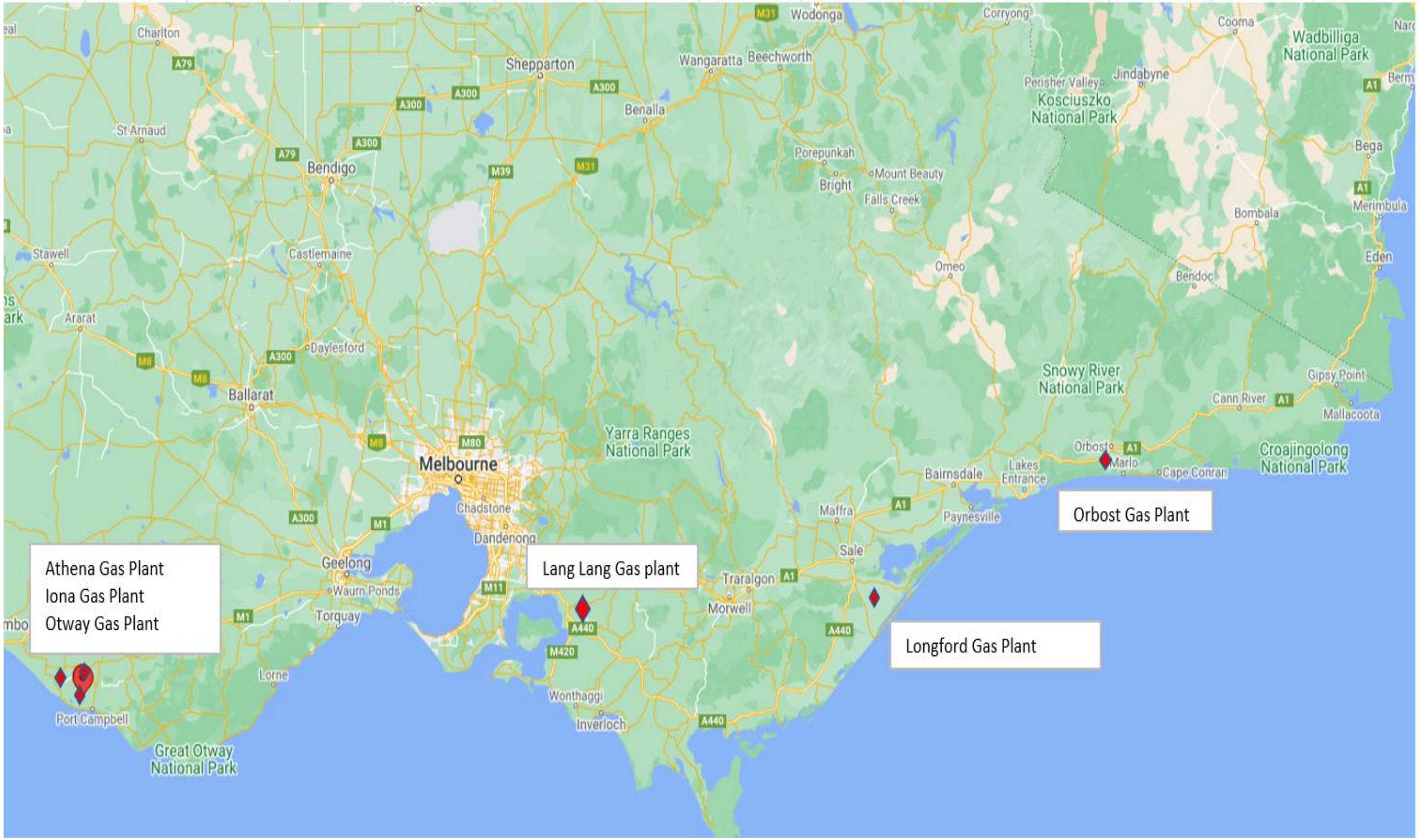


Figure 5: Major Victorian Pipelines

Figure 6Major Victorian Pipelines and Distribution Network Providers

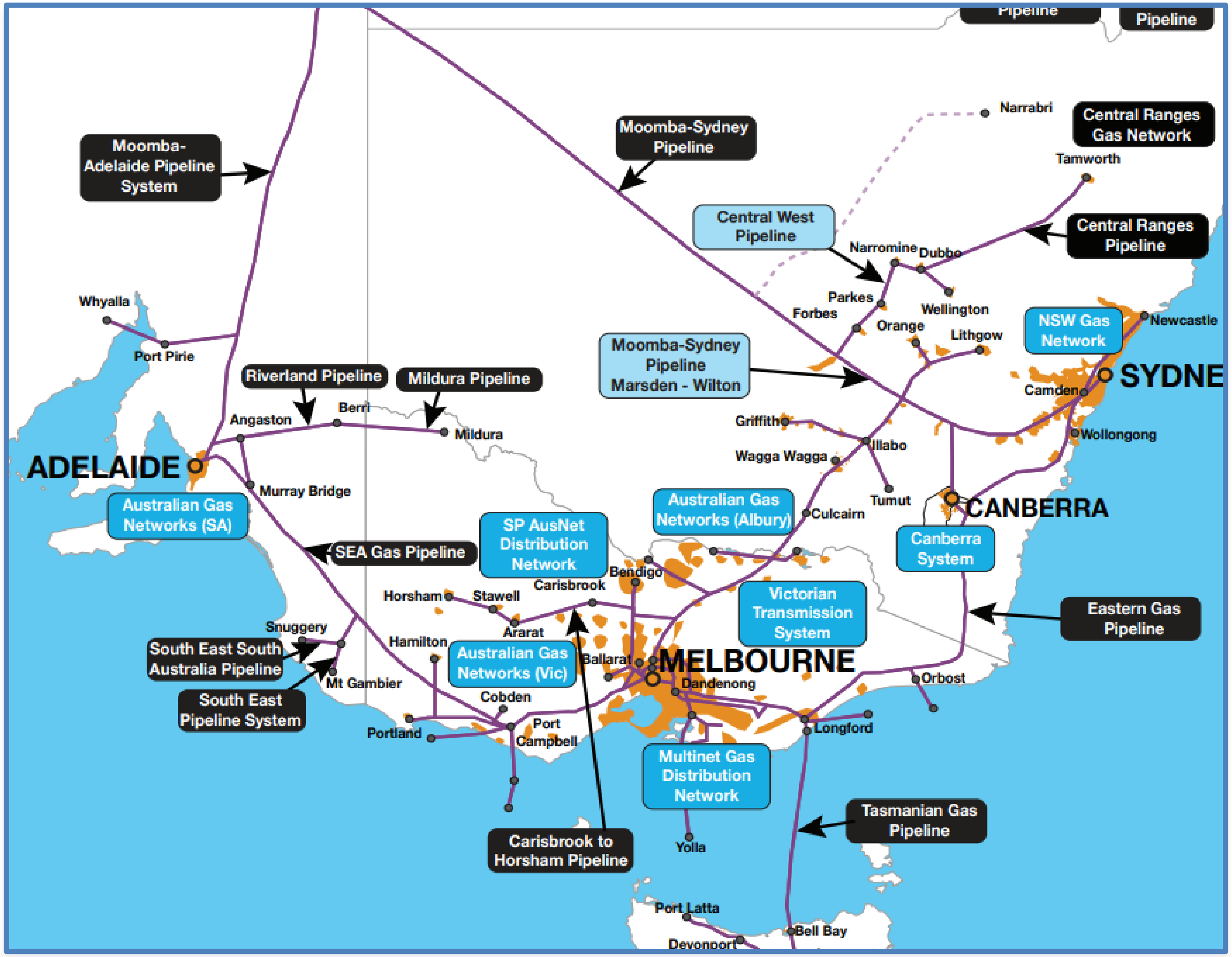
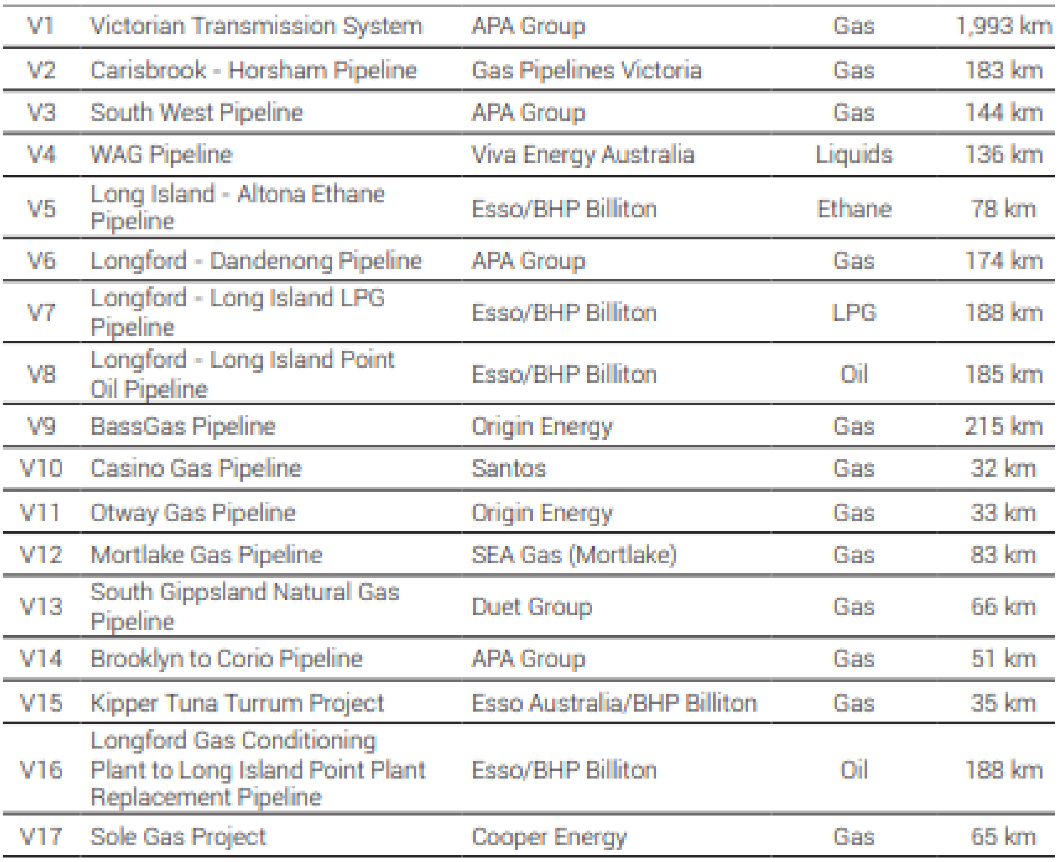


Table 21 Victorian Pipeline Lengths



V1	Victorian Transmission System	APA Group	Gas	1,993 km
V2	Carisbrook - Horsham Pipeline	Gas Pipelines Victoria	Gas	183 km
V3	South West Pipeline	APA Group	Gas	144 km
V4	WAG Pipeline	Viva Energy Australia	Liquids	136 km
V5	Long Island - Altona Ethane Pipeline	Esso/BHP Billiton	Ethane	78 km
V6	Longford - Dandenong Pipeline	APA Group	Gas	174 km
V7	Longford - Long Island LPG Pipeline	Esso/BHP Billiton	LPG	188 km
V8	Longford - Long Island Point Oil Pipeline	Esso/BHP Billiton	Oil	185 km
V9	BassGas Pipeline	Origin Energy	Gas	215 km
V10	Casino Gas Pipeline	Santos	Gas	32 km
V11	Otway Gas Pipeline	Origin Energy	Gas	33 km
V12	Mortlake Gas Pipeline	SEA Gas (Mortlake)	Gas	83 km
V13	South Gippsland Natural Gas Pipeline	Duet Group	Gas	66 km
V14	Brooklyn to Corio Pipeline	APA Group	Gas	51 km
V15	Kipper Tuna Turrum Project	Esso Australia/BHP Billiton	Gas	35 km
V16	Longford Gas Conditioning Plant to Long Island Point Plant Replacement Pipeline	Esso/BHP Billiton	Oil	188 km
V17	Sole Gas Project	Cooper Energy	Gas	65 km

2.1.6 Emissions Factors

Table 22: Emissions Factors used for the Study

	Emission Factor
Electricity Generation	
- Coal	0.094 Mt CO_2e / PJ of coal
- Natural gas	0.052 Mt CO_2e / PJ of natural gas
- Solar	0.000 Mt CO_2e / PJ
- Wind	0.000 Mt CO_2e / PJ
- Hydroelectric	0.000 Mt CO_2e / PJ
Direct Combustion	
- Natural gas	0.055 Mt CO_2e / PJ natural gas
- Biogas (including landfill gas)	-1.100 kg CO_2e / kWh electricity
Direct Heat – geothermal	0.007 t CO_2e / PJ
Green hydrogen	0.000 Mt CO_2e / GWh electricity
Blue hydrogen	0.005 Mt CO_2e / PJ natural gas

Brown hydrogen	0.010 Mt CO_2e / PJ coal
Agro-forestry sequestration	
- Forestry	-18.35 t CO_2e / hectare
- Marine	-830 t CO_2e / hectare
- Soil farming	-1172 t CO_2e / hectare
Carbon credits	-1.000 t CO_2e / credit

All emissions factors are based on Scope 1 – direct emissions as defined in the National Greenhouse Accounts Factors (Ref 48).

Emissions factors are sourced from the National Greenhouse Accounts Factors (Ref 48). Where an emission factor is not provided in Ref 48, the following sources where used:

- Geothermal emission factor is sourced from U.S. Energy Information Administration (Ref 49).
- Biogas emission factors are sourced from US EPA (Ref 50). This study excludes agriculture and waste emissions; however, the generation of biogas has a positive impact on reducing emissions from both of these sectors. Thus the negative emission factor used in this study is associated with capturing the impact of using biogas has on avoiding methane emissions directed to atmosphere when organics break down naturally.
- Hydrogen emissions factors are sourced from CSIRO (Ref 51).
- Forestry and agriculture-based emissions factors are extremely difficult to determine as they are based on a number of factors such as original land use, changed land use, management practice, soil quality. Therefore, the emission factor used in this report is based on a study undertaken by Parks Victoria (Ref 52).
- Soil farming emission factor, like agro-forestry is very site specific. For the purpose of this study the emission factor used is sourced from United Nations Food and Agriculture Organization (Ref 53).

2.1.7 Environmental Targets

The Victorian Climate Change Act 2017 (the Act) has established in law a State-wide target for net zero greenhouse gas emissions by 2050.

Under the Act, Victoria’s greenhouse gas emissions are to be published annually and compared to the 2005 levels (the reference year for emissions reduction targets under the Act) (Ref 9). The last year greenhouse gas emissions where reported was for the calendar year 2019. Table 23 summarizes the 2019 emissions by sector and the change measured since 2005, being 24.8%.

Table 23 : Change in Emissions by Sector between 2005 and 2019 for Victoria

Sector	**2005** **Mt CO_2-e**	**2019** **Mt CO_2-e**	**Change 2005 to 2019** **Mt CO_2-e**	**Change 2005 to 2019** **%**
Electricity generation	67.0	46.9	- 20.1	- 30.0%
Direct combustion	15.2	14.4	- 4.0	- 17.7%
Transport	20.2	22.7	2.5	12.4%
Fugitive emissions	2.4	3.0	0.6	26.0%
IPPU (industrial processes and product use)	3.1	3.3	0.2	9%
Agriculture	18.1	15.6	- 2.5	- 13.8%
LULUCF (land use, land use change and forestry)	-8.7	-17.4	- 8.7	103%
Waste	4.3	2.8	- 1.5	- 34.1%
Total (net emissions)	**121.5**	**91.3**	**- 30.2**	**- 24.8%**

Source: National Greenhouse Accounts, 2021 (Ref 10)

The energy sector – which comprises electricity generation, direct combustion, transport and fugitive emissions from fuels – was responsible for 95% of the total net emissions in Victoria in 2019. Australia's national targets, as part of the Paris Agreement, are currently set at 28% below 2005 levels by 2030 (Ref 11). The Premier and Minister for Environment, Energy and Climate Change have released Victoria's climate change strategy (Ref 12). Targets are shown in Figure 12. Victoria's per capita emissions are amongst the highest in the world at 20.2 tonnes of CO_2e per capita for 2014 (Ref 13). By 2019, this has dropped to 13.73 tonnes of CO_2e per capita (or a 16% reduction). Victoria is a signatory to the Under2 Memorandum of Understanding (MOU) which commits to reducing emissions to under 2 tonnes of CO_2e per capita by 2050 (Ref 14).

Table 24: Victoria's Climate Change Strategy Targets for 2030

Outcome	Target 2030
Greenhouse Gas emissions	50% below 2005
Renewable energy	50%
Large scale solar (Ref 11)	20%
Zero emission vehicle sales	50%
New public transport powered by renewable energy	100%
Residential solar rebates (solar panels, batteries, hot water)	778,500 homes
Small business solar rebates	15,000 small businesses
Organic waste reduction	50%

Outcome	Target 2030
Waste generation reduction per capita	15%
Trees planted	30 million
Restored biodiversity habitat	100,000 Ha
New homes achieving 7-Star energy rating	100%

Source: Victorian Climate Change Strategy, 2021

A comparison of each scenario against the 2030 Benchmark Targets outlined in the Victorian Climate Change Strategy targets is illustrated in Table 25.

Scenarios A, B and C reach net zero emission prior to 2050.

Scenario A, B and D fail to reach the new target of 50% reduction in greenhouse gas emissions by 2030.

Table 25: Measuring each Scenario against Victorian Greenhouse Gas Emission Reduction Targets for 2030

Benchmark	**2030 - Target**	**Scenario A**	**Scenario B**	**Scenario C**	**Scenario D**
Greenhouse gas emissions reduction as compared to 2005	50%	44%	44%	73%	36%
Share of renewable energy	50%	46%	46%	62%	65%
Share of renewables in electricity	50%	86%	86%	88%	71%
Solar energy share of renewable electricity generation	20%	18%	17%	47%	18%
Zero Emission Vehicle sales	50%	Not calc	Not calc	Not calc	Not calc
Residential solar rebates	778,500 homes	1.9 million	1.7 million	2.8 million	0.4 million
Small business solar rebates	15,000 business	52,359	48,506	79,508	11,688
Biodiversity habitat restoration	100,000 hectares	0	0	0	750
Achieves net zero emissions by 2050		Before 2050	Before 2050	Before 2040	2050
2 tonnes CO_2e emissions per capita by 2050 (Ref 57)		0	0	0	0

Score card for each scenario, based on the 10 criteria listed above, are:

- Scenario A and B – 5
- Scenario C – 8
- Scenario D – 4

2.1.8 Zero Emissions Vehicle uptake

The projected number of vehicles over the study time horizons has been based on the KPMG study (Refs 8. 39, 40).

The uptake of electric vehicles (EV) has been taken as

2030 – 30% EVs

2040 – 70% EVs

2050 – 90% EVs for scenario B, C, & D and 100% for Scenario A (full electrification)

2.1.9 Technology Readiness Levels

Technology Readiness Level (TRL) is an index on a scale of 1 to 9 which refers to the technical maturity of new technologies. The Australian Renewable Energy Agency has classified the TRLs for renewable energy technologies (see Figure 7). TRLs of 1 to 4 relate to technologies that are at the early stage of research and feasibility evaluation. TRLs of 5 to 7 relate to technologies at the development and demonstration stage, while TRLs of 8 and 9 refer to technologies that have been fully integrated and operated commercially. In addition to the TRL as a measure of technical maturity, the Commercial Readiness Index (CRI) can be used as a measure of commercial maturity (see Figure 7). A CRI of 1 refers to a hypothetical proposition (TRL < 7), while CRI of 2 refers to the first of kind commercial plants. CRI of 3 to 4 refer to technologies that are being adopted in the marketplace, while CRI 5 and 6 refer to technologies which are becoming widespread and fully accepted. A bankable technology has a CRI of 6.

Table 26 shows the TRL and CRI levels for technologies discussed in this report based on the Australian context. The CRI levels for Australia and for Europe and North America are indicated. Some technologies, such as biomethane and offshore wind, are fully commercial (TRL 9) but not widely deployed yet in Australia. These same technologies are already widely adopted or bankable (CRI 5/6) in Europe and North America. Some technologies such as green hydrogen have a high technical maturity (TRL 8/9) but are not widely adopted in Australia or elsewhere. Though recent announcements indicate that green hydrogen production will increase dramatically in the next five years in Australia, Europe, North America and the Middle East. Technologies such as Carbon Capture and Storage have high technology maturity and there are several projects either in operation or being proposed in Australia. Many technologies to separate and capture carbon dioxide are TRL 9 and CRI 6, however technologies to sequester the CO_2 are much less mature and can be project specific. Overall, the commercial readiness index in Australia is much lower than in North America where multiple CCS projects have been in operation for a decade or more and CO_2

transport pipeline infrastructure is in place in multiple regions such as the Gulf Coast, Mid-West, Permian and in Canada.

There are two emerging technologies, Carbon Capture and Utilisation and Methane Pyrolysis, which may mature and become commercially available before 2050. The utilisation of CO_2 to produce aggregates via carbonation is being worked on by several companies and a number of pilot plants and demonstration projects are operating around the world. However, the CRI is currently 1 and it is not clear if these technologies will be commercially adopted. Methane pyrolysis refers to technologies to crack methane into hydrogen and solid carbon, thereby avoiding CO_2 emissions that are produced when reforming natural gas to make hydrogen. Methane pyrolysis requires high temperatures >900 ^{o}C and the technologies use catalysts, plasma or molten metals and salts to crack the methane into hydrogen and solid carbon. A number of companies are working to demonstrate the technical and commercial feasibility of methane pyrolysis. Right now the TRL is around 5/6 and CRI 1/2.

Figure 7: Technology readiness level and commercial readiness index.

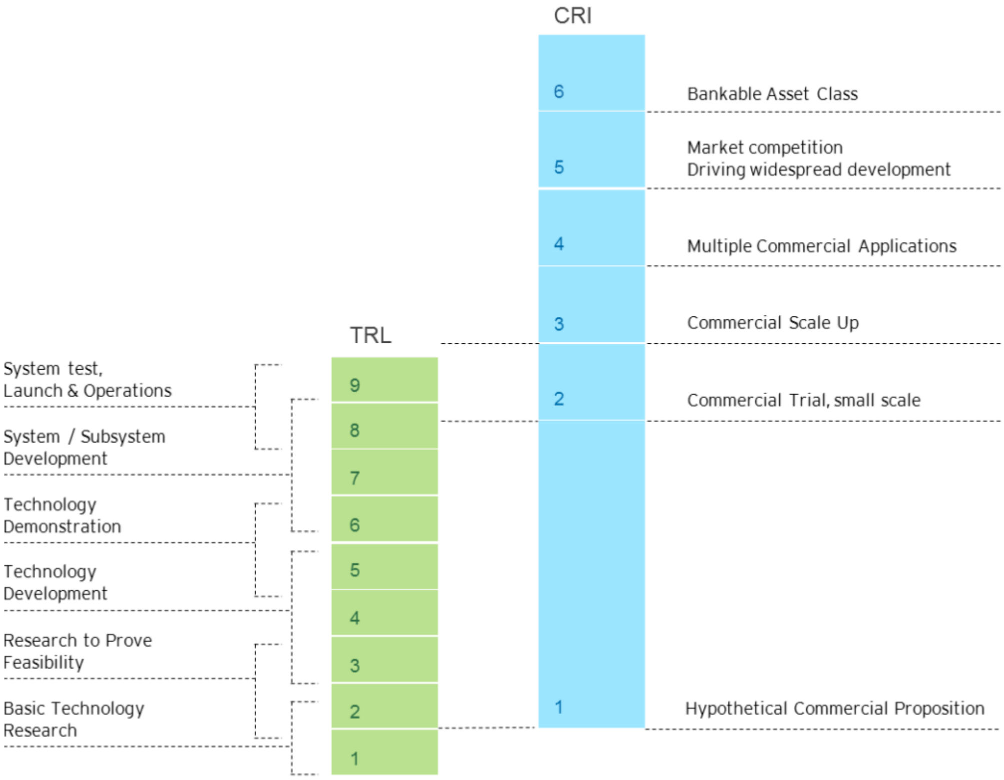


Table 26: Technology readiness level and Commercial readiness index for technologies discussed in this report.

Technology	Technology Readiness Level (TRL)	CRI (Australia)	CRI (Europe & North America)
Solar PV (all types)	9	6	6
Onshore Wind	9	6	6
Offshore Wind	9	2/3	5/6
Pumped Hydro	9	6	6
Geothermal	9	4	5/6
Waste to energy	9	6	6
Landfill gas	9	6	6
Biomethane	9	3/4	6
Biomass	9	5/6	6
Green Hydrogen	8/9	2/3	2/3
Blue Hydrogen	9	2/3	5/6 (North America)
Brown Hydrogen	9	2/3	2/3
Carbon Capture and Storage	8/9	3/4	6 (North America)
Carbon Capture and Utilisation	5/6	1	1
Methane Pyrolysis	5/6	1/2	1/2

2.1.10 Exclusions

The following items have been excluded from the scenario analysis

- Emissions from agriculture
- Infrastructure to support transport – ie road, rail, air transport
- Infrastructure to support the export of hydrogen including ports and loadout

2.1.11Key Assumptions

Table 27: Key Assumptions for the Net Zero Emissions Scenario Analysis

Reference	Assumption
GHG Tool	Gas to power efficiency : 30%
GHG Tool	Coal to power efficiency : 30%
GHG Tool	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. This calculation feature assumes that the proportion of energy used by each user in 2018 remains the same into the future.
GHG Tool	Given the GHG Tool's scope excludes some energy sources (refer Section 2.2.4.0) and therefore the energy production figures calculated by the GHG Tool must be lower than the overall energy demand for the entire State of Victoria. If it is assumed that the energy sources excluded from the scope are the same by type and magnitude for each scenario then this approach will yield useable results for the purposes of scenario comparative analysis in line with the methodology selected for this study.
Hydrocarbon Demand Decline	Hydrocarbon energy demand decline during the transition is based on the assumed profiles in Table 19.
Renewable Electricity	Estimation of new additional renewable electricity capacity undertaken does not consider the decommissioning of the existing assets.
Renewable Electricity	(Storage) It was assumed that, in a snapshot with both wind and solar working, it is necessary to fill up both batteries and pumped hydro in the shorter time to be able to prevent 24h without solar production and 168h without wind production, while meeting power demand. Battery storage was assigned to provide back up for solar power, and pumped hydro was assigned for wind power.
Renewable Electricity	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 as the lifetime as the solar production assets.
Renewable Electricity	It is assumed that all of the storage for solar power is via batteries located local to the solar panels. The storage for wind turbines is provided by hydro located in renewable zone V1.
Cost	Agriculture is excluded from emissions production.
Cost	Forestry is included as emissions sink.
Cost	Air transport is excluded from emissions production.
Cost	Victoria is an island, and has no access to external energy sources.
Cost	Cost to consumer of home and vehicle upgrades resulting from a switch to hydrogen or electrification is ignored. However, the impact to consumers will be noted as high, medium, or low cost.
Cost	It is assumed that plant whose utilization is below 100% is physically capable of being turned down to that level.
Cost	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 (supply of natural gas) is the most likely outcome for industrial gas users.
Cost	Plant that is to be decommissioned is assumed to incur all the cost of decommissioning in that decade. This means that the cost of underutilization and decommissioning occur in the same decade.

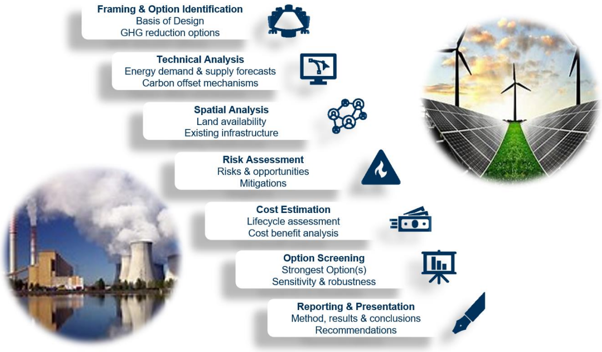
Cost	Plant underutilisation capacity is taken as the renewable capacity displacing it.
Cost	Plant underutilization capacity is taken to be decommissioned at the end of the decade.
Cost	The number of transport fuelled vehicles to be scrapped per decade equals the number of Electric/Hydrogen Vehicles that have displaced them.
Cost	The cost of Carbon offset mechanisms were assumed to be as follows: 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 CO2 : 30.00 $/tonne 2030 International Carbon Credit Cost per tonne CO2 : 150.00 $/tonne 2040 Australian Carbon Credit Cost per tonne CO2 : 150.00 $/tonne 2040 International Carbon Credit Cost per tonne CO2 : 300.00 $/tonne 2050 Australian Carbon Credit Cost per tonne CO2 : 300.00 $/tonne 2050 International Carbon Credit Cost per tonne CO2 : 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).
Existing Infrastructure	The phasing of the decommissioning of the existing gas infrastructure allows for the Viva LNG Import Terminal being operational by 2030 but the production capacity is assumed to come from the existing Victorian gas plants. As the project is currently preparing the EIS and is at pre-FEED stage it is not certain to be installed.
Hydrogen Production	It is assumed that all of the electricity required to produce green hydrogen is supplied by renewable energy generation local and connection 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.
Hydrogen Production	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.

Renewable Energy Location	All new renewable generation is assumed to be located in a Renewable Energy Zone (REZ) (refer to DELWP Victorian Renewable Energy Zones Development plan reference 45). Renewable energy has also been located in the Renewable Energy Zones best suited to weather conditions and geography.
Energy Storage	It is assumed that all solar farms are serviced by battery storage local to the solar farm and that energy produced from wind turbines is stored via hydro located in REZ V1.
CCS	Capture of point source CO_2 emissions in the Latrobe Valley with transport by pipeline to underground storage sites in the offshore Gippsland Basin.
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.

2.2 Assessment Methodology

The work was undertaken in three distinct phases to manage the flow of information, and provide decision gates where required. A staged approach was adopted with the analysis and costing of Scenario A undertaken first to develop an efficient work process, then applying that process to the work through the remaining Scenarios. The level of detail was calibrated to the limited study duration, with high level analysis undertaken and "order of magnitude" results developed for the purpose of comparing the scenarios to identify trends and drivers to support conclusions.

Figure 8: Study Approach



The work was undertaken in three distinct phases to manage the flow of information, and provide decision gates where required. Figure 9 (overleaf) describes the study schedule and illustrates the general workflow, set out in three stages as follows:

Phase 1 : Inception

Following award, an internal Kick-Off Meeting to generally brief the Study Team. The Project Inception Meeting was held via Microsoft Teams during Project Week 1, and was attended by Contractor's Study Team and Company's Project Team. The objective of the Project Inception Meeting was to ensure Company's objectives were well understood, review and clarify Company's Scenarios, review the Project Execution Plan (including the Study Schedule noting all milestones, plus Deliverables), and agree on the key Scenario Screening criteria.

Phase 2 : Analysis & Screening

- Modelling and analysis of the four scenarios was undertaken to develop sufficient data and understanding across several key parameters including environmental, social, economic, technical and safety.
- Technical analysis was undertaken to model each of the scenarios in a purpose built “GHG Tool” calculating energy production from the various sources, emissions and Carbon offsets required to achieve a net zero position in 2050.
- The output of the technical analysis provided input to the spatial analysis which identified the location and scale of energy production and Carbon offsets. A key function of the spatial analysis was to identify how to maximise the use of existing natural gas and electricity infrastructure, considering the location requirements of the new energy sources.
- Qualitative risk & opportunity assessments were undertaken for all scenarios.
- Cost estimates and “triple bottom line” cost benefit analysis were developed for all scenarios using the input from the other analysis activities.
- A comparative ranking of the scenarios was undertaken using a proprietary Screening Tool using a traffic light ranking method to compare the scenarios against a set of pre-agreed weighted parameters. The outcome of the scenario screening exercise was identification of the strongest scenario.

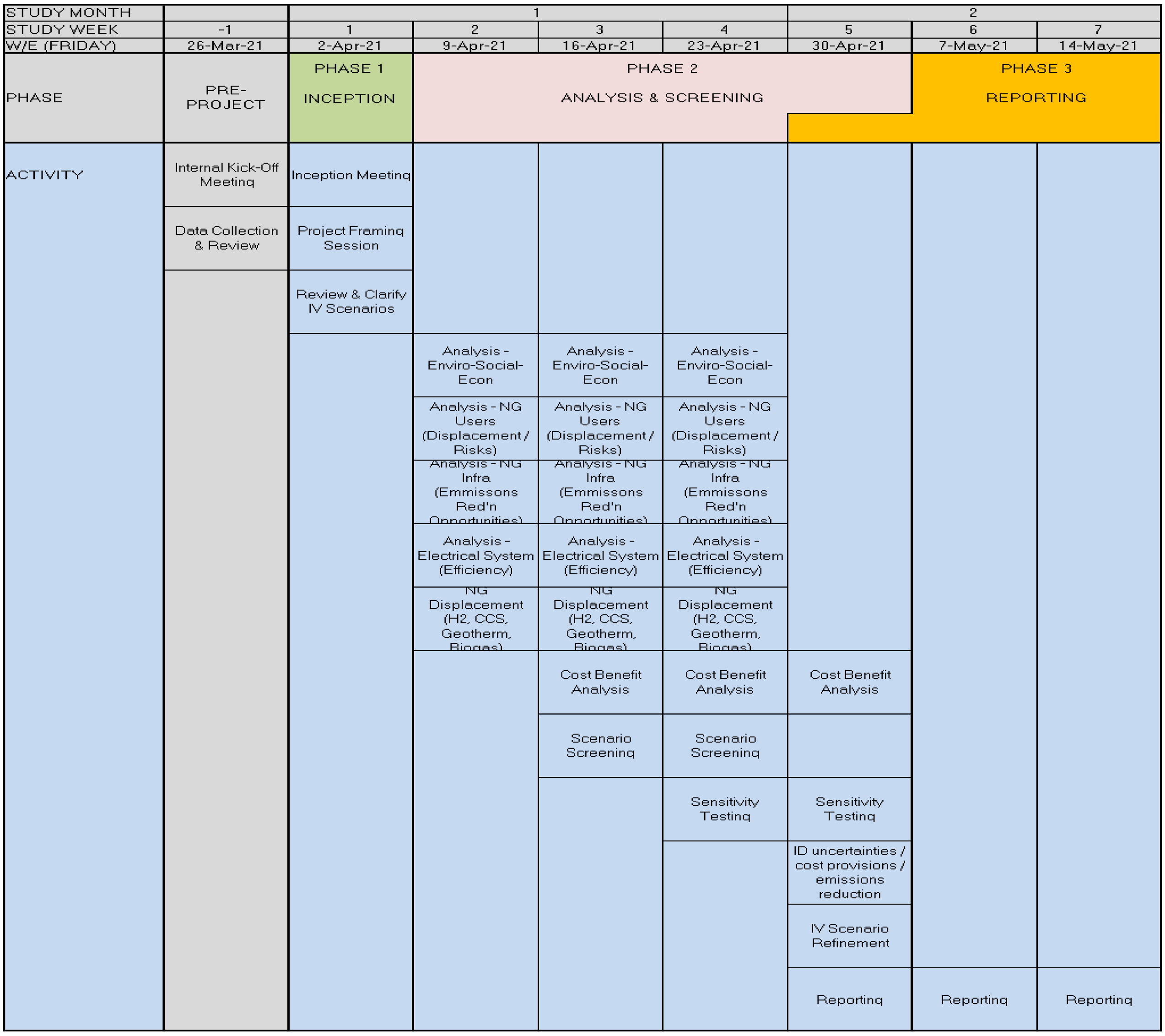
Phase 3 : Reporting

The method, work undertaken, and all results were documented in the Study Report providing a single point of reference. Definitive conclusions and clear recommendations regarding further work for the Detailed Study (Q3-21) were also identified.

Workshops formed a key part of the study methodology providing the opportunity for Contractor’s team and Company to collaborate closely on key activities. The following workshops were held virtually using Microsoft Teams:

- Inception Meeting (Project Week 1) attended by Contractor and Company
- Risk & Opportunity Workshop (Project Week 3) attended by Contractor
- Scenario Screening (Project Week 4) attended by Contractor and Company
- Scenario Refinement Workshop (Project Week 6) attended by Contractor
- Draft Report Clarifications (Project Week 7) attended by Contractor and Company

Figure 9: Study Schedule and Workflow



STUDY MONTH		1				2		
STUDY WEEK	-1	1	2	3	4	5	6	7
W/E (FRIDAY)	26-Mar-21	2-Apr-21	9-Apr-21	16-Apr-21	23-Apr-21	30-Apr-21	7-May-21	14-May-21
PHASE	PRE-PROJECT	PHASE 1 INCEPTION	PHASE 2 ANALYSIS & SCREENING				PHASE 3 REPORTING	
ACTIVITY	Internal Kick-Off Meeting	Inception Meeting						
	Data Collection & Review	Project Framing Session						
		Review & Clarify IV Scenarios						
			Analysis - Enviro-Social-Econ	Analysis - Enviro-Social-Econ	Analysis - Enviro-Social-Econ			
			Analysis - NG Users (Displacement / Risks)	Analysis - NG Users (Displacement / Risks)	Analysis - NG Users (Displacement / Risks)			
			Analysis - NG Infra (Emmissons Red'n Opportunities)	Analysis - NG Infra (Emmissons Red'n Opportunities)	Analysis - NG Infra (Emmissons Red'n Opportunities)			
			Analysis - Electrical System (Efficiency)	Analysis - Electrical System (Efficiency)	Analysis - Electrical System (Efficiency)			
			NG Displacement (H2, CCS, Geotherm, Biogas)	NG Displacement (H2, CCS, Geotherm, Biogas)	NG Displacement (H2, CCS, Geotherm, Biogas)			
				Cost Benefit Analysis	Cost Benefit Analysis	Cost Benefit Analysis		
				Scenario Screening	Scenario Screening			
					Sensitivity Testing	Sensitivity Testing		
						ID uncertainties / cost provisions / emissions reduction		
						IV Scenario Refinement		
						Reporting	Reporting	Reporting

2.2.1 Risk & Opportunity

The four scenarios were initially reviewed by team-based brainstorming to develop the potential risks and opportunities associated with each. The risk identification was undertaken by stepping through various aspects of each scenario to consider the risks and opportunities associated with each. The aspects considered were:-

- Electricity Generation
- Gaseous Fuels
- Energy Storage
- Carbon Offset
- Transmission & Distribution
- Residential & Commercial (Space and water heating, cooking)
- Industrial Use

- Transport
- Energy Efficiency
- Export (potential)

Given the scope of the Scenarios, each of which represent a significant number of projects rolled out over a 25 to 30 year time frame, the risk assessment approach was, out of necessity, broad brush. The intent was to tease out trends associated with the differing scenarios for the above aspects, rather than project risks that can be dealt with at the time. Given this approach, the team considered the consequence and likelihood of an event occurring, for the most critical identified[1] criteria, into three broad categories as follows:

Consequence of Event Occurring	**Criteria**		
	Economic[3]	**Social[2]**	**Environment[34]**
Low	Cost impact that can be borne within + 20% cost estimate Operating cost blowout + 20%	Negative local media, injuries to general public and workforce. Moderate impact to the Company in question's social licence (e.g., short term partial black out), minor damage to items of cultural significance. Potential for civil litigation, regulatory investigation	Minor environmental impact contained within the site of the release, or a release/effect that has short term impact that does not threaten a valued species or habitat
Medium	Cost impact that can be borne within + 50% cost estimate Operating cost blowout + 50%	Serious injury/ies, single fatality of general public, workforce fatality. Major damage to the Company in question's social licence (e.g., longer term partial blackout/ short term wider spread blackouts), major damage to items of cultural significance, negative state/national media, civil/regulatory litigation, potential prosecution and major fine, state/national media story	Major spill or release, displacement of species/partial impairment of ecosystem, major impact on a significant habitat, widespread medium and some long term impact
High	Significant cost implication >100% more than anticipated costings	Event results in multiple fatalities to the general public or workforce. Significant blackouts in state. Loss of items of National Significance. Prolonged litigation, potential for jail terms/very high fines. Ongoing national/global media attention	Primary: not reaching net zero Secondary: Long term/irreversible damage/destruction of highly important ecosystem/habitat, significant effects on endangered species, catastrophic spill/release
Notes:			
1	For the purposes of the broad-brush risk assessment, safety was categorised within the social category. For the comparative analysis, safety was considered separately		
2	Technical risks (technology not fully developed, reliable or available) were considered to have implications that could be categorised as societal, environmental or economic.		

The likelihood of the consequence eventuating was assessed as:

- Unlikely – unlikely that the consequence would occur during the roll-out to Net Zero
- Likely – likely occur during the roll-out
- Highly likely – Can be expected to occur during the roll-out

Following the risk and opportunity identification exercise, a comparative assessment of the four scenarios was undertaken to assess the risk to Victoria of adopting each of the four approaches, and the commensurate opportunities available to Victoria resulting from their adoption for the defined criteria of:

- Environment
- Social
- Economics
- Technical
- Safety

These criteria and their identified significant risks and opportunities are discussed for each scenario below, followed by recommendations to either manage/ameliorate identified risks/threats or capitalise on identified opportunities.

2.2.2 Cost Estimation

2.2.2.1 Goal

The goal of the study was to Identify the strongest scenario(s) to carry forward for more detailed analysis.

2.2.2.2 Overview

The cost estimate will be built up in pre-defined building blocks as described in the Cost Breakdown Structure below. Each block will contain cost and quantity information relating to a specific factor of the scenario.

Both bulk and unit rates for the cost estimate will reside within common cost data sheets included in the cost estimate report. The cost within each estimate will extract cost rates from this common reference. This allows for a more streamlined update of the whole estimate if prices change, or additional sensitivities are added to elements of the study.

The unit rates for the cost estimate will include estimating information specific to regional location as required.

To align with the comparative analysis methodology adopted for the study, the cost estimate for each scenario is presented as a “comparative cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The comparative cost index was calculated by dividing the cost estimate for each scenario by the cost estimate for the lowest cost scenario, by way of example for Scenario A :

$$\text{Cost Index}_{\text{Scenario A}} = \text{Cost Estimate}_{\text{Scenario A}} / \text{Cost Estimate}_{\text{Lowest Cost Scenario}}$$

Using this system the Cost Index for the lowest cost scenario will equal 1.

The development of classed cost estimates for each scenario is beyond the scope of this study.

2.2.2.3 Population Change

For the purposes of quality assurance, a comparison between the base case flatline assumption of 15% growth in energy demand per decade and the population change in Victoria by decade will be conducted.

For the purposes of this check, the change in the population of Victoria will be used as a proxy for the change in energy demand in each of 2030, 2040, and 2050 years.

Year	Population	Data Source
2016	6,173,172	(Ref 14)
2021	6,861,925	(Ref 14)
2026	7,495,194	(Ref 14)
2031	8,114,286 (15% Increase from 2021)	(Ref 14)
2036	8,722,766	(Ref 14)
2040	9,213,795 (12% Increase from 2031)	Estimate *
2050	10,436,061 (12% Increase from 2040)	Estimate *

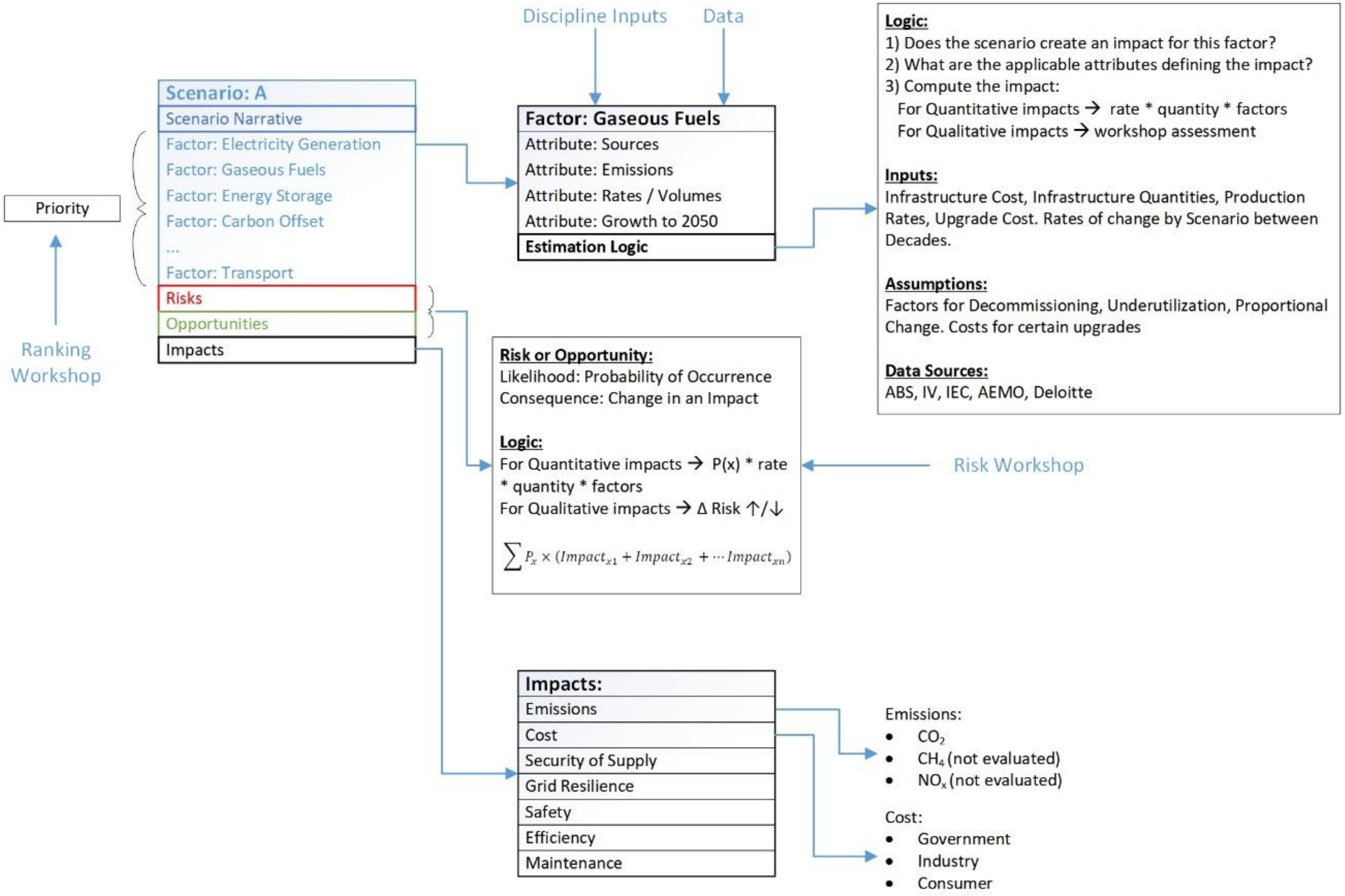
* Estimate calculated from the rate of change of population YOY and extrapolated forward at the average annual rate of change for the preceding two 5-year periods.

From this comparison, the 15% growth assumption is validated.

2.2.2.4 Basis of Estimate

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.

Figure 10: Basis of Cost Estimate



Logic:
1) Does the scenario create an impact for this factor?
2) What are the applicable attributes defining the impact?
3) Compute the impact:
  For Quantitative impacts → rate * quantity * factors
  For Qualitative impacts → workshop assessment

Inputs:
Infrastructure Cost, Infrastructure Quantities, Production Rates, Upgrade Cost. Rates of change by Scenario between Decades.

Assumptions:
Factors for Decommissioning, Underutilization, Proportional Change. Costs for certain upgrades

Data Sources:
ABS, IV, IEC, AEMO, Deloitte

Risk or Opportunity:
Likelihood: Probability of Occurrence
Consequence: Change in an Impact

Logic:
For Quantitative impacts → P(x) * rate * quantity * factors
For Qualitative impacts → Δ Risk ↑/↓

$$\sum P_x \times (Impact_{x1} + Impact_{x2} + \cdots Impact_{xn})$$

Emissions:
- CO_2
- CH_4 (not evaluated)
- NO_x (not evaluated)

Cost:
- Government
- Industry
- Consumer

The cost estimate for the purpose of the study shall be estimated using a combination of bulk rates (where available), and qualitatively scaled or factored costs for the current installed base of infrastructure in Victoria.

The resultant scenarios cost estimates allow a relative comparison of the scenarios from a common basis rather than deterministic estimates of actual cost, which are anticipated to be far higher.

2.2.2.5 Scenarios

The following four scenarios have been defined by IV as the basis of the study.

Scenario	Full Description	Summary
A	Almost full electrification using renewable sources and lots of storage with very little use of any gas except where it is irreplaceable. No carbon capture and storage (CCS).	Full Electrification No Natural Gas No CCS
B	Extensive electrification with renewable sources and storage with some natural gas to support the renewable electricity system and some industrial use, made net zero by CCS and offsets.	Partial Electrification Some Natural Gas Some CCS
C	Hydrogen using renewable sources really takes off as a substitute for natural gas, along with some waste to energy, biogas, and renewable electricity sources with some batteries. No natural gas or CCS.	Medium Electrification G/B Hydrogen & Biogas No Natural Gas No CCS
D	Hydrogen using both renewable sources and coal with CCS, along with some waste to energy and biogas and renewable electricity sources with some batteries. No natural gas.	Brown Hydrogen No Natural Gas Full CCS

The each of the scenarios is comprised of ten factors that have specific forecasts or future visions for the 2030, 2040, and 2050. These factors reflect specific societal changes for investigation to achieve the study goal of identifying the best combination of factors to reach a Net Zero Emissions by 2050 for Victoria.

The scenario factors are: Electricity Generation, Gaseous Fuels, Energy storage, Carbon Offset, Residential and commercial Use, Industrial use, Transmission & Distribution, Transport, Energy Efficiency, and Export.

2.2.2.6 Scenario Maps and Diagrams

As outputs from the study to support the evaluation of each Scenario, a set of diagrams will be created to facilitate screening, decision making, and cost estimation.

These diagrams will summarise the collected input from all the DORIS Subject Matter Experts (SMEs) involved in the study and will include:

- Energy Spatial Analysis → Present, 2030, 2040, and 2050; and,
- Energy Flow Transition Diagrams → Present to 2030 to 2040 to 2050.

The Energy Spatial Analysis for each of Present, 2030, 2040, and 2050 will be used to estimate the changes required in the transmission and distribution networks for gas and electricity.

2.2.2.7 Cost Breakdown Structure

For the purposes of economic analysis each scenario factor is assessed using cost and quantity metrics developed as part of the study.

The following cost breakdown structure shall be used to determine the relative cost between the scenarios.

Scenario Factor or Cost Element	Units	Data Source
Electricity Generation		
▪ Cost of Sources		Study Spreadsheet 6.5
■ Capacity Changing	MW	Energy Spatial Analysis
■ New Generating Plants	AUD$/MW	IEA
▪ Cost of Underutilization	AUD$/MW	Calculation
▪ Cost of Decommissioning		
■ Generating Plants	AUD$/MW	AEMO 2020
Gaseous Fuels		
▪ Cost of Sources		
■ Sources Changing	GJ	Energy Spatial Analysis
■ New Gas Plant	AUD$/GJ/year	Golar FLNG Gimi
■ New H2/BioGas Plant	AUD$/GJ/year	Assumptions
■ H_2 Transmission Pipelines	AUD$/km	50% of Gas CAPEX
■ H_2 Distribution Network	AUD$/km	50% of Gas CAPEX
▪ Cost of Underutilization	AUD$/MW	Calculation
▪ Cost of Decommissioning		
■ Gas Plants	AUD$/MW	20% of CAPEX Cost
■ Gas Transmission Pipelines	AUD$/km	TSB 2015
■ Gas Distribution Network	AUD$/km	20% of CAPEX Cost
Energy storage		
▪ Cost of Storage	AUD$/kw	Study Spreadsheet 6.4.1
Carbon Offset		
▪ Carbon Volume	tonne	Energy Spatial Analysis
▪ Cost of CCS Plant	AUD$/tonne	Gorgon CCS
▪ Cost of Carbon	AUD$/tonne	IEA
Transmission & Distribution		

Scenario Factor or Cost Element	Units	Data Source
▪ Reduction in NG Pipeline use	MW and Km	Energy Spatial Analysis
▪ Reduction in NG Distribution use	MW and Km	Energy Spatial Analysis
▪ Powerline Upgrades	GJ and Km	Energy Spatial Analysis
▪ Cost of Transmission		
▪ New H_2 Pipelines	AUD$/GJ/km	ΔNG Pipeline
▪ New Powerlines	AUD$/GJ/km	AEMO

2.2.2.8 Exclusions

For the purposes of economic analysis, the following scenario factors are excluded from the cost analysis and cost breakdown structure:

- Energy Efficiency
- Transport
- Residential and commercial Use
- Industrial use
- Export

The following macro items are excluded from the estimates carried out for this study:

- Cost changes due to foreign exchange fluctuation,
- Charges for project finance, working capital or interest,
- Taxes on the supply of goods or services for the project.

2.2.2.9 Calculations

Transmission Network Upgrade Calculator

Inputs: Map of Generating Infrastructure, Power Lines and Substations → AEMO
Inputs: Present Capacity of Electricity Network → AEMO
Inputs: Change in Energy Transmission Type → Study Spreadsheet
Output: Change in transferrable energy for 2030, 2040 and 2050 [MW]
Output: Energy Spatial Analysis with length of powerlines requiring upgrade [kms]
Output: Upgrade cost per kilometre (Interpolation of AEMO Building Blocks) [AUD$]

Cost of Underutilization Calculator

Inputs: CAPEX in AUD$/km → Building Blocks
Inputs: Proportion of Reduced Capacity (Proxy for Reduction in Utility) → Displaced Energy
Factor: Underutilization is set at 20% of CAPEX for the asset
Output: Underutilisation Cost [AUD$]

Length of Hydrogen Gas Pipelines Installed

(Quantities indicated relate to length of installed pipeline for the relevant time period. For clarity lengths are not cumulative.)

Scenario	2018	2030	2040	2050
A	0 kms	0 kms	0 kms	0 kms
B	0 kms	0 kms	2,346 kms	2,347 kms
C	0 kms	2,346 kms	1,174 kms	1,174 kms
D	0 kms	2,346 kms	1,174 kms	1,174 kms

Length of Hydrogen Gas Distribution Network Installed

(Quantities indicated relate to length of installed pipeline for the relevant time period. For clarity lengths are not cumulative.)

Scenario	2018	2030	2040	2050
A	0 kms	0 kms	0 kms	0 kms
B	0 kms	0 kms	11,666 kms	11,667 kms
C	0 kms	11,666 kms	10,208 kms	1,459 kms
D	0 kms	11,666 kms	10,208 kms	1,459 kms

Length of Natural Gas Pipelines Decommissioned

The pipeline network conveys large volumes of high-pressure Natural Gas from the source gas plant locations to the end user distribution networks.

The proportion of gas pipeline remaining in use at each of the 2030, 2040 and 2050 study years is an estimate. There is no correlation to characteristic life, the assumption is that it is decommissioned by the end of the decade and the underutilisation cost element accounts for the value lost by decommissioning pipelines with remaining life.

The quantities indicated for 2030, 2040 and 2050 relate to the length of pipeline decommissioned in that time period. The percentage values indicate the proportion of the 2018 (current installed) pipelines that are decommissioned in that time period.

Scenario	2018	2030	2040	2050
A	4,893 kms	0 kms (0%)	1,957 kms (40%)	2,349 kms (80%)
B	4,893 kms	979 kms (20%)	3,523 kms (90%)	0 kms (90%)
C	4,893 kms	4,404 kms (90%)	0 kms (90%)	0 kms (90%)
D	4,893 kms	4,404 kms (90%)	0 kms (90%)	0 kms (90%)

Length of Natural Gas Distribution Network Decommissioned

The distribution network conducts small volumes of low-pressure Natural Gas to the end users using widely distributed networks of small-bore piping.

The same proportions as for Natural Gas Pipelines are applied to the Natural Gas Distribution Network.

The quantities indicated for 2030, 2040 and 2050 relate to the length of pipeline decommissioned in that time period. The percentage values indicate the proportion of the 2018 (current installed) pipelines that are decommissioned in that time period.

Scenario	2018	2030	2040	2050
A	29,166 kms	0 kms (0%)	11,666 kms (40%)	14,000 kms (80%)
B	29,166 kms	5,833 kms (20%)	21,000 kms (90%)	0 kms (90%)
C	29,166 kms	26,249 kms (90%)	0 kms (90%)	0 kms (90%)
D	29,166 kms	26,249 kms (90%)	0 kms (90%)	0 kms (90%)

Length of Powerlines Installed

Scenario	2030		2040		2050	
Line Size	**220kV**	**550kV**	**220kV**	**550kV**	**220kV**	**550kV**
A	6,783 kms	100 kms	14,693 kms	100 kms	20,467 kms	100 kms
B	6,241 kms	100 kms	13,380 kms	100 kms	19,129 kms	100 kms
C	7,112 kms	100 kms	10,302 kms	100 kms	8,499 kms	100 kms
D	2,372 kms	100 kms	3,019 kms	100 kms	4,392 kms	100 kms

Length of Powerlines Upgraded

(Quantities indicated relate to length of installed powerlines for the relevant time period. For clarity lengths are not cumulative.)

Scenario	2018	2030	2040	2050
A	2,935 kms	0 kms	685 kms	1,115 kms
B	2,935 kms	0 kms	435 kms	685 kms
C	2,935 kms	0 kms	435 kms	435 kms
D	2,935 kms	0 kms	435 kms	435 kms

2.2.2.10 Constraints

Nuclear power generation in Australia is prohibited by legislation [Ref 44].

2.2.2.11 Preferences

A key conclusion from the IV strategy documents is that managing assets well is cheaper than new infrastructure.

2.2.2.12 Allowances

No allowances have been applied.

2.2.2.13 Financial Parameters

The estimate will have a base date of 2021.

The base currency of the estimate is Australian dollars (AUD$).

Prices quoted in foreign currency shall be converted using adjusted exchange rates as per the below:

Currency	Conversion Factor
AUD$ to USD$	Multiply by 0.7786
USD$ to AUD$	Multiply by 1.2713

2.2.2.14 Cost Indexing

No indexing is applied.

Some cost levels are adjusted for the 2030, 2040 and 2050 study years, where there has been an assumption for that factor, however, there is no index that applies.

Where necessary prices will be adjusted in accordance with IHS Markit (https://ihsmarkit.com) historic price index.

2.2.2.15 Escalation

No escalation is applied.

Where cost phasing is used, price escalation will be not be applied.

2.2.2.16 Coding and Formatting

Where applicable, the ISO 19008 taxonomy for coding Physical Breakdown Structure, Standard Activity Breakdown, and Code of Resource will be used to classify cost elements.

2.2.2.17 Units of Measure

Classification	Units	Conversion Factor
Energy Units	GJ	Gigajoule (Base Units)
	J	1,000,000,000 Joules = 1 GJ

	PJ	1 Petajoule = 1,000 GJ
	PJ	1 Petajoule = 277 777 777 kWhr
	kWh	1 Kilowatt Hour = 0.0036 GJ
	MW	1 Megawatt = 1,000 kilowatts
Dimension Units	m	Metres (Base Unit)
	km	1 kilometre = 1,000m
Weight Unit	kg	1,000 kilogram = 1 tonne
	Tonne	Tonne (Base Unit)

2.2.3 Vehicle Fuel Analysis

The study broadened the pre-existing forecast analysis of BEV uptake in Victoria [Reference 8] to cover HFCVs based on Infrastructure Victoria's Scenario Descriptions (Appendix 1). The scope of the analysis included road vehicles, both light (cars, commercial vehicles, etc) and heavy (trucks, buses, etc).

The aim of the analysis was to determine the amount of :

- Hydrogen production required to supply the HFCVs for the three time periods. The source of Hydrogen (green, blue or brown) would be dictated by the energy mix of the Scenario eg Scenario A would be predominantly green H2, whilst Scenario D would be predominantly brown H2.
- Renewable electricity production required to supply both the BEVs and also any green Hydrogen required for the HFCVs for the three time periods. The source of the renewable electricity (solar, wind, hydro) would be dictated by the energy mix of the Scenario.
- Carbon emissions from all road vehicles (diesel & gasoline, BEVs and HFCVs) for the three time periods.

The scale of uptake for BEVs and HFCVs was categorised using the qualitative scale in Table 28. 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.

Table 28: Scale of Uptake of New Fuel Vehicles

🟩	Large uptake of new energy vehicles
🟧	Medium uptake of new energy vehicles
🟥	Small uptake of new energy vehicles
🟦	No uptake of new energy vehicles

Introduction of HFCVs in accordance with Infrastructure Victoria's Scenario Descriptions (Appendix 1) leads to a pro-rata reduction in the amount of kilometres travelled for both hydrocarbon vehicles and BEVs in order to maintain the overall total kilometres travelled for all road vehicles described in the prior analysis [Reference 8], and the GHG Tool uses these two data points to calculate the kilometres travelled by vehicle category and fuel type for three time periods.

Based on typical fuel consumption for each type of vehicle, the GHG Tool estimated the fuel requirements, along with the subsequent Carbon emissions.

2.2.4 Energy-Emissions-Offset Calculation

Calculation of the energy and emissions streams for each Scenario was undertaken using a purpose built Green House Gas Emissions Analysis Tool ("GHG Tool"), the output of which is provided in Appendix 2. A general overview of the GHG Tool is provided below, and Scenario specific information in provided in sections 2.3.3, 4, 5, and 0.

2.2.4.0 Scope and Exclusions

The GHG Tool covers:

- Electricity for residential, commercial and industrial use. Depending upon the scenario, several new sources of electricity are available to replace that produced by brown coal including:
    - Solar (PV)
    - Wind (turbines)
    - Hydropower (turbines)
    - Combined heat & power (biogas from waste or biomass used for both heating and power generation)
- Energy storage as required to support renewable electricity generation (solar and wind) including:
    - Batteries
    - Pumped hydro
    - Chemical (green Hydrogen)
- Energy gas for non-power generation uses for example space & water heating (residential and commercial), and combustion and chemical feedstock (industrial). Depending on the scenario, several new energy gases are available to replace natural gas including:
    - Hydrogen including:
        - renewables (green)
        - natural gas reforming (blue)
        - brown coal gasification (brown)
    - Biogas (also covering landfill gas) – from crops, or waste (urban or farm)

    - Biomethane
- Low grade heat including :
    - Combined heat & power (biogas from waste or biomass used for both heating and power generation)
    - Geothermal
- Energy efficiency including:
    - Heat pumps
    - Insulation
    - Smart meter and smart grids
    - Energy efficient appliances
- Fuel for Road Vehicles, both light (cars, light commercial vehicles, etc) and heavy (trucks, buses, etc) including :
    - Hydrocarbons - diesel and gasoline
    - BEVs – renewable electricity generated from solar, wind or hydro-power
    - HFCVs – Hydrogen generated from either renewables (green), natural gas reforming (blue) or brown coal gasification (brown)
- Brown coal for electricity generation, and Hydrogen production (depending upon the Scenario)
- Carbon offset including:
    - CCS including
        - Onshore
        - Offshore
        - Chemical
    - Agro forestry including:
        - Forestry (trees)
        - Marine e.g., seagrass, mangroves
        - Soil farming
    - Emissions trading including:
        - Australian Carbon credits
        - International Carbon credits

The GHG does not cover:

- Non-road vehicles e.g., ships, trains and aircraft
- Energy sources other than those specifically stated above for example:

    - Nuclear
    - Wood
    - (Other than diesel and gasoline for road vehicles) petroleum liquids such as LPG, aviation fuel, diesel for non-road vehicle purposes, etc.

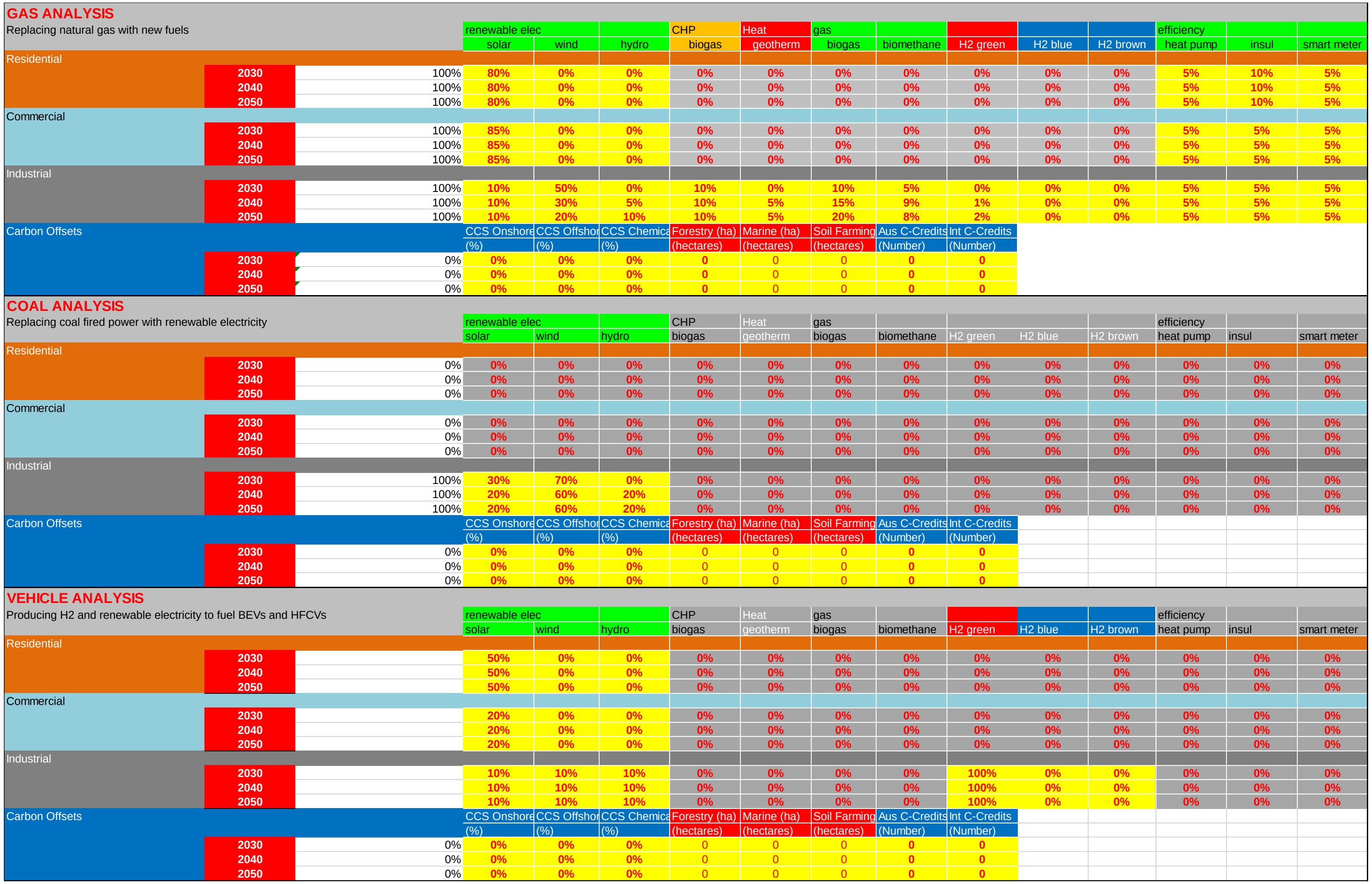
2.2.4.1 Architecture

The format of the GHG Tool is described below.

- **Summary Sheet** – this section contains an overview of the input and results including :
    - **“Control Panel”** (refer Figure 11 overleaf) [key user input section to be used in conjunction with the “Electricity & Energy Gas Balance” section] – defines the new energy generation-offset mix for each time period. The new energy *generation* sector may not necessarily correspond to the new energy *consumption* sector for instance industrial generation of green Hydrogen may be consumed (partly) by the residential sector.
        - new energy generation by type e.g., solar, wind, biogas, green H2, etc;
        - new energy generation by sector (residential, commercial and industrial); and
        - Carbon offset type e.g., CCS, agro-forestry, carbon trading, etc.
    - **Electricity & Energy Gas Balance** (refer Figure 12 overleaf) [key user input section to be used in conjunction with the “Control Panel” section] – compares demand and supply results for both electricity and energy gas across each time period, with a breakdown by fuel source e.g., natural gas, coal, solar, Hydrogen, etc. The primary function of the Energy Balance summary is to input additional energy required to balance demand.
    - **Energy-Emissions-Offsets Results** (refer Figure 13 overleaf) this is the primary summary of results contributing to the net emission value for each decade with a breakdown for each category including energy consumed, electricity in the grid, Carbon emissions, Carbon offsets and net emissions.
    - **Electricity & Hydrocarbon Fuel Demand Estimation** (refer Figure 14 overleaf) key input to the GHG Tool is the forecasted demand for both electricity and hydrocarbon fuels including natural gas and road vehicle fuels (gasoline & diesel).
- **Coal Fuel Replacement Calculator** – for each time period the following calculations are made :
    - Brown coal – the Carbon emissions resulting from the use of brown coal for electricity generation
    - Replacement of brown coal – estimates of the required amount of new sources of electricity generation to replace that produced by brown coal including solar, wind and hydropower as well as the emissions from these new sources
    - Carbon offsets – to counter the emissions produced

Figure 11: Example of the GHG Tool Summary Sheets – "Control Panel"

(Yellow fields are active, grey fields are not relevant to the Scenario)

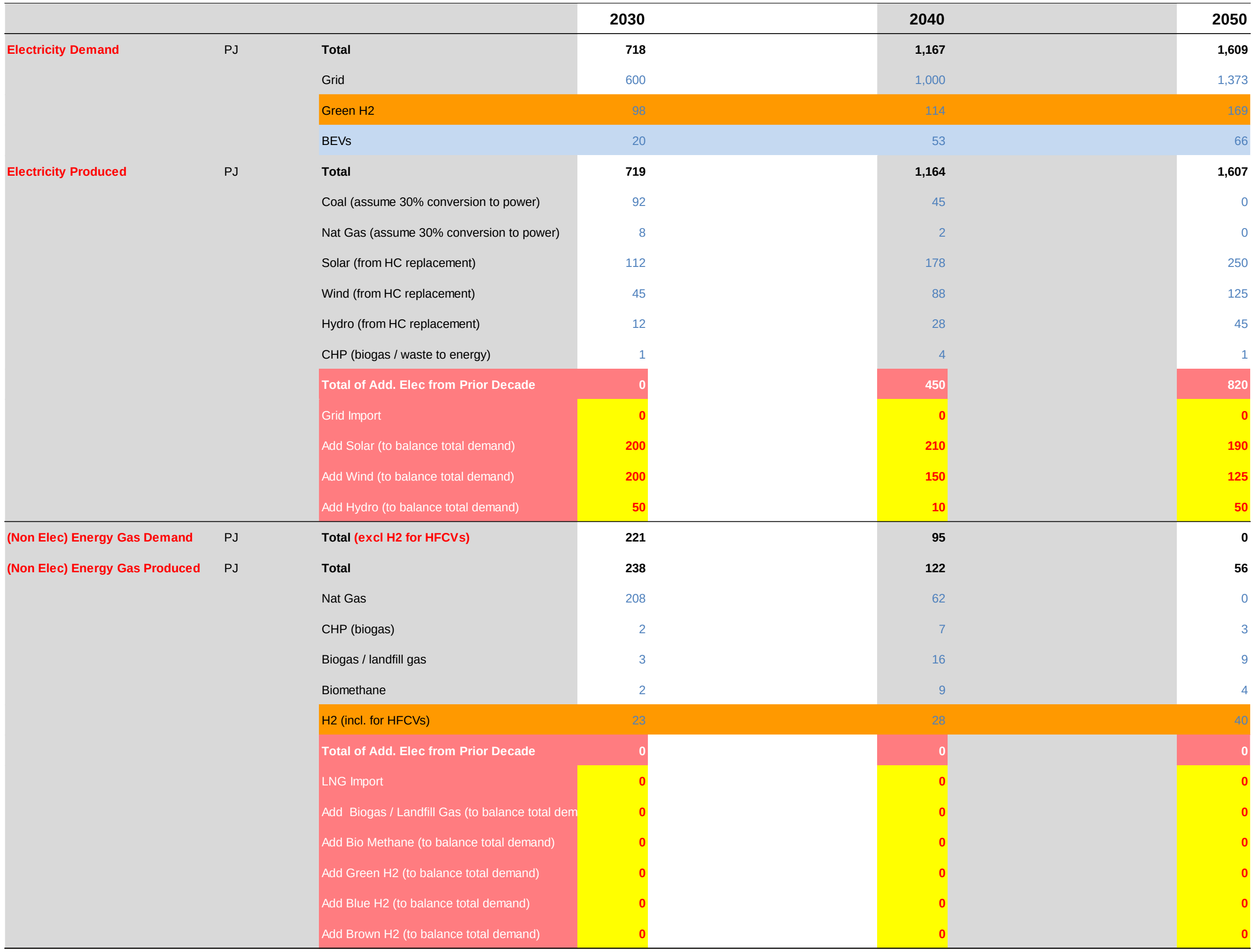


GAS ANALYSIS			renewable elec			CHP	Heat	gas					efficiency		
Replacing natural gas with new fuels			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	100%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	10%	5%
	2040	100%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	10%	5%
	2050	100%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	10%	5%
Commercial															
	2030	100%	85%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	5%
	2040	100%	85%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	5%
	2050	100%	85%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	5%	5%
Industrial															
	2030	100%	10%	50%	0%	10%	0%	10%	5%	0%	0%	0%	5%	5%	5%
	2040	100%	10%	30%	5%	10%	5%	15%	9%	1%	0%	0%	5%	5%	5%
	2050	100%	10%	20%	10%	10%	5%	20%	8%	2%	0%	0%	5%	5%	5%
Carbon Offsets			CCS Onshore	CCS Offshor	CCS Chemica	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credits	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	0%	0%	0%	0	0	0	0	0					
	2040	0%	0%	0%	0%	0	0	0	0	0					
	2050	0%	0%	0%	0%	0	0	0	0	0					

COAL ANALYSIS			renewable elec			CHP	Heat	gas					efficiency		
Replacing coal fired power with renewable electricity			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030	100%	30%	70%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshore	CCS Offshor	CCS Chemica	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credits	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	0%	0%	0%	0	0	0	0	0					
	2040	0%	0%	0%	0%	0	0	0	0	0					
	2050	0%	0%	0%	0%	0	0	0	0	0					

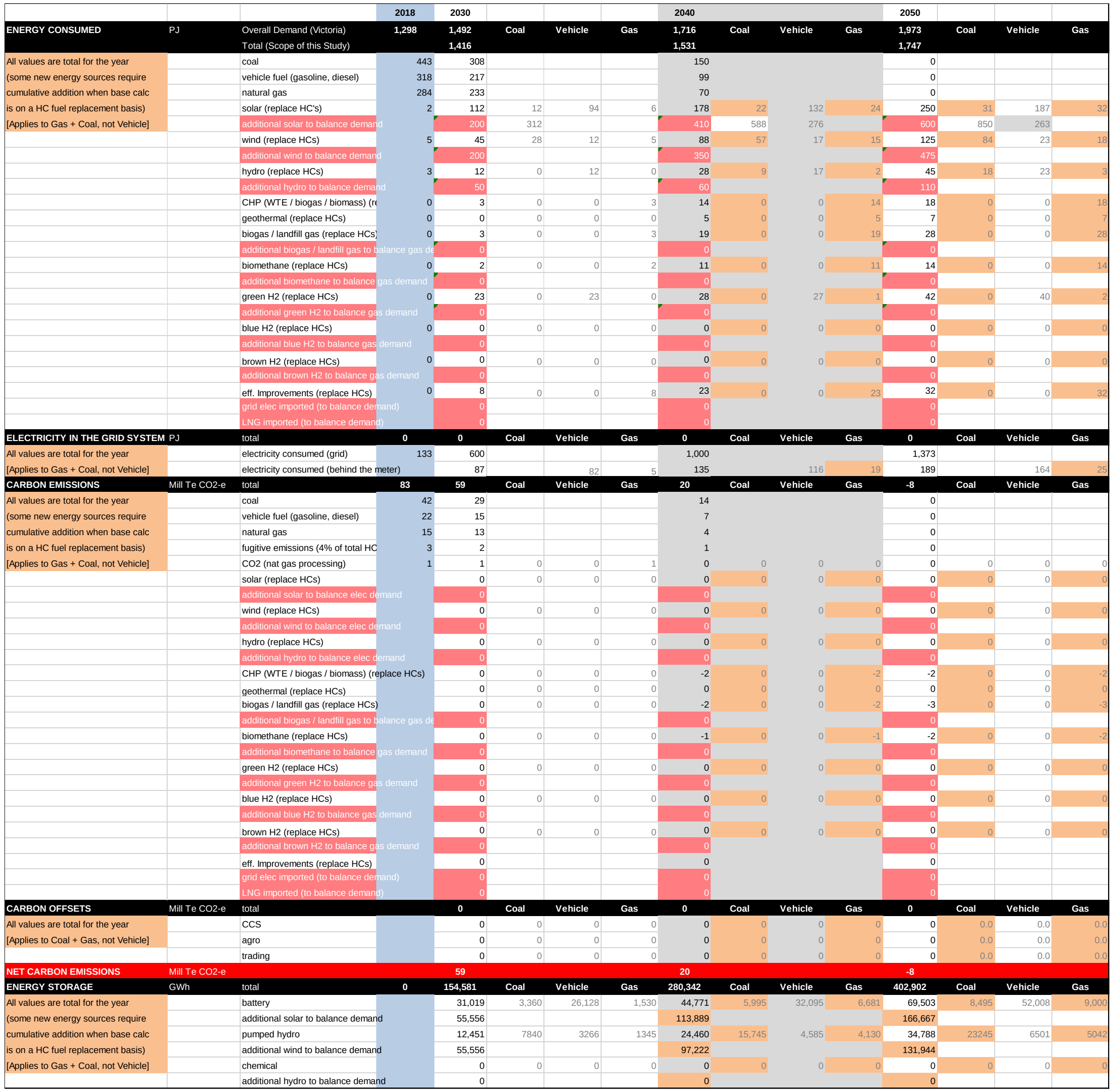
VEHICLE ANALYSIS			renewable elec			CHP	Heat	gas					efficiency		
Producing H2 and renewable electricity to fuel BEVs and HFCVs			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
	2040		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
	2050		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshore	CCS Offshor	CCS Chemica	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credits	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	0%	0%	0%	0	0	0	0	0					
	2040	0%	0%	0%	0%	0	0	0	0	0					
	2050	0%	0%	0%	0%	0	0	0	0	0					

Figure 12: Example of the GHG Tool Summary Sheets – "Electricity & Energy Gas Balance"



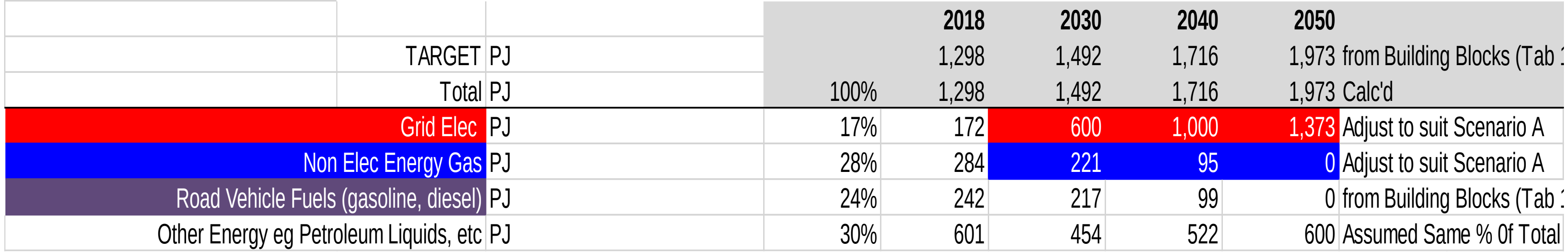
			2030	2040	2050
Electricity Demand	PJ	**Total**	**718**	**1,167**	**1,609**
		Grid	600	1,000	1,373
		Green H2	98	114	169
		BEVs	20	53	66
Electricity Produced	PJ	**Total**	**719**	**1,164**	**1,607**
		Coal (assume 30% conversion to power)	92	45	0
		Nat Gas (assume 30% conversion to power)	8	2	0
		Solar (from HC replacement)	112	178	250
		Wind (from HC replacement)	45	88	125
		Hydro (from HC replacement)	12	28	45
		CHP (biogas / waste to energy)	1	4	1
		Total of Add. Elec from Prior Decade	**0**	**450**	**820**
		Grid Import	**0**	**0**	**0**
		Add Solar (to balance total demand)	**200**	**210**	**190**
		Add Wind (to balance total demand)	**200**	**150**	**125**
		Add Hydro (to balance total demand)	**50**	**10**	**50**
(Non Elec) Energy Gas Demand	PJ	**Total (excl H2 for HFCVs)**	**221**	**95**	**0**
(Non Elec) Energy Gas Produced	PJ	**Total**	**238**	**122**	**56**
		Nat Gas	208	62	0
		CHP (biogas)	2	7	3
		Biogas / landfill gas	3	16	9
		Biomethane	2	9	4
		H2 (incl. for HFCVs)	23	28	40
		Total of Add. Elec from Prior Decade	**0**	**0**	**0**
		LNG Import	**0**	**0**	**0**
		Add Biogas / Landfill Gas (to balance total dem	**0**	**0**	**0**
		Add Bio Methane (to balance total demand)	**0**	**0**	**0**
		Add Green H2 (to balance total demand)	**0**	**0**	**0**
		Add Blue H2 (to balance total demand)	**0**	**0**	**0**
		Add Brown H2 (to balance total demand)	**0**	**0**	**0**

Figure 13: Example of the GHG Tool Summary Sheets – "Energy-Emissions-Offset Results"



			2018	2030				2040				2050			
ENERGY CONSUMED	PJ	Overall Demand (Victoria)	1,298	1,492	Coal	Vehicle	Gas	1,716	Coal	Vehicle	Gas	1,973	Coal	Vehicle	Gas
		Total (Scope of this Study)		1,416				1,531				1,747			
All values are total for the year		coal	443	308				150				0			
(some new energy sources require		vehicle fuel (gasoline, diesel)	318	217				99				0			
cumulative addition when base calc		natural gas	284	233				70				0			
is on a HC fuel replacement basis)		solar (replace HC's)	2	112	12	94	6	178	22	132	24	250	31	187	32
[Applies to Gas + Coal, not Vehicle]		additional solar to balance demand		200	312			410	588	276		600	850	263	
		wind (replace HCs)	5	45	28	12	5	88	57	17	15	125	84	23	18
		additional wind to balance demand		200				350				475			
		hydro (replace HCs)	3	12	0	12	0	28	9	17	2	45	18	23	3
		additional hydro to balance demand		50				60				110			
		CHP (WTE / biogas / biomass) (re	0	3	0	0	3	14	0	0	14	18	0	0	18
		geothermal (replace HCs)	0	0	0	0	0	5	0	0	5	7	0	0	7
		biogas / landfill gas (replace HCs)	0	3	0	0	3	19	0	0	19	28	0	0	28
		additional biogas / landfill gas to balance gas de		0				0				0			
		biomethane (replace HCs)	0	2	0	0	2	11	0	0	11	14	0	0	14
		additional biomethane to balance gas demand		0				0				0			
		green H2 (replace HCs)	0	23	0	23	0	28	0	27	1	42	0	40	2
		additional green H2 to balance gas demand		0				0				0			
		blue H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0	0
		additional blue H2 to balance gas demand		0				0				0			
		brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0	0
		additional brown H2 to balance gas demand		0				0				0			
		eff. Improvements (replace HCs)	0	8	0	0	8	23	0	0	23	32	0	0	32
		grid elec imported (to balance demand)		0				0				0			
		LNG imported (to balance demand)		0				0				0			
ELECTRICITY IN THE GRID SYSTEM	PJ	total	0	0	Coal	Vehicle	Gas	0	Coal	Vehicle	Gas	0	Coal	Vehicle	Gas
All values are total for the year		electricity consumed (grid)	133	600				1,000				1,373			
[Applies to Gas + Coal, not Vehicle]		electricity consumed (behind the meter)		87		82	5	135		116	19	189		164	25
CARBON EMISSIONS	Mill Te CO2-e	total	83	59	Coal	Vehicle	Gas	20	Coal	Vehicle	Gas	-8	Coal	Vehicle	Gas
All values are total for the year		coal	42	29				14				0			
(some new energy sources require		vehicle fuel (gasoline, diesel)	22	15				7				0			
cumulative addition when base calc		natural gas	15	13				4				0			
is on a HC fuel replacement basis)		fugitive emissions (4% of total HC	3	2				1				0			
[Applies to Gas + Coal, not Vehicle]		CO2 (nat gas processing)	1	1	0	0	1	0	0	0	0	0	0	0	0
		solar (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional solar to balance elec demand		0				0				0			
		wind (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional wind to balance elec demand		0				0				0			
		hydro (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional hydro to balance elec demand		0				0				0			
		CHP (WTE / biogas / biomass) (replace HCs)		0	0	0	0	-2	0	0	-2	-2	0	0	-2
		geothermal (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		biogas / landfill gas (replace HCs)		0	0	0	0	-2	0	0	-2	-3	0	0	-3
		additional biogas / landfill gas to balance gas de		0				0				0			
		biomethane (replace HCs)		0	0	0	0	-1	0	0	-1	-2	0	0	-2
		additional biomethane to balance gas demand		0				0				0			
		green H2 (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional green H2 to balance gas demand		0				0				0			
		blue H2 (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional blue H2 to balance gas demand		0				0				0			
		brown H2 (replace HCs)		0	0	0	0	0	0	0	0	0	0	0	0
		additional brown H2 to balance gas demand		0				0				0			
		eff. Improvements (replace HCs)		0				0				0			
		grid elec imported (to balance demand)		0				0				0			
		LNG imported (to balance demand)		0				0				0			
CARBON OFFSETS	Mill Te CO2-e	total		0	Coal	Vehicle	Gas	0	Coal	Vehicle	Gas	0	Coal	Vehicle	Gas
All values are total for the year		CCS		0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
[Applies to Coal + Gas, not Vehicle]		agro		0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
		trading		0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
NET CARBON EMISSIONS	Mill Te CO2-e			59				20				-8			
ENERGY STORAGE	GWh	total	0	154,581	Coal	Vehicle	Gas	280,342	Coal	Vehicle	Gas	402,902	Coal	Vehicle	Gas
All values are total for the year		battery		31,019	3,360	26,128	1,530	44,771	5,995	32,095	6,681	69,503	8,495	52,008	9,000
(some new energy sources require		additional solar to balance demand		55,556				113,889				166,667			
cumulative addition when base calc		pumped hydro		12,451	7840	3266	1345	24,460	15,745	4,585	4,130	34,788	23245	6501	5042
is on a HC fuel replacement basis)		additional wind to balance demand		55,556				97,222				131,944			
[Applies to Gas + Coal, not Vehicle]		chemical		0	0	0	0	0	0	0	0	0	0	0	0
		additional hydro to balance demand		0				0				0			

Figure 14: Example of the GHG Tool Summary Sheets – "Demand Estimate for Electricity & (Non-Elec) Energy Gas"



			2018	2030	2040	2050	
TARGET	PJ		1,298	1,492	1,716	1,973	from Building Blocks (Tab
Total	PJ	100%	1,298	1,492	1,716	1,973	Calc'd
Grid Elec	PJ	17%	172	600	1,000	1,373	Adjust to suit Scenario A
Non Elec Energy Gas	PJ	28%	284	221	95	0	Adjust to suit Scenario A
Road Vehicle Fuels (gasoline, diesel)	PJ	24%	242	217	99	0	from Building Blocks (Tab
Other Energy eg Petroleum Liquids, etc	PJ	30%	601	454	522	600	Assumed Same % Of Total

- **Vehicle Fuel Replacement Calculator** – for road vehicles both light (cars, commercial vehicles, etc) and heavy (trucks, buses, etc) a forecast of the uptake of BEVs and HFCVs to replace hydrocarbon vehicles is made for each time period to support the following calculations:
    - Hydrocarbon fuel – the Carbon emissions resulting from the use of diesel and gasoline as fuels for road vehicles
    - BEVs - estimates of the required amount of new sources of electricity generation to re-charge the BEVs including solar, wind and hydropower as well as the emissions from these new sources
    - HFCVs - estimates of the required amount of Hydrogen to fuel the HFCVs as well as the subsequent emissions including green (renewables), blue (natural gas reforming), and brown (brown coal gasification).
    - Carbon offsets – to counter the emissions produced

- **Natural Gas Fuel Replacement Calculator** - for each time period the following calculations are made :
    - Natural gas – the Carbon emissions resulting from the use of natural gas for electricity generation, heating and chemical feedstock.
    - Replacement of natural gas – estimates of the required amount of new sources of energy to replace that provided by natural gas as well as the emissions from these new sources including:
        - Renewable electricity including solar, wind and hydropower plus the energy storage requirements
        - Energy gas including Hydrogen (green, blue and brown), biogas, and biomethane
        - Low grade heat including combined heat & power, and geothermal
        - Energy efficiency including heat pumps, insulation, efficient appliances and smart grids
    - Carbon offsets – to counter the emissions produced, including
        - CCS
        - Agro forestry
        - Emissions trading

2.2.4.2 Process

Input Data

The basis for the model is defined by the following parameters:

- Forecast demand for electricity & hydrocarbon fuels for each time period [based on Scenario requirements, see Sections 2.3.3, 4, 5 for details]. This information is estimated in the following “Electricity & Hydrocarbon Fuel Demand Estimation” section of the GHG Tool Summary Sheet. Given the GHG Tool’s scope excludes some energy sources (refer Section 2.2.4.0) the energy production figures calculated by the GHG Tool will be lower than the overall energy demand for the entire State of Victoria (refer Table 18) unless energy export is predicted. If it is assumed that the energy sources excluded from the scope are the same by type and magnitude for each scenario then this approach will yield useable results for the purposes of scenario comparative analysis in line with the methodology selected for this study.
- Hydrocarbon energy demand decline during the transition is based on the assumed profiles in Table 19.
- Amount of energy consumed (by type) for each time period [reference Infrastructure Victoria’s Scenario Descriptions (Appendix 1)]. Definition of the amount of new energy to replace natural gas, coal and road vehicle hydrocarbon fuels is done in the following sections of the GHG Tool Summary Sheet:
- “Control Panel” [key user input section to be used in conjunction with the “Energy Balance” section] - with the for each time period defines the split of :
    - energy by new energy type e.g., solar, wind, biogas, green H2, etc;
    - energy by user type (residential, commercial and industrial); and
    - Carbon offset type e.g., CCS, agro-forestry, carbon trading, etc.

  Based on Infrastructure Victoria’s Scenario Descriptions (Appendix 1) the degree, or scale, of uptake for each new energy or offset mechanism is defined in the GHG Tool Control Panel using the guidance in Table 29.Table 29: Uptake Scale

Table 29: Uptake Scale

🟩	Large upscale / transfer of energy is made to this energy type Large uptake of new energy vehicles
🟧	Medium upscale / transfer of energy is made to this energy type Medium uptake of new energy vehicles
🟥	Small upscale / transfer of energy is made to this energy type Small uptake of new energy vehicles
🟦	No upscale / transfer of energy is made to this energy type No uptake of new energy vehicles

- Electricity & Energy Gas Balance [key user input section to be used in conjunction with the "Control Panel" section] – compares demand and supply results for both electricity and energy gas across each time period, with a breakdown by fuel source eg natural gas, coal, solar, Hydrogen, etc. The primary function of the Energy Balance summary is to input additional energy required to balance demand.
- Amount of carbon offsets (by type) for each time period [reference Infrastructure Victoria's Scenario Descriptions (Appendix 1)]

Calculations

The following key calculations are made based on the definition above:

- Natural Gas replacement – see "Gas Calculator", Section 2.2.4.1
- Vehicle hydrocarbon fuel replacement – see "Vehicle Calculator", Section 2.2.4.1
- Coal replacement – see "Coal Calculator", Section 2.2.4.1

Key features of the calculations include:

- Green Hydrogen – the amount of electricity required for green Hydrogen is added to the base load for the renewables electricity calculations
- Breakdown by User (Gas) – for the "Gas Calculator", the amount of energy by source (new and hydrocarbon based) is split out by user in accordance with DISER categories described below. This calculation feature assumes that the proportion of energy used by each user in 2018 remains the same into the future.
- Div. A Agriculture, forestry and fishing
- Div. B Mining
- 06 Coal mining
- 07 Oil and gas extraction
- 08-10 Other mining
- Div. C Manufacturing
- 11-12 Food, beverages and tobacco
- 13 Textile, clothing, footwear and leather
- 14 Wood and wood products
- 15-16 Pulp, paper and printing
- 1701 Petroleum refining
- 1709 Other petroleum and coal product manufacturing
- 18-19 Basic Chemical and Chemical, Polymer and Rubber Product Manufacturing

- 20 Non-metallic mineral products
- 201 Glass and glass products
- 202 Ceramics
- 203 Cement, lime, plaster and concrete
- 209 Other non-metallic mineral products
- 211-212 Iron and steel
- 213-214 Basic non-ferrous metals
- 22 Fabricated metal products
- 23-24 Machinery and equipment
- 25 Furniture and other manufacturing
- Div. D Electricity, Gas, Water & Waste Services
- 26 Electricity supply
- 27 Gas supply
- 28-29 Water supply, sewerage and drainage services
- Div. E Construction
- Commercial and services a
- Div. I Transport, postal & warehousing
- 46 Road transport
- 47 Rail transport
- 48 Water transport
- 49 Air transport
- 50-53 Other transport, services and storage
- Residential
- Solvents, lubricants, greases and bitumen

Output Data

The primary output data from the GHG Tool are:

- Description of the scale of each of the new energy sources, broken down by user (residential, commercial and industrial) for example:
  - Solar
    - Land area requirement (refer Table 33)
    - Number of typical units e.g., 5 x 200 MW installations

    - Emissions produced (refer Section 2.1.6)
    - Energy storage requirements broken down by type e.g., battery, pumped hydro and chemical (selected to match the requirements of the specific Scenario)
- CHP (biogas from waste or biomass used for both heating and power generation)
    - Feedstock rate (selected to match energy requirement for the specific Scenario)
    - Biogas production rate (refer Section 2.3.3)
    - Heat production rate (refer Section 2.3.3)
    - Electricity production rate (refer Section 2.3.3)
    - Emissions produced (refer Section 2.1.6)
    - Number of typical units e.g., 5 x 5,368 Nm3 biogas / day plants
- Green Hydrogen
    - Electricity feed rate (refer Section 0)
    - Water feed rate (refer Section 0)
    - Hydrogen production rate (refer Section 0)
    - Emissions produced (refer Section 2.1.6)
    - Number of typical units e.g., 5 x 4,655 Te H2 / year plants

2.3 Renewable Electricity

2.3.1 Generation

2.3.1.1 General

Six types of renewable electricity infrastructure types were considered, summarized in Table 30 (to be read in conjunction with Figure 15).

Table 30: Renewable Electricity Generation Types

(Reference to DELWP's Renewable Energy Zones)

Renewable Energy	**Average load factor from local projects**	**Considered load factor in the calculations**	**Major Application Zone (Note 1)**	**Lifetime (years)**
Hydro power	-	(an efficiency of 90% has been considered)	V1	-
Onshore Wind	35%	35%	V3,V4	25
Offshore Wind	-	40%	V5	30
Residential Solar	-	25%	MELBOURNE	10
Commercial Solar	-	25%	-	10
Industrial/Large scale Solar	25%	25%	V2,V6	20

(Note 1) The zones indicated are the Renewable Energy Zones used by AEMO in their ISP and consistent with the DELWP Renewable Zones (Reference 45). The location of each zone is covered under Section 2.3.8

The load factors have a capital importance in the model as they support definition of the electrical capacity requirements (GWh). The share of renewable electricity in the overall energy mix was set in accordance with Infrastructure Victoria's Scenario Descriptions (Appendix 1) – refer Section 2.2.4 for details. Factors affecting renewable electricity location analysis are referenced in AEMO studies on the various potential of each region.

A conservative life time of 10 years has been nominated for both residential and commercial solar systems, matching the selected efficiency For the industrial solar systems a life time of 20 years has been nominated, given the expectation of better levels of frequent maintenance. The life time of solar systems is dependent on the local weather conditions and the level of maintenance, requiring frequent cleaning. Nominating a longer lifetime is feasible, though efficiency would need to be decreased accordingly. A lifetime of longer than 20 years would need considerable justification. The analysis did not account for end-of-life recycling / disposal of batteries, PVs, etc which aligns with the emissions factor nominated for solar.

2.3.1.2 Generation Modelling

For each decade, calculation of the quantity of new generation infrastructure needed was undertaken.

<u>Inputs:</u> required electrical generation capacity by year (2030, 2040 or 2050), GWh or PJ, of each renewable electricity described above.

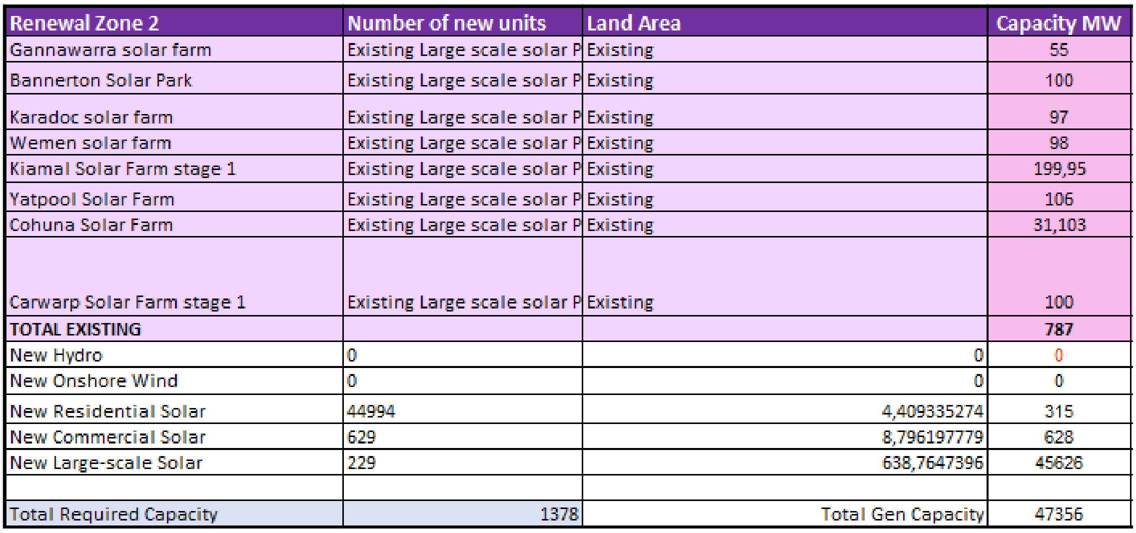
- Calculation of the required installed power, MW, of each renewable electricity to achieve the required electrical generation capacity.
- Choose the share of renewable electricity in each Renewable Electricity Zone:

Table 31: Typical Mix of Renewable Electricity *per* Renewable Electricity Zone

	V1	V2	V3	V4	V5	V6	Melbourne and Geelong
New Hydro	100%						
New Onshore Wind			50%	40%	10%		
New Offshore Wind				0%	100%		
New Residential Solar	3%	2%	10%	9%	12%	2%	62%
New Commercial Solar	10%	10%	10%	20%	10%	20%	20%
New Large-scale Solar		80%				20%	

- For each zone, the required new generation infrastructure per type of renewable electricity is calculated from the total installed power and the share per zone of each renewable electricity.
- Following preliminary allocation of energy type per zone the actual number was balanced to minimize overall impact on transmission systems refer to methodology in Section 2.3.8.

Table 32: Typical New Installed Power Capacity in Region V2 in 2030



Renewal Zone 2	Number of new units	Land Area	Capacity MW
Gannawarra solar farm	Existing Large scale solar P	Existing	55
Bannerton Solar Park	Existing Large scale solar P	Existing	100
Karadoc solar farm	Existing Large scale solar P	Existing	97
Wemen solar farm	Existing Large scale solar P	Existing	98
Kiamal Solar Farm stage 1	Existing Large scale solar P	Existing	199,95
Yatpool Solar Farm	Existing Large scale solar P	Existing	106
Cohuna Solar Farm	Existing Large scale solar P	Existing	31,103
Carwarp Solar Farm stage 1	Existing Large scale solar P	Existing	100
TOTAL EXISTING			**787**
New Hydro	0	0	0
New Onshore Wind	0	0	0
New Residential Solar	44994	4,409335274	315
New Commercial Solar	629	8,796197779	628
New Large-scale Solar	229	638,7647396	45626
Total Required Capacity	1378	Total Gen Capacity	47356

- For each new decade, the previous new infrastructure becomes “existing assets”, allowing consideration of the life time of the assets. As in 2050 all the existing wind and solar of 2030 have been considered decommissioned. Only the hydro power remains. This point will need further work as the estimation of new additional renewable electricity capacity undertaken in this study does not consider the decommissioning of the existing assets.
- A factor is determined for an average footprint (area), an average unit capacity and a cost per unit and provides input to the cost estimation.

Table 33: Renewable Electricity Sizing Parameters

Renewable electricity	Victorian projects superficial area (km²/MW)	Victorian projects Unit capacity (MW)	Considered Superficial area (km²/MW)	Considered Unit capacity (MW)
Hydro power	0,0009	76,6	0,0009	20
Onshore Wind farm	0,003	90	0,003	200
Offshore Wind farm	-	-	0,125	500 **(Note 1)**
Residential Solar	-	-	0,014	0,007
Commercial Solar	-	-	0,014	1
Industrial Solar	0,028	91,7	0,014	200

(Note 1) *revised during spatial analysis to 2,100 MW capacity equivalent to the Star of the South development.*

- The factors support determination of the number of assets needed for each renewable electricity in each Renewable Electricity Zone and the footprint that it represents, as well as for the cost estimation.
- Using the new and existing installed power generation infrastructure (MW) per zone and the renewable electricity load factors, the production capacity (GWh) of each region is determined.
- Electrical network power balance is performed using generation and consumption inputs per Renewable Electricity Zone. Energy to be transferred from region to region is defined.

2.3.2 Storage

2.3.2.1 General

Given the magnitude of storage required and its criticality in firming a high proportion of variable renewable power, two major types of storage were considered:

- Batteries
  - Used to compensate 24h of solar power generation.
  - Efficiency: considered = 80%
  - Location: downstream of solar power generation infrastructure for all users (residential, commercial and industrial (Renewable Electricity Zones).
- Pumped hydro

  - Used to compensate 168h of wind power generation.
  - Efficiency: considered = 90%
  - Location: V1

Table 34: Pumped Hydro Locations Considered in the Study

Location	Capacity (MW)
Hume Dam VIC	29
Bogong / Mackay	300
Dartmouth	185
Eildon	135
Murray 1	950
Murray 2	552
West Kiewa	68

Battery charging has been considered as part of the inputs to the electrical generation capacity requirements.

It was conservatively assumed that, in a snapshot with both wind and solar working, it is necessary to fill up both batteries and pumped hydro in the shorter time to be able to prevent 24h without solar production and 168h without wind production, while meeting power demand.

2.3.2.2 Storage Modeling

- The share per type of storage was determined as:
  - Pumped hydro covers 168 hours of the wind production with a load factor of 60%.
  - Battery covers 24 hours of the solar production with a load factor of 50%.
- With the inputs per Renewable Electricity Zone (capacity of each renewable electricity per Renewable Electricity Zone per decade), the autonomy, the efficiency of the storage are used as input to the calculation of storage required per Renewable Electricity Zone, per decade, per type of storage (pumped hydro or battery)
- Applying the footprint (area) factor and an average unit power capacity (for battery park or pumped hydro) the quantity of new storage infrastructure is estimated.
- Batteries will be associated with new solar production facilities. But pumped hydro has to be located in V1.
- 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 as the lifetime as the solar production assets.

2.3.3 Biogas

2.3.3.1 Waste to Energy

Waste to energy refers to the thermal treatment of residual wastes destined for landfill to produce electricity and in some cases combined heat (steam) and power (electricity). The most common form of waste to energy plant uses mass grate incineration in which the residual wastes are completely combusted directly to produce heat in a boiler which is used to produce steam which can drive a turbine power generator. This configuration is similar to how coal fired power plants work. Less common forms of waste to energy plant use gasification to produce a synthetic gas (syngas) which can be combusted in a second stage to produce heat in a boiler or may be further cleaned and purified to produce power, chemicals or hydrogen. A wide variety of gasification technologies exist and are in commercial operation in Europe, Japan and China. Waste to energy technologies using incineration or gasification-combustion have a TRL of 9, while there are a range of new technologies aimed at smaller scale plants and the production of purified syngas which could be used to produce hydrogen and chemicals, which have TRLs between 5 and 8.

The net lifecycle greenhouse gas emissions of waste to energy facilities depends on what waste is being consumed and what the current use of the waste is. Generally, when municipal solid waste is diverted from landfill and sent to a waste to energy facility, the net GHG emissions are negative, as the combustion of the waste in the facility avoids significant methane emissions that occur during landfill and a large portion of the combustible waste has a biogenic origin, meaning it is deemed to be a renewable energy source. Lifecycle analyses are normally conducted on a project by project basis. For the Kwinana waste to energy facility being built in Western Australia, the emissions intensity was calculated to be -860 kgCO2eq/MWh. This compares with the brown coal plants in the Latrobe Valley which have emissions intensities of around +1300 kgCO2eq/MWh.

A typical waste to energy plant applying incineration will receive 200,000 to 400,000 tpa of residual waste and produce around 17 – 35 MWe of electricity to the grid and will operate as a baseload power generator. This is equivalent to 2 to 4 PJ of chemical energy (ie. equivalent in form to natural gas). In this study the waste to energy plants are modelled based on the Kwinana waste to energy project in Western Australia which will convert 400,000 tpa of residual wastes using 2 x 600 tonnes per day integrated moving grate fired furnace/boiler lines each with Selective Non-Catalytic Reduction systems and Semi-Dry air pollution flue gas cleaning systems. Plant availability is 8000 hours per annum. Electricity production is 276,440 MWh/yr, around 35 MWe. The lifecycle emissions have been forecast at -860 kgCO_2eq/MWh. Plant capital cost is estimated at $696 million.

Victorian government policy is to limit the total capacity of energy from waste projects to 1 million tons per annum until 2040. This is around 10 PJ of energy (Victoria, 2020 – Reference 46). Currently, Victoria has no waste to energy plants in operation, however several have been permitted to be built or are in the planning stages.

Recovered Energy has recently obtained permission to build a 200,000 tpa waste to energy plant using a Chinese gasification-combustion technology in Laverton North. Australian

Paper and Suez are planning to build a waste to energy plant at the Maryvale paper mill in Gippsland which will take up to 650,000 tpa of residual wastes from Melbourne and Gippsland and convert it into electricity to be injected into the electricity grid and steam which will be used in the papermill. Prospect Hill International is proposing to build a waste to energy facility in Lara which will convert up to 400,000 tpa of residual waste into 35 MWe of electricity.

2.3.3.2 Landfill Gas

Landfill gas and biogas refer to technologies used to produce a combustible gas from the decomposition of wastes under anaerobic conditions (ie. free from oxygen). In the absence of oxygen, organic wastes decompose in a process called anaerobic digestion, forming predominately CO_2 and CH_4, which may be trapped and collected and used for beneficial purposes. Landfill gas refers to applications where the gas is trapped and collected as part of a landfill operation, while biogas generally refers to other applications that use organic wastes, e.g. from the food and agricultural sectors and also when the gas emissions from water treatment plants are collected for beneficial use. In biogas plants, especially designed digestor vessels may be used or in some cases the digestion process occurs in ponds which are covered to enable the collection of the biogas.

Landfill and biogas plants are generally small scale, producing from about 200 to 5,000 kWe of electricity using gas engines. In agricultural applications combined heat and power plants are attractive to produce both electricity behind the meter to avoid purchases from the grid and steam or hot water for industrial heating to displace the use of natural gas or LPG.

In this study, landfill gas and biogas plants produce gas which is combusted in gas engines to produce electricity. A small scale agricultural plant processes about 50,000 tpa of waste feedstock (solid and liquid) and produces 42 TJ/yr of biogas which is combusted with 40% conversion efficiency to produce 530 kWe and 4,265 MWh of electricity per annum. The data is based on published results for a plant in Greece. Indicative capital cost is $4 million, giving a specific capex of around 8 $million/MWe, or 90 $/(GJ/yr). The net emissions are estimated at -3.6 tCO2eq/MWh, and are dominated by avoiding the breakdown of the feedstocks into methane which is emitted directly to the atmosphere. Landfill and biogas plants in Australia will produce from about 200 to 5000 kWe.

In 2017, there were 242 biogas plants across Australia, half of which were collecting landfill gas, producing about 1,200 GWh of electricity (4 PJ of gas) and representing about 0.5% of the national electricity generation. There is a significant potential to increase biogas production, especially using organic wastes from the agricultural, industrial, wastewater treatment and biowaste sectors. Bioenergy Australia estimates that the potential for biogas in Victoria could be about 45 – 50 PJ/yr of biogas (Bioenergy Australia, 2019 – Reference 47).

2.3.3.3 Biomethane

Biomethane refers to the conversion of landfill gas and biogas into a methane rich gas which is suitable for injecting into the natural gas grid. Biomethane is a renewable substitute for natural gas. The technologies to convert landfill gas and biogas into biomethane are proven and at technology readiness level (TRL) 9. To achieve a high purity of methane from biogas, the CO_2 must be removed. This can be done with high pressure water adsorption, pressure swing adsorption and various other physical and chemical adsorption technologies. The main challenge with biomethane is not technical but economic. At the scale of most biogas production facilities (<0.5 PJ/yr), it is relatively expensive to separate out the CO_2 and compress the gas so that it can be injected into the natural gas grid. It is generally expected that biomethane production will have costs that range from about 20 to 40 $/GJ on an energy basis – and these costs are significantly higher than current natural gas prices. Therefore, policy incentives must be in place to support the adoption of biomethane. The federal government is currently working on a new emissions methodology for the biomethane sector, which would provide financial incentives under the emissions reduction fund for new biomethane plants.

In this work the biomethane plants are taken as a split of biogas that is upgraded to biomethane and injected into the gas grid. Upgrading of biogas to biomethane will favour the larger scale plants (>3 MWth) due to the economies of scale required for upgrading and compression to produce biomethane. At these large scales, the order of magnitude costs for biomethane are similar to biogas, as capital intensive gas engines are replaced with biogas upgrading.

2.3.3.4 Biomass

Biomass energy refers to the production of renewable energy from biomass sources using boilers and small scale gasifiers, typically running on wood chips. These plants will often produce heat/steam for industrial use and may also co-produce electricity. The technologies for these plants are at TRL 9 and are particularly common throughout Northern Europe. Biomass energy plants generally operate as baseload energy providers, however there will be a trend to further integrate them with intermittent renewables such as solar PV and wind to respond to changes in electrical energy supply and demand.

In this work biomass energy was taken as the combustion of biomass in simple furnace and boilers to produce heat and steam. Generally such plants are small, around 1 MWth and are used to convert wood chips into hot water and steam for use in greenhouses, farms and small industrial and agricultural factories.

2.3.4 Hydrogen

2.3.4.1 Green Hydrogen

Green hydrogen refers to the production of hydrogen from the splitting of water into hydrogen and oxygen using electrolysis, powered by renewable electricity. During the production process there are no GHG emissions associated with green hydrogen production. Electrolysis can use a number of different technologies, including alkaline electrolysis and proton electrolyte membrane (PEM). These technologies are TRL 9 (see Section 2.1.9 for details) however there is a lot of innovation occurring and a lot of new vendors and so technology risk needs be evaluated on a case by case basis. For example, some technology risk may remain when scaling up the balance of plant utilities for mega-scale green hydrogen production; or combining many stacks of electrolysers into a single unit; even though the core technology is completely proven.

The recent steep declines in the costs of renewable electricity have led to a renewed interest into using electrolysis to produce hydrogen. However, even with the recent cost reductions, producing green hydrogen is still currently very expensive, being about 5 to 10 times more expensive than using natural gas which costs about 1 to 2 $/kg depending upon the natural gas price. The main cost drivers in the production of green hydrogen are the renewable electricity price, the capacity factor and the capital cost of the electrolyser and the electrolyser efficiency. The combination of future reductions in renewable electricity costs, higher availability of renewable electricity to increase capacity factors and reduced capital cost and improved efficiency have lead many organisations such as IRENA and CSIRO to forecast that green hydrogen costs could fall from 5 to 15 $/kg in 2020 to around 2 to 3 $/kg by 2030 and below 2 $/kg by 2050. The forecast cost reductions depend primarily on very low cost renewable electricity (<20 $/MWh), high capacity factors (>50%) and reduced electrolyser capital costs. The very best projects, which can access low cost high availability electricity will be low cost; while the average projects will have high production costs.

Green hydrogen is modular in nature and so in this work we have focused on the specific capex of the electrolysers which are expected to reach between 300 and 500 $/kW by 2040.

2.3.4.2 Blue Hydrogen

Blue hydrogen generally refers to the production of hydrogen from fossil fuel sources together with the use of carbon capture and storage technologies.

In this work blue hydrogen refers to the use of natural gas as the feedstock coupled with CCS to reduce GHG emissions. The most common method to produce hydrogen from natural gas is to use steam methane reforming (SMR), though auto-thermal reforming (ATR) and partial oxidation (POX) can also be used. In the SMR process, the natural gas is reacted at high temperatures (>800 ^{o}C) over a nickel based catalyst with steam to form a syngas composed of carbon monoxide and hydrogen ($CO + H_2$). The high temperatures are achieved by burning natural gas and any residual tail gas in a furnace. In a second step the CO is reacted further with steam to achieve complete conversion to hydrogen and the hydrogen is separated and purified to the required quality. SMR is a proven technology which can be purchased from a wide range of technology and equipment vendors and has a TRL of 9 (see Section 2.1.9 for details). To produce blue hydrogen, the conventional SMR is fitted with carbon capture to separate the produced CO_2 from the syngas into a separate stream which may be dehydrated and compressed ready for sequestration. In North America, two SMR facilities have been retrofitted with CCS to capture around 2 million tons per annum of CO_2 to produce blue hydrogen. So blue hydrogen using SMRs is proven and has a TRL of 8/9. Not all of the CO_2 produced from the SMR is readily captured – CO_2 in the flue gas from the furnace is expensive to capture and is typically vented. This is one advantage of the ATR and POX technologies, which do enable almost all of the CO_2 to be captured - however these two technologies are more expensive than SMRs.

In this work the SMR with CCS design and performance is based on a plant built by Air Products in Texas. A generic plant is assumed to consume around 1 mtpa of natural gas and produce 270,000 tpa of H_2. The capital cost is estimated at $1.6 million and yields a specific capex of 6 $/(kg-H2/yr) which is similar to that also provided in the CSIRO National Hydrogen Roadmap. A 90% capture rate leads to specific CO_2 emissions of 2.4

kgCO$_2$eq/kg-NG and 0.9 kgCO$_2$eq/kg-H$_2$. At 6 – 8 $/GJ for NG the levelized cost of hydrogen is around 1.7 – 2 $/kg.

2.3.4.3 Brown Hydrogen

Brown Hydrogen in this work refers to gasification of brown coal with CCS to produce Hydrogen.

In the context of Victoria, with declining and relatively high cost natural gas and ample supplies of low cost brown coal, hydrogen production from fossil fuels will mostly likely be focused on the development of brown coal reserves to produce hydrogen. The process to convert brown coal into hydrogen is well proven and combines coal gasification with syngas cleaning, separation of CO2, water gas shift reaction to increase the hydrogen content and finally the purification of hydrogen to achieve the required hydrogen specification. The technologies in this value chain are all proven and at TRL 9 (see Section 2.1.9 for details). Multiple vendors exist for each technology step in the conversion process.

The Australian and Japanese governments are currently funding the HESC (Hydrogen Energy Supply Chain) project to demonstrate the conversion of brown coal into hydrogen, the liquefaction of the hydrogen, storage and marine transport to Japan where it is offloaded and stored, ready for use. Recently, the production of purified hydrogen from a pilot scale gasifier in the Latrobe Valley was accomplished. Later this year, the first cargo of liquefied hydrogen will be transported to Japan.

A commercial brown coal to Hydrogen project with CCS will likely process about 5 million tonnes per annum of coal producing over 250,000 tpa of Hydrogen and 14 mtpa of CO$_2$ that must be sequestered. The rate of CO2 production is greater than the coal feed rate because the gasification process introduces a significant mass of Oxygen. The CO2 emissions calculated by the GHG Tool represent the rate of CO2 that is not captured by the CCS system. The capital cost for the gasification, CO$_2$ capture and hydrogen purification steps will likely be in the order of 5 to 10 billion Australian dollars, with additional costs required for CO$_2$ compression, transport and sequestration and hydrogen liquefaction, storage and transport. Multiple projects could be required to supply Australia and Japan with large quantities of hydrogen.

The production of hydrogen from coal is proven, with the major technical and economic risks associated with the carbon sequestration and the transport of the hydrogen. A high degree of certainty will be required regarding the carbon sequestration component as the CO$_2$ emissions will be unacceptable without sequestration. Even with sequestration, the CO$_2$ capture rate is likely to be between about 90 and 98%, so there will still be significant absolute CO$_2$ emissions even with CCS. While project proponents are also considering co-feeding biomass to reduce emissions, it is unlikely there is a sufficiently large and cheap supply of biomass is available. The costs of hydrogen liquefaction and transport will also need to be well understood, as these can be significant due to the difficulties of storing and transporting hydrogen.

In Australia, projects of this size and scope and technical complexity will require about five to ten years of work to finalise feasibility, obtain permits and financing and another three to five years to construct and bring into operation. Therefore, the first plant could only be in operation by 2030 at the earliest.

2.3.5 Geothermal

Geothermal energy is a form of clean energy extracted from the naturally occurring heat within hot rocks and water reservoirs below the earth’s surface. The heat is typically transferred to surface via hot water, which may be naturally occurring or generated from cold water injected from surface, but other specialised fluids may also be used for heat transfer.

If the temperature of the hot water is high enough, the heat can be used for electrical power generation while lower temperatures are also suitable for direct heating.

In Australia most of the geothermal energy is used for direct heating, such as for community swimming pools. The Gippsland Regional Aquatic Centre (GRAC) in Traralgon is as example of this application. The only operating geothermal power plant in Australia is at Winton, Queensland where is a small-scale 310kWe plant commenced operation in 2019.

Most of the large-scale geothermal power plants are based on extracting hot water sourced from volcanic regions such as New Zealand, Indonesia and the Philippines. Since Victoria does not possess any proven high temperature geothermal resources, it is expected that any contribution of geothermal energy to the future energy mix will be reactively small and limited to direct heating of commercial and industrial complexes or premises.

Geothermal energy is a mature technology with a low implementation risk, low operating cost and low HSE risk. In the direct heat application, it results in low or no emissions, depending on the source of the electricity required to drive the pumps for lift the water to surface and/or inject the cooled water back into the ground.

The main disadvantage of geothermal energy used for direct heat is the high capital cost to drill the geothermal wells. Generally, higher water temperatures can be obtained by drilling deeper, but this increases the drilling cost. In addition, the water flow rate from the well typically degrades as the well depth increases, due to a reduction in rock permeability with depth.

A separate technology that is often categorised as geothermal energy is ground source heat pumps (GSHP) which may be used for heating or cooling. Since this technology relies on the shallow soil or water temperature being more stable than the air temperature and does not extract heat from deep within the earth, GSHP’s are considered an efficiency improvement technology for the purposes of this study.

The use of geothermal energy for electricity generation and direct heating applications is well proven in Australia and overseas. Given the absence of high temperature geothermal resources in Victoria, only direct heating has been considered in the study and this is the simplest of the geothermal technologies. Therefore, geothermal energy has a TRL of 9 (see Section 2.1.9 for details).

2.3.6 Energy Efficiency

All Scenarios incorporate ground source heat pumps (GSHP) as an energy efficiency measure for both heating and cooling. GSHP is sometimes discussed alongside or included as a form of geothermal energy, but this study treats GSHP as an energy efficiency technology, since electrical power is required to power the heat pump and the air handling equipment.

GSHP use the relatively stable temperature of the soil a few metres below surface for heat exchange rather that the more variable air temperature. A large body of water may also be used to for the same purpose for a water source heat pump. As with any heat pump, GSHPs are able to heat, cool or supply hot water if appropriately equipped.

Ground source heat pumps can be categorised as having closed or open loops, and those loops can be installed in three ways: horizontally, vertically, or in a pond or lake. The type chosen depends on the available land areas and the soil and rock type at the installation site and will help determine the most economical choice for installation of the ground loop.

Closed loop systems may be water-based or refrigerant-based. For water-based system, water (possible including antifreeze solution) is circulated through plastic pipes buried beneath the earth’s surface. In refrigerant-based systems, a refrigerant is circulated through copper tubing buried in the ground. During the winter, the fluid collects heat from the earth and carries it to the heat pump to heat the building. During the summer, the heat pump reverses to cool the building by extracting heat from the building, and transferring to the ground which is cooler than the air temperature. This process can be used to creates free hot water in the summer and delivers substantial hot water cost savings in the winter.

Open loop systems operate on the same principle as closed loop systems and can be installed where an adequate supply of suitable water is available and open discharge is feasible. These systems have lower installation costs and running costs.

Relative to the familiar air source heat pumps (aka reverse cycle air conditioner), GSHPs are 20-50% more efficient but have a significantly higher installation price. Approximately 50,000 units are installed in the United States every year, therefore the technology is well proven.

In Australia about 65% of GSHPs are installed in residential properties where it is more suited to new housing construction, due to access for earthworks and/or drilling being difficult for existing houses, especially in high density areas.

Commercial and public building applications make up the remaining 35% of GSHPs in Australia. In Victoria, examples of GSHPs installations are the University of Melbourne in Carlton and the Rivergum Residential Treatment Centre, Department of Justice and Regulation in Ararat.

Other energy efficiency measures that have been considered to be imbedded into the scenario assessment include improved insulation, smart meters combined with smart grids, and energy efficient appliances.

Improved insulation of dwellings and commercial buildings will reduce the energy load for space heating and cooling. The amount of investment, degree of implementation and the benefits accrued will vary between the scenarios, with insulation standard for new buildings being easier to upgrade than existing buildings. The optimum level of residential & commercial energy efficiency improvements corresponding to the lowest overall cost of reliable electricity was not identified. The complex, dynamic and interconnected nature of behind the meter demand on firming grid electricity capacity would need to be considered to determine this optimum energy efficiency level which is beyond the scope of the study. The levels of energy savings calculated by the GHG Tool are sufficiently low as to not be a differentiator between scenarios at the level of accuracy achievable for this analysis.

Smart electricity meters, in combination with smart grids allow electricity usage to be monitored by the consumer and the distributer in real time and to better manage peak loads and enable behind-the-meter battery storage to be implement, thus improving the utilisation of renewable energy such as roof top solar PV.

The penetration of household appliances with higher energy ratings will increase as old and inefficient appliances are replaced by modern appliances and this may be accelerated by initiatives such as the 7-Star building standards planned to be taken effect in September 2022. Electric hot water systems powered by roof top solar PV are also expected to be adopted.

2.3.7 Carbon Capture and Storage

Carbon Capture and Storage (CCS) is a technological approach for removal carbon dioxide (CO_2) from emissions sources, or the atmosphere, and store it permanently underground or in the form of stable chemical compounds. Natural approaches for capturing and storing CO_2 such as biomass, soils and oceans are not included in the definition of CCS.

While CCS with underground geological storage is a relatively mature technology, its high costs and the lack of economic incentive has limited the uptake of this technology, apart from where it has been used for enhanced oil recovery from oil reservoirs, but recently large-scale CCS investment in CCS hubs and projects have been announced on a global basis. The goal to decarbonise the use fossil fuels has been a major driver for these plans and investments.

As of 2021 there are approximately 26 commercial scale CCS projects in operation, injecting about 40 Mtpa of CO_2 including those projects injecting CO_2 for enhanced oil recovery (EOR). Many of the EOR projects capture CO_2 from oil and gas processing rather than flue gas from gas or coal power generation plants. The Gorgon CCS project is the only commercial scale CCS project located in Australia, with a capacity of 3.4 – 4.9 Mtpa, and is associated with the gas processing for the production of liquified natural gas (LNG) for export.

A number of research and demonstration projects are currently operating or have previously operated in Australia, including the CO2CRC Otway project in Western Victoria and the Latrobe Valley Post Combustion Capture Project at the Loy Yang and Hazelwood power plants. The solvent capture plant at Hazelwood began operation in 2009, capturing and chemically sequestered CO_2 at a nominal rate of 10,000 tpa. The Hazelwood Power Station closed in March 2017.

The CO2CRC/HRL Mulgrave Capture Project involved three CO_2 capture research rigs at HRL's gasifier research facility at Mulgrave. The CO2CRC rigs captured CO_2 from syngas, the product of the brown coal gasifier, using solvent, membrane and adsorbent technologies. During the project, researchers evaluated each technology for efficiency and cost-effectiveness. Advanced gasifier technologies are highly suitable for carbon dioxide capture for CCS as they produce a concentrated stream of carbon dioxide.

The CarbonNet Project was established by the Federal and Victorian Governments in 2009 to investigate the potential for establishing a large-scale, multi-user carbon capture and storage network in Victoria. An offshore well was drilled at the Pelican site to collect subsurface information.

There are generally four areas where CCS may have a role to play in achieving net zero emissions.

- Achieving decarbonisation in hard to abate industries, such as cement, iron and steel and chemical sectors.
- Enabling the production of low-carbon hydrogen at large scale using coal or natural gas
- Providing low-carbon dispatchable power from the combustion of fossil fuels
- Delivering negative emissions, when combined with other technologies such as bioenergy or direct air capture.

In the Victorian context, the primary application for CCS is for removal of CO_2 from emissions produced by coal fired power stations or coal gasification plants (for production of carbon neutral or blue hydrogen from brown coal) located in the Latrobe valley. This is aligned with the objectives of the CarbonNet Project which seeks to establish CO_2 storage sites in the nearshore area of the Gippsland Basin to provide permanent and safe storage for 1 to 5 Mt CO_2 per year (Mtpa) initially, totalling 25 to 125 Mt of CO_2 over a 25 year project life, with expansion to 20 Mtpa of CO_2.

It is worth noting that there are only three commercial CCS projects globally, where the storage sites are located offshore.

Even though CCS is a mature technology, it involves the permanent geological sequestration of CO_2, which highly dependent on site specific underground conditions. Given that neither small-scale nor large-scale operating CCS projects have yet been established in the offshore Gippsland basin, the achievable injection rates, storage volumes and long-term containment for this location have yet to be demonstrated.

In general, CCS projects have high capital investment (CAPEX) requirements. The CO_2 capture and processing plants, injection wells and transportation pipelines are all expensive components, but this can be mitigated somewhat by locating the storage site close to the source(s) of the CO_2 emissions.

However, the CCS operating costs (OPEX) are even more significant as CO_2 capture and purification requires some complex processes, and the gaseous CO_2 must be compressed to high pressure for injection and storage at supercritical conditions. In addition, the underground storage must be continuously monitored and verified throughout the project lifetime to ensure that the storage is effective. Where the storage site is located offshore rather than on land, both the CAPEX and OPEX for CCS project will escalate even further.

Costs for CCS projects are typically quoted in the literature in $ per tonne of CO2 stored. For a Victorian scenario, a cost of approximately $100/tonne may be expected, including capture, compression, pipeline transport and offshore injection. Therefore, the overall cost for a 5 mtpa CCS project would be around $500 million on a levelised cost of storage basis.

Chemical storage of CO_2, which may include the utilisation of such chemicals, is a less mature technology, but may be incorporated into the CCS mix in future, as the technology develops for large-scale commercial application. For the purposes of this study, the vast majority of the CO_2 storage capacity if provided by underground geological storage with only minor portion attributed to chemical storage in later years.

There are three main stages in the CCS chain; CO_2 capture, CO_2 compression and transport and CO_2 storage. Various techniques or technologies may be used to support each of these steps and these technologies have differing levels of maturity or technology readiness.

The available technologies for CO_2 capture span the full range of Technology Readiness Levels (TRL). Those with a TRL of 9 include traditional amine solvents, physical solvents, Benfield process, sterically hindered amine, Pressure Swing Adsorption / Vacuum Swing Adsorption and gas separation membranes. Therefore, CO_2 capture is considered to be a proven and mature technology with many new technologies under development developed to improve the efficiency and reduce the cost of CO_2 capture for various applications.

Direct air capture (DAC) is an emerging negative emissions technology (NET) that extracts CO_2 directly from the atmosphere, instead of from point source emissions such as flue gas. This technology has yet to be demonstrated at large scale although about 15 small-scale DAC plants are operational globally. The TRL for various DAC technologies ranges from 3 to 9 but the contribution of potential DAC projects to achieving Victoria's net zero target has not been included in any of the scenario assessments due to the significantly higher costs than CO_2 capture from point source emissions.

CO_2 compression and transport at large scale, including for existing CCS projects, is currently through pipelines, while at a smaller scale ships, truck and rail have also been widely used. For the purposes of this study, CO_2 transport for CCS is considered to be conducted by pipeline and is therefore commercially proven at large-scale with a TRL of 9.

The geological storage of CO_2 is the final step in a CCS project. Three forms or geological storage are currently mature with a TRL of 9: storage through CO_2-EOR, storage in saline aquifers and storage in depleted oil and gas fields, however only the latter two technologies should be considered for achieving Victoria's net-zero target.

It should be noted that while the storage technology is proven, the ability to inject CO_2 at the desired rate and store the CO_2 without leakage must be proven at each individual storage site, and no such trials have yet been conducted offshore Gippsland

The CarbonNet CCS project is based upon CO_2 storage in saline aquifers in areas that have not been penetrated by oil and gas wells. However, the geology of the Gippsland Basin and drilling in the area is relatively well understood since it is a major oil and gas province.

Chemical storage and potentially the utilisation of such chemicals, as large scale is less mature, but this technology could provide an alternative CO_2 storage opportunity where access to a pipeline is difficult. However, the pathways to the net zero target are not reliant on this technology.

2.3.8 Spatial Analysis

Electrical

The spatial analysis commenced by setting a base line capacity of the current electrical transmission system when operating in a "Victorian" energy demand supply mode. The current installed generation capacity including committed projects was taken from the AEMO 2020 Inputs and Assumptions Workbook and each generation source allocated to the renewable energy zone it was physically located in and serviced to identify the generation capacity for each zone. The designated renewable zones and their transmission corridors are in line with the Victorian governments identified Zones and are as identified below:

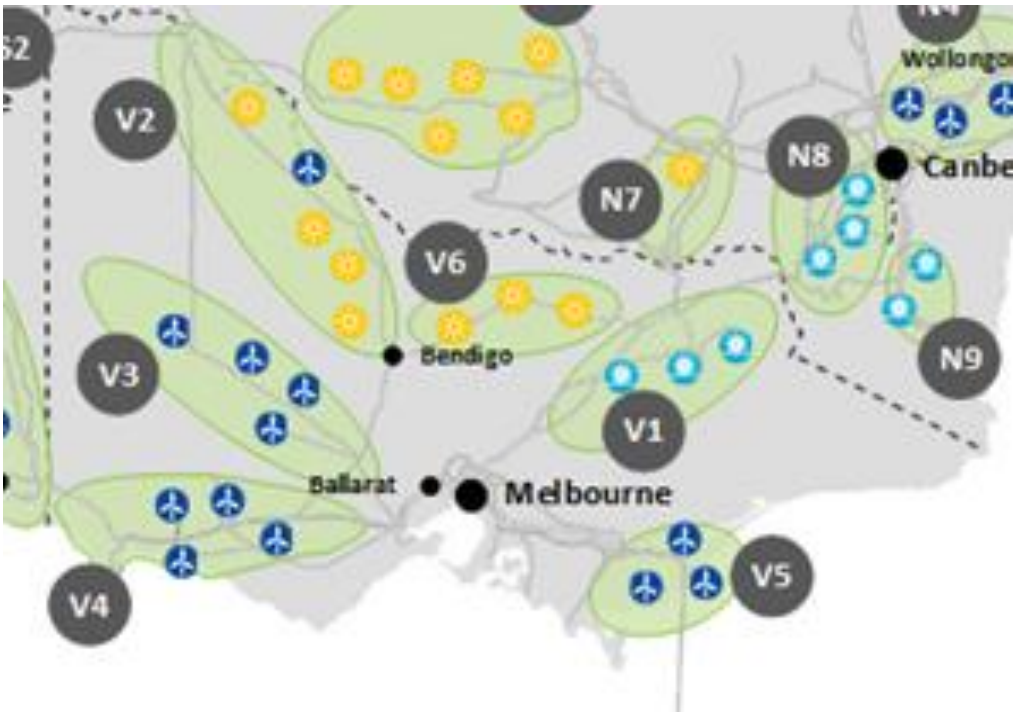
Table 35: Designated Renewable Energy Zones (Ref 45)

Renewable Zone	Transmission System Collection Area
V1	Oven's Murray Northern Corridor transmission collection
V2	Murray River Regional transmission collection
V3	Western Victoria Regional transmission collection
V4	South West Victoria corridor transmission collection
V5	Gippsland Eastern corridor transmission collection
V6	Central North Victoria (Shepparton collection)
M	Melbourne and Geelong Users

The current overall capacity per renewable zone was determined as per Table 36 following. Historical data was then reviewed to identify a case where the transmission system was operating in a mode with energy flow directions similar to the net zero analysis scenario basis i.e., most of the electrical energy was generated and distributed for use in Victoria. A high demand day 31st January 2021 was identified as the most representative case and a simple flow model set up, identifying capacity generated and used in the renewable zones and the flow routes to distribute energy to other areas largely to supply the Melbourne and Geelong area. This was compared against the maximum demand snap-shot data of continuous and short term loadings for each transmission line in each of the transmission corridors for that day of operation to determine a "maximum" capacity for each segment.

Table 36 includes committed generation projects and the study has assumed that these committed projects will be complete prior to 2030.

Figure 15 Location of Renewable Energy Zones

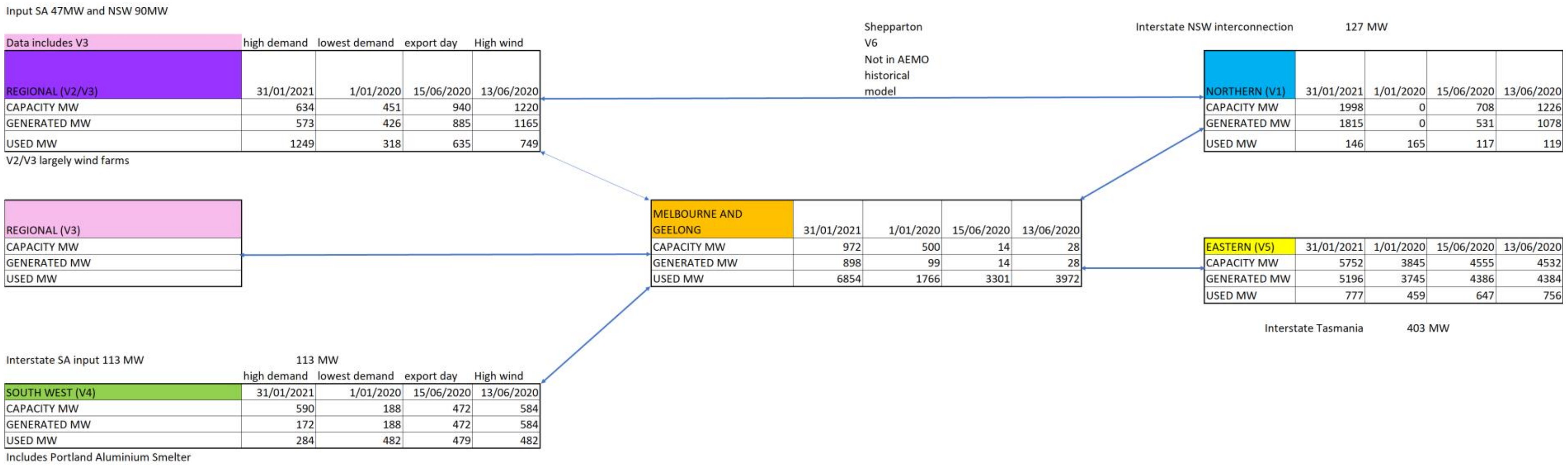


Having established a base network construction and capacity the data for electrical energy generation requirements for Scenario A was extracted from the technical. The model output included overall energy generation requirements, renewable energy mix between solar, wind and hydrogen and the number of each generator type for each of the time horizons.

The renewable energy generation was located based on the following overall guidelines:

- All new electricity generation was located in a renewable energy zone
- Electrical generation types were allocated to the region with the most suitable weather
- conditions ie V2 in north west of Victoria is most suited to solar power as shown by Figure 15.
- To minimise changes to electrical transmission generation capacity was allocated to ensure each renewable zone could service its own needs prior to transmission of electricity to Melbourne and Geelong
- Renewable generators are generally located along the current transmission routes to minimise additional infrastructure
- Allowance has been made for transmission collection to minimise the number of connections to the grid (10 renewable energy facilities have been allowed per collection and a nominal 100 Km of collection transmission has been allowed for). Figure 16 is provided to indicate the significant time a project should allow for in planning and application processes for connection to the grid.
- Planned announced projects such as the Star of the South Offshore Wind farm development were included in the layout considerations.

Figure 16: Simplified Electrical Network Flow scheme



Input SA 47MW and NSW 90MW

Data includes V3

REGIONAL (V2/V3)	high demand 31/01/2021	lowest demand 1/01/2020	export day 15/06/2020	High wind 13/06/2020
CAPACITY MW	634	451	940	1220
GENERATED MW	573	426	885	1165
USED MW	1249	318	635	749

V2/V3 largely wind farms

REGIONAL (V3)
CAPACITY MW
GENERATED MW
USED MW

Shepparton
V6
Not in AEMO
historical
model

Interstate NSW interconnection 127 MW

NORTHERN (V1)	31/01/2021	1/01/2020	15/06/2020	13/06/2020
CAPACITY MW	1998	0	708	1226
GENERATED MW	1815	0	531	1078
USED MW	146	165	117	119

MELBOURNE AND GEELONG	31/01/2021	1/01/2020	15/06/2020	13/06/2020
CAPACITY MW	972	500	14	28
GENERATED MW	898	99	14	28
USED MW	6854	1766	3301	3972

EASTERN (V5)	31/01/2021	1/01/2020	15/06/2020	13/06/2020
CAPACITY MW	5752	3845	4555	4532
GENERATED MW	5196	3745	4386	4384
USED MW	777	459	647	756

Interstate Tasmania 403 MW

Interstate SA input 113 MW 113 MW

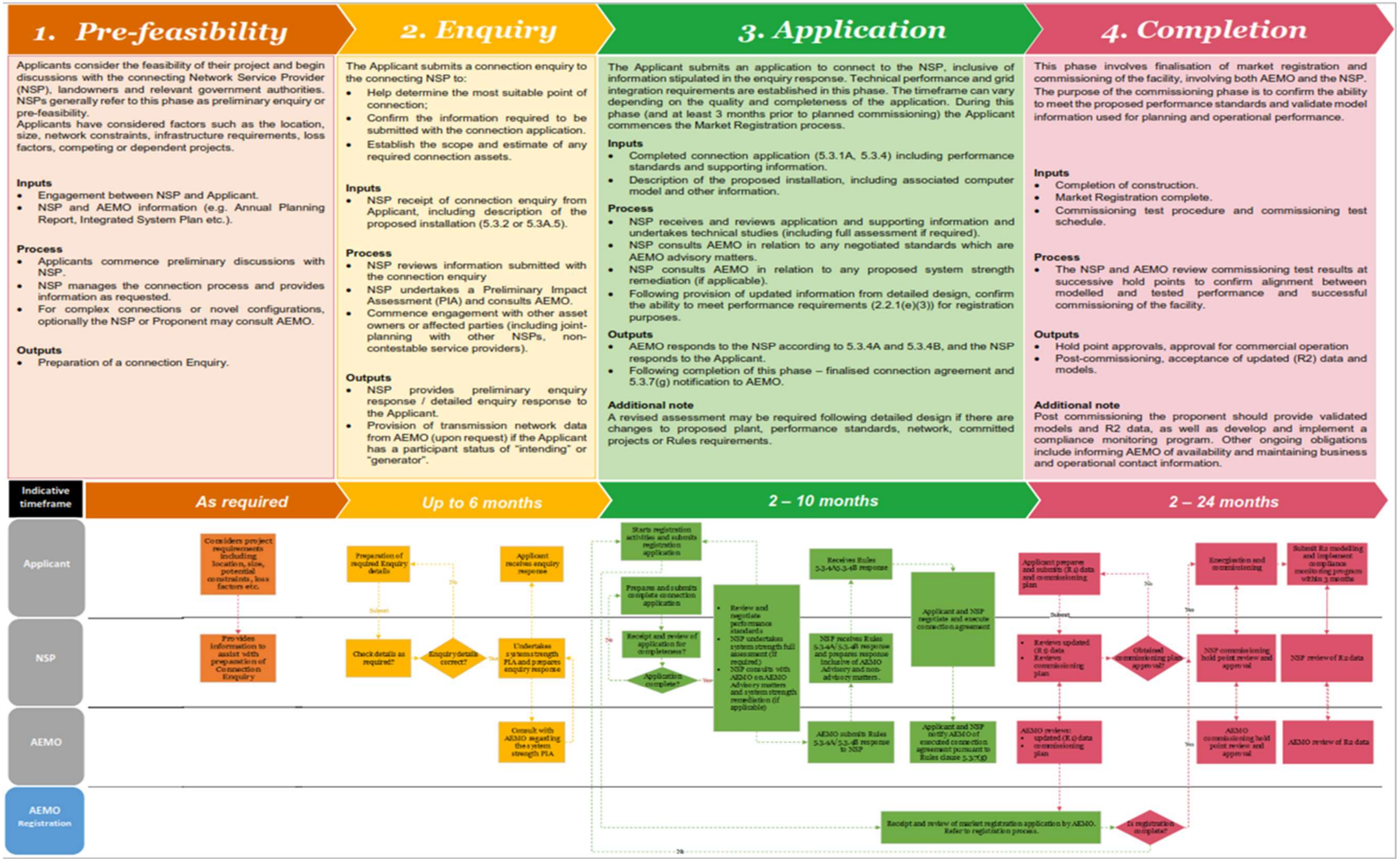
SOUTH WEST (V4)	high demand 31/01/2021	lowest demand 1/01/2020	export day 15/06/2020	High wind 13/06/2020
CAPACITY MW	590	188	472	584
GENERATED MW	172	188	472	584
USED MW	284	482	479	482

Includes Portland Aluminium Smelter

Table 36: Existing Generation Capacity Victorian Transmission System

Generator (existing)	Generation / Fuel Type	Maximum Capacity (MW)	REGION/ZONE		LIFE
Loy Yang A Power Station	Steam Brown Coal VIC	2210	Eastern corridor	V5	2048
Loy Yang B	Steam Brown Coal VIC	1115	Eastern corridor	V5	2047
Yallourn W	Steam Brown Coal VIC	1450	Eastern corridor	V5	2029
Somerton	OCGT	170	Melbourne	M1	2033
Bairnsdale	OCGT	94	Eastern corridor	V5	2042
Jeeralang A	OCGT	212	Eastern corridor	V5	2039
Jeeralang B	OCGT	228	Eastern corridor	V5	2039
Laverton North	OCGT	312	Melbourne	M1	2070
Mortlake	OCGT	584	south west corridor	V4	2047
Newport	Gas-powered steam turbine	500	Melbourne	M1	2039
Valley Power	OCGT	300	Eastern corridor	V5	2070
Hume Dam VIC	Hydro	29	Norther corridor	V1	2057
Bogong / Mackay	Hydro	300	Norther corridor	V1	2057
Dartmouth	Hydro	185	Norther corridor	V1	2057
Eildon	Hydro	135	Norther corridor	V1	2057
Murray 1	Hydro	950	Norther corridor	V1	2070
Murray 2	Hydro	552	Norther corridor	V1	2070
West Kiewa	Hydro	68	Norther corridor	V1	2057
Ararat wind farm	Wind	240	Regional	V3	2047
Bald Hills wind farm	Wind	107	Regional	V3	2040
Challicum Hills wind farm	Wind	53	Regional	V3	2033
Kiata wind farm	Wind	31	Regional	V3	2042
Macarthur wind farm	Wind	420	south west corridor	V4	2038
Mortons Lane wind farm	Wind	20	south west corridor	V4	2042
Mt Gellibrand wind farm	Wind	139	south west corridor	V4	2043
Mt Mercer Wind Farm	Wind	131	south west corridor	V4	2043
Oaklands Hill wind farm	Wind	67	south west corridor	V4	2037
Portland wind farm	Wind	152	south west corridor	V4	2040
Salt Creek wind farm	Wind	54	south west corridor	V4	2043
Waubra wind farm	Wind	192	Regional	V3	2039
Yambuk wind farm	Wind	30	south west corridor	V4	2040
Yaloak South wind farm	Wind	28.7	Regional	V3	2048
Gannawarra solar farm	Solar	55	Regional	V2	2048
Bannerton Solar Park	Solar	100	Regional	V2	2049
Karadoc solar farm	Solar	97	Regional	V2	2048
Wemen solar farm	Solar	98	Regional	V2	2049
Crowlands Wind Farm	Wind	79.95	Regional	V3	2049
Numurkah Solar Farm	Solar	108	Shepparton users	V6	2044
Yendon Wind Farm	Wind	144.4	Regional	V3	2049
Murra Warra Wind Farm - stage 1	Wind	225.7	Regional	V3	2049
Cherry Tree Wind Farm	Wind	58	Shepparton users	V6	2050
Dundonnell Wind Farm	Wind	336	south west corridor	V4	2045
Elaine Wind Farm	Wind	83.6	Regional	V3	2049
Bulgana Green Power Hub - Wind Farm	Wind	204.4	Regional	V3	2049
Moorabool Wind Farm	Wind	312	Regional	V3	2044
Stockyard Hill Wind Farm	Wind	531.93	Regional	V3	2045
Kiamal Solar Farm stage 1	Solar	199.95	Regional	V2	2049
Yatpool Solar Farm	Solar	106	Regional	V2	2050
Cohuna Solar Farm	Solar	31.103	Regional	V2	2045
Winton Solar Farm	Solar	85	Norther corridor	V1	2050
Berrybank Wind Farm	Wind	181	Regional	V3	2045
Glenrowan West Sun Farm	Solar	132	Shepparton	V6	2051
Berrybank Wind Farm - Stage 2	Wind	151	Regional	V3	2045
Murra Warra Wind Farm - Stage 2	Wind	209	Regional	V3	2051
Carwarp Solar Farm stage 1	Solar	100	Regional	V2	2051
Mortlake South Wind Farm	Wind	157.5	south west corridor	V4	2051

Figure 17 Indicative Timeline of Connection to the Grid



1. Pre-feasibility

Applicants consider the feasibility of their project and begin discussions with the connecting Network Service Provider (NSP), landowners and relevant government authorities. NSPs generally refer to this phase as preliminary enquiry or pre-feasibility.

Applicants have considered factors such as the location, size, network constraints, infrastructure requirements, loss factors, competing or dependent projects.

Inputs

- Engagement between NSP and Applicant.
- NSP and AEMO information (e.g. Annual Planning Report, Integrated System Plan etc.).

Process

- Applicants commence preliminary discussions with NSP.
- NSP manages the connection process and provides information as requested.
- For complex connections or novel configurations, optionally the NSP or Proponent may consult AEMO.

Outputs

- Preparation of a connection Enquiry.

2. Enquiry

The Applicant submits a connection enquiry to the connecting NSP to:

- Help determine the most suitable point of connection;
- Confirm the information required to be submitted with the connection application.
- Establish the scope and estimate of any required connection assets.

Inputs

- NSP receipt of connection enquiry from Applicant, including description of the proposed installation (5.3.2 or 5.3A.5).

Process

- NSP reviews information submitted with the connection enquiry
- NSP undertakes a Preliminary Impact Assessment (PIA) and consults AEMO.
- Commence engagement with other asset owners or affected parties (including joint-planning with other NSPs, non-contestable service providers).

Outputs

- NSP provides preliminary enquiry response / detailed enquiry response to the Applicant.
- Provision of transmission network data from AEMO (upon request) if the Applicant has a participant status of "intending" or "generator".

3. Application

The Applicant submits an application to connect to the NSP, inclusive of information stipulated in the enquiry response. Technical performance and grid integration requirements are established in this phase. The timeframe can vary depending on the quality and completeness of the application. During this phase (and at least 3 months prior to planned commissioning) the Applicant commences the Market Registration process.

Inputs

- Completed connection application (5.3.1A, 5.3.4) including performance standards and supporting information.
- Description of the proposed installation, including associated computer model and other information.

Process

- NSP receives and reviews application and supporting information and undertakes technical studies (including full assessment if required).
- NSP consults AEMO in relation to any negotiated standards which are AEMO advisory matters.
- NSP consults AEMO in relation to any proposed system strength remediation (if applicable).
- Following provision of updated information from detailed design, confirm the ability to meet performance requirements (2.2.1(e)(3)) for registration purposes.

Outputs

- AEMO responds to the NSP according to 5.3.4A and 5.3.4B, and the NSP responds to the Applicant.
- Following completion of this phase – finalised connection agreement and 5.3.7(g) notification to AEMO.

Additional note

A revised assessment may be required following detailed design if there are changes to proposed plant, performance standards, network, committed projects or Rules requirements.

4. Completion

This phase involves finalisation of market registration and commissioning of the facility, involving both AEMO and the NSP. The purpose of the commissioning phase is to confirm the ability to meet the proposed performance standards and validate model information used for planning and operational performance.

Inputs

- Completion of construction.
- Market Registration complete.
- Commissioning test procedure and commissioning test schedule.

Process

- The NSP and AEMO review commissioning test results at successive hold points to confirm alignment between modelled and tested performance and successful commissioning of the facility.

Outputs

- Hold point approvals, approval for commercial operation
- Post-commissioning, acceptance of updated (R2) data and models.

Additional note

Post commissioning the proponent should provide validated models and R2 data, as well as develop and implement a compliance monitoring program. Other ongoing obligations include informing AEMO of availability and maintaining business and operational contact information.

3 SCENARIO A

Scenario A is summarised as "full electrification / no gas / no CCS". Based on the detailed description provided in Appendix 1 the scale of uptake of new energy, offset mechanisms and new energy road vehicles is defined in the following tables using the qualitative scale in Table 28.

Table 37: Uptake Scale

🟩	Large upscale / transfer of energy is made to this energy type Large uptake of new energy vehicles
🟧	Medium upscale / transfer of energy is made to this energy type Medium uptake of new energy vehicles
🟥	Small upscale / transfer of energy is made to this energy type Small uptake of new energy vehicles
🟦	No upscale / transfer of energy is made to this energy type No uptake of new energy vehicles

Table 38: Scenario A - Uptake of New Energy

Renewable Elec			**CHP**	**Heat**	**Gas**	**Gas**	**Gas**	**Gas**	**Gas**	**Efficiency**		
solar	wind	hydro	biogas	geotherm	biogas	biometh.	H2 green	H2 blue	H2 brown	heat pump	insul.	smart grids

Table 39: Scenario A – Uptake of Offset Mechanisms

CCS			**Agro-Forestry**			**Trading**	
Onshore	Offshore	Chemical	Forestry	Marine	Soil	Aus C-Credit	Internat. C-Credits

Table 40: Scenario A – Uptake of New Fuel Vehicles

Vehicle	**Vehicle**
BEV	HFCV

3.1 Energy-Emissions-Offsets

The energy-emissions-offset flows for each time period for Scenario A demonstrating a path to net zero carbon emissions by 2050 were calculated using the GHG Tool, with results summarised in Table 41.

Schematic representations “Sankey diagrams” of the flows of energy, emissions and offsets leading to the net emissions position for each time frame are provided Figure 18 (overleaf). These illustrations are intended to provide a simplified, graphical representation of the complex, interconnected data provided in Table 41.

It is important to note that both the “Table of Results” and “Sankey Diagrams” present exactly the same set of results, but on a slightly different basis : Table 41 assumes coal on a thermal basis; whilst Figure 18 reports coal on an electrical basis (applying a 30% conversion factor assumed for a typical brown coal power plant) in order to more clearly illustrate the scale of energy flows relating to electricity consumption, emissions and required offsets.

The basis and build-up of these results, along with a discussion thereof is provided in the following sections.

Table 41: Scenario A – Energy-Emissions-Offset Results

(Coal reported on thermal basis)

Energy Consumed (PJ)	**2030**				**2040**				**2050**			
Overall Demand (Victoria)	**1,492**	**Coal**	**Vehicle**	**Gas**	**1,716**	**Coal**	**Vehicle**	**Gas**	**1,973**	**Coal**	**Vehicle**	**Gas**
Total (Scope of this Study)	**1,416**				**1,531**				**1,747**			
coal	308				150				0			
vehicle fuel (gasoline, diesel)	217				99				0			
natural gas	233				70				0			
solar (replace HC's)	112	12	94	6	178	22	132	24	250	31	187	32
additional solar to balance demand	200				410				600			
wind (replace HCs)	45	28	12	5	88	57	17	15	125	84	23	18
additional wind to balance demand	200				350				475			
hydro (replace HCs)	12	0	12	0	28	9	17	2	45	18	23	3
additional hydro to balance demand	50				60				110			
CHP (WTE / biogas / biomass) (replace HCs)	3	0	0	3	14	0	0	14	18	0	0	18
geothermal (replace HCs)	0	0	0	0	5	0	0	5	7	0	0	7
biogas / landfill gas (replace HCs)	3	0	0	3	19	0	0	19	28	0	0	28
additional biogas / landfill gas to balance gas demand	0				0				0			
biomethane (replace HCs)	2	0	0	2	11	0	0	11	14	0	0	14
additional biomethane to balance gas demand	0				0				0			

green H2 (replace HCs)	23	0	23	0	28	0	27	1	42	0	40	2
additional green H2 to balance gas demand	0				0				0			
blue H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional blue H2 to balance gas demand	0				0				0			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	8	0	0	8	23	0	0	23	32	0	0	32
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			
Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**59**	**Coal**	**Vehicle**	**Gas**	**20**	**Coal**	**Vehicle**	**Gas**	**-8**	**Coal**	**Vehicle**	**Gas**
coal	29				14				0			
vehicle fuel (gasoline, diesel)	15				7				0			
natural gas	13				4				0			
fugitive emissions (4% of total HC)	2				1				0			
CO2 (nat gas processing)	1	0	0	1	0	0	0	0	0	0	0	0
solar (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional solar to balance elec demand	0				0				0			
wind (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional wind to balance elec demand	0				0				0			

hydro (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance elec demand	0				0				0			
CHP (WTE / biogas / biomass) (replace HCs)	0	0	0	0	-2	0	0	-2	-2	0	0	-2
geothermal (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
biogas / landfill gas (replace HCs)	0	0	0	0	-2	0	0	-2	-3	0	0	-3
additional biogas / landfill gas to balance gas demand	0				0				0			
biomethane (replace HCs)	0	0	0	0	-1	0	0	-1	-2	0	0	-2
additional biomethane to balance gas demand	0				0				0			
green H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional green H2 to balance gas demand	0				0				0			
blue H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional blue H2 to balance gas demand	0				0				0			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	0				0				0			
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			
Carbon Offsets (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**0**	**Coal**	**Vehicle**	**Gas**	**0**	**Coal**	**Vehicle**	**Gas**	**0**	**Coal**	**Vehicle**	**Gas**

CCS	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
agro-forestry	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
trading	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
Net Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**59**				**20**				**-8**			
Energy Storage (GWh)	**2030**				**2040**				**2050**			
Total	**154,581**	**Coal**	**Vehicle**	**Gas**	**280,342**	**Coal**	**Vehicle**	**Gas**	**402,902**	**Coal**	**Vehicle**	**Gas**
battery	31,019	3,360	26,128	1,530	44,771	5,995	32,095	6,681	69,503	8,495	52,008	9,000
additional solar to balance demand	55,556				113,889				166,667			
pumped hydro	12,451	7840	3266	1345	24,460	15,745	4,585	4,130	34,788	23245	6501	5042
additional wind to balance demand	55,556				97,222				131,944			
chemical	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance demand	0				0				0			

Figure 18: Scenario A – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

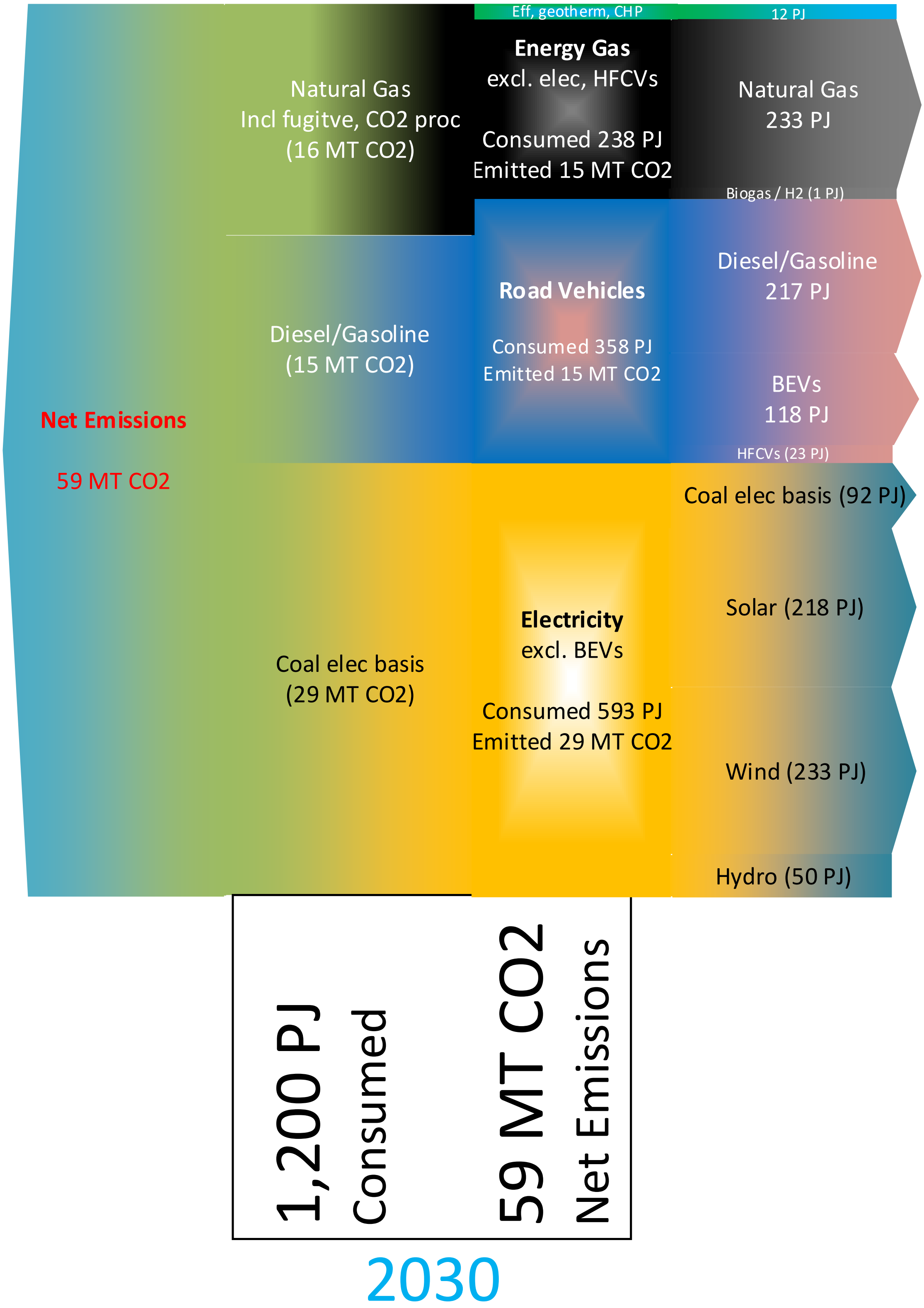


Figure 19: Scenario A – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

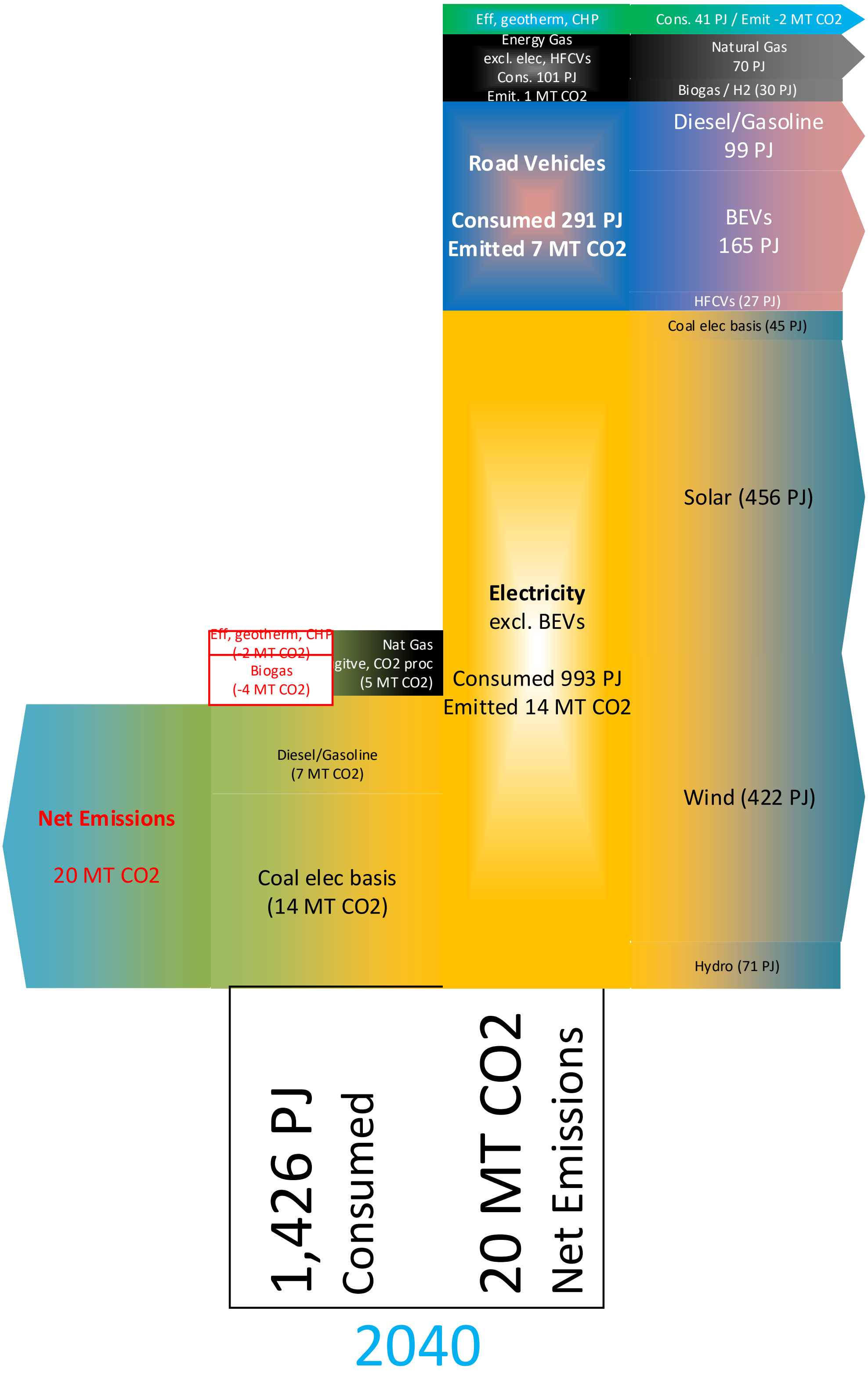
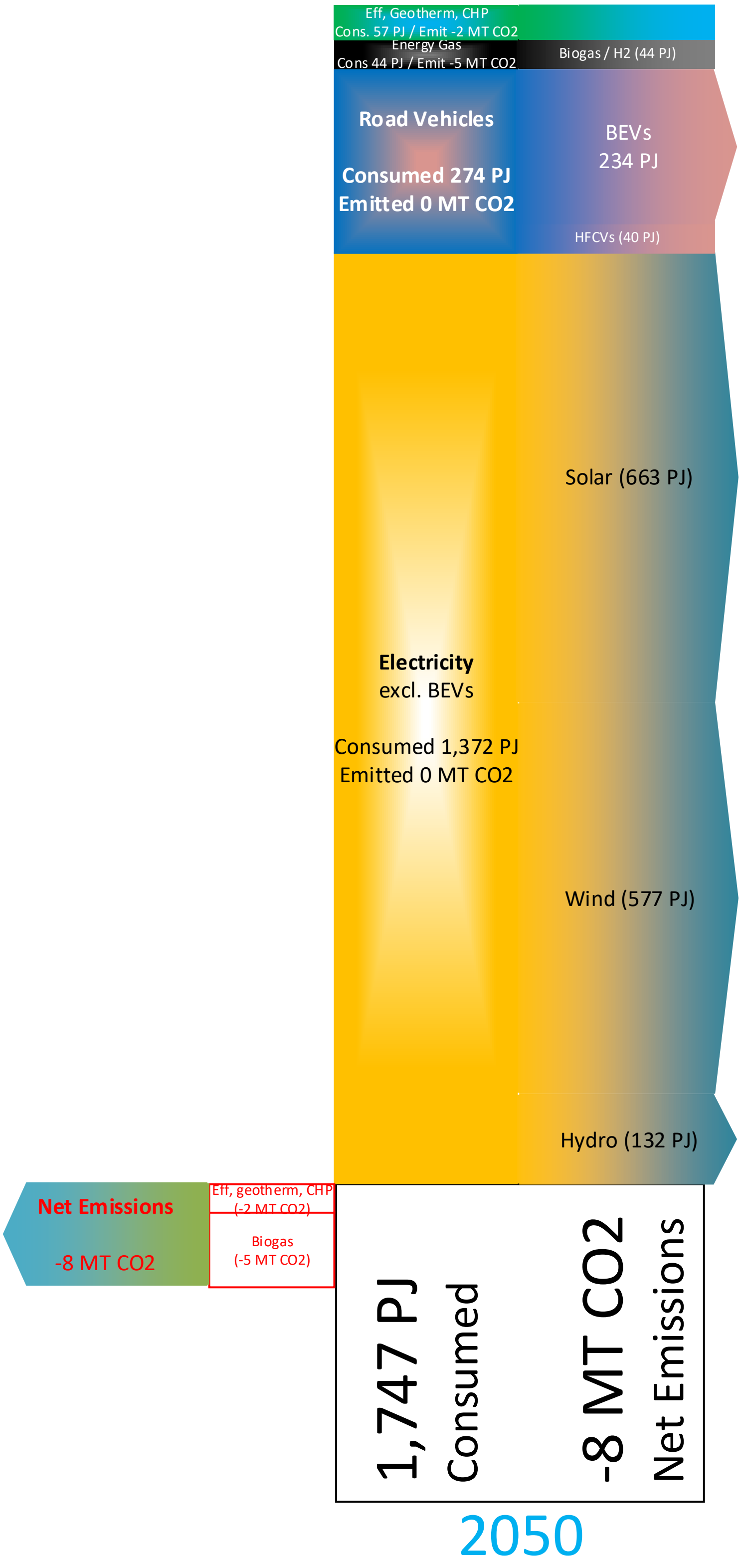


Figure 20: Scenario A – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).



3.1.1 Forecast Demand for Electricity & Hydrocarbon Fuels

The forecast demand for electricity and hydrocarbon fuels was defined for Scenario A, recorded in Table 42 and used as key input to the GHG Tool.

Given the study scope excludes some energy sources (eg aviation fuel, LPG, other petroleum liquids) the forecast energy demand for the study will be lower than the overall energy demand for the State of Victoria as defined in Table 18.

Where forecast energy demand for the scope of the study exceeds the overall energy demand for the State of Victoria, then energy export is predicted. For Scenario A energy export is defined.

Table 42: Scenario A - Forecast Demand for Electricity & Hydrocarbon Fuels

		2030	**2040**	**2050**
Total	**PJ**	**1,492**	**1,716**	**1,973**
Grid Elec **[STUDY SCOPE]** **(adjust to suit Scenario A)**	PJ	600	1,000	1,373
Non Elec Energy Gas **[STUDY SCOPE]** **(adjust to suit Scenario A)**	PJ	221	95	0
Road Vehicle Fuels (gasoline, diesel) **[STUDY SCOPE]**	PJ	217	99	0
Other Energy e.g., Petroleum Liquids, etc **(Excluded from the scope of the analysis)**	PJ	454	522	600

3.1.2 Energy Generation Mix

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each new energy source was categorised using the qualitative scale in Table 37, the energy generation mix was defined per guidance notes below and results recorded in Table 43, Table 44, and Table 45 (overleaf). When the energy splits were "balanced" with additional loads to match the energy demand forecasts defined in Table 18 the amount of energy for each time period was calculated using the GHG Tool and summarised in Table 41.

Selection Notes

A broad description of the general approach to defining the energy generation mix required to match Infrastructure Victoria's Scenario Descriptions (Appendix 1) is provided below and should be read in conjunction with the tables that follow. Unless a timeframe is quoted, values stated will refer to an approximate average during the transition. The new energy *generation* sector may not necessarily correspond to the new energy *consumption* sector for instance industrial generation of green Hydrogen may be consumed (partly) by the residential sector.

Natural Gas Replacement Mix (reference Table 43)

- Residential & Commercial Generation
    - Renewable dominant proportion 80% of the mix, only solar (wind & hydro not allocated / consumed)
    - Geothermal not allocated / consumed
    - Energy gases not allocated / consumed
    - Efficiency moderate proportion 20% of the mix.
- Industrial Generation
    - Renewables average 50% of the mix (between 40% and 60%), predominantly wind, limited hydroelectricity
    - Geothermal low proportion building to 5% of the mix
    - Energy gas building to 40% of the mix, predominantly biogases including combined heat and power, limited green Hydrogen
    - Efficiency low proportion approximately 15% of the mix
- Offsets
    - No allocation was necessary due to the high proportion of zero and negative emissions energy production (renewables and biogases).

Coal Replacement Mix (reference Table 44)

- 100% allocation of generation capacity to industrial renewables, predominantly wind.
- Offsets
    - No allocation was necessary due to the use of zero emissions energy production (renewables).

Vehicle Hydrocarbon Fuel Replacement Mix (reference Table 45)

- Electricity for BEVs was generated by renewables with 70% allocated to residential & commercial, and the remainder to industrial generation.
- Hydrogen generation for HFCVs was allocated entirely to industrial green Hydrogen.
- Offsets
    - No allocation was necessary due to the high proportion of zero and negative emissions energy production (renewables and biogases).

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Table 43: Scenario A – Mix of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Natural Gas

(Yellow fields are active, grey fields are not relevant to the Scenario)

GAS ANALYSIS															
Replacing natural gas with new fuels			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	100%	**80%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**10%**	**5%**
	2040	100%	**80%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**10%**	**5%**
	2050	100%	**80%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**10%**	**5%**
Commercial															
	2030	100%	**85%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**5%**	**5%**
	2040	100%	**85%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**5%**	**5%**
	2050	100%	**85%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**5%**	**5%**	**5%**
Industrial															
	2030	100%	**10%**	**50%**	**0%**	**10%**	**0%**	**10%**	**5%**	**0%**	**0%**	**0%**	**5%**	**5%**	**5%**
	2040	100%	**10%**	**30%**	**5%**	**10%**	**5%**	**15%**	**9%**	**1%**	**0%**	**0%**	**5%**	**5%**	**5%**
	2050	100%	**10%**	**20%**	**10%**	**10%**	**5%**	**20%**	**8%**	**2%**	**0%**	**0%**	**5%**	**5%**	**5%**
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	**0%**	**0%**	**0%**	**100**	100	100	**0**	**0**					
	2040	0%	**0%**	**0%**	**0%**	**250**	250	250	**0**	**0**					
	2050	0%	**0%**	**0%**	**0%**	**500**	500	500	**0**	**0**					

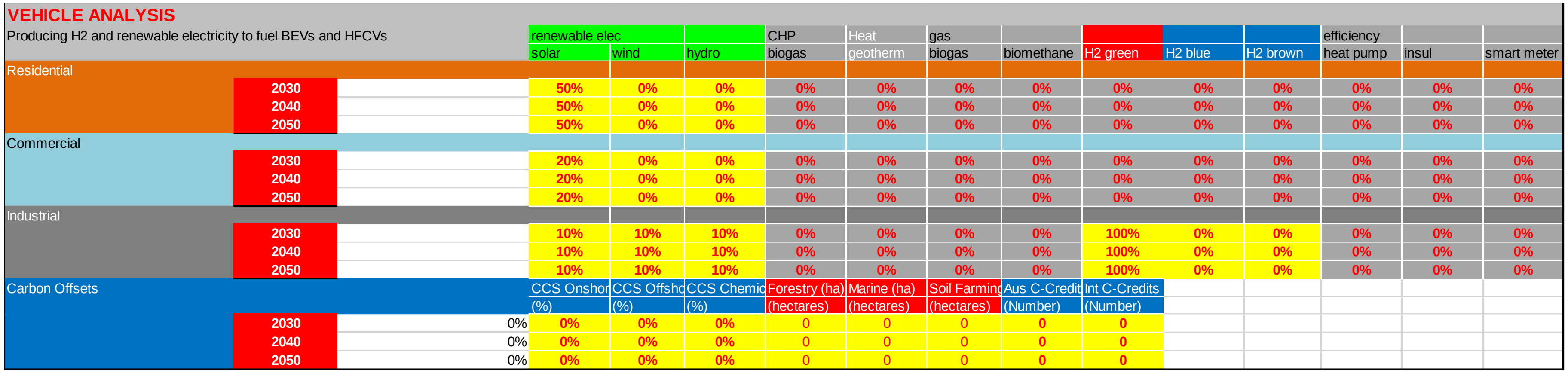
Table 44: Scenario A – Mix of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Coal

(Yellow fields are active, grey fields are not relevant to the Scenario)

COAL ANALYSIS															
Replacing coal fired power with renewable electricity			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2040	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2050	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Commercial															
	2030	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2040	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2050	0%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Industrial															
	2030	100%	**30%**	**70%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2040	100%	**20%**	**60%**	**20%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2050	100%	**20%**	**60%**	**20%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	**0%**	**0%**	**0%**	100	100	100	**0**	**0**					
	2040	0%	**0%**	**0%**	**0%**	250	250	250	**0**	**0**					
	2050	0%	**0%**	**0%**	**0%**	500	500	500	**0**	**0**					

Table 45: Scenario A – Mix of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Hydrocarbon Fuels for Road Vehicles

(Yellow fields are active, grey fields are not relevant to the Scenario)



VEHICLE ANALYSIS															
Producing H2 and renewable electricity to fuel BEVs and HFCVs			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
	2040		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
	2050		10%	10%	10%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	0%	0%	0%	0%	0	0	0	0	0					
	2040	0%	0%	0%	0%	0	0	0	0	0					
	2050	0%	0%	0%	0%	0	0	0	0	0					

3.1.3 Carbon Emissions

The Carbon emissions associated with energy consumption was calculated in the GHG Tool based on the emissions factors listed in Table 22, with results summarised for each time period in Table 41.

3.1.4 Carbon Offsets

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each Carbon offset mechanism was defined and documented in Table 39 and the split of Carbon offset mechanisms necessary to abate emissions associated with energy production was defined and recorded in Table 43, Table 44, and Table 45.

The amount of Carbon offsets were adjusted over time to provide a schedule of net emissions reaching zero by 2050. These calculations were undertaken in the GHG Tool and the results summarised in Table 41.

3.1.5 Energy Storage

Energy storage required to support renewable electricity generation (solar and wind) was calculated in the GHG Tool using the basis described in Section 2.3.2, and results summarised in Table 41.

3.1.6 Discussion of Results

Scenario A targets a complete replacement of natural gas and coal relying primarily on adoption of renewables, with a moderate contribution from:

- Biogas
- Hydrogen (green)
- Energy efficiency

Limited Carbon offsets are provided using agro-forestry.

A comparison of the energy-emissions-offset results for Scenario A against the other scenarios identified the following observations:

- Achieves Net Zero slightly before 2050 given the relatively high proportion of zero emissions electricity generation in the energy mix.
- Similar energy-emissions-offset profile to Scenario B.
- Whilst the estimated Carbon emissions levels for Scenarios A and B are higher than Scenario C (approximately twice in 2030), they are an order of magnitude lower than Scenario D (six times less in 2030 and even more so as the transition continues).

Potential refinements to Scenario A could include:

- Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
    - Increase the utilisation of gas infrastructure

  - Reduce overall Carbon emissions
- Include green hydrogen for heavy transportation and suitable commercial transportation

3.2 Spatial Analysis

3.2.1 Electrical

The number of renewable energy installations per region is indicated in Table 46 below. These have been allocated as per the methodology described in Section 2.3 and balanced to minimise the impact on the transmission system for the demand flow case. The increased requirement for renewable energy for each of the time horizons is shown in Figure 21 for 2030, Figure 22 for 2040, and Figure 23 for 2050. The technical modelling includes for additional transmission capacity and storage to cover generator downtime, short-term peaking demand, and night or poor weather conditions. The figures have been produced for comparison purposes only and demonstrate the significant increase in renewable installations over the time zones. For clarity, the storage requirements are not shown on the spatial schematics. Every solar farm includes battery storage locally and additional hydro installations have been allowed for in the estimate as storage for areas serviced by wind turbines. It is assumed these are located in Renewable Energy Zone V1. The comparison of storage requirements for each scenario is covered in section 3.4.

Table 46 Scenario A Renewable Installations By REZ

Year	**Renewable Energy**	**V1 Ovens Murray**	**V2 Murray River**	**V3 Western Victoria**	**V4 South West Victoria**	**V5 Gippsland (Note 1)**	**V6 Central North Victoria**
2030	Hydro	21					
	Solar		200				38
	Onshore Wind			100	50	81	
	Offshore Wind					1	
2040	Hydro	39					
	Solar		543				135
	Onshore Wind			140	130	130	
	Offshore Wind					1	
2050	Hydro	59					
	Solar		733				183
	Onshore Wind			211	200	130	
	Offshore Wind					3	

(Note 1) *Although the map taken from the AEMO website indicates a relatively small Renewable Zone for V5 the DEWLP plan extends zone 5 to cover the Latrobe valley past Hazlewood.*

The analysis indicates only the transmission lines from Renewable Zone V1 to Melbourne need uprating in 2030 due to location of the hydro storage in this zone. This transmission line would need significant upgrade by 2040, and further upgrade by 2050. The allocation of storage has been conservative for the purpose of comparison of scenarios and in reality, the peaking demand and poor weather conditions would be managed using electricity from interstate as the system is currently managed by AEMO. While approximately 95% of the power lines in Victoria are overhead transmission lines it is assumed that the power lines in bushfire areas will be buried. Further analysis would be required to determine the split between overhead and buried lines and the lead time implications. The significant additional renewable energy generation facilities required to progress to full electrification by 2050 requires significant augmentation of the 220kv transmission section from renewable zone V2 in 2040 and further significant augmentation in 2050. In 2050 the transmission lines from V3 and V4 to Melbourne will also require significant upgrade. These upgrades have been delayed by maintaining the gas infrastructure in 2030 and 2040. The quantity of transmission lines requiring upgrade is indicated in the cost estimate section. The analysis indicates there is significant generation capacity in the regional zones V2 and V3 which would be underutilised. This has already been recognised by AEMO and the Western Victorian Transmission Network Project is being implemented to unlock this area. This is a two-stage project including a combination of 500 kV and 220 kV transmission augmentation to alleviate constraints identified on the 220 kV network between Moorabool and Horsham to facilitate access to new renewable generation.

The analysis also indicates that the transmission lines from renewable zone V5 would be under-utilised as generation from the coal fired power stations in the Latrobe valley are removed from the grid as these power stations are closed. To support Victorian energy production and maximise the use of existing infrastructure the balance of wind turbine installation should be reviewed to rebalance the production in the Gippsland and V5 area. Due to the high land requirements required for onshore wind farms additional offshore wind generation should be considered. Offshore wind turbines are nominally 10% more efficient than onshore wind turbines but have a higher installation cost. The Star of the South, which is the first offshore wind farm planned in Australia, has been included in the spatial layout which should be installed by 2030. The infrastructure advice on policy direction will need to be made prior to the successful outcome of this installation being known. Some of the capacity of the electrical infrastructure from V5 is likely to be filled by electricity produced in Tasmania via the Marinus link which is a proposed 1500MW underground and undersea electrical connection. This would still leave additional capacity in the transmission system for additional renewable energy to be located in this zone either as onshore or offshore wind. The spatial analysis indicates the requirement for a significant number of electrical connections to the grid to accommodate the number of renewable installations. Each electrical connection to the grid could take a year or more for the approval process. This process will require additional regulatory resources or streamlining to manage the expansion planned to achieve net zero by 2050. While the modelling has allowed for the installation of local transmission lines to collect nominally 10 renewable energy facilities to minimise the number of connections to the grid this will add complexity to the planning of these developments.

Electrical Infrastructure Upgrade Results

The number of transmission lines affected in Scenario B were slightly less than Scenario A as the selection of renewable energy types had allowed for a better balance of electrical use in the scenario.

Data in the table below defines the extent of new or upgraded electrical infrastructure required for each scenario over and above existing electrical infrastructure. The values are presented as a “relative index” and, by way of example for Scenario A, calculated as follows:

Relative Electrical Infrastructure Index Scenario A = Electrical Infrastructure Estimate Scenario A / Electrical Infrastructure Estimate Scenario with Lowest Level of Electrical Infrastructure

Using this “relative index” system the scenario having the lowest level of electrical infrastructure required will equal 1, in this case being Scenarios C and D in 2030. Other values indicate the extent of additional electrical infrastructure compared to Scenarios C and D in 2030 for example Scenarios A and B in 2030 each requires twice as much electrical infrastructure than Scenarios C and D in 2030.

Table 47: Relative Extent of Upgrades to Electrical Infrastructure for each Scenario

Scenario	2030	2040	2050
A	2	4	5
B	2	4	5
C	1	3	3
D	1	2	2

Refer to Cost Estimate Section 2.2.2 for quantities assumed as comparative cost estimate basis.

Figure 21: Scenario A – Electrical Spatial Analysis (2030)

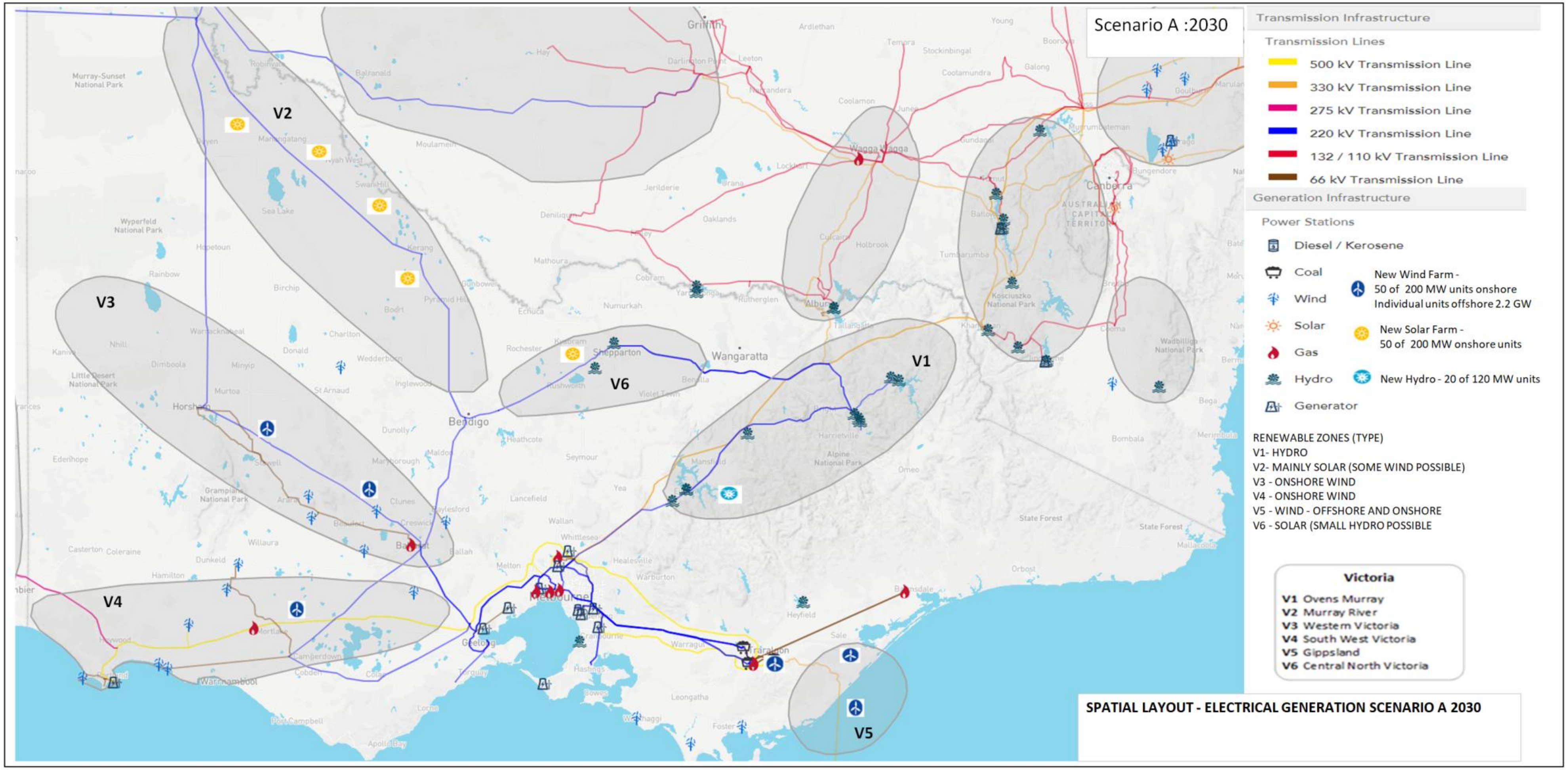


Figure 22: Scenario A – Electrical Spatial Analysis (2040)

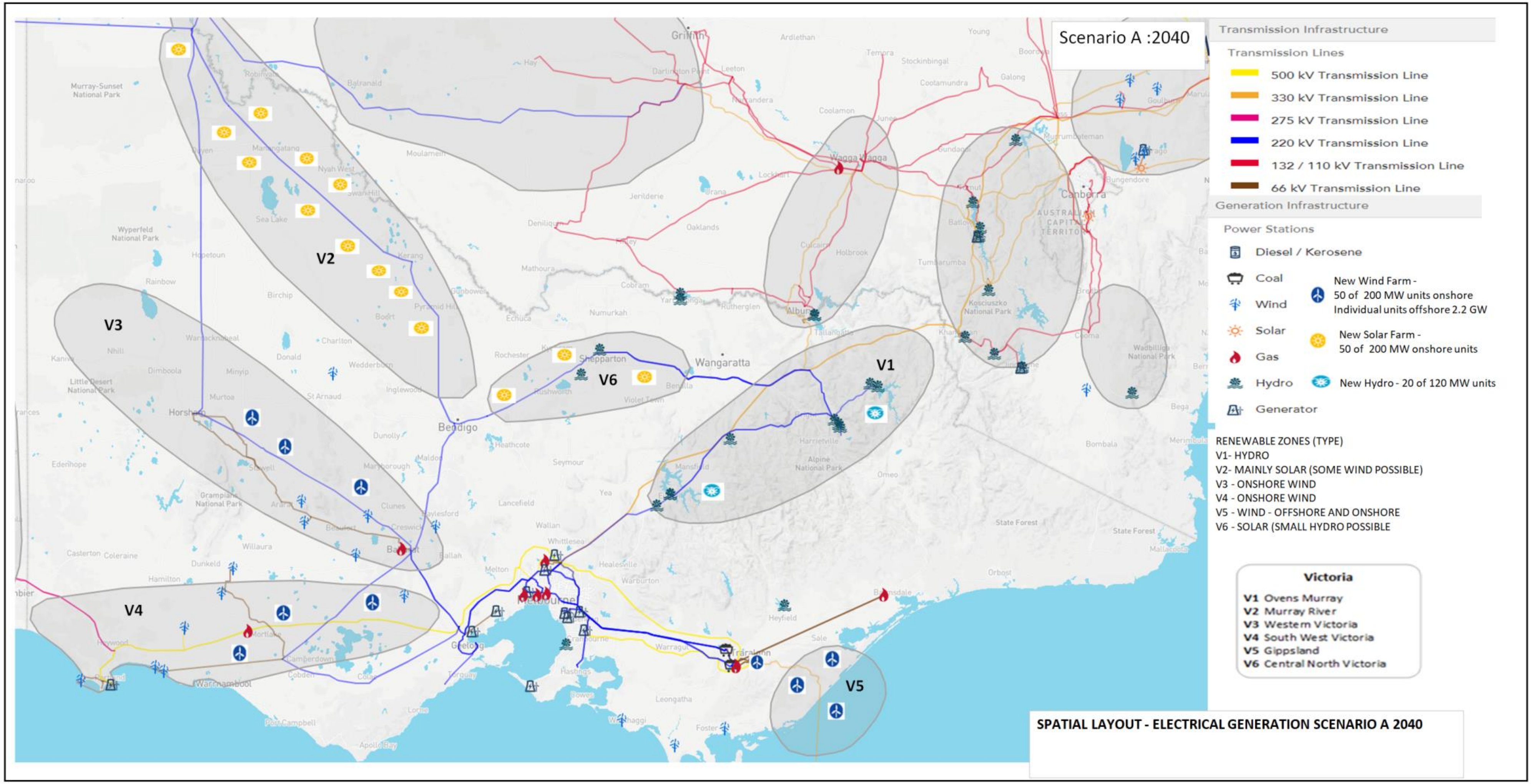
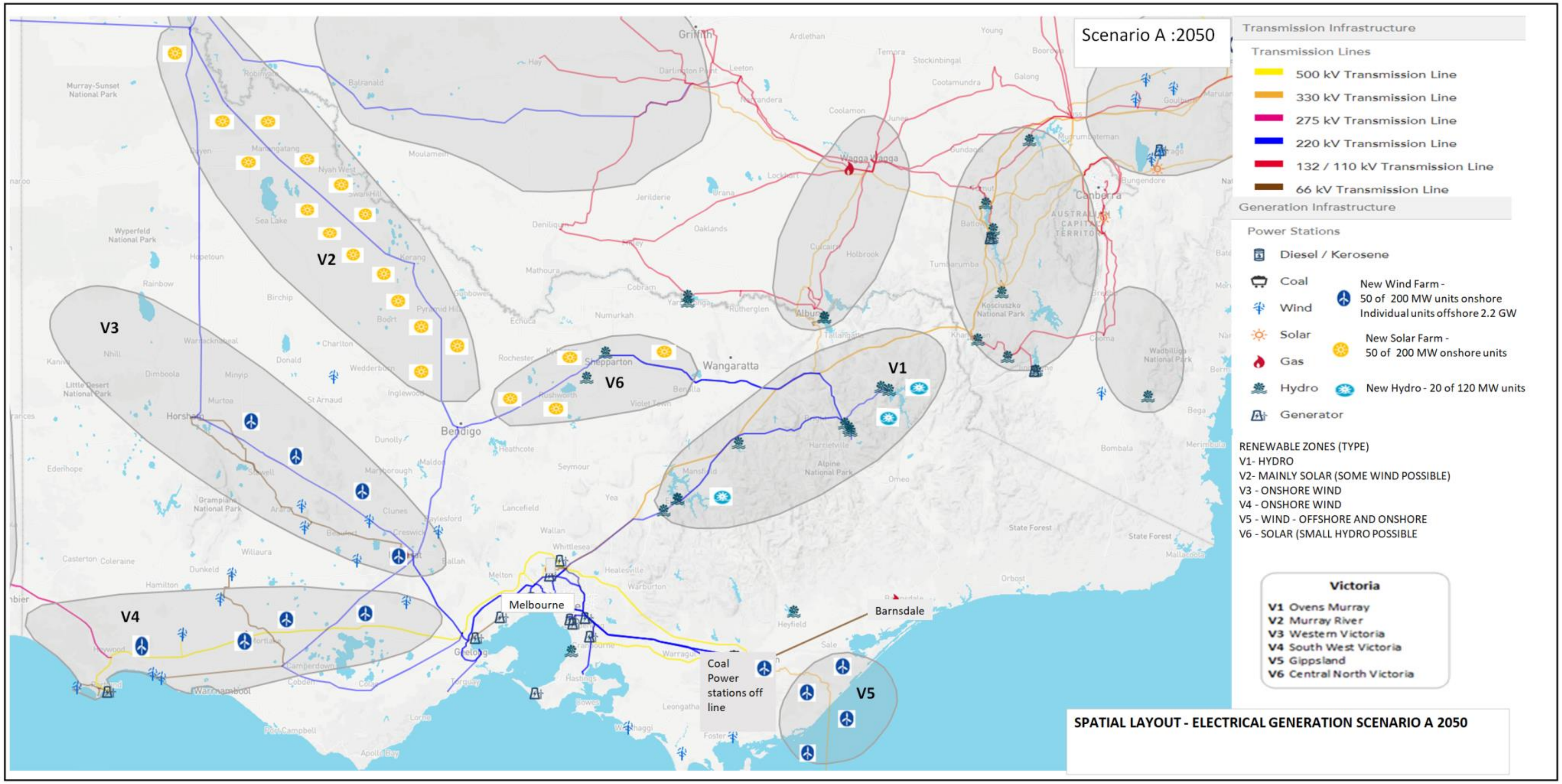


Figure 23: Scenario A – Electrical Spatial Analysis (2050)



3.2.2 Gas

For Scenario A it has been assumed that the natural gas usage will remain similar to today in 2030, while the Esso Longford Facility is still in operation, but drop off to a lower amount in 2040 after the closure of Longford and completely cease by 2050 when all Victorian gas plants are expected to reach their end of life. It is anticipated that the commercially viable gas reserves will be depleted by 2050.

In 2040 the remaining gas plants have the production capacity to support the reduced gas demand and the two storage facilities are still available to provide dispatchable peaking demand. A small amount of waste to energy production has been added to the scenario, which due to the regulations limiting the maximum size of these facilities only increases slightly over the three decades. The bio-gas facilities have been located in urban areas south west of Melbourne to better access waste feedstock, service the highest consumers and allow a planned decommissioning of the natural gas infrastructure. The initial site selected is local to the Laverton North gas fired power station which has a planned decommission date of 2070. The south west section of gas infrastructure also encompasses the Iona Gas Storage facility, which also services South Australia via the SEA Gas pipeline, the planned location of the Viva LNG import terminal and the APA LNG storage facility in Dandenong. It also includes two producing gas plants Otway Gas Plant and Athena Gas Plant which both have current projects to ensure continued production. The modifications at Athena will include cut over of production from the Casino wells previously producing to the Iona Gas Plat and Storage Facility. The Athena Gas Plant is planned to restart in 2021.

There are no major modifications to the gas transmission system identified in 2030, refer to Figure 24, as all gas plants are still operational These are grouped in two geographical areas on either side of the state. It is anticipated that a program of modifications local to users to assist the switch over to electricity is commenced prior to 2030. This should include all local electrical connections and metering requirements. As this switchover is progressed it is anticipated that the smaller gas distribution pipework will also commence decommissioning prior to 2030 and the scenario allows for 20% of this piping to have been decommissioned by 2030.

In 2040 additional bio-gas is added into the south west network and it has been allowed for approximately 40% of the transmission network and an additional 20% of the distribution pipework to be decommissioned over the preceding decade. For purpose of the scenario, the modelling is based on the northern part of the gas network shown in the decommissioning scope cloud on Figure 25 being decommissioned over the previous decade. The northern section has been selected as this allows continued access to production from the Lang Lang gas plant and the Orbost Gas plant if these are still operational and servicing of hard to abate gas users in the industrial areas of Victoria. It allows some but limited operation of the Viva LNG import terminal if this project has progressed. A decision to fully electrify by 2050 may reduce the life of this facility. An export/import pipeline route to New South Wales will be lost due to this decommissioning but the Eastern Gas Pipeline connection with NSW is retained.

In 2050 further bio-gas is added and injected into the remaining network servicing the Melbourne and Geelong Area. It is assumed that further decommissioning of the gas infrastructure (both transmission and distribution) continues over the decade – refer to Figure 32. By 2050 it is assumed that 20% of the infrastructure is retained. There is limited use of the existing infrastructure and the amount of bio-gas may not warrant retention. Either complete removal of all gas infrastructure or additional bio-gas should be considered to improve this scenario. It is anticipated that technology developments and regulations will allow larger bio-gas facilities by 2050.

The results from this part of the analysis support consideration of making policy recommendations to clarify the future of the role natural gas and the natural gas pipeline infrastructure, including any interstate import, export or use of interconnections. This aspect of policy would impact on any investment decisions by the infrastructure asset owners to either maintain, decommission or potentially expand the pipeline network.

Gas Infrastructure Upgrade Results

Table 48: Estimated Extent of Demolition of Existing Gas Transmission Pipelines for each Scenario

(4,694 kms installed transmission pipelines)

Scenario	2030	2040	2050
A	0%	40%	80%
B	0%	50%	90%
C	0%	75%	100%
D	0%	75%	100%

Table 49: Estimated Extent of Demolition of Existing Gas Distribution Pipelines for each Scenario

(26,249 kms total installed infrastructure for the 4 network suppliers)

Scenario	2030	2040	2050
A	20%	40%	80%
B	20%	60%	90%
C	20%	75%	100%
D	20%	75%	100%

Table 50: Installation of Hydrogen Infrastructure

(Refer separate capacity table for relative size of the infrastructure)

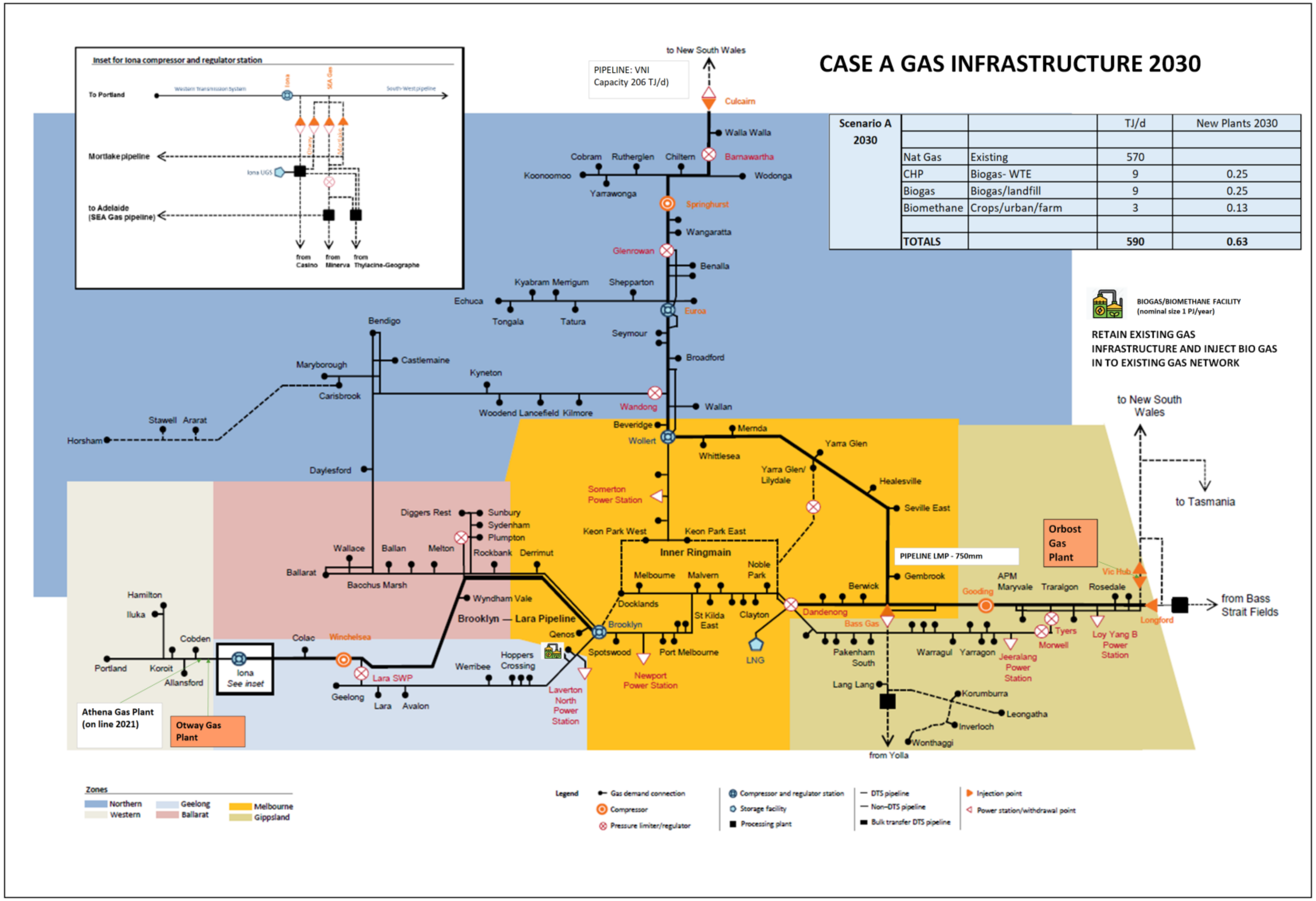
Scenario	2030	2040	2050
A	0 kms	0 kms	0 kms
B	0 kms	50%	100%
C	25%	75%	100%
D	25%	75%	100%

Table 51: Relative Average Diameter of Hydrogen Pipeline Network Compared to Existing Natural Gas Infrastructure

(Hydrogen requires larger pipe diameters to transport the same amount of energy as natural gas)

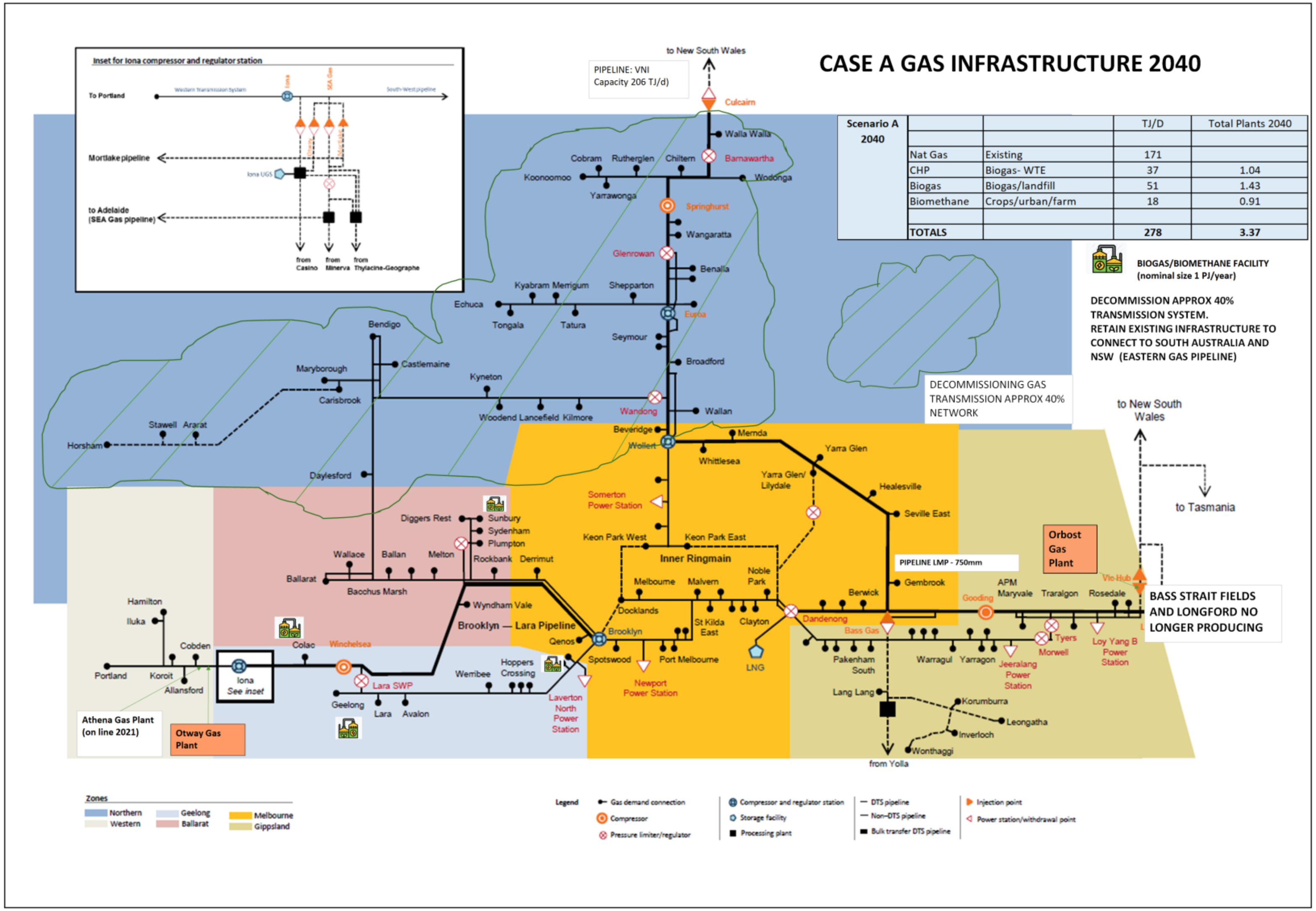
Scenario	Capacity of Hydrogen Infrastructure
A	NA – no new hydrogen infrastructure
B	0.4 of current gas infrastructure
C	2 x current infrastructure
D	6 x current infrastructure

Figure 24: Scenario A - Gas Spatial Analysis Scenario 2030



Scenario A 2030			TJ/d	New Plants 2030
	Nat Gas	Existing	570	
	CHP	Biogas- WTE	9	0.25
	Biogas	Biogas/landfill	9	0.25
	Biomethane	Crops/urban/farm	3	0.13
	TOTALS		**590**	**0.63**

Figure 25: Scenario A - Gas Spatial Analysis 2040



CASE A GAS INFRASTRUCTURE 2040

Scenario A 2040			TJ/D	Total Plants 2040
	Nat Gas	Existing	171	
	CHP	Biogas- WTE	37	1.04
	Biogas	Biogas/landfill	51	1.43
	Biomethane	Crops/urban/farm	18	0.91
	TOTALS		**278**	**3.37**

BIOGAS/BIOMETHANE FACILITY (nominal size 1 PJ/year)

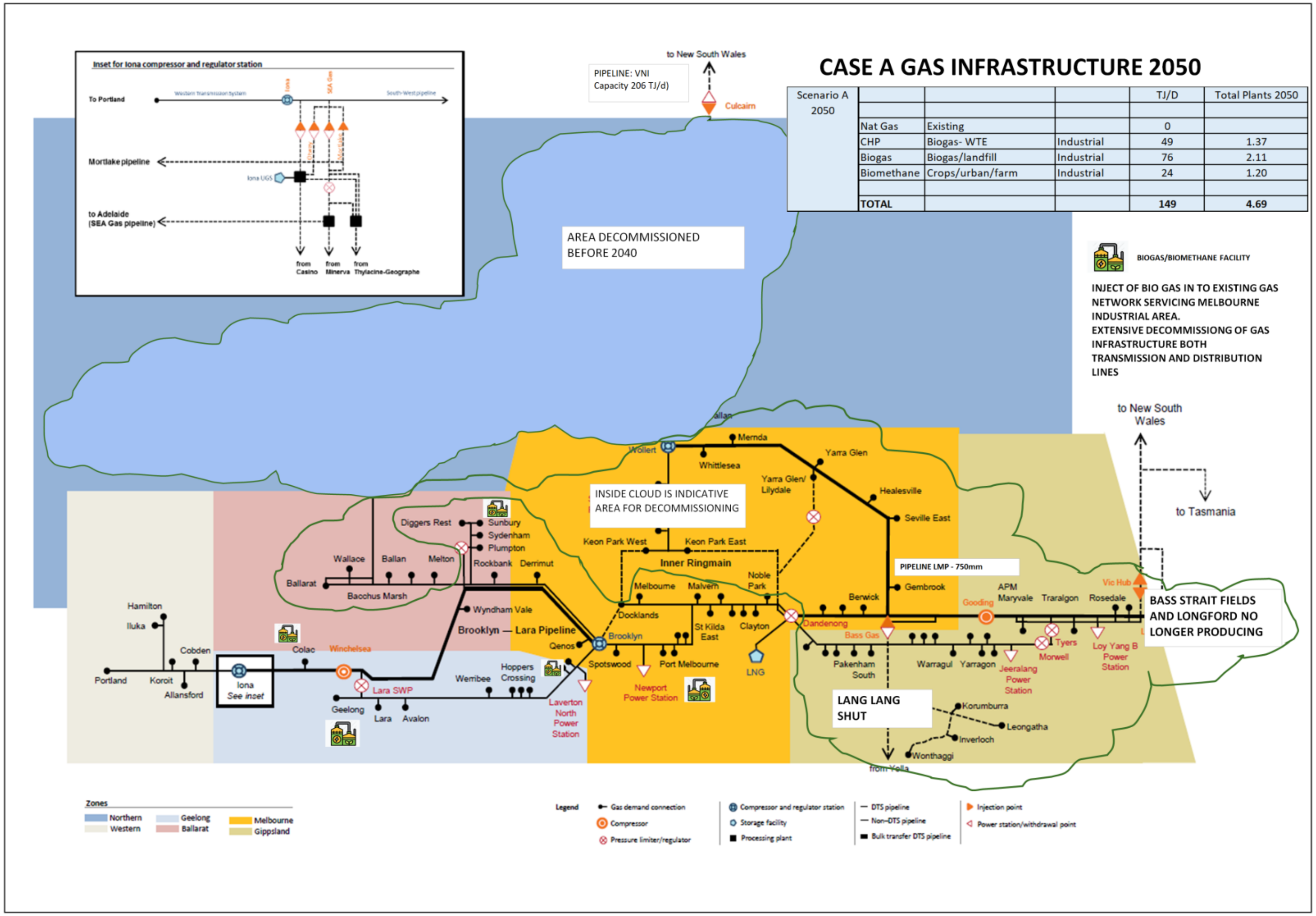
DECOMMISSION APPROX 40% TRANSMISSION SYSTEM. RETAIN EXISTING INFRASTRUCTURE TO CONNECT TO SOUTH AUSTRALIA AND NSW (EASTERN GAS PIPELINE)

DECOMMISSIONING GAS TRANSMISSION APPROX 40% NETWORK

PIPELINE: VNI Capacity 206 TJ/d)

BASS STRAIT FIELDS AND LONGFORD NO LONGER PRODUCING

Figure 26: Scenario A – Gas Spatial Analysis (2050)



CASE A GAS INFRASTRUCTURE 2050

Scenario A 2050				TJ/D	Total Plants 2050
	Nat Gas	Existing		0	
	CHP	Biogas- WTE	Industrial	49	1.37
	Biogas	Biogas/landfill	Industrial	76	2.11
	Biomethane	Crops/urban/farm	Industrial	24	1.20
	TOTAL			**149**	**4.69**

BIOGAS/BIOMETHANE FACILITY

INJECT OF BIO GAS IN TO EXISTING GAS NETWORK SERVICING MELBOURNE INDUSTRIAL AREA.
EXTENSIVE DECOMMISSIONING OF GAS INFRASTRUCTURE BOTH TRANSMISSION AND DISTRIBUTION LINES

AREA DECOMMISSIONED BEFORE 2040

INSIDE CLOUD IS INDICATIVE AREA FOR DECOMMISSIONING

BASS STRAIT FIELDS AND LONGFORD NO LONGER PRODUCING

LANG LANG SHUT

PIPELINE: VNI Capacity 206 TJ/d)

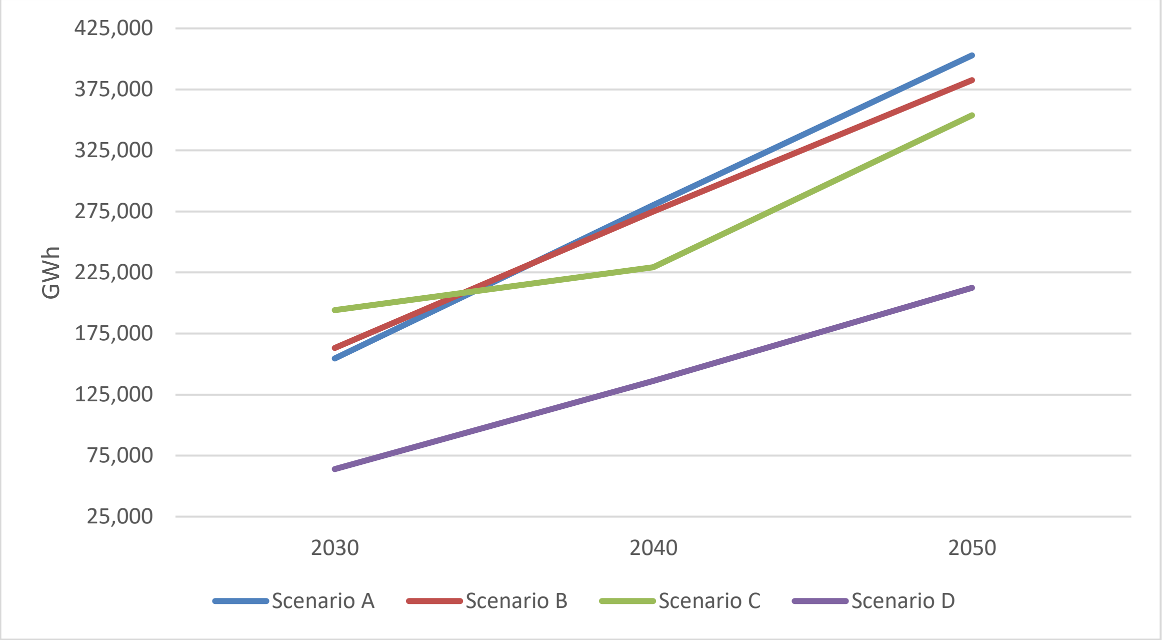
PIPELINE LMP - 750mm

3.3 Renewable Electricity and Storage

The allocation of renewable electricity production per region has been on the basis that the renewable energy will service the area it is in and thus reduce the load on the transmission lines between Renewable Energy Zones.

An estimate of total storage requirements was made using the GHG Tool and results summarised in Table 41 and Figure 27.

Figure 27: Energy Storage



Areas with solar farms have installed batteries to cover overnight, poor weather and peaking requirements. During periods of weak wind energy, the new pumped hydro installed in Renewable Zone V1 (Ovens Murray) will compensate for areas serviced by wind turbines in V3 (Western Victoria), V4 (South West Victoria) and V5 (Gippsland) and some of Melbourne’s demand. Refer Table 34 for a list of pumped hydro locations assessed in this study An allowance has been made to upgrade the transmission lines from V1 (Ovens Murray) to Melbourne, as discussed in Section 3.2.0. It is assumed that the secondary transmission lines and interconnections between V1 (Ovens Murray) and V3 (Western Victoria) and V4 (South West Victoria) will be sufficient to cover the distribution to these areas.

The results from this part of the analysis support consideration of making policy recommendations to streamline the regulatory process for connection of renewable facilities to the grid.

3.3.1 Solar

Residential solar represents a significant proportion of the overall energy production level modelled and given its zero Carbon footprint, is an important factor in achieving net zero emissions position. To ensure the level of solar modelled is adopted by residential and commercial users, the government should consider subsidizing its cost.

Under Scenario A it is expected that 1.93 million households / businesses will have rooftop solar systems, by 2030. According to the 2016 Census data, Victoria has approximately 2.52 million private households (Ref 21). Under Scenario A, 77% of all private households would have rooftop solar.

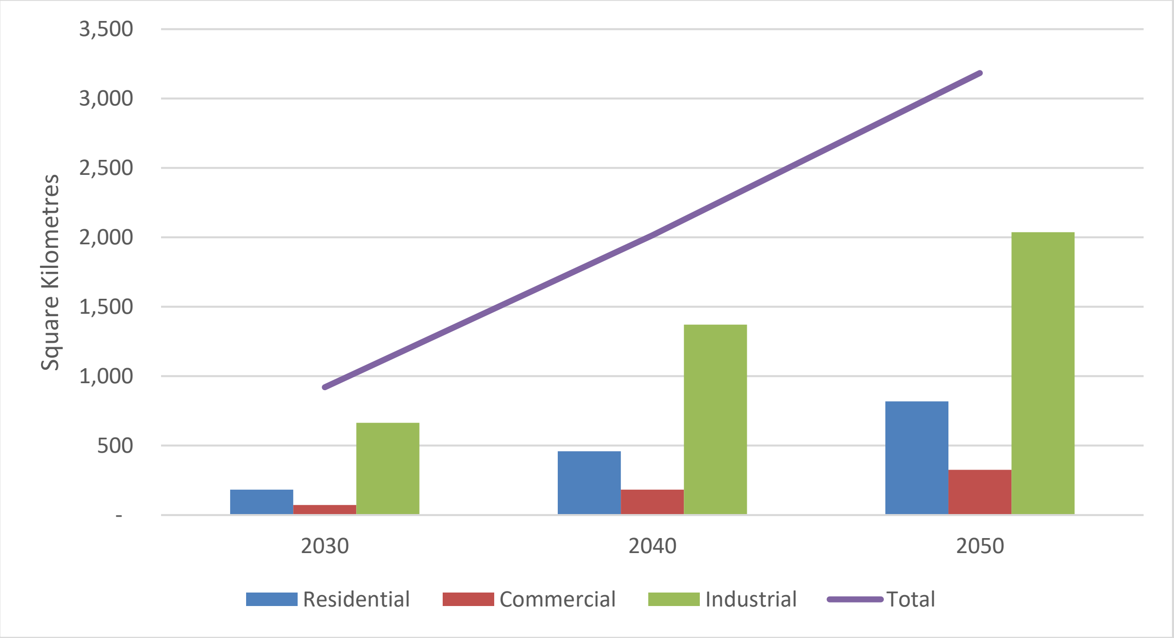
The large uptake of renewables from homeowners can lead to a “traffic jam” in the electricity grid. If too much electricity is pushed into the grid the result can be high voltages. If the voltage is allowed to get too high this could result in household inverters tripping and possible failure, and even damage to network transformers (Ref 22).

One way to ease the pressure on the electricity grid network is to combine home solar systems with a home battery system.

Large scale solar will also be required for each scenario. In 2050, the land requirement peaks at 2,016 km^2 (or 0.9% of Victoria’s total land area (Ref 23)), for Scenario A.

Figure 28 shows the total land requirements required for all solar installations for Scenario A, which is approximately 1.4% of all Victorian land.

Figure 28: Land Requirements for all Solar Installations in Scenario A



3.3.2 Wind

Scenario A has the largest uptake of wind derived energy of the four Scenarios, as shown in Figure 29. This power generation is comprised of both onshore and offshore installations, as outlined in Figure 30. The land required for all onshore installations is equivalent to 13,825 km^2 or 6.1% of the total Victorian land mass.

Figure 29: Wind Powered Energy Consumption

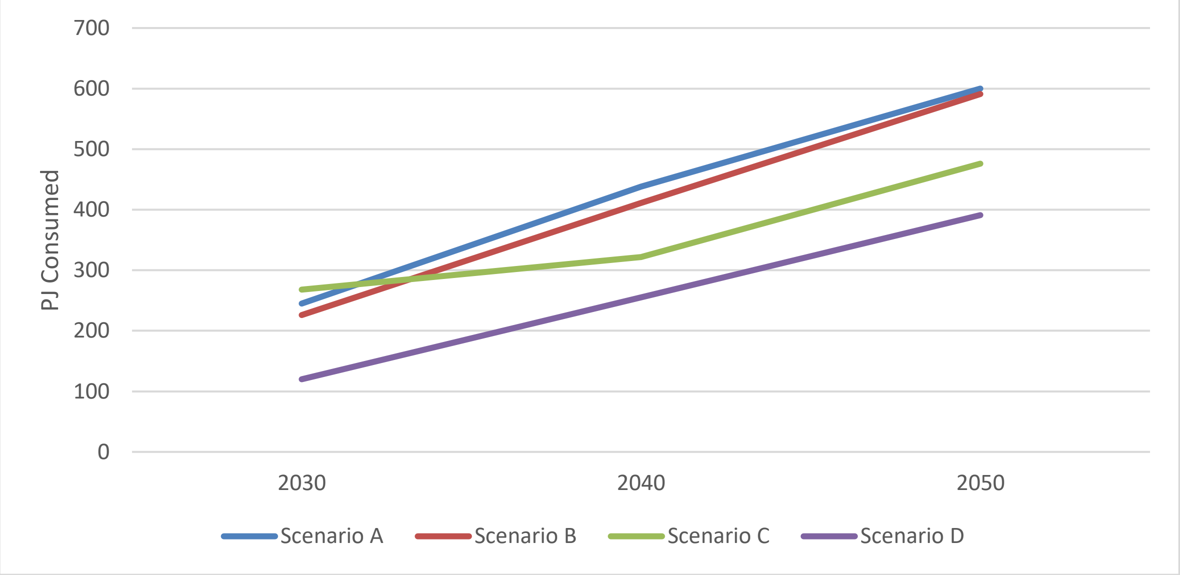
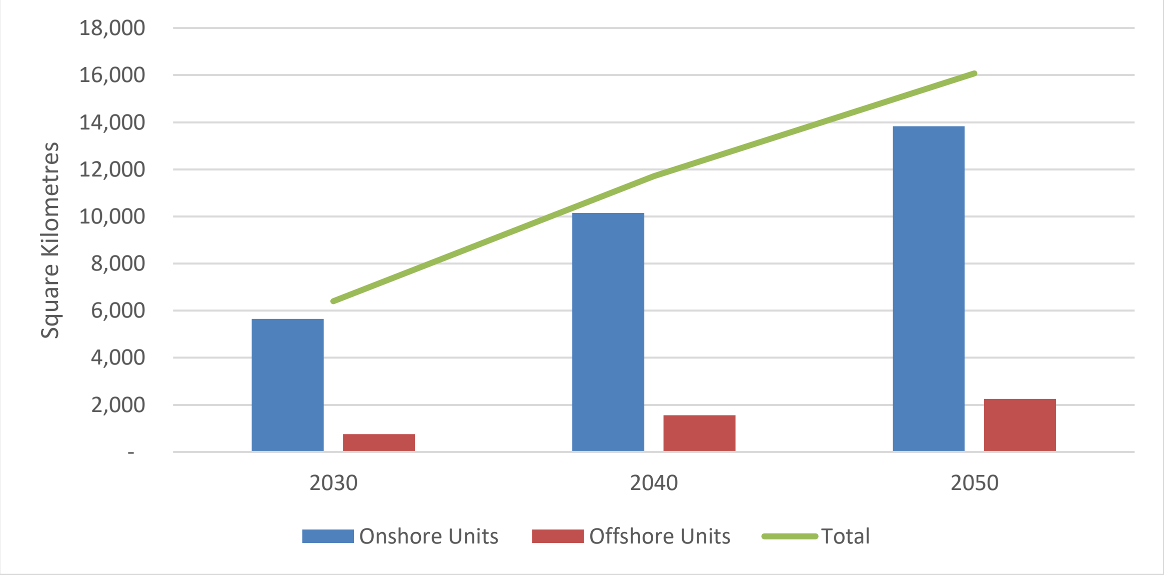


Figure 30: Land Requirements for Wind Generated Power



3.4 Natural Gas

Scenario A targets a complete replacement of natural gas and coal relying primarily on the adoption of renewables, with a moderate contribution from:

- Biogas
- Energy efficiency

Utilisation of the existing natural gas infrastructure for Scenario A is limited but a slow phase out of gas and use of bio-gas has enabled some infrastructure to be retained.

Potential refinements to Scenario A could include:

- Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
  - Increase the utilisation of gas infrastructure, noting that logistical constraints on the scale of biogas production mean it is unlikely to achieve an economic case for maintaining a large proportion of the existing natural gas infrastructure. The logistical challenges would typically favour a regional “biogas hubs” model creating a distribution of biogas production centres each having a modest levels of gas production. Scenario C would provide the best economic conditions for maintenance of large scale gas infrastructure.
  - Reduce overall Carbon emissions given the significantly negative emissions factor associated with biogas.
  - Minimise upgrades to electrical infrastructure including hydro storage to provide peaking back up to wind turbines.

3.5 Road Vehicle Fuels

The scale of uptake for BEVs and HFCVs was assessed for Infrastructure Victoria’s description of Scenario A (Appendix 1) and recorded in Table 40. 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.

Introduction of HFCVs in accordance with Table 40 causes a pro-rata reduction in the amount of kilometres travelled for both hydrocarbon vehicles and BEVs in order to maintain the overall total kilometres travelled for all road vehicles described in the prior analysis [Reference 8]. The selected split of kilometres travelled by vehicle category and fuel type for Scenario A for the three time periods is defined inTable 52, Table 53, and Table 54.

Table 52: Scenario A (2030) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**77,519,729,017 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	48,793,877,737	63%	1,748,986,234	2%
BEVs	21,022,404,359	27%	1,303,277,886	2%
HFCVs	775,197,300	1%	3,875,986,501	5%
Total	**70,591,479,396**		**6,928,250,621**	

Table 53: Scenario A (2040) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**89,147,689,520 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	23,908,321,944	27%	161,554,226	0%
BEVs	56,380,402,466	63%	3,348,549,512	4%
HFCVs	891,476,895	1%	4,457,384,476	5%
Total	**81,180,201,305**		**7,967,488,215**	

Table 54: Scenario A (2050) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**93,411,274,671 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	0	0%	0	0%
BEVs	83,194,507,178	89%	1,809,752,772	2%
HFCVs	1,868,225,493	2%	6,538,789,227	7%
Total	**85,062,732,672**		**8,348,541,999**	

Based on typical fuel consumption for each type of vehicle, the GHG Tool estimated the fuel requirements, with results provided in Table 55, along with the emissions, with results reported in Table 41.

Table 55: Scenario A – Total Fuel Consumption by Road Vehicle Type

Year	**All Road Hydrocarbon Vehicles**	**All Road BEVs**	**All Road HFCVs**
	Gasoline & Diesel (PJ / yr)	**Electricity (PJ / yr)**	**Hydrogen (PJ / yr)**
2030	217	20	23
2040	99	53	27
2050	0	66	40

The results from this part of the analysis support consideration of making policy recommendations to establish a clear position on the use of battery electric vehicles and hydrogen fuel cells vehicles for various modes of ground transport and review import tariffs imposed on BEVs and HFCVs to ensure alignment with planned uptake rates. Investment in establishing widespread recharging / refuelling infrastructure is expected control the rate of adoption of these technologies.

3.6 Biogas

3.6.1 Waste to Energy

Currently Victorian Government policy is to limit the quantity of residual wastes for use in waste to energy plants to 1 million tonnes per annum until 2040. In Scenario A, we assume that waste to energy plants will consume around 600,000 tpa of waste and produce 57 MWe of electricity in 2030 and 1,000,000 tpa of waste and 87 MWe of electricity by 2040. This is consistent with the current policy settings and the time required to bring new plants from the proposal stage to the operations stage (typically about 5 years for each new plant). We further assume that by 2040, the current policy will be relaxed as the community accepts the technology and population increases lead to significant increases in the amount of residual wastes being sent to landfill. By 2050, we assume that 1.5 mtpa of waste will be consumed in waste to energy facilities producing around 135 MWe of electricity into the grid (12 PJ of chemical energy).

3.6.2 Landfill Gas

In Scenario A, we assume that landfill gas stays largely flat over the period as a results of the combination of population increases which generate more waste and objectives to reduce wastes (especially organic wastes) being sent to landfill. However, biogas production from industrial and agricultural sources is dramatically ramped up, increasing from around 1 PJ of biogas in 2020 to around 28 PJ of biogas in 2050. The landfill gas and biogas is used to generate renewable electricity from gas engines.

3.6.3 Biomethane

In Scenario A, biomethane production is ramped up to reach around 14 PJ/yr by 2050. The biomethane is generated by upgrading a combination of landfill gas from domestic wastes and biogas from agricultural wastes to reach natural gas pipeline specifications.

3.6.4 Biomass

In Scenario A, biomass energy is assumed to increase from around 50 MWe in 2020 to 175 MWe by 2050.

3.7 Geothermal Energy

Scenario A incorporates small scale geothermal heating primarily for commercial use in low density areas. These direct heating applications include commercial use such as community swimming pool complexes, shopping malls, universities and sporting complexes, in addition to individual industrial sites and industrial complexes. In this operating model, the consumers of the energy would either own and operate the geothermal facilities or would contribute to the cost of a shared facility, rather than purchase energy from an energy supplier.

3.8 Energy Efficiency

Scenario A includes large-scale energy efficiency improvements including the widespread use of smart meters and smart grids to optimise the use of variable renewable power sources and energy storage systems. Improved insulation standards and energy efficient appliance requirements for new and existing buildings are also imbedded into this scenario.

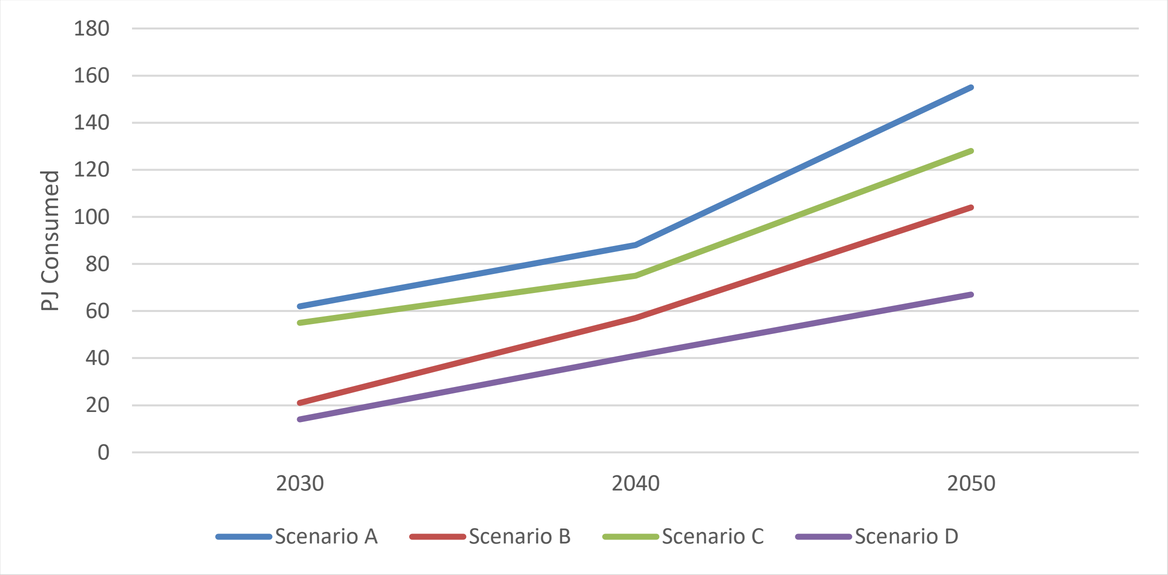
Scenario A also incorporates ground source heat pumps (GSHP) as an energy efficiency measure for both heating and cooling and hot water supply for commercial and industrial users.

The results from this part of the analysis support consideration for making policy recommendations relating to accelerating the adoption of energy efficiency measures and appliances, and broadening the application to cover, for example, existing buildings.

3.9 Hydroelectricity

Scenario A has the highest uptake of hydroelectricity of the four scenarios, and this is illustrated in the figure below.

Figure 31: Hydroelectricity Consumption



Recognising that much of Victoria’s hydroelectricity potential has been realised, only moderate levels of additional hydro-power have been specified for this analysis. Potential for increased variability in rainfall creates a risk for dependence on significant levels of additional hydroelectricity (Ref 20).

3.10 Social

3.10.1 Employment

The Commonwealth government is committed to supporting the gas industry to be used as a transition fuel to 100% renewable energy, and to aid Australia's manufacturing recovery from the Covid-19 recession (Ref 15). However, critics are quick to point out that the gas industry only employs 0.2% of all Australian jobs (Ref 16). For every $1 million in sales income generated only 0.4 jobs are created in gas production, while the national average is 3.4 jobs. Ernst and Young (Ref 17) estimate that for every $1 million spent on renewables creates 4.8 full time jobs in renewable infrastructure or 4.95 jobs in energy efficiency. By comparison $1m spent on fossil fuel projects has been found to create 1.7 full time jobs.

Solar and wind provide the greatest opportunity for job growth in Australia (Ref 18). Most in construction and installation, but over time an increasing proportion of jobs would be on-going operations and maintenance.

Renewable energy currently employs more people than the domestic coal sector and will continue to do so (Ref 18).

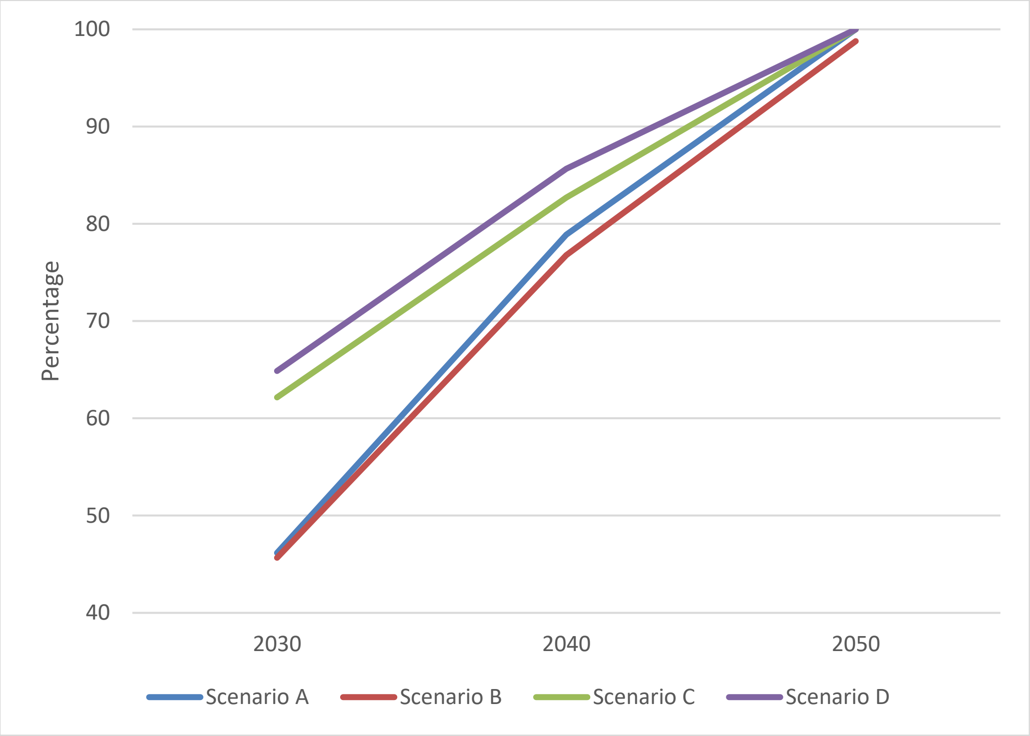
Renewable energy will create employment across regional Australia, including coal regions. The occupational mix and location indicate the sector can play a meaningful role in creating alternative employment.

But a rapid uptake of renewables can also lead to constraints as shown in 2018-2019, when an experienced skill shortage was encountered in the renewable energy sector (Ref 18).

Scenario A's initial reliance on renewables, such as wind, solar and hydropower; is amongst the lowest with Scenario B in 2030; when including other renewable energy sources such as biogases. By 2050, Scenario A is meeting 100% renewable energy meeting the state's energy needs. The Climate Council (Ref 19) has predicted that with the introduction of 50% renewable electricity by 2030 this could lead to a net gain of around 4,000 jobs over a business-as-usual scenario. These jobs will be created in construction, operation and maintenance of renewable energy installations. With over half of the renewable energy jobs created in the rooftop solar arena.

Scenario A will adopt 46% renewable energy, by 2030 (refer to Figure 32). Based on the Climate Council's estimates it can be predicted that Scenario A will generate approximately 3,700 jobs in Victoria by 2030 and 8,000 by 2050.

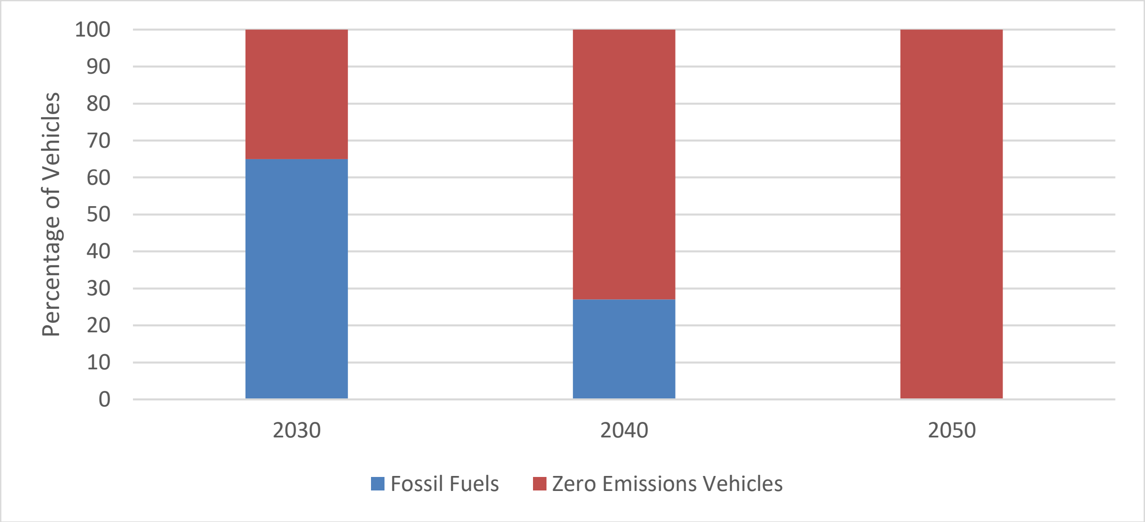
Figure 32: Uptake of Renewable Energy



3.10.2 Zero Emissions Vehicles

Section 2.1.8 details the uptake of the zero emissions vehicles for the study. Each scenario has adopted the same uptake rate and this is shown in Figure 33.

Figure 33: Update of Zero Emissions Vehicles



3.10.2.1 Vehicle Batteries

Electric vehicles (EV) may be carbon neutral during their working lifetime however, their batteries have a limited life span of approximately 10-15 years. At this point it will be important for there to be a recycling industry to cope with the influx.

Most EV components are similar to those of conventional cars, but the big difference is the battery. Traditional lead-acid batteries are widely recycled (98%), at present that is not the case for lithium-ion batteries used in electric vehicles.

Electric vehicle batteries are larger and heavier than regular car batteries. They are made up of several hundred individual lithium-ion cells, all of which require dismantling. In addition, they contain hazardous materials. Lithium-ion batteries also pose an explosive risk if disassembled incorrectly (Ref 24).

Australia currently produced 3,300 tonnes of lithium-ion battery waste each year (Ref 25). Presently 2% of this waste is recycled, but it is growing by 20% per year. If recycled, 95% of components can be turned into new batteries or used in other industries. CSIRO research into battery recycling is ongoing and detailed in '*Australian Landscape for Lithium-Ion Battery Recycling and Reuse in 2020'*.

Under each scenario approximately 1.5 million electric vehicles are expected on the roads of Victoria by 2030. By 2040 that could mean 0.75 million tonnes of car battery waste to be disposed of. This volume increases to 6.8 million electric vehicles on the roads by 2050.

3.10.2.2 Semiconductor Chip Supply

Technology has seen an increase in the electronic functions of vehicles, and thus an increase in the demand for semiconductor chips. This increased demand, coupled with the covid crisis led to short falls in semiconductor chips and the temporary slowdown and in some instances shutting down of some manufacturer's electric vehicle production lines (Ref 54). Semiconductors, which utilise gallium and silicon carbide, allow electric vehicle batteries to operate at high voltages. They are also responsible for safety sensors, brake systems and driver assistance technology. Asia, presently, dominates the manufacture of semiconductors with Taiwan (54%) and South Korea (16.6%) being the largest suppliers. Multibillion dollar chip wafer fabrication plants do not have a great deal of flexibility to change production capacity. Adding significant wafer fabrication capacity could take years and billions of dollars (Ref 60). It has been forecast that chip supply could take till 2023 before it has caught up with demand.

With the closing down of Victoria's car manufacture industry in 2017, Australia is reliant upon external global markets for all new vehicles. Victoria's target of 50% of new vehicles being zero emission vehicles by 2030, will require competition with global markets for the supply of these vehicles. Any ongoing short falls in critical components, such as semiconductor chips will have an impact.

3.10.2.3 Critical Mineral Supply

Another factor that could impact the supply of zero emission vehicles is the availability of critical minerals or rare earth minerals. Hydrogen fuel cells require small but expensive quantities of platinum and palladium; while electric vehicle cars require substantial amounts of copper (83 kilograms per car) and lithium (2.4 kilograms per car). Lithium and copper recycling could greatly reduce the need for new mines to be developed, however, the current issue is that there is only a small amount of zero emission vehicles currently on the roads and the recycling technology is not sufficiently advanced (Ref 55). Currently the world is heavily dependent upon Asia for both electric vehicle batteries and the raw materials to produce them. Australia could be a global leader in the production of lithium (Ref 60). The current outlook is for Australia to produce 10% of global production. Lithium mine development is often hampered by financial difficulties and long-term price volatility (Ref 55). To develop a new mine can take between 5 to 10 years. Analysts have predicted that there could be material shortage due to limited lithium supplies by 2025 (Ref 56).

3.11 Environmental

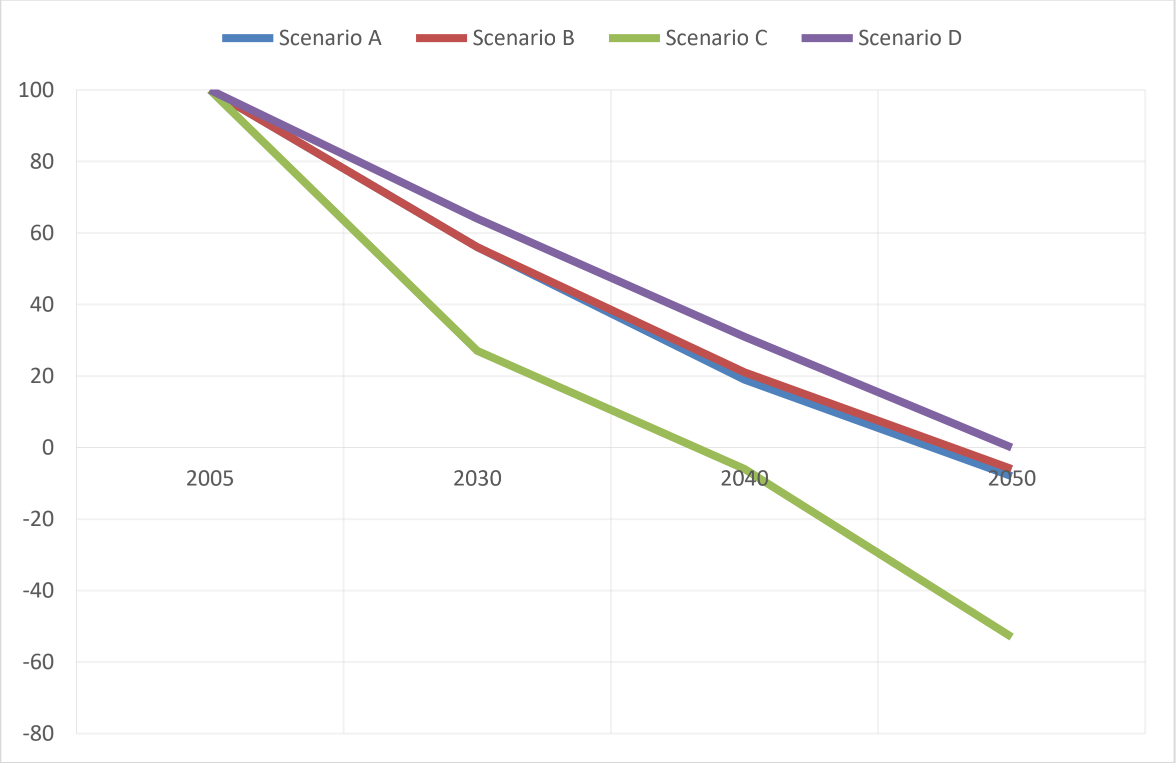
This study only examines the energy sector, excluding some sectors examined in the Victorian greenhouse gas reports shown in Table 56 Greenhouse gas emissions from the sectors – Industrial Processes, Agriculture and Waste are excluded from the 2005 reference data.

Under Scenario A Victoria will reach net zero emissions before 2050, as shown in and Figure 34.

Table 56: Scenario A Greenhouse Gas Emissions

Sector	**2005 Mt CO_2-e**	**2030 Mt CO_2-e**	**2005 to 2030 % Reduction**	**2040 Mt CO_2-e**	**2005 to 2040 % Reduction**	**2050 Mt CO_2-e**	**2005 to 2050 % Reduction**
Electricity generation	67	29	56.7	14	79.1	0	100.0
Direct combustion	15.2	14	7.9	-1	106.6	-7	146.1
Transport	20.2	15	25.7	7	65.3	0	100.0
Fugitive emissions	2.4	2	16.7	1	58.3	0	100.0
LULUCF (land use, land use change and forestry)	-8.7	0	100.0	0	100.0	0	100.0
Total (net emissions)	**104.8**	**59**	43.7	**20**	80.9	**-8**	107.6

Figure 34: Comparison of Each Scenario's Greenhouse Gas Emissions Reduction against the Reference Year 2005



3.12 Risk & Opportunities

Environment

In terms of environmental impact for Scenario A, the use of hydrocarbons to power the state is almost entirely removed and electricity from renewable resources becomes the energy type of choice. This results in no requirement for commissioning offshore CCS as what little CO_2 that is produced can be offset by forestry, soil farming or marine offsets.

High levels of electric demand (as in the cases for Scenarios A, B and C) result in significant electrical infrastructure, particularly in Western Victoria, as additional transmission infrastructure is installed to supply electrical power around the state from the Renewable Energy Zones. This additional infrastructure presents an increased bushfire risk, and to manage this risk, requires tree removal and ongoing clearance in accordance with the *Electrical Safety (Electric line clearance) regulations 2013)*, and the tree clearances reduce available habitat for local wildlife.

For this scenario, batteries and hydroelectric power provides peaking capacity, as well as backup power during periods of cloudy or calm weather days. The use of hydroelectric power generally requires dam construction, the flooding of valleys (the extent required depending upon the topography of the surrounding landscape) with subsequent loss of habitat, and a reduction in water levels downstream of the dam, also eroding environmental values. Climate change itself poses a risk to hydropower projects; As an example Tasmania needed to recommission a gas powered generator that had been scheduled for closure during the drought of 2016 due to inadequate water levels in dams (Ref 33).

Societal

The main societal risk associated with Scenario A is the ability for society to adapt to the degree of change necessary to move to the reality of a non-hydrocarbon economy. Changes necessary include:

- Full adoption of electric heating and cooking appliances
- Significant increases in the numbers of wind and solar farms and hydroelectric power plants in the state
- Significant increases in the amount of rooftop solar, and house-based battery storage systems, changing the dynamic of power supply and demand
- Significant increase in the electricity distribution infrastructure
- As biofuels take off, greatly increased focus on recycling and waste segregation

All of these changes are required to a certain extent for all scenarios, but are most clearly seen for Scenario A. The Victorian public already has a high take up rate of roof top solar, and there is a risk that the market for rooftop solar becomes saturated resulting in a greater requirement for industrial scale solar and windpower. Societal resistance to the number of windfarms can be expected to grow based on experience both in Australia (Ref 34) and overseas. Resistance to hydropower based on previous experience in Australia (eg Franklin Dam) can be expected to be high. This is particularly the case as the available locations in Victoria to exploit for hydropower are limited and conflict with other societal values as these regions are popular tourism destinations. And, although Australia holds high reserves of lithium which is required for battery manufacture, it is considered highly likely that public resistance to Li mining would be high.

Economics

Scenario A is more susceptible to price increase in the cost of rare earth materials and polysilicon than Scenarios B & D as the world demand for solar panels and batteries increases. Cost blowouts associated with the installation of local distribution infrastructure required to support the network of home solar providers is also considered highly likely. The management of power connections into the electricity grid is also expected to have economic and technical risks due to the sheer numbers of connections that will need to be made in a full electrification scenario, particularly with the potential cost implications should planning determinations require burial of lines to mitigate environmental risk. The potential for delays resulting from processing the number of planning applications that would be required also has economic impact.

In this scenario, the gas pipeline and production infrastructure is unused and any remaining value written off, resulting in a potential lost opportunity for Victoria, specifically as Victoria is currently a net exporter of gas, and abandonment of Victoria's pipeline infrastructure has implications for South Australia and NSW. This is somewhat offset by forecast demand levels which predict that Victoria will soon become a net importer of gas, with the reduction is gas production from the Bass Strait Platforms. This decline in production will not be fully offset by identified Victorian gas resources. On the flip side, the degree of infrastructure required represents a significant amount of installation activity and therefore employment opportunity. In addition, as home solar reaches greater penetration, systems management job opportunities (inspection and maintenance) will arise. There will be a transition requirement for personnel working in the gas industry to other forms of employment.

Technical

All of the elements of energy production in Scenario A are proven technologies and as such considered to be low risk. The technical risks associated with this scenario are associated with the sheer number of energy providers into a distributed network, and the commensurate risk of power drop-outs and production unreliability. Currently power provision is in the hands of Industry providers whose base business is to supply power into the grid. In this scenario the uptake of home and commercial premises solar is vastly increased, however, this is not their core business and the reliability of these systems to provide the power (either for themselves or to feed into the grid) cannot be guaranteed. This situation is exacerbated by the design life of the solar panels and batteries that are installed and may not necessarily be replaced when their productivity drops off.

In Scenario A there is a reliance on hydropower to provide peak shaving. There is a technical risk that there are not sufficient locations with the appropriate topography required in non – National Park settings. Hydropower can be sourced from other states to provide backup (Tasmania and NSW) with use of the Marinus link and other state interconnections.

Safety

In Scenario A, the numbers of batteries to support home solar systems increases exponentially. Batteries are a fire risk and management of this fire hazard requires careful consideration.

3.13 Comparative Cost Index

The cost estimate for each scenario is presented as a “cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The example of the “comparative cost index” illustrates the general intent and mandate of this study being a comparative analysis of scenarios to identify trends, drivers, risks and opportunities in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050. The development of classed cost estimates for each scenario is beyond the scope of this study.

The comparative cost index for Scenario A was calculated to be 1,1 using the method described in Section 2.2.2, and this value is used as input to the Scenario Screening described in Section 7.

4 SCENARIO B

Scenario B is summarised as " partial electrification / limited gas / limited CCS”. Based on the detailed description provided in Appendix 1 the scale of uptake of new energy, offset mechanisms and new energy road vehicles is defined in the following tables using the qualitative scale in Table 57.

Table 57: Uptake Scale

🟩	Large upscale / transfer of energy is made to this energy type Large uptake of new energy vehicles
🟧	Medium upscale / transfer of energy is made to this energy type Medium uptake of new energy vehicles
🟥	Small upscale / transfer of energy is made to this energy type Small uptake of new energy vehicles
🟦	No upscale / transfer of energy is made to this energy type No uptake of new energy vehicles

Table 58: Scenario B - Uptake of New Energy

🟩 **Renewable Elec**			🟥 **CHP**	🟥 **Heat**	🟥 **Gas**	🟥 **Gas**	🟥 **Gas**	🟥 **Gas**	🟦 **Gas**	🟧 **Efficiency**		
solar	wind	hydro	biogas	geotherm	biogas	biometh.	H2 green	H2 blue	H2 brown	heat pump	insul.	smart grids

Table 59: Scenario B – Uptake of Offset Mechanisms

🟥 **CCS**			🟧 **Agro-Forestry**			🟧 **Trading**	
Onshore	Offshore	Chemical	Forestry	Marine	Soil	Aus C-Credit	Internat. C-Credits

Table 60: Scenario B – Uptake of New Fuel Vehicles

🟩 **Vehicle**	🟥 **Vehicle**
BEV	HFCV

4.1 Energy-Emissions-Offsets

The energy-emissions-offset flows for each time period for Scenario B demonstrating a path to net zero carbon emissions by 2050 were calculated using the GHG Tool, with results summarised in Table 61.

Schematic representations “Sankey diagrams” of the flows of energy, emissions and offsets leading to the net emissions position for each time frame are provided Figure 35 (overleaf).

These illustrations are intended to provide a simplified, graphical representation of the complex, interconnected data provided in Table 61.

It is important to note that both the “Table of Results” and “Sankey Diagrams” present exactly the same set of results, but on a slightly different basis : Table 61 assumes coal on a thermal basis; whilst Figure 35 reports coal on an electrical basis (applying a 30% conversion factor assumed for a typical brown coal power plant) in order to more clearly illustrate the scale of energy flows relating to electricity consumption, emissions and required offsets.

The basis and build-up of these results, along with a discussion thereof is provided in the following sections.

Table 61: Scenario B – Energy-Emissions-Offset Results

(Coal reported on thermal basis)

Energy Consumed (PJ)	**2030**				**2040**				**2050**			
Overall Demand (Victoria)	**1,492**	**Coal**	**Vehicle**	**Gas**	**1,716**	**Coal**	**Vehicle**	**Gas**	**1,973**	**Coal**	**Vehicle**	**Gas**
Total (Scope of this Study)	**1,395**				**1,509**				**1,656**			
coal	308				150				0			
vehicle fuel (gasoline, diesel)	217				99				0			
natural gas	233				100				20			
solar (replace HC's)	106	12	86	8	174	22	119	34	238	31	160	47
additional solar to balance demand	255				420				549			
wind (replace HCs)	46	28	11	7	96	57	15	25	136	84	20	32
additional wind to balance demand	180				315				455			
hydro (replace HCs)	11	0	11	0	27	9	15	3	44	18	20	5
additional hydro to balance demand	10				30				60			
CHP (WTE / biogas / biomass) (replace HCs)	1	0	0	1	5	0	0	5	9	0	0	9
geothermal (replace HCs)	1	0	0	1	6	0	0	6	10	0	0	10
biogas / landfill gas (replace HCs)	1	0	0	1	6	0	0	6	10	0	0	10
additional biogas / landfill gas to balance gas demand	0				5				6			
biomethane (replace HCs)	1	0	0	1	6	0	0	6	10	0	0	10
additional biomethane to balance gas demand	0				5				6			

green H2 (replace HCs)	22	0	21	1	29	0	23	6	42	0	32	10
additional green H2 to balance gas demand	0				5				6			
blue H2 (replace HCs)	3	0	2	1	10	0	4	6	19	0	8	11
additional blue H2 to balance gas demand	0				15				24			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	1	0	0	1	7	0	0	7	14	0	0	14
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			

Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**59**	**Coal**	**Vehicle**	**Gas**	**23**	**Coal**	**Vehicle**	**Gas**	**-5**	**Coal**	**Vehicle**	**Gas**
coal	29				14				0			
vehicle fuel (gasoline, diesel)	15				7				0			
natural gas	13				5				1			
fugitive emissions (4% of total HC)	2				1				0			
CO2 (nat gas processing)	1	0	0	1	0	0	0	0	0	0	0	0
solar (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional solar to balance elec demand	0				0				0			
wind (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional wind to balance elec demand	0				0				0			

hydro (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance elec demand	0				0				0			
CHP (WTE / biogas / biomass) (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
geothermal (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
biogas / landfill gas (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
additional biogas / landfill gas to balance gas demand	0				-2				-2			
biomethane (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
additional biomethane to balance gas demand	0				-2				-2			
green H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional green H2 to balance gas demand	0				0				0			
blue H2 (replace HCs)	0	0	0	0	0	0	0	0	1	0	0	0
additional blue H2 to balance gas demand	0				0				1			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	0				0				0			
grid elec imported (to balance demand)	0	0	0	0	0	0	0	0	0	0	0	0
LNG imported (to balance demand)	0				0				0			
Carbon Offsets **(Mill Te CO2-e)**	**2030**				**2040**				**2050**			
Total	**0**	**Coal**	**Vehicle**	**Gas**	**-1**	**Coal**	**Vehicle**	**Gas**	**-1**	**Coal**	**Vehicle**	**Gas**

CCS	0	0	0	0	-1	0	0	-1	-1	0.0	-0.2	-0.9
agro-forestry	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
trading	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
Net Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**59**				**23**				**-6**			
Energy Storage (GWh)	**2030**				**2040**				**2050**			
Total	**163,177**	**Coal**	**Vehicle**	**Gas**	**275,024**	**Coal**	**Vehicle**	**Gas**	**382,573**	**Coal**	**Vehicle**	**Gas**
battery	29,546	3,360	23,956	2,230	44,135	5,995	28,816	9,323	65,973	8,495	44,558	12,919
additional solar to balance demand	70,833				116,667				152,500			
pumped hydro	12,798	7840	2995	1963	26,723	15,745	4,117	6,861	37,712	23245	5570	8897
additional wind to balance demand	50,000				87,500				126,389			
chemical	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance demand	0				0				0			

Figure 35: Scenario B – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

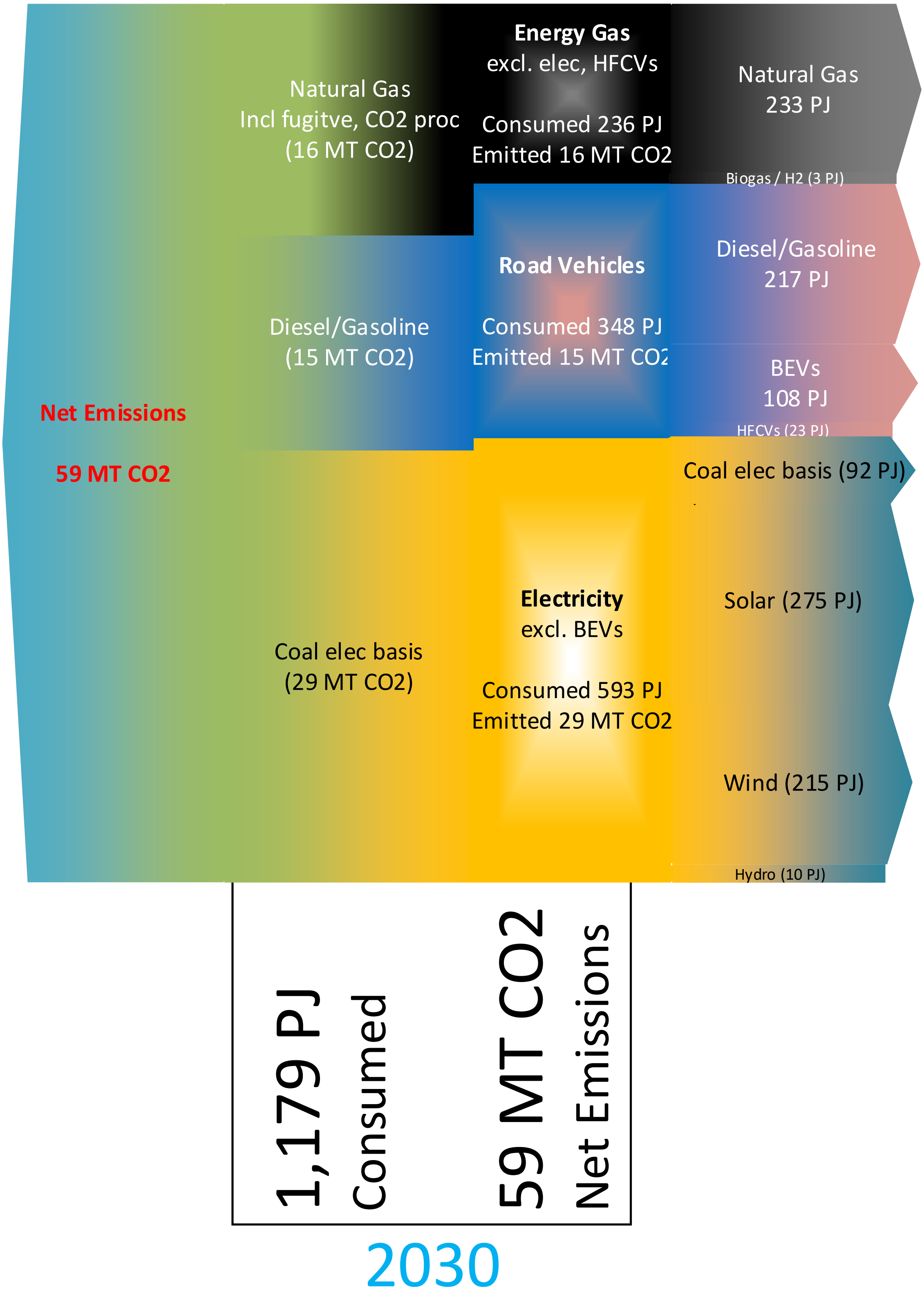


Figure 36: Scenario B – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

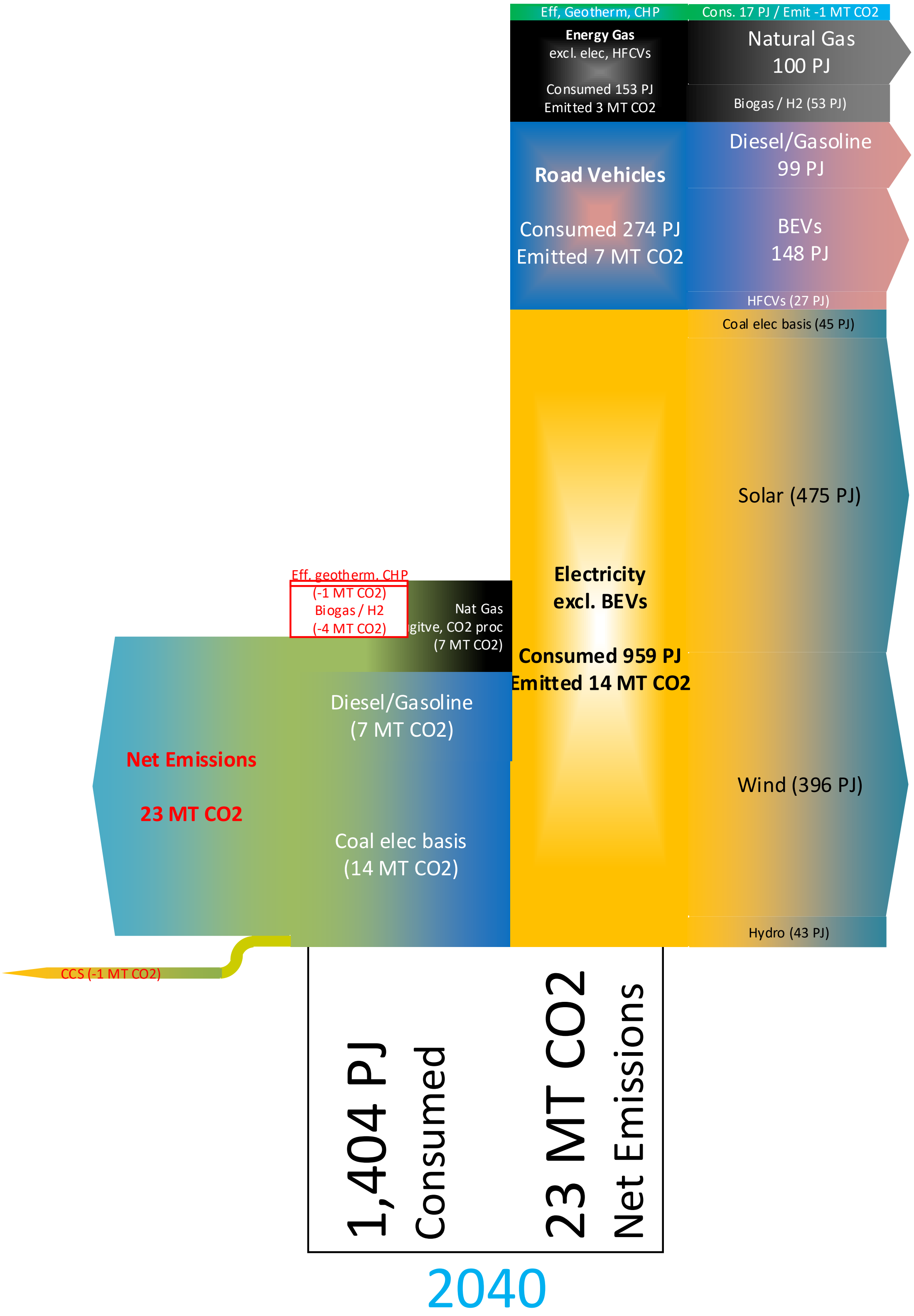
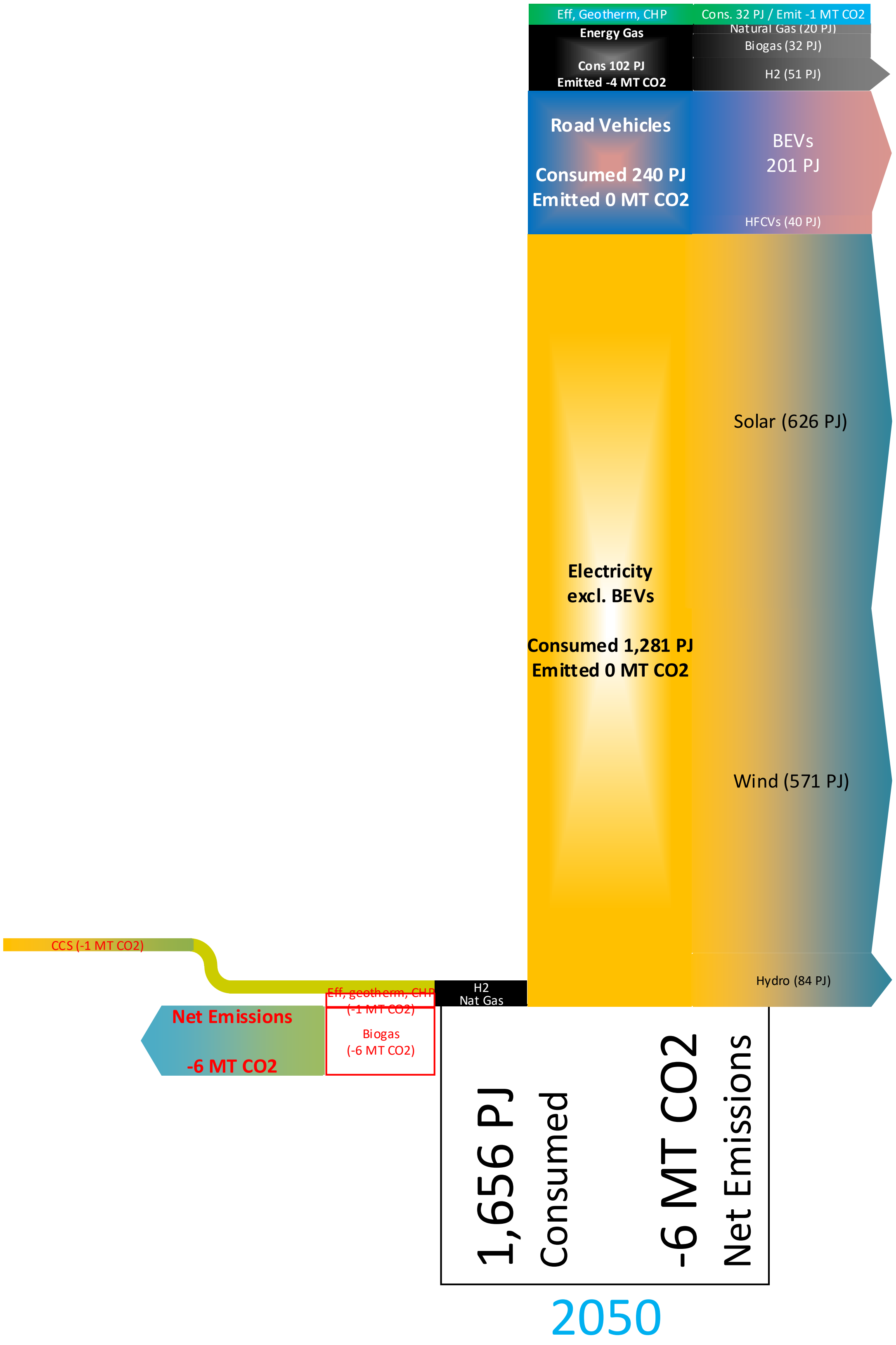


Figure 37: Scenario B – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).



4.1.1 Forecast Demand for Electricity & Hydrocarbon Fuels

The forecast demand for electricity and hydrocarbon fuels was defined for Scenario B, recorded in Table 62 and used as key input to the GHG Tool.

Given the study scope excludes some energy sources (eg aviation fuel, LPG, other petroleum liquids) the forecast energy demand for the study will be lower than the overall energy demand for the State of Victoria as defined in Table 18.

Where forecast energy demand for the scope of the study exceeds the overall energy demand for the State of Victoria, then energy export is predicted. For Scenario B energy export is defined.

Table 62: Scenario B - Forecast Demand for Electricity & Hydrocarbon Fuels

		2030	**2040**	**2050**
Total	**PJ**	**1,492**	**1,716**	**1,973**
Grid Elec **(adjust to suit Scenario B)**	PJ	600	945	1,273
Non Elec Energy Gas **(adjust to suit Scenario B)**	PJ	221	150	100
Road Vehicle Fuels (gasoline, diesel)	PJ	217	99	0
Other Energy e.g., Petroleum Liquids, etc **(Excluded from the scope of the analysis)**	PJ	454	522	600

4.1.2 Energy Generation Mix

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each new energy source was categorised using the qualitative scale in Table 57, the energy mix was defined per guidance notes below and results recorded in Table 63, Table 64, and Table 65 (overleaf). When the energy splits were "balanced" with additional loads to match the energy demand forecasts defined in Table 18, the amount of energy for each time period was calculated using the GHG Tool and summarised in Table 61.

Selection Notes

A broad description of the general approach to defining the energy mix required to match Infrastructure Victoria's Scenario Descriptions (Appendix 1) is provided below and should be read in conjunction with the tables that follow. Unless a timeframe is quoted, values stated will refer to an approximate average during the transition. The new energy *generation* sector may not necessarily correspond to the new energy *consumption* sector for instance industrial generation of green Hydrogen may be consumed (partly) by the residential sector.

Natural Gas Replacement Mix (reference Table 63)

- Residential & Commercial Generation
    - This portion of the energy generation mix is very similar to Scenario A.

  - Renewables dominant proportion at least 80% of the mix, only solar (wind & hydro not allocated / consumed)
  - Geothermal not allocated / consumed
  - Energy gases not allocated / consumed
  - Efficiency low proportion growing to 20% of the mix.
- Industrial Generation
  - Renewables high proportion of the mix in 2030 over 80% reducing to approximately 50% in 2050 as biogases and geothermal proportions build.
  - Geothermal low proportion building to almost 10% of the mix over time
  - Energy gas building to 40% of the mix over time, predominantly biogases including combined heat and power, limited green and blue Hydrogen
  - Efficiency low proportion building to almost 5% of the mix over time
- Offsets
  - Offsets were allocated to CCS, predominantly offshore.

Coal Replacement Mix (reference Table 64)

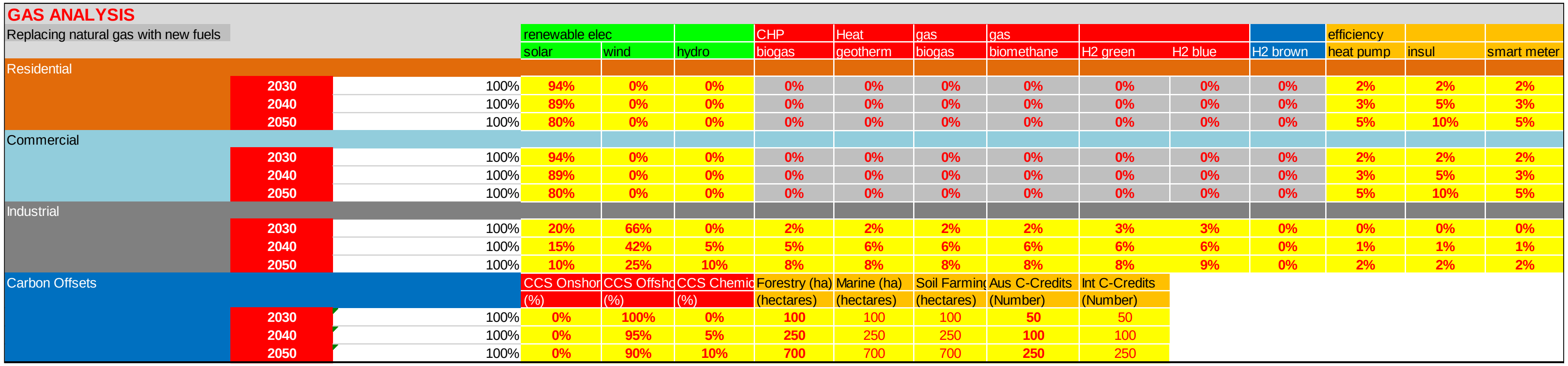
- 100% allocation of energy generation to industrial renewables, predominantly wind.
- Offsets
  - Whilst offsets were allocated to CCS, none were required due to the use of zero emissions energy production (renewables).

Vehicle Hydrocarbon Fuel Replacement Mix (reference Table 65)

- Electricity for BEVs was generated by renewables with 70% allocated to residential & commercial, and the remainder to industrial generation.
- Hydrogen generation for HFCVs was allocated entirely to industrial green Hydrogen.
- Offsets
  - Offsets were allocated to CCS, predominantly offshore.

Table 63: Scenario B – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Natural Gas

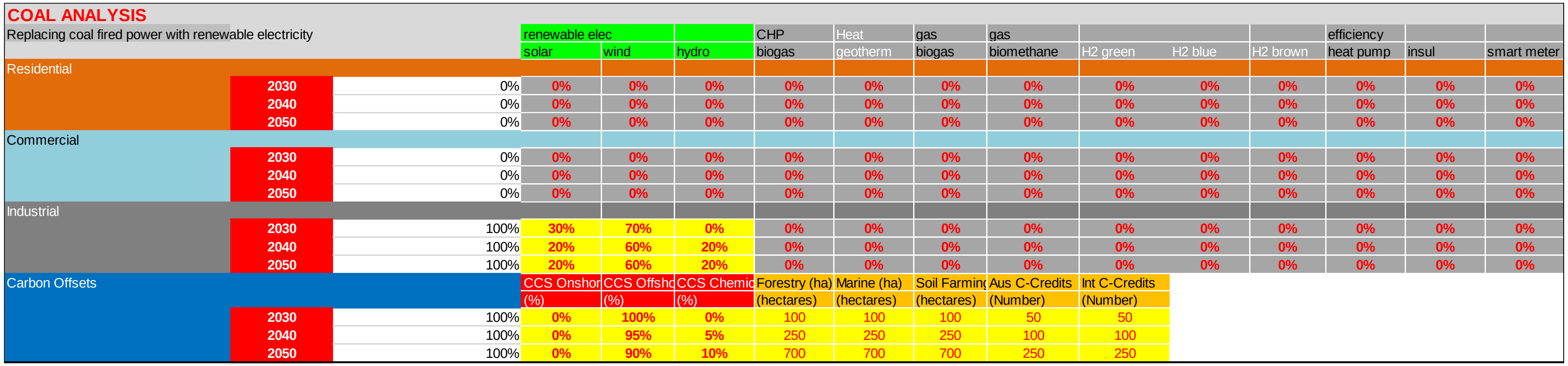
(Yellow fields are active, grey fields are not relevant to the Scenario)



GAS ANALYSIS Replacing natural gas with new fuels			renewable elec			CHP	Heat	gas	gas				efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	100%	94%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
	2040	100%	89%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	3%
	2050	100%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	10%	5%
Commercial															
	2030	100%	94%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
	2040	100%	89%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	3%
	2050	100%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	10%	5%
Industrial															
	2030	100%	20%	66%	0%	2%	2%	2%	2%	3%	3%	0%	0%	0%	0%
	2040	100%	15%	42%	5%	5%	6%	6%	6%	6%	6%	0%	1%	1%	1%
	2050	100%	10%	25%	10%	8%	8%	8%	8%	8%	9%	0%	2%	2%	2%
Carbon Offsets			CCS Onshor (%)	CCS Offsho (%)	CCS Chemic (%)	Forestry (ha) (hectares)	Marine (ha) (hectares)	Soil Farming (hectares)	Aus C-Credits (Number)	Int C-Credits (Number)					
	2030	100%	0%	100%	0%	100	100	100	50	50					
	2040	100%	0%	95%	5%	250	250	250	100	100					
	2050	100%	0%	90%	10%	700	700	700	250	250					

Table 64: Scenario B – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Coal

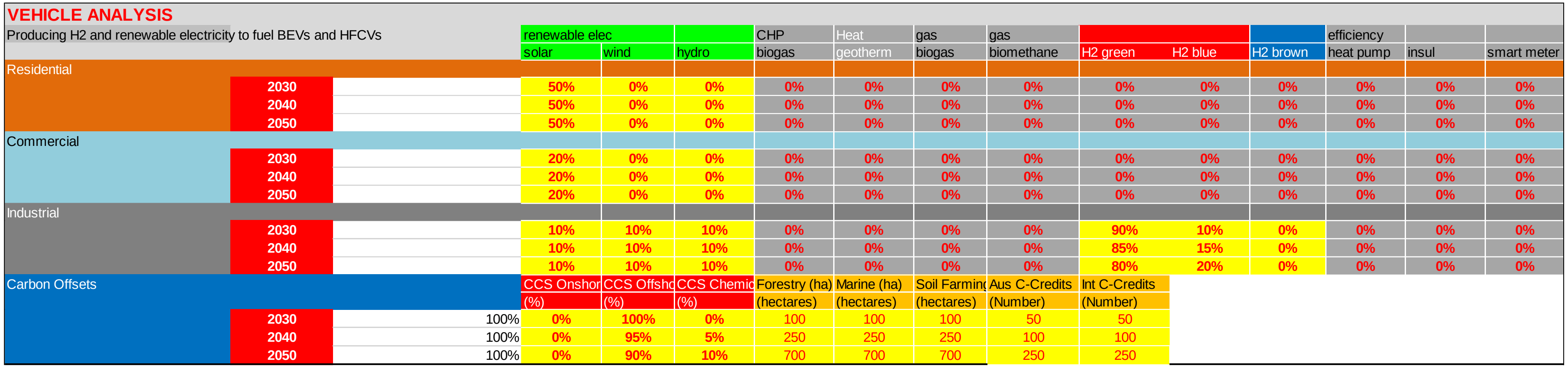
(Yellow fields are active, grey fields are not relevant to the Scenario)



COAL ANALYSIS Replacing coal fired power with renewable electricity			renewable elec			CHP	Heat	gas	gas				efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030	100%	30%	70%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshor (%)	CCS Offsho (%)	CCS Chemic (%)	Forestry (ha) (hectares)	Marine (ha) (hectares)	Soil Farming (hectares)	Aus C-Credits (Number)	Int C-Credits (Number)					
	2030	100%	0%	100%	0%	100	100	100	50	50					
	2040	100%	0%	95%	5%	250	250	250	100	100					
	2050	100%	0%	90%	10%	700	700	700	250	250					

Table 65: Scenario B – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Hydrocarbon Fuels for Road Vehicles

(Yellow fields are active, grey fields are not relevant to the Scenario)



VEHICLE ANALYSIS															
Producing H2 and renewable electricity to fuel BEVs and HFCVs			renewable elec			CHP	Heat	gas	gas				efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030		10%	10%	10%	0%	0%	0%	0%	90%	10%	0%	0%	0%	0%
	2040		10%	10%	10%	0%	0%	0%	0%	85%	15%	0%	0%	0%	0%
	2050		10%	10%	10%	0%	0%	0%	0%	80%	20%	0%	0%	0%	0%
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credits	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	100%	0%	100%	0%	100	100	100	50	50					
	2040	100%	0%	95%	5%	250	250	250	100	100					
	2050	100%	0%	90%	10%	700	700	700	250	250					

4.1.3 Carbon Emissions

The Carbon emissions associated with energy consumption was calculated in the GHG Tool based on the emissions factors listed in Table 22, with results summarised for each time period in Table 61.

4.1.4 Carbon Offsets

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each Carbon offset mechanism was defined and documented in Table 59 and the split of Carbon offset mechanisms necessary to abate emissions associated with energy production was defined and recorded in Table 63, Table 64, and Table 65.

The amount of Carbon offsets were adjusted over time to provide a schedule of net emissions reaching zero by 2050. These calculations were undertaken in the GHG Tool and the results summarised in Table 61.

4.1.5 Energy Storage

Energy storage required to support renewable electricity generation (solar and wind) was calculated in the GHG Tool using the basis described in Section 2.3.2, and results summarised in Table 61.

4.1.6 Discussion of Results

Scenario B targets a near complete replacement of natural gas and total replacement of coal relying primarily on the adoption of renewables, with a contribution from:

- Biogas
- Hydrogen (green)

Limited Carbon offsets are provided using CCS and agro-forestry.

A comparison of the energy-emissions-offset results for Scenario B against the other scenarios identified the following observations:

- Achieves Net Zero slightly before 2050 given the relatively high proportion of zero emissions electricity generation in the energy mix.
- Similar energy-emissions-offset profile to Scenario A.
- Whilst the estimated Carbon emissions levels for Scenarios A and B are higher than Scenario C (approximately twice in 2030), they are an order of magnitude lower than Scenario D (six times less in 2030 and even more so as the transition continues).
- Retains relatively small level of natural gas beyond transition (20 PJ in 2050) to provide electricity peaking coverage to firm variable renewable power, and support hard to abate manufacturing.

Potential refinements to Scenario B could include:

- Confirm the source of natural gas to satisfy residual demand beyond the transition for hard to abate users and potentially also blue Hydrogen in the event it is introduced into Scenario B. Likely candidates may include Victorian natural gas production (based on new discoveries of economic reserves), LNG import (for example through the proposed Viva facility), or inter-state supply via the existing natural gas network.
- Optimise the phasing and blending of Hydrogen / natural gas / biogas.
- Optimise the location of biogas production facilities (including biomethane) versus demand (users) with due consideration of feedstock logistics and energy regionalisation objectives.
- Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
    - Increase the utilisation of gas infrastructure
    - reduce overall Carbon emissions

4.2 Spatial Analysis

4.2.1 Electrical

The number of renewable energy installations and type allocated per region is indicated in Table 66 below. These have been allocated as per the methodology described in Section 2.3 and balanced to minimise the impact on the transmission system for the demand flow case. The increased requirement for renewable energy for each of the time horizons is shown in Figure 21 for 2030, Figure 22 for 2040, and Figure 23 for 2050. The technical modelling includes for additional transmission capacity and storage to cover generator downtime, short-term peaking demand, and night or poor weather conditions. The figures have been produced for comparison purposes only and demonstrate the significant increase in renewable installations over the time zones. For clarity, the storage requirements are not shown on the spatial schematics. Every solar farm includes battery storage locally and additional hydro installations have been allowed for in the estimate as storage for areas serviced by wind turbines. It is assumed these are located in V1. The comparison of storage requirements for each scenario is covered in section 3.4. The amount of additional natural gas in Scenario B compared to Scenario A is very small and therefore the electrical consumption in Scenario B is only marginally lower than in Scenario A.

Table 66Scenario B Allocation of Renewable Energy

Year	Renewable Energy	V1 Ovens Murray	V2 Murray River	V3 Western Victoria	V4 South West Victoria	V5 Gippsland Note 1	V6 Central North Victoria
2030	Hydro	12					
	Solar		250				47

	Onshore Wind			80	50	81	
	Offshore Wind					1	
2040	Hydro	31					
	Solar		500				156
	Onshore Wind			150	122	100	
	Offshore Wind					1	
2050	Hydro	55					
	Solar		663				166
	Onshore Wind			188	159	196	
	Offshore Wind					3	

Note 1 Although the map taken from the AEMO website indicates a relatively small Renewable Zone for V5 the DEWLP plan extends zone 5 to cover the Latrobe valley past Hazlewood.

The main difference between the two scenarios is that in Scenario B a larger percentage of the renewable wind has been allocated to Renewable Energy Zone V5. This provides a better infill for use of the electrical infrastructure from the renewable zone V5 along the transmission system into Melbourne. However, the scenario spatial analysis still identifies the need to augment the 220kv transmission section from renewable zone V2 in 2040 and further augmentation in 2050. The scenario analysis also identifies congestion in additional transmission lines from the Shepparton area and from regional zone V3 in 2050. No augmentation from V4 is indicated probably due to the better balancing of energy from V5 and Scenario B modifications are expected to be slightly less than Scenario A.

Similar to Scenario A the transmission lines from Renewable Zone V1 to Melbourne need uprating in 2030 due to location of the hydro storage in this zone. This transmission line would need significant upgrade by 2040, and further upgrade by 2050. The magnitude of uprated is the same as Scenario A.

As per Scenario A there is significant generation capacity in the regional zones V2 and V3 which would be underutilised and similar issues with the number of connections to the grid. Refer discussion on Scenario A for a comparison of the electrical upgrades for Scenario B.

Figure 38: Scenario B – Electrical Spatial Analysis (2030)

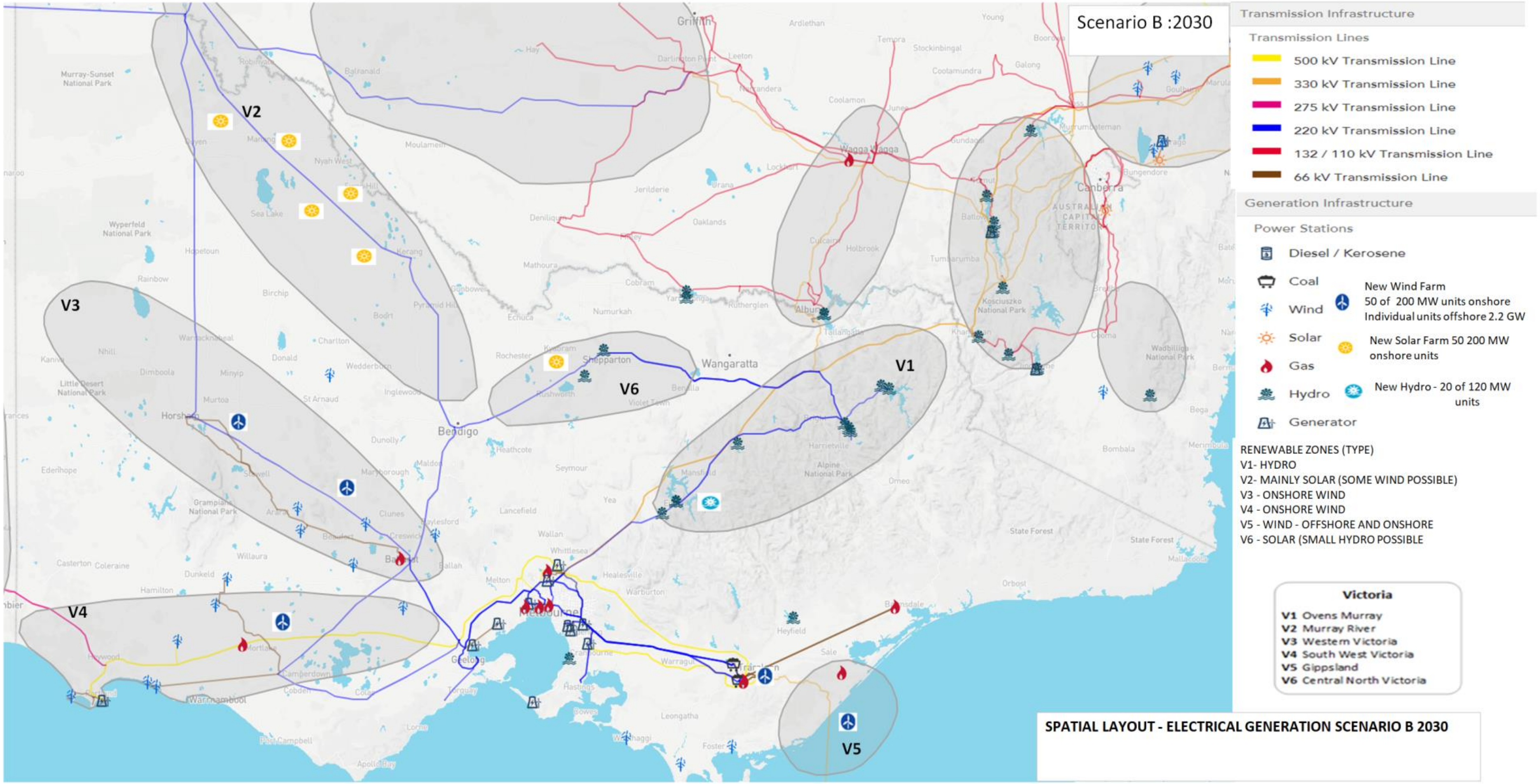


Figure 39: Scenario B – Electrical Spatial Analysis (2040)

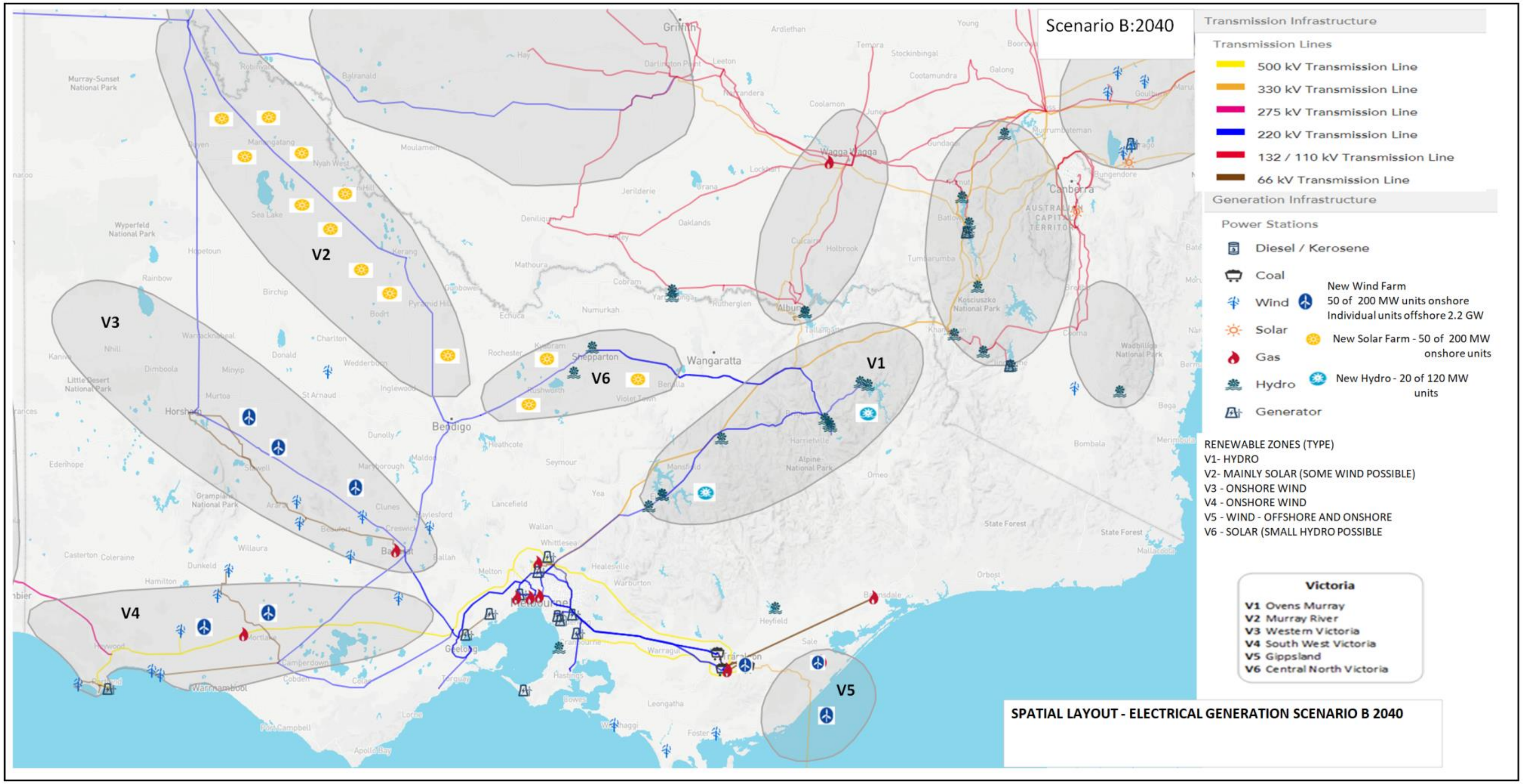
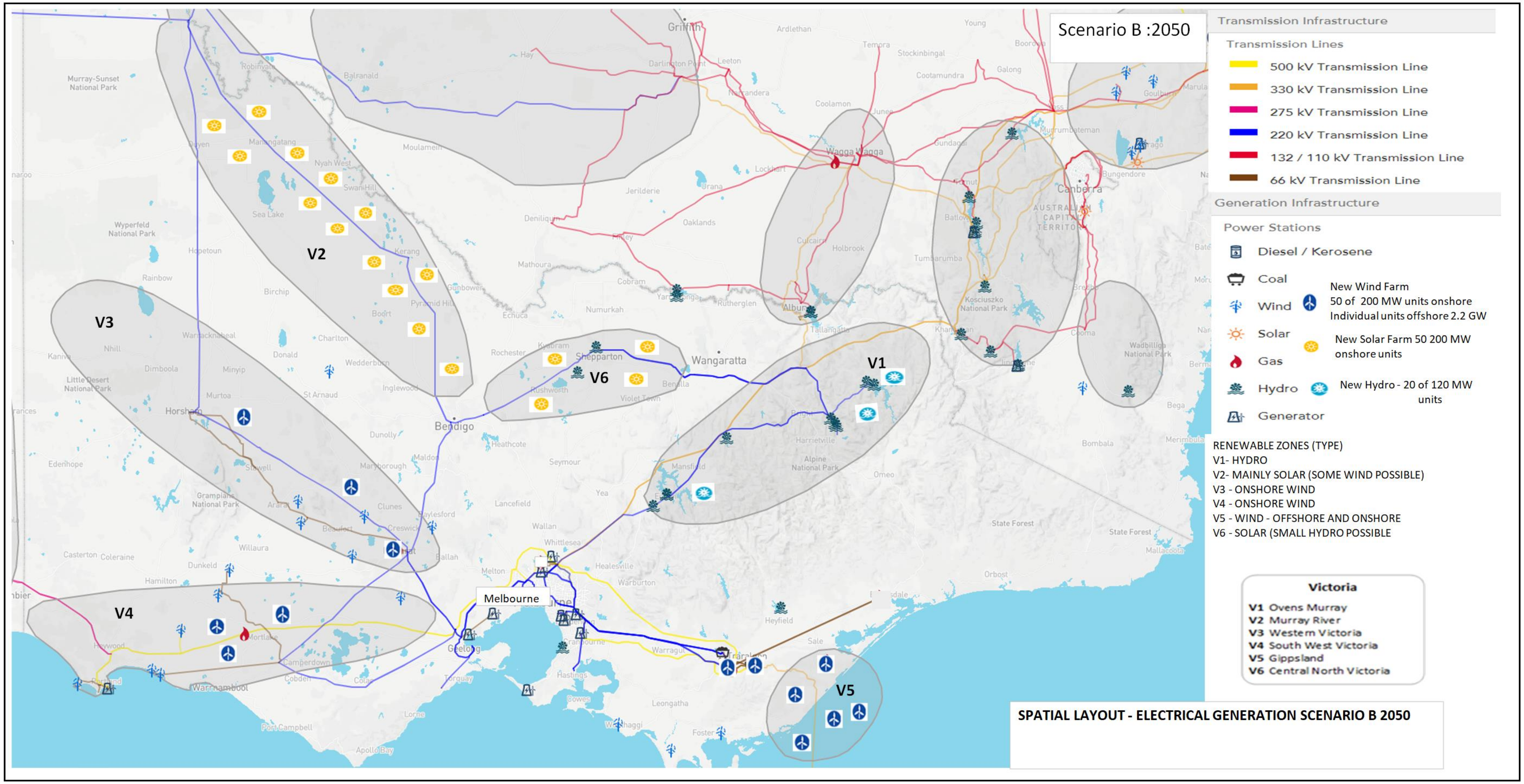


Figure 40: Scenario B – Electrical Spatial Analysis (2050)



4.2.2 Gas

For Scenario B it has been assumed that the natural gas usage will remain similar to today's usage in 2030, while the Esso Longford Facility is still in operation, but drop off to less than half in 2040 and again to a nominal amount in 2050 to service hard to abate users. It is anticipated that one of the Otway gas plants and the Iona storage facility will still be operational in 2050. The scenario is supported by the production of bio-gas to be injected into the existing infrastructure and the production of a small amount of blue hydrogen and increasing amounts of green hydrogen.

In 2030 indicated in Figure 41 the bio-gas facility will be located in an urban location close to the high energy demand and industrial zone close to Qenos or Laverton, dependent on land availability. No major infrastructure changes are needed but in or prior to 2030 modifications to adapt users to hydrogen ready distribution piping and supply should commence to facilitate the switch over by 2040. The 2030 hydrogen facilities have been located at sites already announced in the press as likely hydrogen plants i.e., at the Viva Energy Hub close to Geelong and at Loy Yang in the Latrobe valley. The hydrogen concentration is below 10% and can be injected into the existing infrastructure.

In 2040 indicated by Figure 42 significant additional hydrogen facilities will be installed and most of these have been located along the coastal areas close to wind farms. The number required means several will need to be in land due to anticipated land constraints along the coast. These should be located near a water source as the process to produce green hydrogen using electrolysis can consume between 9 – 40 Kgs of water for every ton of hydrogen produced. The water consumption depends on the quality of the feedwater and the amount of treatment required to produce electrolyser feed quality. The collection and transmission infrastructure around the coast and Renewable Energy Zone V4 will need to be replaced by a hydrogen network. It is anticipated that a phase transition occurs with slow decommissioning of the existing gas infrastructure while a new hydrogen network is built. Table 67 and Table 68 indicate the phasing of decommissioning of existing infrastructure and installation of the hydrogen network. The new hydrogen network can be smaller than the existing gas infrastructure and a capacity factor of 40% has been applied. Similar to Scenario A it is assumed the northern part of the natural gas infrastructure is decommissioned first and that the infrastructure with access to the existing gas plants (both Otway and Gippsland side basins) and the potential Viva LNG terminal are available for as long as possible. Capacity from the Viva LNG Terminal has not been used in the gas capacity depletion profile but the future infrastructure plans should take into account expected project life for current proposed projects.

The new bio-gas plants are installed in the northern part of the Victorian Transmission System to maximise the use of the existing gas infrastructure.

Table 67 Scenario B Decommissioning of Gas Infrastructure

Scenario B	**2030**	**2040**	**2050**
Transmission	0 (0%)	2347 km (50%)	4224 km (90%)

Distribution	5833 (20%)	17499 km (60%)	26249 km (90%)

In 2050, shown by Figure 43, further hydrogen generation is added. The scenario is based on these facilities being built with their own renewable energy production local to minimise impact on the grid. Further analysis is required to confirm suitable locations and land areas are available to service the required level of hydrogen production required to be installed. Careful consideration of user location may improve the ability to use more of the existing infrastructure for longer but in current scenario the use of the existing natural gas infrastructure is less than Scenario A.

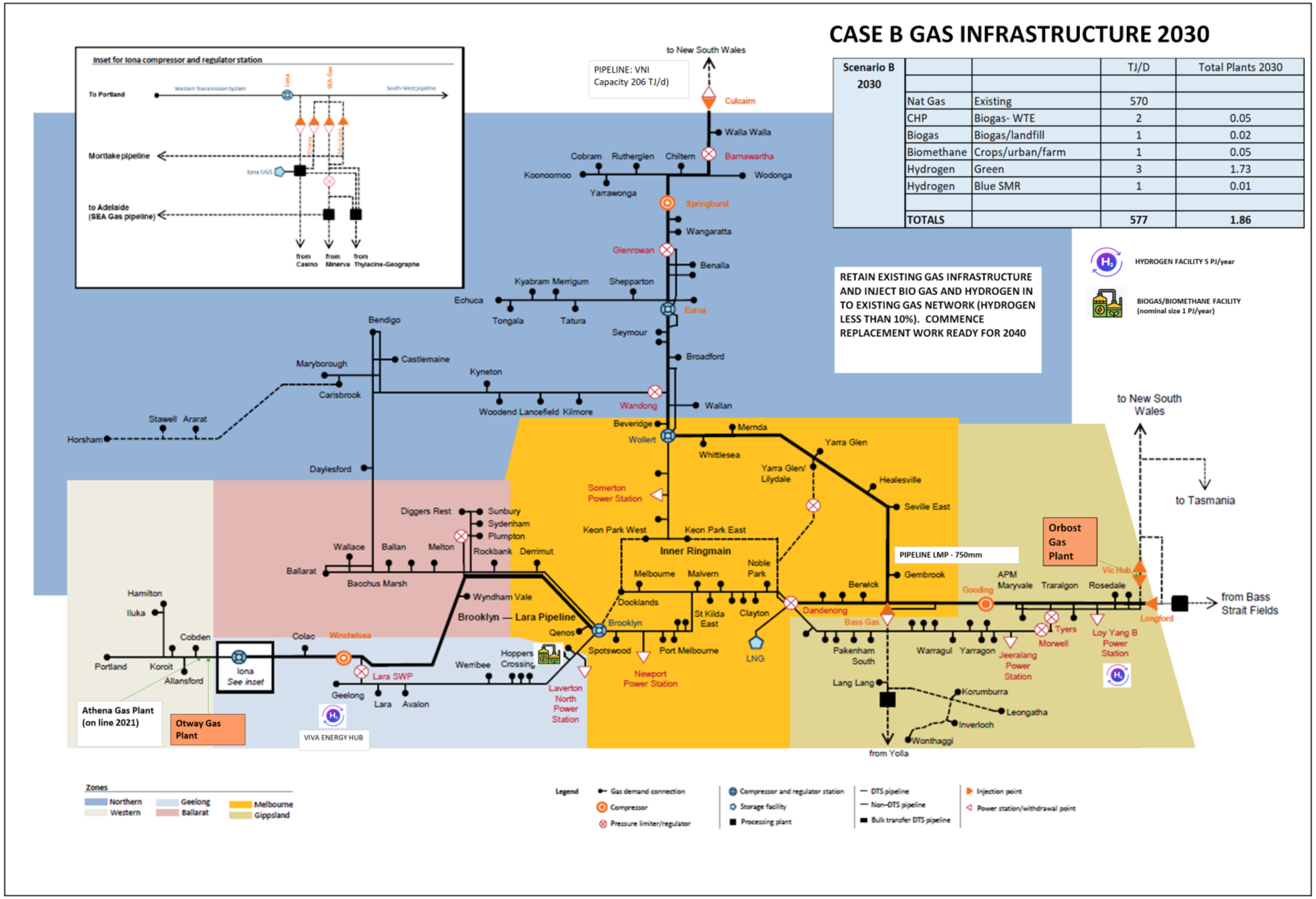
There has been very limited use of bio-gas in this scenario. It could be improved by reviewing the quantity of bio-gas and operation of the gas plants to facilitate a more gradual and phased switch over of the currently installed gas infrastructure to a new hydrogen network.

Table 68 Scenario B Installation of Hydrogen Pipelines

Scenario B	2030	2040	2050
Transmission	0 kms	2346 kms	4694 kms
Distribution	2346 kms	3520 kms	4694 kms

Refer to Scenario A for comparison of Scenario B against the other scenarios.

Figure 41: Scenario B - Gas Spatial Analysis Scenario 2030

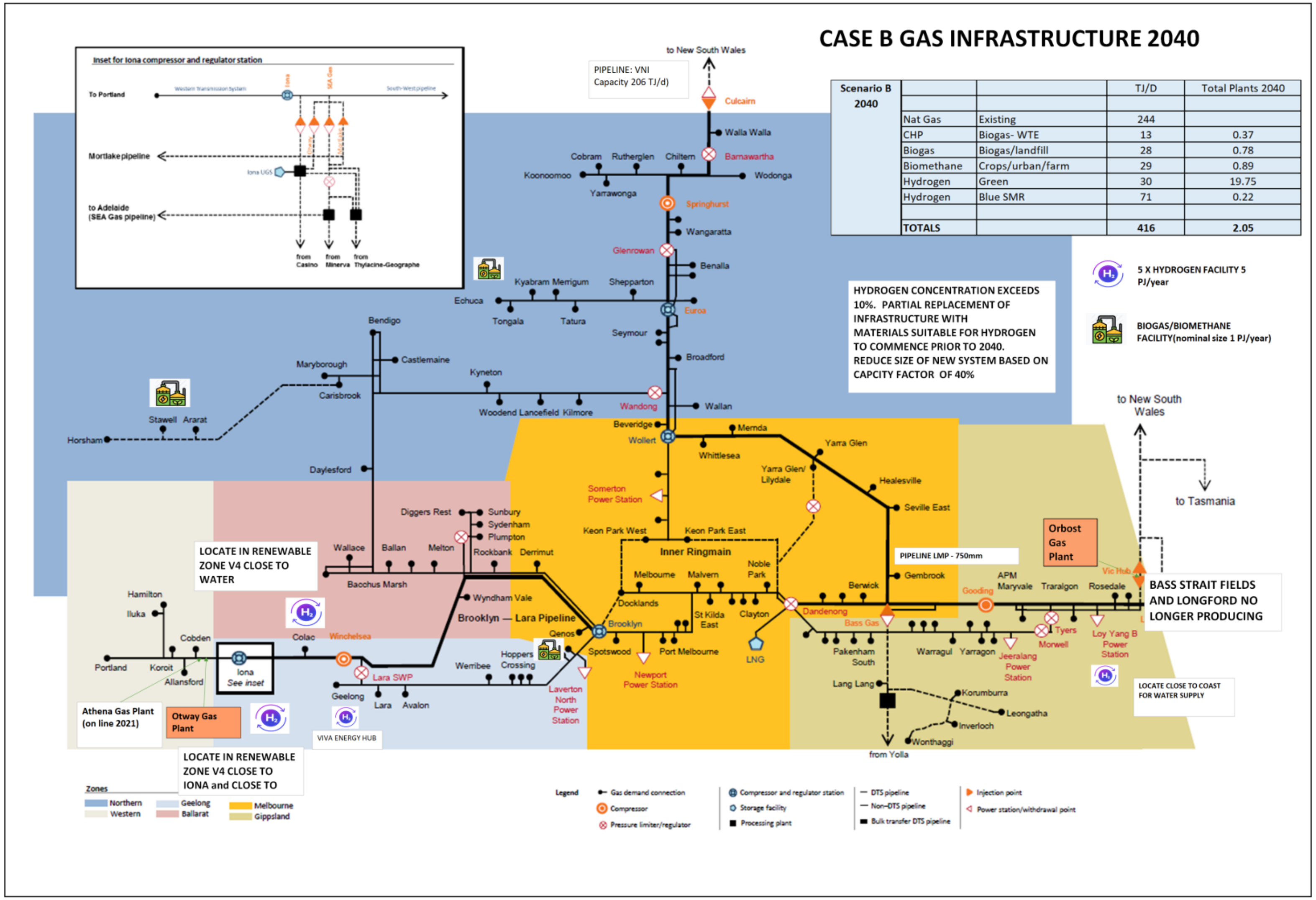


CASE B GAS INFRASTRUCTURE 2030

Scenario B 2030			TJ/D	Total Plants 2030
	Nat Gas	Existing	570	
	CHP	Biogas- WTE	2	0.05
	Biogas	Biogas/landfill	1	0.02
	Biomethane	Crops/urban/farm	1	0.05
	Hydrogen	Green	3	1.73
	Hydrogen	Blue SMR	1	0.01
	TOTALS		**577**	**1.86**

RETAIN EXISTING GAS INFRASTRUCTURE AND INJECT BIO GAS AND HYDROGEN IN TO EXISTING GAS NETWORK (HYDROGEN LESS THAN 10%). COMMENCE REPLACEMENT WORK READY FOR 2040

Figure 42: Scenario B - Gas Spatial Analysis 2040



CASE B GAS INFRASTRUCTURE 2040

Scenario B 2040			TJ/D	Total Plants 2040
	Nat Gas	Existing	244	
	CHP	Biogas- WTE	13	0.37
	Biogas	Biogas/landfill	28	0.78
	Biomethane	Crops/urban/farm	29	0.89
	Hydrogen	Green	30	19.75
	Hydrogen	Blue SMR	71	0.22
	TOTALS		**416**	**2.05**

HYDROGEN CONCENTRATION EXCEEDS 10%. PARTIAL REPLACEMENT OF INFRASTRUCTURE WITH MATERIALS SUITABLE FOR HYDROGEN TO COMMENCE PRIOR TO 2040. REDUCE SIZE OF NEW SYSTEM BASED ON CAPCITY FACTOR OF 40%

5 X HYDROGEN FACILITY 5 PJ/year

BIOGAS/BIOMETHANE FACILITY(nominal size 1 PJ/year)

PIPELINE: VNI Capacity 206 TJ/d)

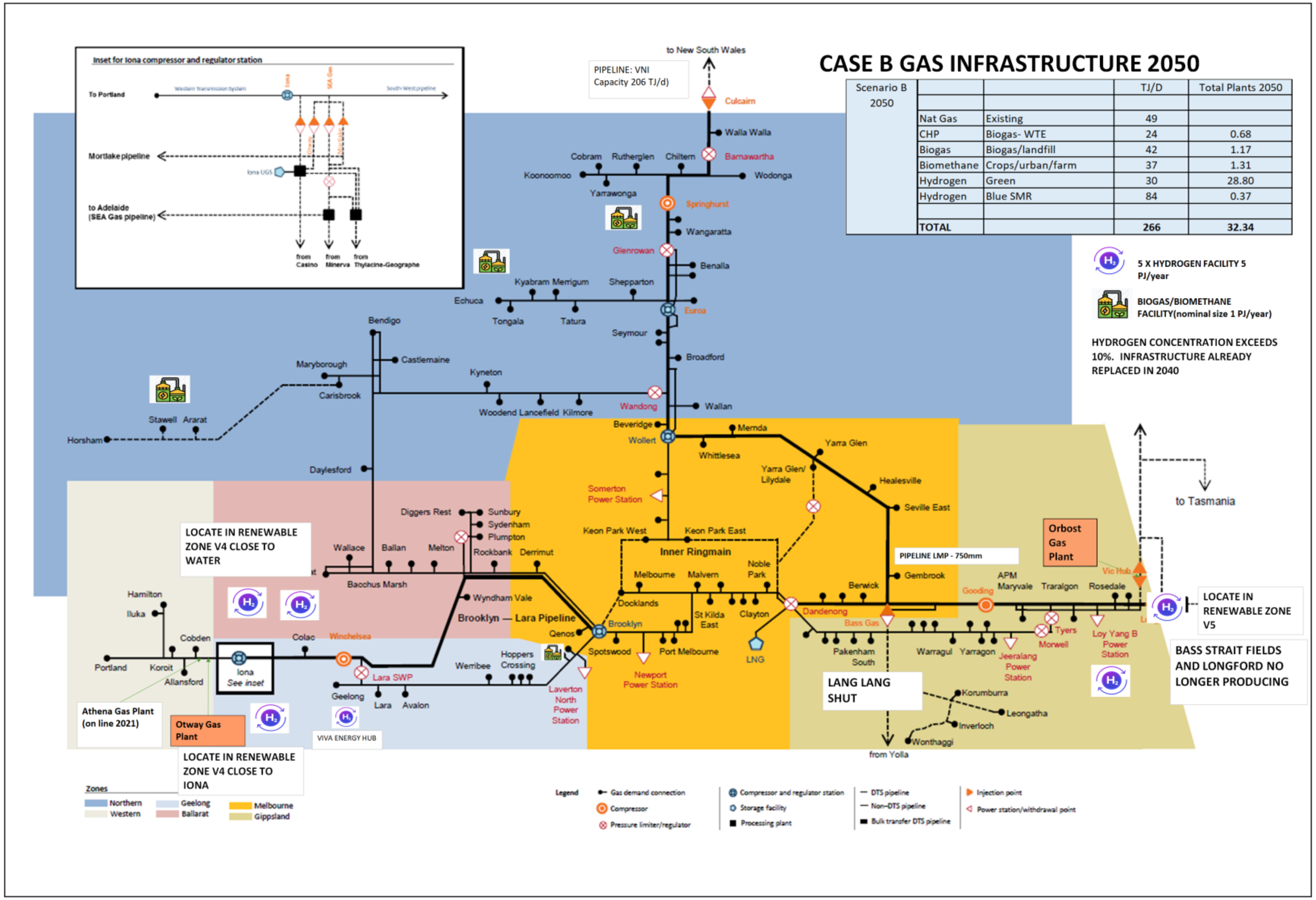
LOCATE IN RENEWABLE ZONE V4 CLOSE TO WATER

LOCATE IN RENEWABLE ZONE V4 CLOSE TO IONA and CLOSE TO

LOCATE CLOSE TO COAST FOR WATER SUPPLY

BASS STRAIT FIELDS AND LONGFORD NO LONGER PRODUCING

Figure 43: Scenario B – Gas Spatial Analysis (2050)



CASE B GAS INFRASTRUCTURE 2050

Scenario B 2050			TJ/D	Total Plants 2050
	Nat Gas	Existing	49	
	CHP	Biogas- WTE	24	0.68
	Biogas	Biogas/landfill	42	1.17
	Biomethane	Crops/urban/farm	37	1.31
	Hydrogen	Green	30	28.80
	Hydrogen	Blue SMR	84	0.37
	TOTAL		**266**	**32.34**

5 X HYDROGEN FACILITY 5 PJ/year

BIOGAS/BIOMETHANE FACILITY(nominal size 1 PJ/year)

HYDROGEN CONCENTRATION EXCEEDS 10%. INFRASTRUCTURE ALREADY REPLACED IN 2040

LOCATE IN RENEWABLE ZONE V4 CLOSE TO WATER

LOCATE IN RENEWABLE ZONE V4 CLOSE TO IONA

LOCATE IN RENEWABLE ZONE V5

BASS STRAIT FIELDS AND LONGFORD NO LONGER PRODUCING

LANG LANG SHUT

PIPELINE: VNI Capacity 206 TJ/d)

PIPELINE LMP - 750mm

Athena Gas Plant (on line 2021)

4.3 Renewable Electricity

Scenario B has the second highest uptake of solar power of the 4 scenarios. Figure 44 shows the number of residential and commercial units are illustrated, showing that both Scenario A and B meet Victoria's Climate Change Strategy Target of 778,500 homes and 15,000 businesses having solar installations. Whilst Scenario B has a similar profile to Scenario A, it does not include 100% renewable electricity and will have more pilotable energy (hydro + gas) than Scenario A. For this reason, it is expected that less storage would be needed.

Figure 44: Percentage of Solar Generated Energy Consumed

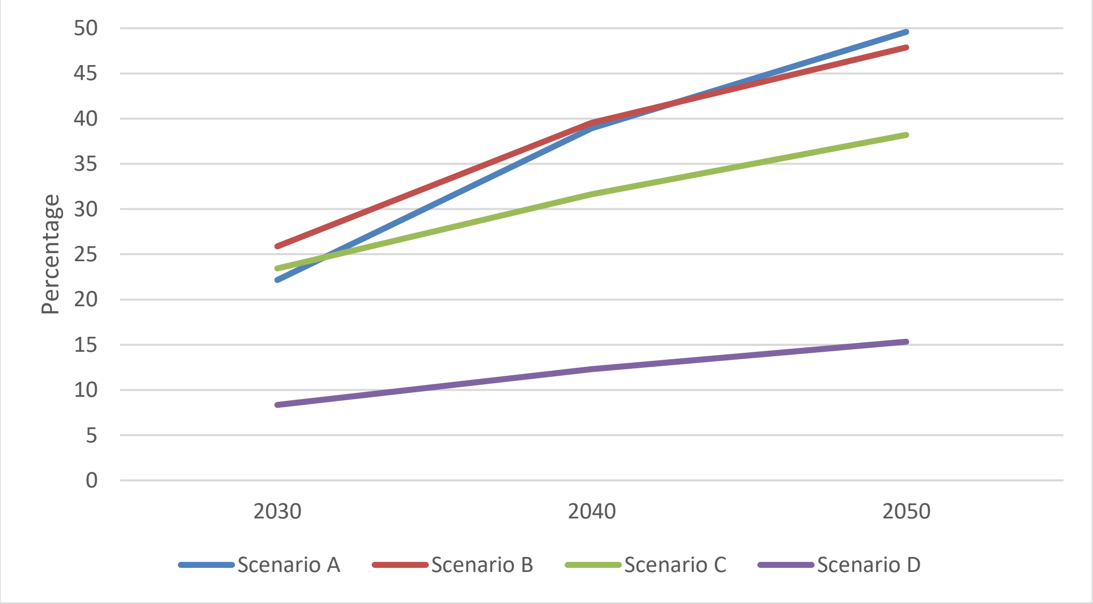
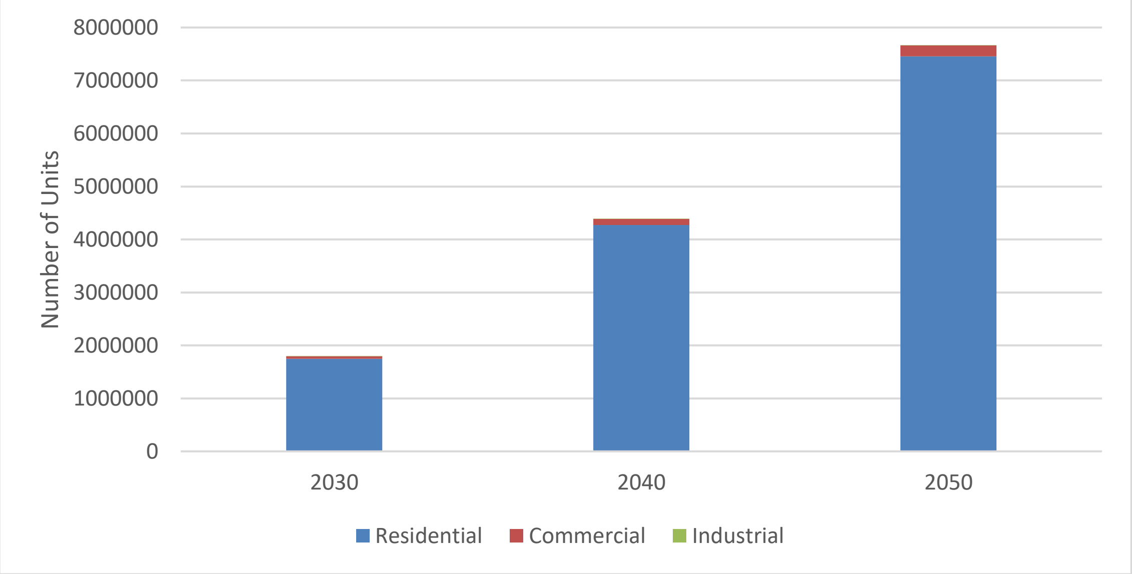
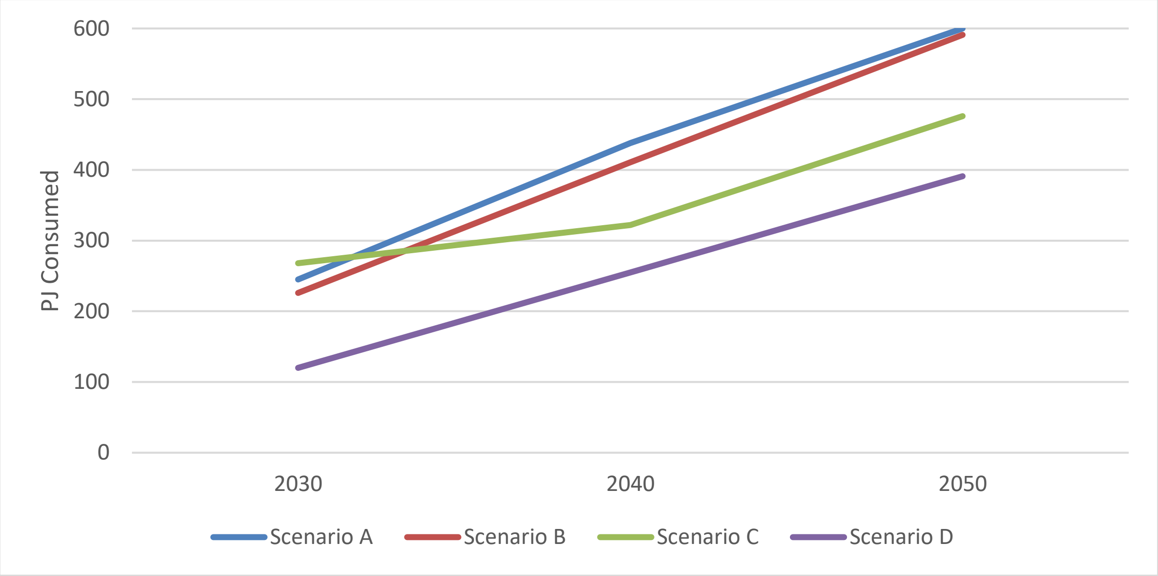


Figure 45: Number of Solar Unit Required for Scenario B



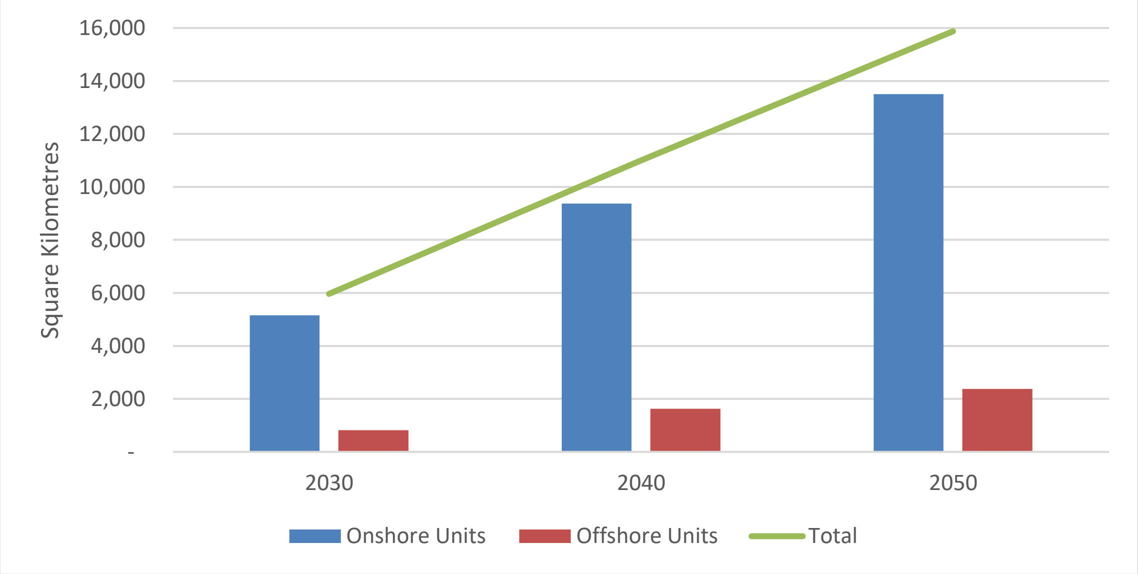
Wind generated electricity is the second highest in Scenario B, behind Scenario A, as shown in Figure 46.

Figure 46: Wind Generated Power Consumption



The total land required for Scenario B's wind farms is approximately 6% of Victoria's total land mass, and this is shown in Figure 47.

Figure 47: Land Requirement for Wind Generated Power for Scenario B



4.4 Natural Gas

Scenario B targets a near complete replacement of natural gas and total replacement of coal relying primarily on the adoption of renewables, with a contribution from:

- Biogas

- Hydrogen (green)

Utilisation of the existing natural gas infrastructure for Scenario B is expected to be limited given it has a low proportion of energy gas. The larger proportion and quicker introduction of Hydrogen in this scenario could actually reduce the use of the existing infrastructure compared Scenario A. Refer to Section 4.7 for discussion on the extent and applications for Hydrogen.

Potential refinements to Scenario B could include:

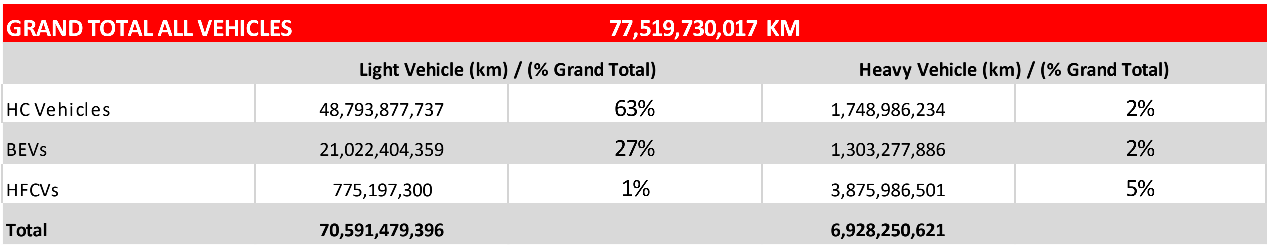
- Increase the proportion of biogas (with a subsequent reduction in the proportion of renewables) in order to :
    - Increase the utilisation of gas infrastructure
    - Reduce overall Carbon emissions

4.5 Road Vehicle Fuels

The scale of uptake for BEVs and HFCVs was assessed for Infrastructure Victoria’s description of Scenario B (Appendix 1) and recorded in Table 60. 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.

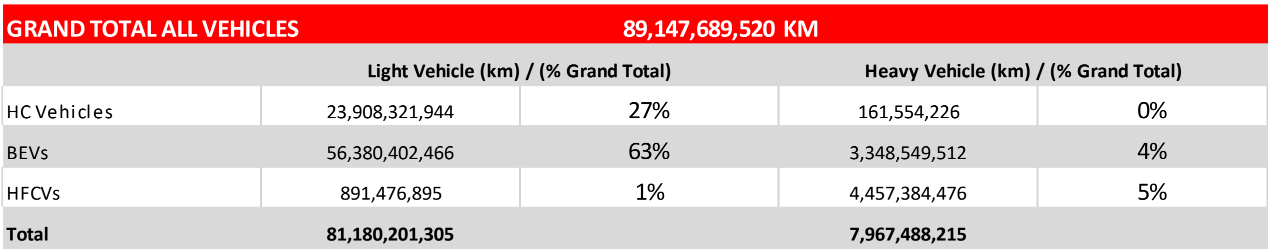
Introduction of HFCVs in accordance with Table 60 causes a pro-rata reduction in the amount of kilometres travelled for both hydrocarbon vehicles and BEVs in order to maintain the overall total kilometres travelled for all road vehicles described in the prior analysis [Reference 8]. The selected split of kilometres travelled by vehicle category and fuel type for Scenario B for the three time periods is defined in Table 69, Table 70 and Table 71.

Table 69: Scenario B (2030) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type



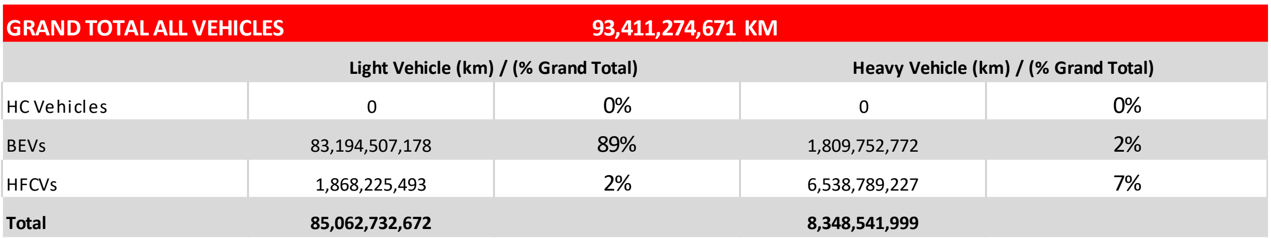
GRAND TOTAL ALL VEHICLES	77,519,730,017 KM			
	Light Vehicle (km) / (% Grand Total)		Heavy Vehicle (km) / (% Grand Total)	
HC Vehicles	48,793,877,737	63%	1,748,986,234	2%
BEVs	21,022,404,359	27%	1,303,277,886	2%
HFCVs	775,197,300	1%	3,875,986,501	5%
Total	**70,591,479,396**		**6,928,250,621**	

Table 70: Scenario B (2040) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type



GRAND TOTAL ALL VEHICLES	89,147,689,520 KM			
	Light Vehicle (km) / (% Grand Total)		Heavy Vehicle (km) / (% Grand Total)	
HC Vehicles	23,908,321,944	27%	161,554,226	0%
BEVs	56,380,402,466	63%	3,348,549,512	4%
HFCVs	891,476,895	1%	4,457,384,476	5%
Total	**81,180,201,305**		**7,967,488,215**	

Table 71: Scenario B (2050) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type



GRAND TOTAL ALL VEHICLES	93,411,274,671 KM			
	Light Vehicle (km) / (% Grand Total)		Heavy Vehicle (km) / (% Grand Total)	
HC Vehicles	0	0%	0	0%
BEVs	83,194,507,178	89%	1,809,752,772	2%
HFCVs	1,868,225,493	2%	6,538,789,227	7%
Total	**85,062,732,672**		**8,348,541,999**	

Based on typical fuel consumption for each type of vehicle, the GHG Tool estimated the fuel requirements, with results provided in Table 72, along with emissions, with results reported in Table 61.

Table 72: Scenario B – Total Fuel Consumption by Road Vehicle Type

Year	**All Road Hydrocarbon Vehicles**	**All Road BEVs**	**All Road HFCVs**
	Gasoline & Diesel (PJ / yr)	**Electricity (PJ / yr)**	**Hydrogen (PJ / yr)**
2030	217	20	23
2040	99	53	27
2050	0	66	40

4.6 Biogas

In Scenario B, the continued use of natural gas reduces the imperative for biogas and biomass and so the quantities of these renewable energy sources are ramped up more slowly than in Scenario A. The total of waste to energy, biogas and biomass ramps slowly reaching 9 PJ/yr in 2050. Similarly, landfill gas and biogas also ramp up slowly reaching 16 PJ/yr in 2050. Biomethane plants are built also at a slower rate than in Scenario A and produce about 16 PJ/yr by 2050. The total from bio-energy sources reaches about 42 PJ/yr in 2050, around 70% of the energy in Scenario A.

4.7 Hydrogen

Scenario B has a small uptake of green and blue hydrogen generation and this is illustrated in Figure 48. In Scenario B, blue hydrogen is used as well, with first production from 2040 of 25 PJ/yr or around 210,000 tpa of hydrogen. This could come from a number of natural gas steam-methane-reforming plants with small-scale CCS or CCUS. If the quantity were to be produced from coal it would require a single 5 mtpa coal to hydrogen plant with CCS in the Latrobe Valley with a similar levelized cost of hydrogen production. Blue hydrogen is assumed to reach 43 PJ/yr by 2050. It is envisaged by this date CCUS or methane pyrolysis technologies could be commercially available and ready to enable blue hydrogen production from natural gas with much lower emissions than current steam methane reforming technologies.

In Scenario B, blue hydrogen is used as well, with first production from 2040 of 25 PJ/yr or around 210,000 tpa of hydrogen. This could come from a number of natural gas steam-methane-reforming plants with small-scale CCS or CCUS. If the quantity were to be produced from coal it would require a single 5 mtpa coal to hydrogen plant with CCS in the Latrobe Valley with a similar levelized cost of hydrogen production. Blue hydrogen is assumed to reach 43 PJ/yr by 2050. It is envisaged by this date CCUS or methane pyrolysis technologies could be commercially available and ready to enable blue hydrogen production from natural gas with much lower emissions than current steam methane reforming technologies.

Figure 48In Scenario B, blue hydrogen is used as well, with first production from 2040 of 25 PJ/yr or around 210,000 tpa of hydrogen. This could come from a number of natural gas steam-methane-reforming plants with small-scale CCS or CCUS. If the quantity were to be produced from coal it would require a single 5 mtpa coal to hydrogen plant with CCS in the Latrobe Valley with a similar levelized cost of hydrogen production. Blue hydrogen is assumed to reach 43 PJ/yr by 2050. It is envisaged by this date CCUS or methane pyrolysis technologies could be commercially available and ready to enable blue hydrogen production from natural gas with much lower emissions than current steam methane reforming technologies.

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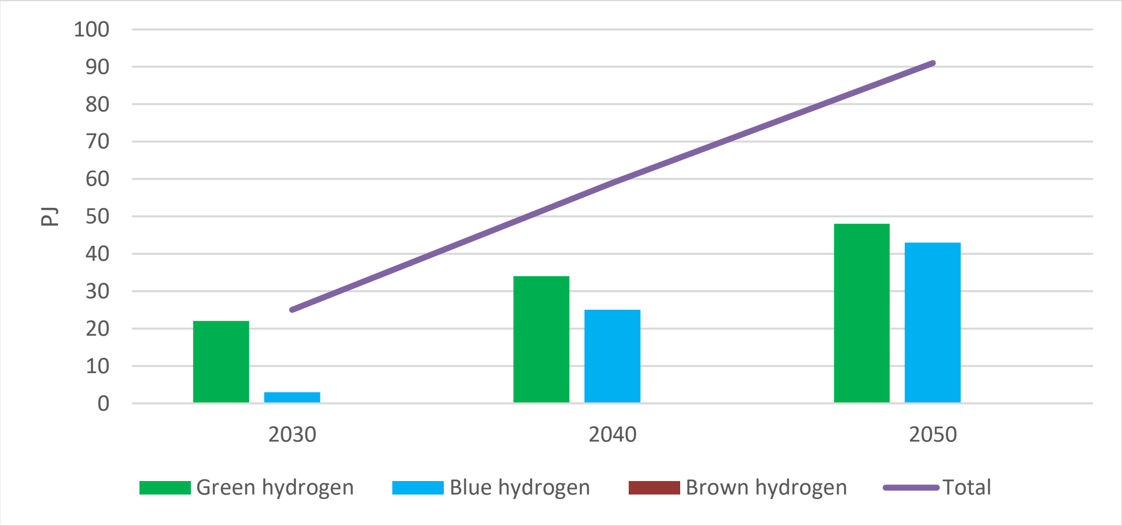
Figure 48: Hydrogen Generation in Scenario B



4.8 Carbon Capture and Storage (CCS)

In Scenario B, some natural gas production and combustion is assumed to continue for peak supply of electricity as well as industrial use. Emissions from gas fired power generation plants and suitable heavy industry are made net zero by CCS and carbon offsets.

In this scenario the amount of CO_2 required to be captured and stored reaches 1.1 Mtpa and would be supported by the initial phase of the CarbonNet project which seeks to establish CO2 storage sites in the nearshore area of the Gippsland Basin to provide permanent and safe storage for 1 to 5 Mt CO2 per year (Mtpa) initially, totalling 25 to 125 Mt of CO2 over a 25 year project life, with expansion to 20 Mtpa of CO_2.

Re-use of gas pipelines for the transport of CO_2 has not been considered by the CarbonNet project and is unlikely to be viable as the CO_2 is transported in the dense phase. The CarbonNet transport system design pressure is 20 MPa which would exceed the maximum allowable operating pressure of the gas transmission system which ranges from 10 to 15 MPa. A significant amount (approx. 40%) of the installed natural gas infrastructure has been in operation for over 50 years. The Longford to Melbourne (Longford to Dandenong) Pipeline located around the CarbonNet transport route was installed in 1971. While it is possible to significantly extend pipeline life with careful management and maintenance this along with the rerating required is unlikely to make re-use a viable option.

4.9 Geothermal Energy

In Scenario B, the widespread uptake of ground source heat pumps (GSHP) is assumed. This technology is covered under energy efficiency.

This scenario also incorporates small scale geothermal heating primarily for commercial use in low density areas as described in Section 2.3.5.

4.10 Energy Efficiency

Scenario B includes moderate-scale energy efficiency improvements including the use of smart meters and smart grids to optimise the use of variable renewable power sources and energy storage systems. Improved insulation standards and energy efficient appliance requirements for new and existing buildings are also imbedded into this scenario. Scenario B also incorporates ground source heat pumps (GSHP) as an energy efficiency measure for both heating and cooling and hot water supply for commercial and industrial users.

The optimum level of residential & commercial energy efficiency improvements corresponding to the lowest overall cost of reliable electricity was not identified. The complex, dynamic and interconnected nature of behind the meter demand on firming grid electricity capacity would need to be considered to determine this optimum energy efficiency level which is beyond the scope of the study. The levels of energy savings calculated by the GHG Tool are sufficiently low as to not be a differentiator between scenarios at the level of accuracy achievable for this analysis.

4.11 Social

Scenario A and Scenario B are broadly similar in terms of the major contributors to the energy mix, and as a result, Social implications are broadly similar. For example, the similar potential for increasing job opportunities associated with the rapid uptake of renewable energy are the same, as can be seen from Table 6. The use of gas fired power for peak demand electricity for this Scenario in addition to hydroelectric power is expected to have relatively lower social impact as land use requirements for hydroelectric are reduced.

4.12 Environmental

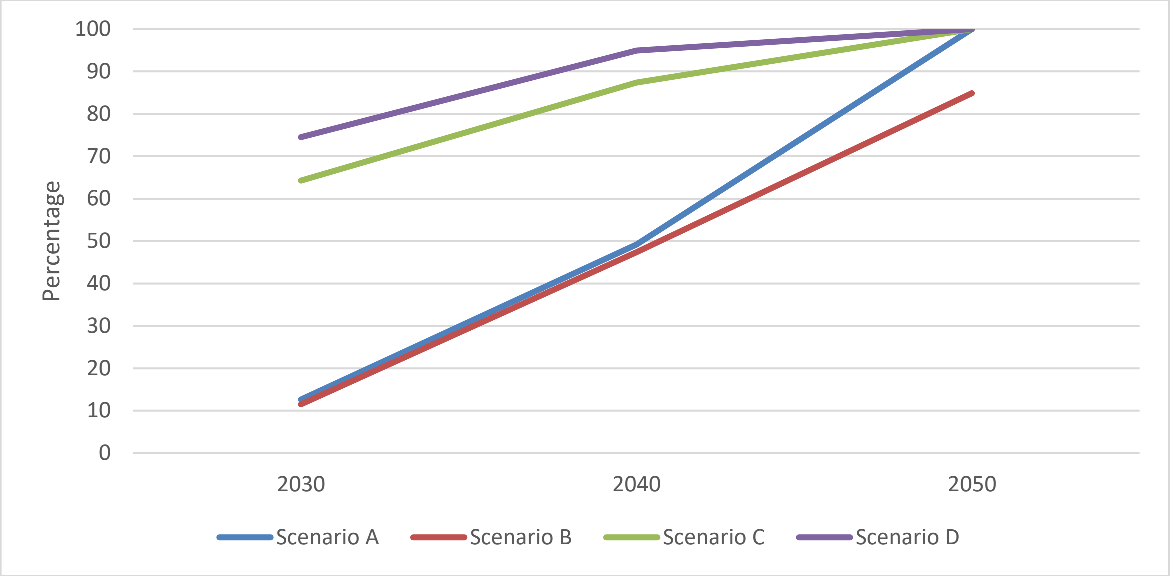
Under Scenario B, Victoria will reach net zero emissions before 2050, as shown in Table 73.

Table 73: Scenario B Greenhouse Gas Emissions

Sector	**2005 Mt CO_2-e**	**2030 Mt CO_2-e**	**Change 2005 to 2030 %**	**2040 Mt CO_2-e**	**Change 2005 to 2040 %**	**2050 Mt CO_2-e**	**Change 2005 to 2050 %**
Electricity generation	67	29	56.7	13	80.6	-1	101.5
Direct combustion	15.2	14	7.9	-2	113.2	-5	132.9
Transport	20.2	15	25.7	7	65.3	0	100.0
Fugitive emissions	2.4	2	16.7	1	58.3	0	100.0
LULUCF (land use, land use change and forestry)	-8.7	0	100.0	0	100.0	0	100.0
Total (net emissions)	**104.8**	**59**	43.7	**22**	79.0	**-6**	105.7

Scenario B is the only option that does not have a complete replacement of gas demand with renewables by 2050. It is projected that by 2050 80% of all gas is replaced with renewables as shown in Figure 49.

Figure 49: Uptake of Renewables to Replace Gas Demand



4.13 Risk & Opportunities

Environment

Scenario B represents a similar electrification approach to Scenario A, except that natural gas is used to provide peak power demand. The use of natural gas in this manner represents a potential risk to the stated aim of reaching net zero. This is because it is expected that 1MT/annum of CO_2 CCS is required by 2050 to reach net zero if natural gas is used. However, in the CarbonNet project, which is undergoing technical assessment for commercial development, these levels of CO_2 production are assumed to be feasible, as the anticipated CO_2 capture rate is predicted to be 5MT/annum.

As the reliance on hydroelectric power is substantially reduced for Scenario B the environmental impact of these plants is less.

Societal

For Scenario B, there are also societal risks associated with resistance to the adoption of new technology. The reduction in the number of hydroelectric power installations, however, reduces the societal risks associated with loss of amenity and perceived environmental impact.

Economics

Scenario B is also susceptible to cost blowouts associated with the installation of the local distribution infrastructure and to pricing pressure due to polysilicon and rare earth material supplies resulting from global demand.

In this scenario, the gas production and pipeline infrastructure utilisation is limited to the supply of peak electricity requirements into the grid using gas fired power generation assets.

This reduces the economic risk associated with the provision of hydroelectric power for peak shaving power generation.

Maintaining an interstate gas network will provide economic benefit to Victoria in addition to providing power supply reliability allowing confidence for businesses to expand.

Similar to Scenario A, the degree of infrastructure required represents a significant amount of installation activity and therefore employment opportunity.

Technical

Scenario B has the least technical risk in terms of reliability of supply in comparison with the other Scenarios. The majority of technical risk is associated with the development of the CarbonNet facility. This is still undergoing technical assessment. CarbonNet is offshore, and Victoria has a long history of offshore drilling and hydrocarbon production, so, should this facility be realised, the ongoing management of the facility is expected to be comparatively low risk technically. It is unlikely that any existing pipeline infrastructure will be useable for CO_2 injection due to the high operating pressure requirements.

In addition, some of the gas pipeline infrastructure is reaching end of life, and its potential for reuse is limited. Over half the Victorian onshore pipeline infrastructure is greater than 40 years old now, and although management of pipeline integrity is an important part of the Victorian pipeline regulations, certainty around the potential use of and development of an ongoing viable gas network is required to give Operators the confidence to replace aging infrastructure, as necessary.

Safety

Safety risks can be categorised broadly similar to Scenario A, in that the numbers of batteries to support home solar systems increases exponentially, and the fire risk and management of this hazard requires careful consideration.

4.14 Comparative Cost Index

The cost estimate for each scenario is presented as a “cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The example of the “comparative cost index” illustrates the general intent and mandate of this study being a comparative analysis of scenarios to identify trends, drivers, risks and opportunities in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050. The development of classed cost estimates for each scenario is beyond the scope of this study.

The comparative cost index for Scenario B was calculated to be 1,1 using the method described in Section 2.2.2, and this value is used as input to the Scenario Screening described in Section 7.

5 SCENARIO C

Scenario C is summarised as "green & blue Hydrogen with offsets / electrification / no gas / no CCS* ". Based on the detailed description provided in Appendix 1 the scale of uptake of new energy, offset mechanisms and new energy road vehicles is defined in the following tables using the qualitative scale in Table 74.

***** Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised.

Table 74: Uptake Scale

🟩	Large upscale / transfer of energy is made to this energy type Large uptake of new energy vehicles
🟧	Medium upscale / transfer of energy is made to this energy type Medium uptake of new energy vehicles
🟥	Small upscale / transfer of energy is made to this energy type Small uptake of new energy vehicles
🟦	No upscale / transfer of energy is made to this energy type No uptake of new energy vehicles

Table 75: Scenario C - Uptake of New Energy

Renewable Elec			**CHP**	**Heat**	**Gas**	**Gas**	**Gas**	**Gas**	**Gas**	**Efficiency**		
🟩 solar	🟩 wind	🟩 hydro	🟥 biogas	🟥 geotherm	🟧 biogas	🟧 biometh.	🟩 H2 green	🟧 H2 blue	🟦 H2 brown	🟧 heat pump	🟧 insul.	🟧 smart grids

Table 76: Scenario C – Uptake of Offset Mechanisms

(Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised)

CCS			**Agro-Forestry**			**Trading**	
🟥 Onshore	🟥 Offshore	🟥 Chemical	🟧 Forestry	🟧 Marine	🟧 Soil	🟧 Aus C-Credit	🟧 Internat. C-Credits

Table 77: Scenario C – Uptake of New Fuel Vehicles

Vehicle	**Vehicle**
🟩 BEV	🟩 HFCV

5.1 Energy-Emissions-Offsets

The energy-emissions-offset flows for each time period for Scenario C demonstrating a path to net zero carbon emissions by 2050 were calculated using the GHG Tool, with results summarised in Table 78.

Schematic representations “Sankey diagrams” of the flows of energy, emissions and offsets leading to the net emissions position for each time frame are provided Figure 50 (overleaf). These illustrations are intended to provide a simplified, graphical representation of the complex, interconnected data provided in Table 78.

It is important to note that both the “Table of Results” and “Sankey Diagrams” present exactly the same set of results, but on a slightly different basis : Table 78 assumes coal on a thermal basis; whilst Figure 50 reports coal on an electrical basis (applying a 30% conversion factor assumed for a typical brown coal power plant) in order to more clearly illustrate the scale of energy flows relating to electricity consumption, emissions and required offsets.

The basis and build-up of these results, along with a discussion thereof is provided in the following sections.

Table 78: Scenario C – Energy-Emissions-Offset Results

(Coal reported on thermal basis)

(Whilst the definition of Scenario C calls for no CCS, the loading was estimated to determine manageability if it were utilised)

Energy Consumed (PJ)	**2030**				**2040**				**2050**			
Overall Demand (Victoria)	**1,492**	**Coal**	**Vehicle**	**Gas**	**1,716**	**Coal**	**Vehicle**	**Gas**	**1,973**	**Coal**	**Vehicle**	**Gas**
Total (Scope of this Study)	**1,841**				**1,678**				**2,098**			
coal	300				150				0			
vehicle fuel (gasoline, diesel)	163				69				0			
natural gas	233				70				0			
solar (replace HC's)	351	13	145	193	449	22	205	222	718	31	320	367
additional solar to balance demand	80				80				80			
wind (replace HCs)	201	30	18	153	255	57	26	172	409	84	40	285
additional wind to balance demand	67				67				67			
hydro (replace HCs)	55	0	18	37	72	9	26	37	124	18	40	66
additional hydro to balance demand	0				0				0			
CHP (WTE / biogas / biomass) (replace HCs)	0	0	0	0	2	0	0	2	5	0	0	5
geothermal (replace HCs)	0	0	0	0	2	0	0	2	5	0	0	5
biogas / landfill gas (replace HCs)	1	0	0	1	8	0	0	8	15	0	0	15
additional biogas / landfill gas to balance gas demand	35				35				80			
biomethane (replace HCs)	18	0	16	3	32	0	16	16	32	0	7	25

additional biomethane to balance gas demand	35				35				80			
green H2 (replace HCs)	43	0	40	3	69	0	54	16	110	0	86	25
additional green H2 to balance gas demand	210				210				360			
blue H2 (replace HCs)	17	0	13	3	34	0	18	16	0	0	0	0
additional blue H2 to balance gas demand	30				30				0			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	1	0	0	1	7	0	0	7	14	0	0	14
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			
Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**28**	**Coal**	**Vehicle**	**Gas**	**-6**	**Coal**	**Vehicle**	**Gas**	**-56**	**Coal**	**Vehicle**	**Gas**
coal	28				14				0			
vehicle fuel (gasoline, diesel)	11				5				0			
natural gas	13				4				0			
fugitive emissions (4% of total HC)	2				1				0			
CO2 (nat gas processing)	1	0	0	1	0	0	0	0	0	0	0	0
solar (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional solar to balance elec demand	0				0				0			
wind (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0

additional wind to balance elec demand	0				0				0			
hydro (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance elec demand	0				0				0			
CHP (WTE / biogas / biomass) (replace HCs)	0	0	0	0	0	0	0	0	-1	0	0	-1
geothermal (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
biogas / landfill gas (replace HCs)	0	0	0	0	-1	0	0	-1	-2	0	0	-2
additional biogas / landfill gas to balance gas demand	-11				-11				-24			
biomethane (replace HCs)	-7	0	-7	0	-9	0	-7	-2	-6	0	-3	-3
additional biomethane to balance gas demand	-11				-11				-24			
green H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional green H2 to balance gas demand	0				0				0			
blue H2 (replace HCs)	1	0	0	0	1	0	1	0	0	0	0	0
additional blue H2 to balance gas demand	1				1				1			
brown H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional brown H2 to balance gas demand	0				0				0			
eff. Improvements (replace HCs)	0				0				0			
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			

Carbon Offsets (Mill Te CO2-e)	**2030**	**2040**	**2050**

Total	**-1**	**Coal**	**Vehicle**	**Gas**	**-2**	**Coal**	**Vehicle**	**Gas**	**-1**	**Coal**	**Vehicle**	**Gas**
CCS	-1	0	0	-1	-2	0	0	-1	-1	0.0	0.0	-1.2
agro-forestry	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
trading	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
Net Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**27**				**-8**				**-57**			
Energy Storage (GWh)	**2030**				**2040**				**2050**			
Total	**194,169**	**Coal**	**Vehicle**	**Gas**	**229,338**	**Coal**	**Vehicle**	**Gas**	**353,807**	**Coal**	**Vehicle**	**Gas**
battery	97,483	3,563	40,415	53,506	117,663	6,063	49,880	61,721	199,414	8,563	88,871	101,980
additional solar to balance demand	22,222				22,222				22,222			
pumped hydro	55,853	8313	5052	42489	70,842	15,813	7,126	47,903	113,560	23313	11109	79138
additional wind to balance demand	18,611				18,611				18,611			
chemical	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance demand	0				0				0			

Figure 50: Scenario C – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

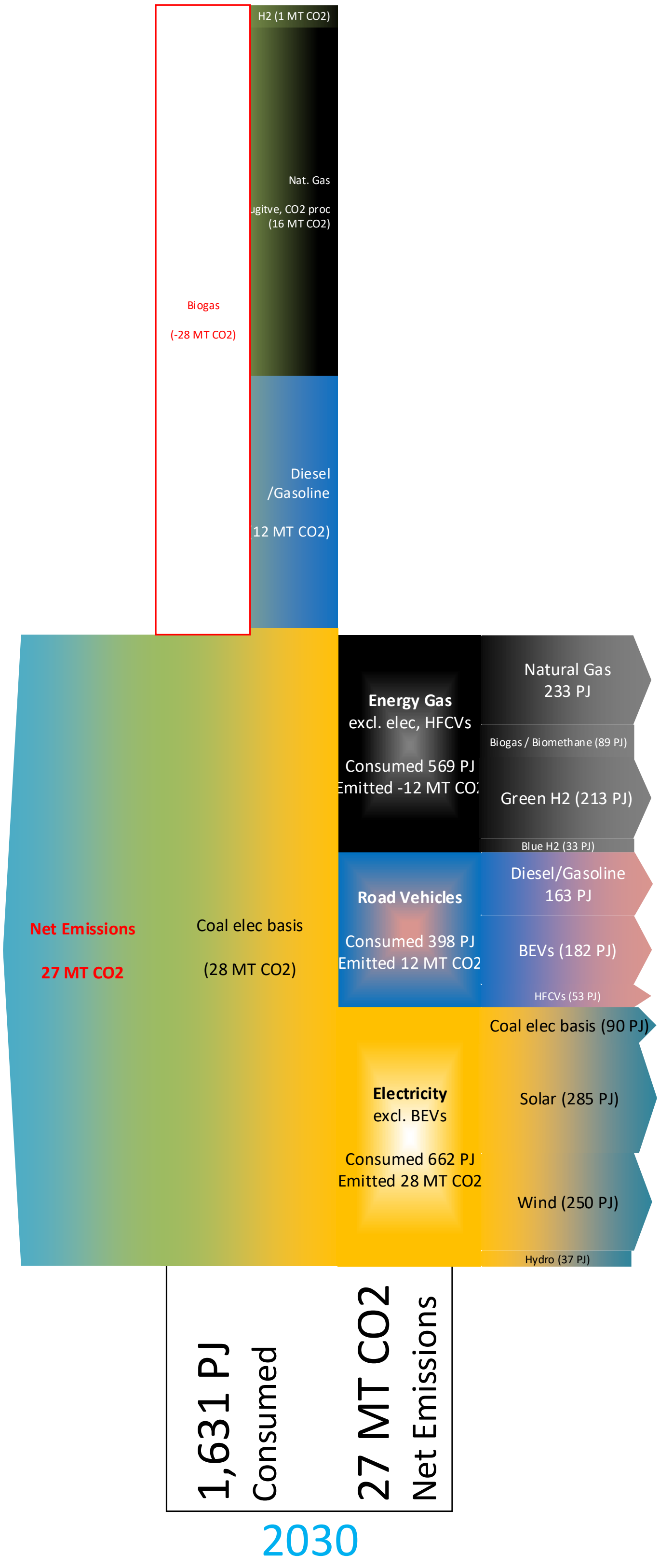


Figure 51: Scenario C – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

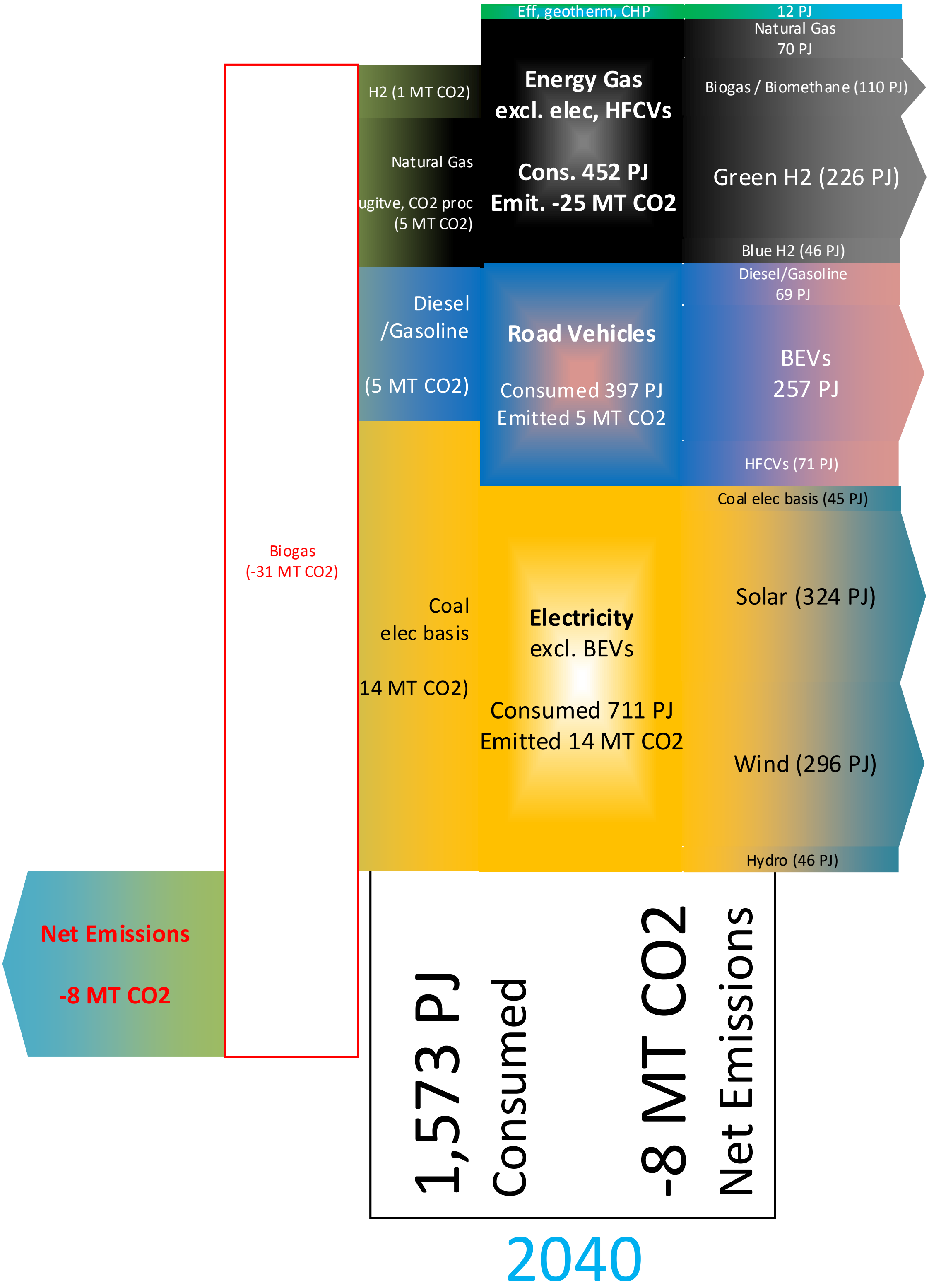
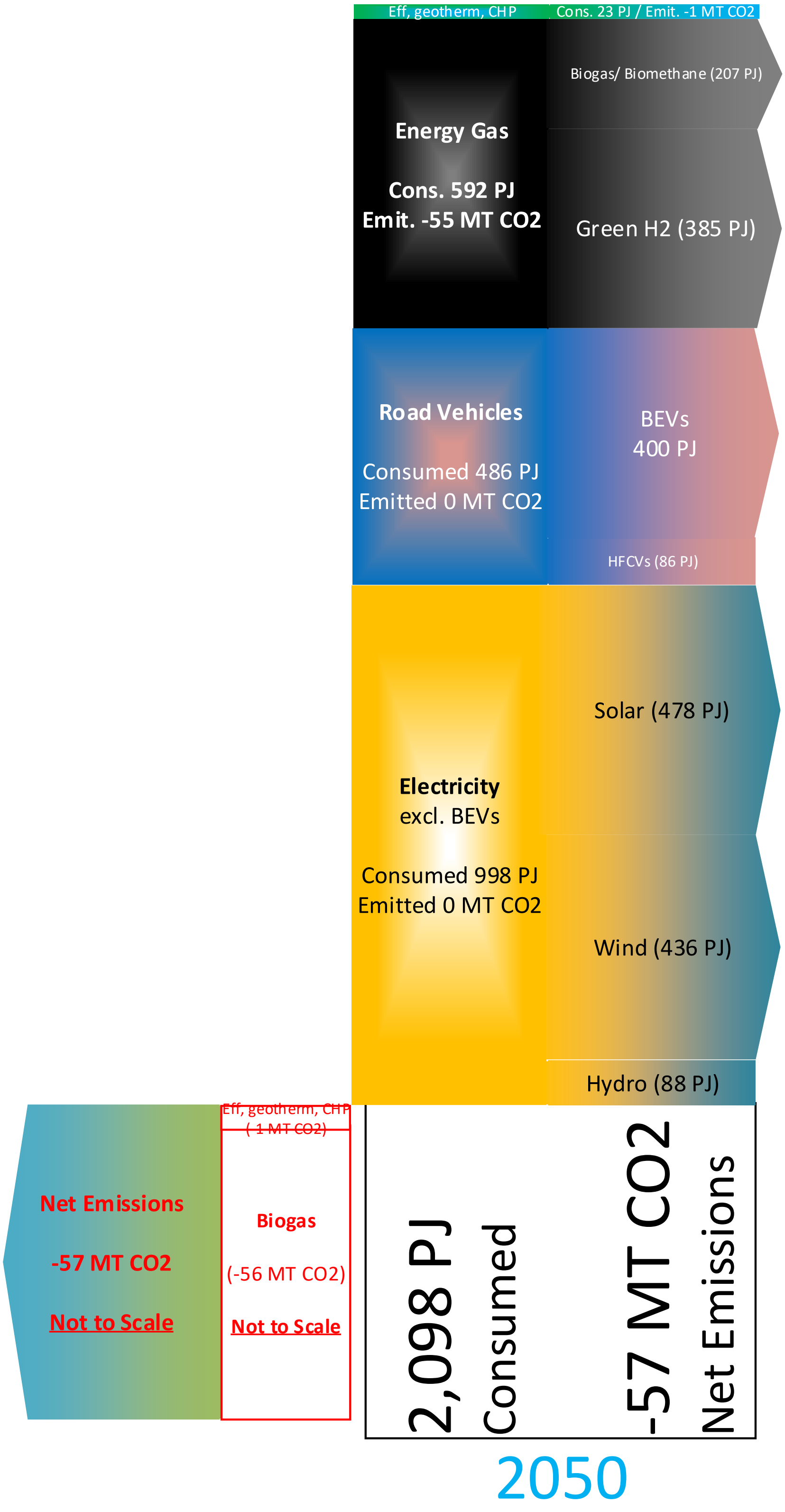


Figure 52: Scenario C – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).



5.1.1 Forecast Demand for Electricity & Hydrocarbon Fuels

The forecast demand for electricity and hydrocarbon fuels was defined for Scenario C, recorded in Table 79 and used as key input to the GHG Tool.

Given the study scope excludes some energy sources (eg aviation fuel, LPG, other petroleum liquids) the forecast energy demand for the study will be lower than the overall energy demand for the State of Victoria as defined in Table 18.

Where forecast energy demand for the scope of the study exceeds the overall energy demand for the State of Victoria, then energy export is predicted. For Scenario C energy export is defined.

Table 79: Scenario C - Forecast Demand for Electricity & Hydrocarbon Fuels

		2030	2040	2050
Total	**PJ**	**1,492**	**1,716**	**1,973**
Grid Elec **(adjust to suit Scenario C)**	PJ	300	700	730
Non Elec Energy Gas **(adjust to suit Scenario C)**	PJ	576	425	643
Road Vehicle Fuels (gasoline, diesel)	PJ	163	69	0
Other Energy e.g., Petroleum Liquids, etc **(Excluded from the scope of the analysis)**	PJ	454	522	600

5.1.2 Energy Generation Mix

Based on Infrastructure Victoria’s Scenario Descriptions (Appendix 1) the scale of uptake for each new energy source was categorised using the qualitative scale in Table 74, the energy mix was defined per guidance notes below and results recorded in Table 80, Table 81 and Table 82 (overleaf). When the energy splits were “balanced” with additional loads to match the energy demand forecasts defined in Table 18 the amount of energy for each time period was calculated using the GHG Tool and summarised in Table 78.

Selection Notes

A broad description of the general approach to defining the energy mix required to match Infrastructure Victoria’s Scenario Descriptions (Appendix 1) is provided below and should be read in conjunction with the tables that follow. Unless a timeframe is quoted, values stated will refer to an approximate average during the transition. The new energy *generation* sector may not necessarily correspond to the new energy *consumption* sector for instance industrial generation of green Hydrogen may be consumed (partly) by the residential sector.

Natural Gas Replacement Mix (reference Table 80)

- Residential & Commercial Generation
  - This portion of the energy generation mix is very similar to Scenario A.

  - Renewables dominant proportion at least 80% of the mix, only solar (wind & hydro not allocated / consumed)
  - Geothermal not allocated / consumed
  - Energy gases not allocated / consumed
  - Efficiency low proportion growing to 20% of the mix over time
- Industrial Generation
  - Renewables high proportion of the mix in 2030 over 70% reducing to approximately 30% in 2050 as biogases and geothermal proportions build.
  - Geothermal low proportion building to 5% of the mix over time
  - Energy gas building to over 50% of the mix over time, predominantly biogases including combined heat and power, and green Hydrogen. Blue Hydrogen 10% of the energy mix in 2030 equivalent to green Hydrogen, however un like green Hydrogen which continues to build, blue Hydrogen declines to 0% in 2050, following the decline of Victorian natural gas production.
  - Efficiency low proportion building to approximately 5% of the mix over time
- Offsets
  - Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised.
  - It was found that the relatively small loading of CCS required for blue Hydrogen had no significant impact on reaching a net zero emission position by 2050 due to the high proportion of zero and negative emissions energy production (renewables and biogases), along with the decline to zero for blue Hydrogen by 2050.

Coal Replacement Mix (reference Table 81)

- 100% allocation of energy generation to industrial renewables, predominantly wind.
- Offsets
  - Whilst offsets were allocated to CCS, none were required due to the use of zero emissions energy production (renewables).

Vehicle Hydrocarbon Fuel Replacement Mix (reference Table 82)

- Electricity for BEVs was generated by renewables with 70% allocated to residential & commercial, and the remainder to industrial generation.
- Hydrogen generation for HFCVs was allocated primarily to industrial green Hydrogen in 2030 climbing to 100% in 2050, with a lower proportion to blue Hydrogen in 2030, declining to 0% in 2050.

- Offsets
  - Despite the use of CCS for blue Hydrogen, it was found that no allocation was necessary to reach a net zero emission position in 2050 due to the high proportion of zero and negative emissions energy production (renewables and biogases), along with the decline to zero for blue Hydrogen by 2050.

Table 80: Scenario C – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Natural Gas

(Yellow fields are active, grey fields are not relevant to the Scenario)

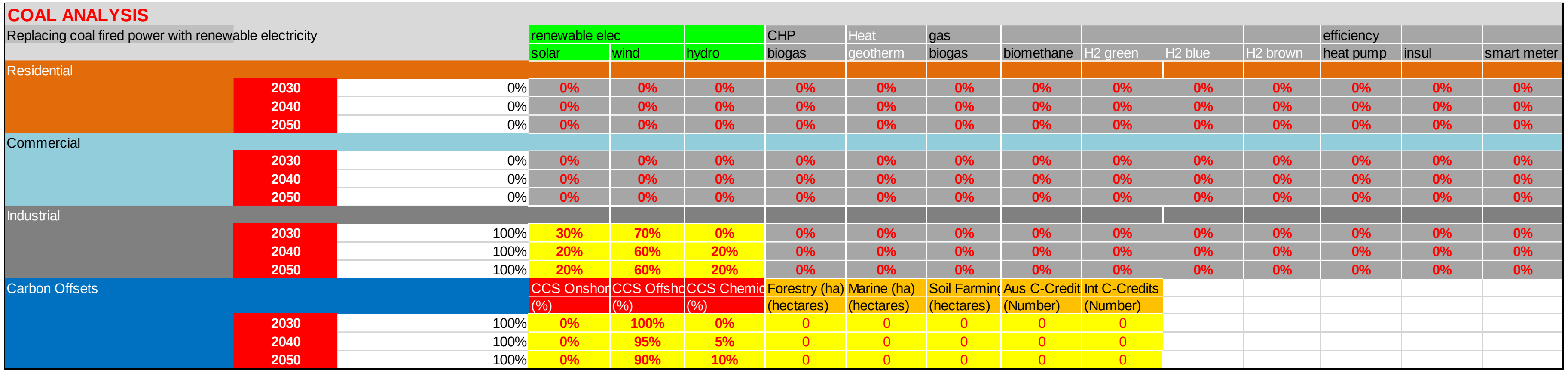
(Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised).

GAS ANALYSIS															
Replacing natural gas with new fuels			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	100%	84%	0%	0%	0%	0%	0%	10%	0%	0%	0%	2%	2%	2%
	2040	100%	79%	0%	0%	0%	0%	0%	10%	0%	0%	0%	3%	5%	3%
	2050	100%	70%	0%	0%	0%	0%	0%	10%	0%	0%	0%	5%	10%	5%
Commercial															
	2030	100%	84%	0%	0%	0%	0%	0%	10%	0%	0%	0%	2%	2%	2%
	2040	100%	79%	0%	0%	0%	0%	0%	10%	0%	0%	0%	3%	5%	3%
	2050	100%	70%	0%	0%	0%	0%	0%	10%	0%	0%	0%	5%	10%	5%
Industrial															
	2030	100%	25%	47%	0%	1%	1%	3%	3%	10%	10%	0%	0%	0%	0%
	2040	100%	15%	35%	5%	2%	2%	7%	7%	12%	12%	0%	1%	1%	1%
	2050	100%	10%	14%	10%	5%	5%	15%	15%	20%	0%	0%	2%	2%	2%
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	100%	0%	100%	0%	0	0	0	0	0					
	2040	100%	0%	95%	5%	0	0	0	0	0					
	2050	100%	0%	90%	10%	0	0	0	0	0					

Table 81: Scenario C – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Coal

(Yellow fields are active, grey fields are not relevant to the Scenario)

(Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised).

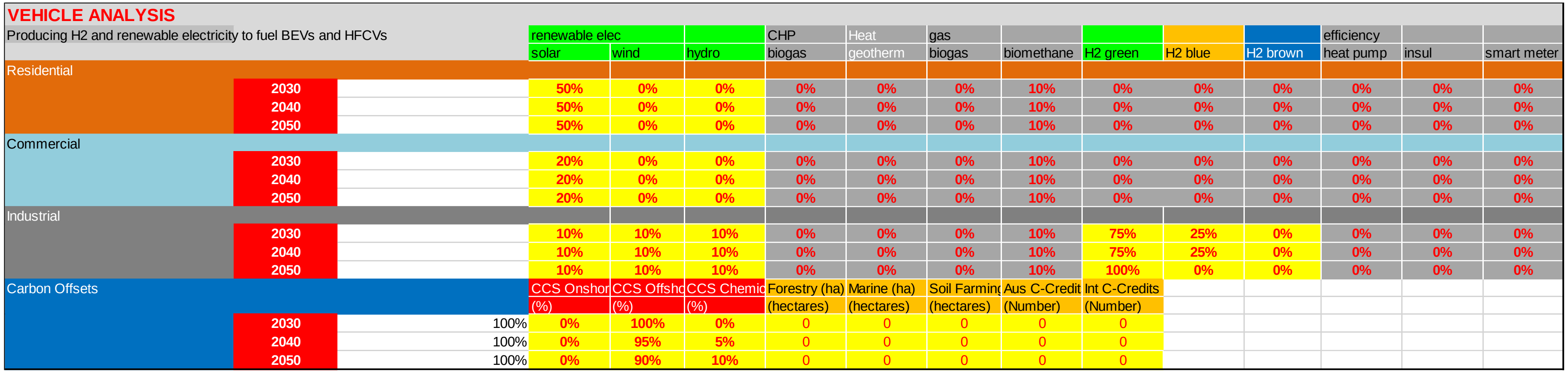


COAL ANALYSIS															
Replacing coal fired power with renewable electricity			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030	100%	30%	70%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshor (%)	CCS Offsho (%)	CCS Chemic (%)	Forestry (ha) (hectares)	Marine (ha) (hectares)	Soil Farming (hectares)	Aus C-Credit (Number)	Int C-Credits (Number)					
	2030	100%	0%	100%	0%	0	0	0	0	0					
	2040	100%	0%	95%	5%	0	0	0	0	0					
	2050	100%	0%	90%	10%	0	0	0	0	0					

Table 82: Scenario C – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Hydrocarbon Fuels for Road Vehicles

(Yellow fields are active, grey fields are not relevant to the Scenario)

(Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised).



VEHICLE ANALYSIS															
Producing H2 and renewable electricity to fuel BEVs and HFCVs			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030		**50%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2040		**50%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2050		**50%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Commercial															
	2030		**20%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2040		**20%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
	2050		**20%**	**0%**	**0%**	**0%**	**0%**	**0%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Industrial															
	2030		**10%**	**10%**	**10%**	**0%**	**0%**	**0%**	**10%**	**75%**	**25%**	**0%**	**0%**	**0%**	**0%**
	2040		**10%**	**10%**	**10%**	**0%**	**0%**	**0%**	**10%**	**75%**	**25%**	**0%**	**0%**	**0%**	**0%**
	2050		**10%**	**10%**	**10%**	**0%**	**0%**	**0%**	**10%**	**100%**	**0%**	**0%**	**0%**	**0%**	**0%**
Carbon Offsets			CCS Onshor	CCS Offsho	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	100%	**0%**	**100%**	**0%**	0	0	0	0	0					
	2040	100%	**0%**	**95%**	**5%**	0	0	0	0	0					
	2050	100%	**0%**	**90%**	**10%**	0	0	0	0	0					

5.1.3 Carbon Emissions

The Carbon emissions associated with energy consumption was calculated in the GHG Tool based on the emissions factors listed in Table 22, with results summarised for each time period in Table 78.

5.1.4 Carbon Offsets

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each Carbon offset mechanism was defined and documented in Table 76 and the split of Carbon offset mechanisms to abate emissions associated with energy production was defined and recorded in Table 80, Table 81 and Table 82.

The amount of Carbon offsets were adjusted over time to provide a schedule of net emissions reaching zero by 2050. These calculations were undertaken in the GHG Tool and the results summarised in Table 78.

5.1.5 Energy Storage

Energy storage required to support renewable electricity generation (solar and wind) was calculated in the GHG Tool using the basis described in Section 2.3.2, and results summarised in Table 78.

5.1.6 Discussion of Results

Scenario C targets a complete replacement of natural gas and coal relying primarily on the balanced adoption of renewable electricity, green Hydrogen and biogas. The adoption of Blue Hydrogen is limited by the availability of Victorian natural gas production, assumed to cease before 2050.

Carbon offsets are available using agro-forestry and emissions trading.

A comparison of the energy-emissions-offset results for Scenario C against the other scenarios identified the following observations:

- Achieves Net Zero significantly earlier than 2050 given the relatively high proportion of zero and negative emissions electricity and gas in the energy mix (renewables and biogas).
- For the reasons described in the prior point, the estimated Carbon emissions levels for Scenario C are much lower than Scenarios A and B (approximately half in 2030), and an order of magnitude lower than Scenario D (thirteen times less in 2030 and even more so as the transition continues).
- Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was calculated to assess manageability if it were utilised. Based on these results the level of CCS that would be required (no more than 2 Mill Te CO_2 per annum) falls within that proposed by the CarbonNet project.
- Most balanced mix of energy sources / least focused on one specific energy source to provide flexibility for adoption of new technologies that may reach

competitive pricing in the future, in addition to providing a level of protection in the event that the necessary scale green Hydrogen production cannot be achieved.

Potential refinements to Scenario C could include:

- Optimise the phasing and blending of biomethane and Hydrogen to maximise the use of existing natural gas infrastructure during the early phases of the transition. A blend of up to 20% Hydrogen in methane (actual value dependent on pipeline pressure) would allow use of existing natural gas infrastructure during the early phases of the transition, offsetting the requirement for purpose-built Hydrogen infrastructure.
- Consider transferring blue Hydrogen production to Scenario B where the supply of natural gas is maintained beyond the transition. When specified in Scenario C the future of blue Hydrogen is tied to the availability of Victorian natural gas (assumed to cease prior to 2050), resulting in the cost of finance for the large capital outlay required to establish the blue Hydrogen industry would likely be significantly higher than that for an equivalent green Hydrogen industry given the uncertain long term outlook for Victorian natural gas production, and limited time horizon for return on investment.
- Noting that the speed at which Net Zero Carbon emissions can be achieved in Scenario C is determined to a large degree by the uptake of biogas, it is proposed to increase the level of natural gas during the early phases of the transition to slow the deployment of biogas resulting in more time to introduce the logistics required for biogas (for example biomass supply chains) and thereby improve the economics of Scenario C whilst still achieving Net Zero Carbon Emissions prior to 2050.

5.2 Spatial Analysis

5.2.1 Electrical

The number of renewable energy installations and type allocated per region is indicated in Table 83 below. These have been allocated as per the methodology described in Section 2.3 and balanced to minimise the impact on the transmission system for the demand flow case. The increased requirement for renewable energy for each of the time horizons is shown in Figure 21 for 2030, Figure 22 for 2040, and Figure 23 for 2050. The technical modelling includes for additional transmission capacity and storage to cover generator downtime, short-term peaking demand, and night or poor weather conditions. The figures have been produced for comparison purposes only and demonstrate the increase in renewable installations over the time zones. For clarity, the storage requirements are not shown on the spatial schematics. Every solar farm includes battery storage locally and additional hydro installations have been allowed for in the estimate as storage for areas serviced by wind turbines. It is assumed these are located in V1. The comparison of storage requirements for each scenario is covered in section 3.4.

The amount of green and blue hydrogen introduced into Scenario C compared to Scenario A significantly reduces the electrical consumption. The electricity requirement to produce green hydrogen is assumed to be largely produced by renewable energy facilities associated with the hydrogen production to avoid impacting the transmission system. This assumption needs to be confirmed once suitable land has been identified for the hydrogen facilities.

The analysis still indicates some transmission augmentation for the section from Renewable Energy Zone V2 to Melbourne from 2040 and augmentation of the transmission line from Renewable Energy Zone V1 to draw from storage during peak demand or poor wind days from 2030. The augmentation from V2 is approximately half that identified for Scenario A and the augmentation of the transmission lines from V1 is approximately 60% of that for Scenario A. The scenario still indicates significant under-utilisation of the infrastructure from Renewable Energy Zone V5 and underutilisation of renewable energy in Zones V2 and V3.

Table 83 Scenario C Renewable Installations by REZ

Year	Renewable Energy	V1 Ovens Murray	V2 Murray River	V3 Western Victoria	V4 South West Victoria	V5 Gippsland Note 1	V6 Central North Victoria
2030	Hydro	16					
	Solar		253				63
	Onshore Wind			100	100	35	
	Offshore Wind					3	
2040	Hydro	42					
	Solar		288				71
	Onshore Wind			100	100	52	
	Offshore Wind					3	
2050	Hydro	67					
	Solar		439				110
	Onshore Wind			140	134	77	
	Offshore Wind					3	

Refer to Scenario A for a comparison of Scenario C against other scenarios.

Figure 53: Scenario C – Electrical Spatial Analysis (2030)

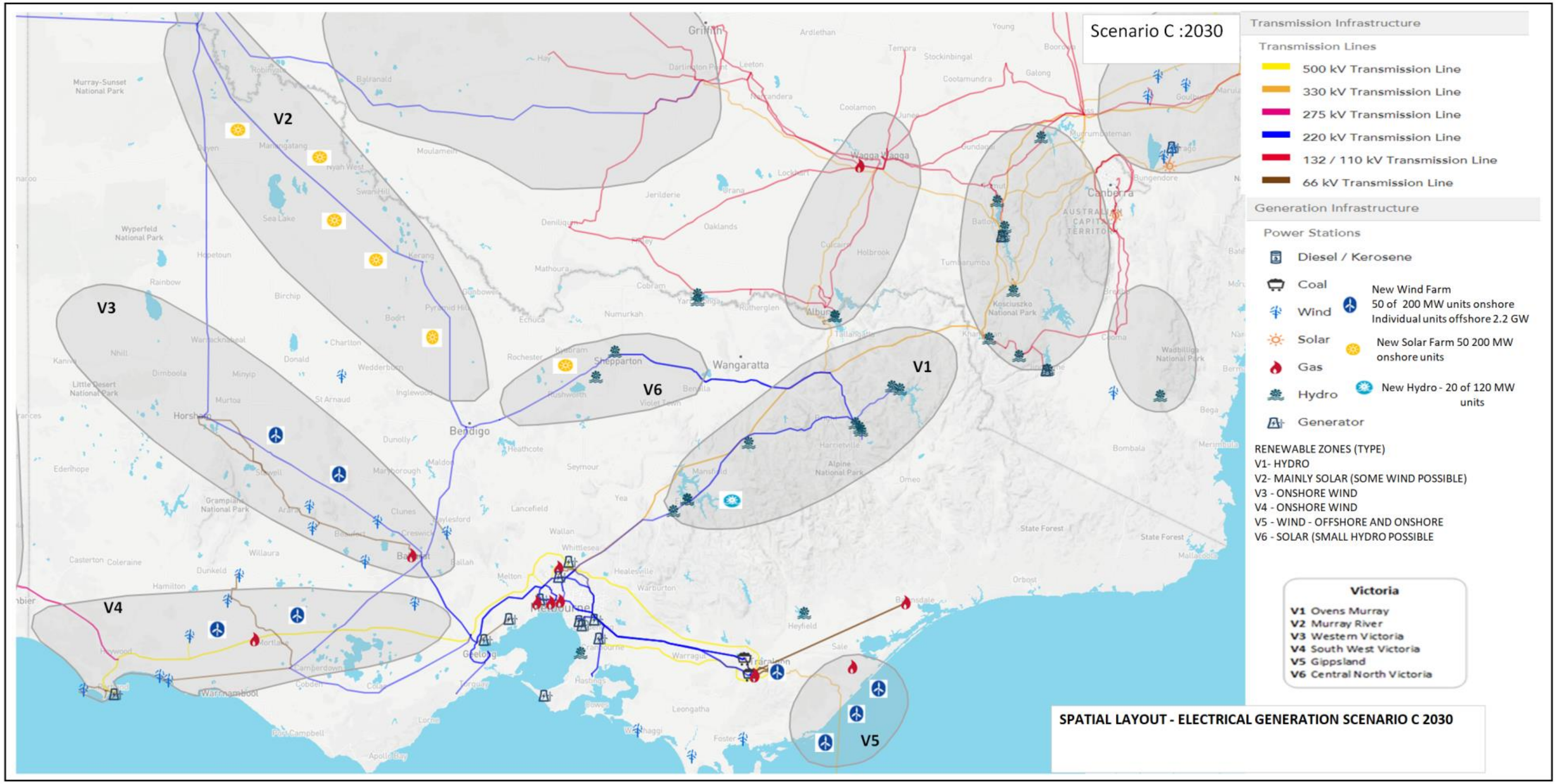


Figure 54: Scenario C – Electrical Spatial Analysis (2040)

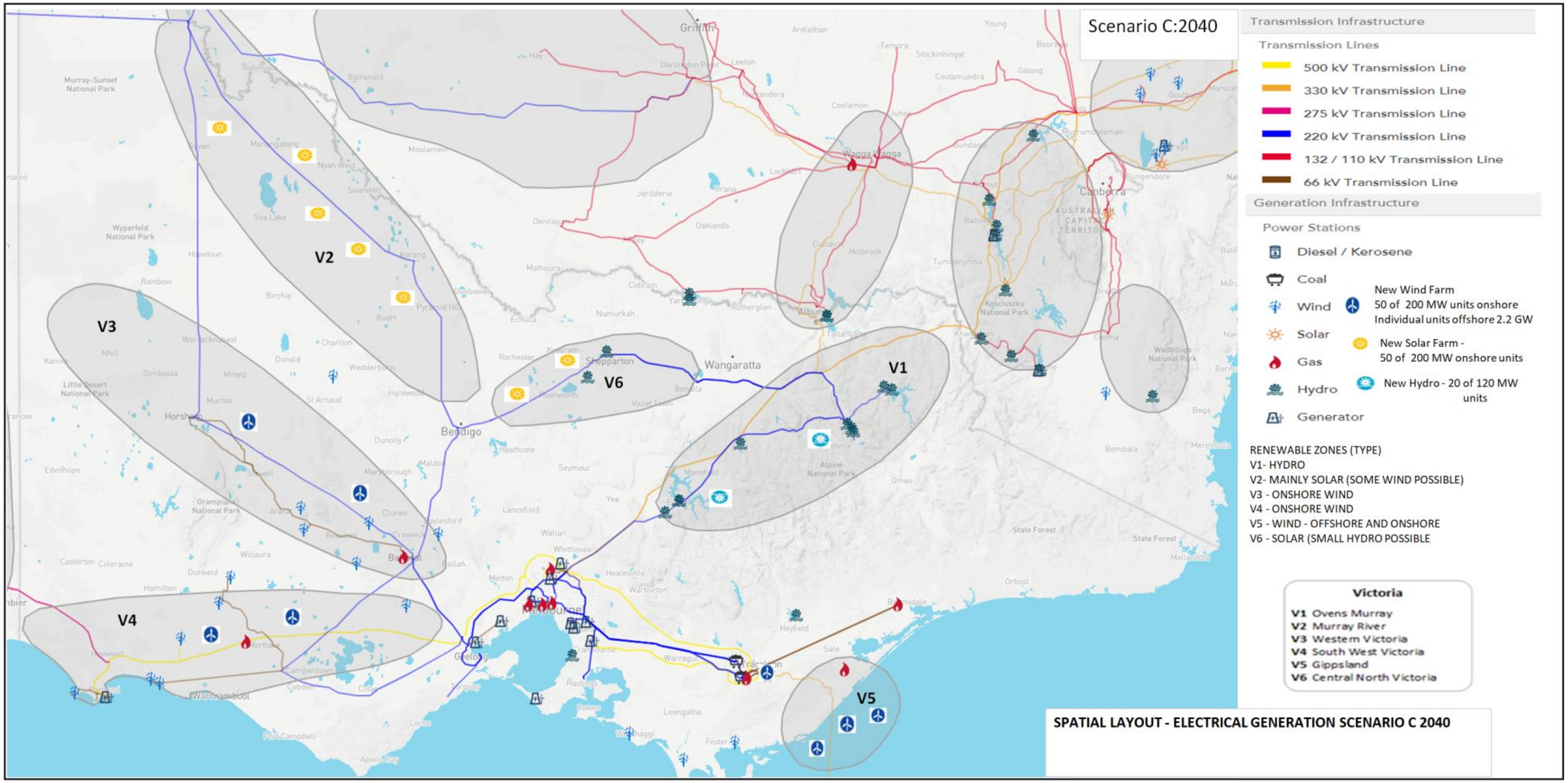
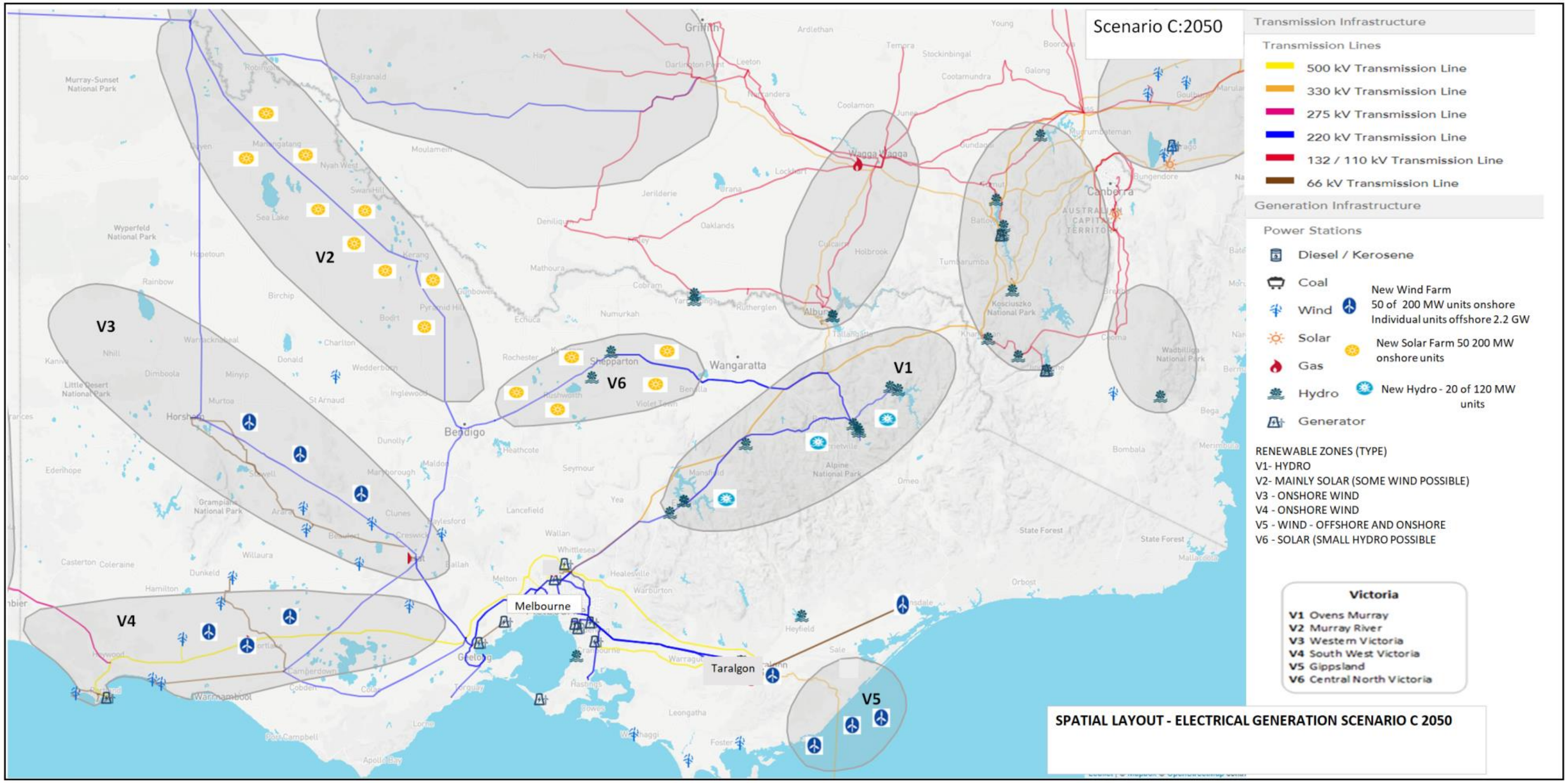


Figure 55: Scenario C – Electrical Spatial Analysis (2050)



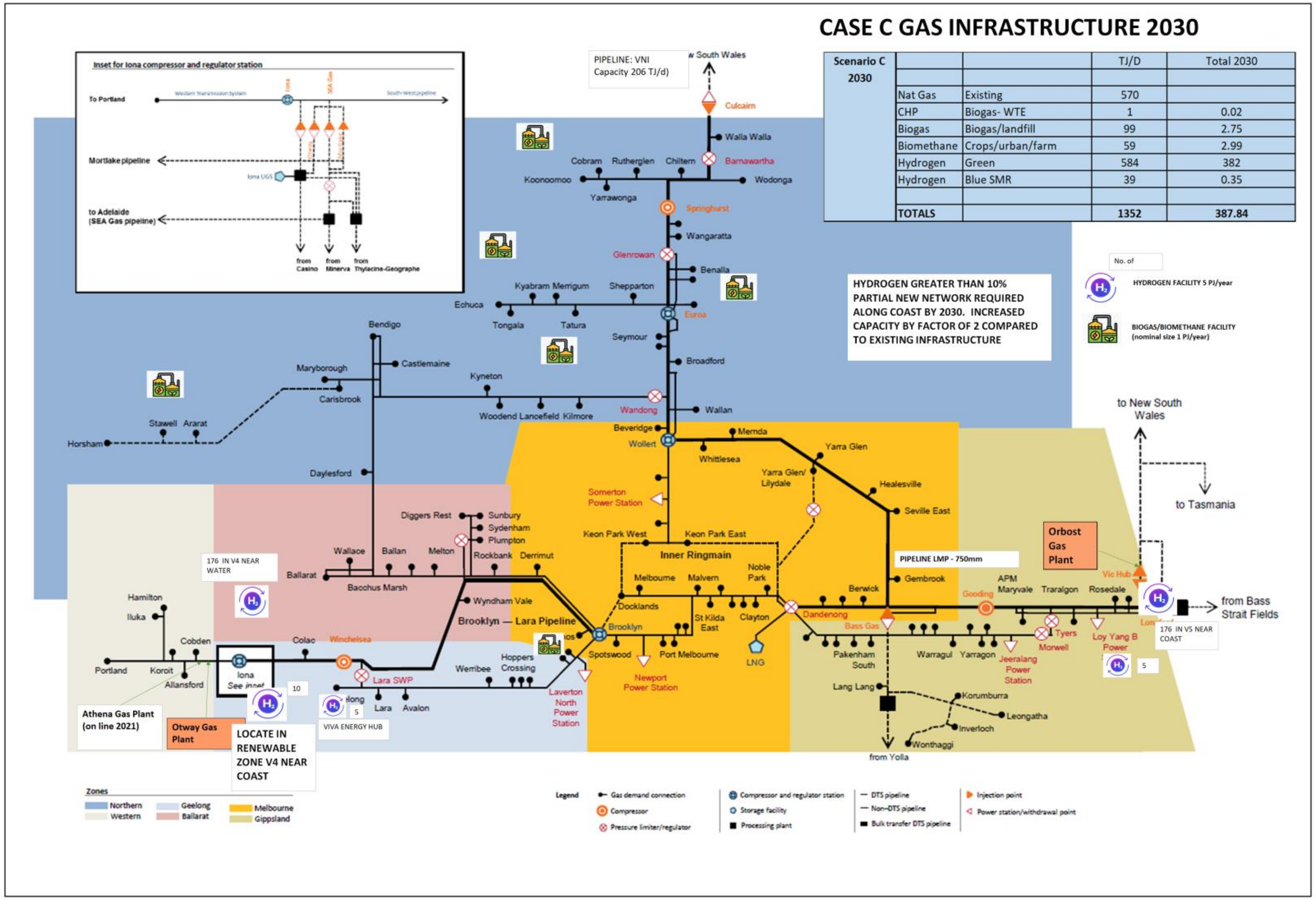
5.2.2 Gas

Scenario C has the same natural gas depletion profile as Scenario A but has significantly more hydrogen production than Scenario B – particularly green hydrogen. The same strategy has been applied as for Scenario B where the hydrogen plants installed in 2030 are all installed along the coast or in Renewable Zone V4 close to water, while the bio-gas facilities are located to the north of the state to maximise the use of the existing gas infrastructure in 2030. Refer to Figure 56, Figure 57, and Figure 58. Some new hydrogen suitable infrastructure will need to be in place by 2030 and this scenario sees a more rapid decommissioning of the existing infrastructure. The hydrogen infrastructure will need to be approximately twice the capacity on the existing infrastructure to support the transmission of hydrogen. The number of hydrogen facilities will mean that these need to be further distributed through the state in 2050 using suitable locations in V2 and V3 close to water.

The advantage of Scenario C is that the biogas facilities can be more distributed across the state which means they can be located closer to the users and can maximise the use of different feedstocks. The hydrogen facility located at Viva Energy hub is ideally located close to a suitable port, The Port of Geelong, to take advantage of a small hydrogen export potential.

Refer to Scenario A for a comparison of Scenario C against other scenarios.

Figure 56: Scenario C - Gas Spatial Analysis Scenario 2030



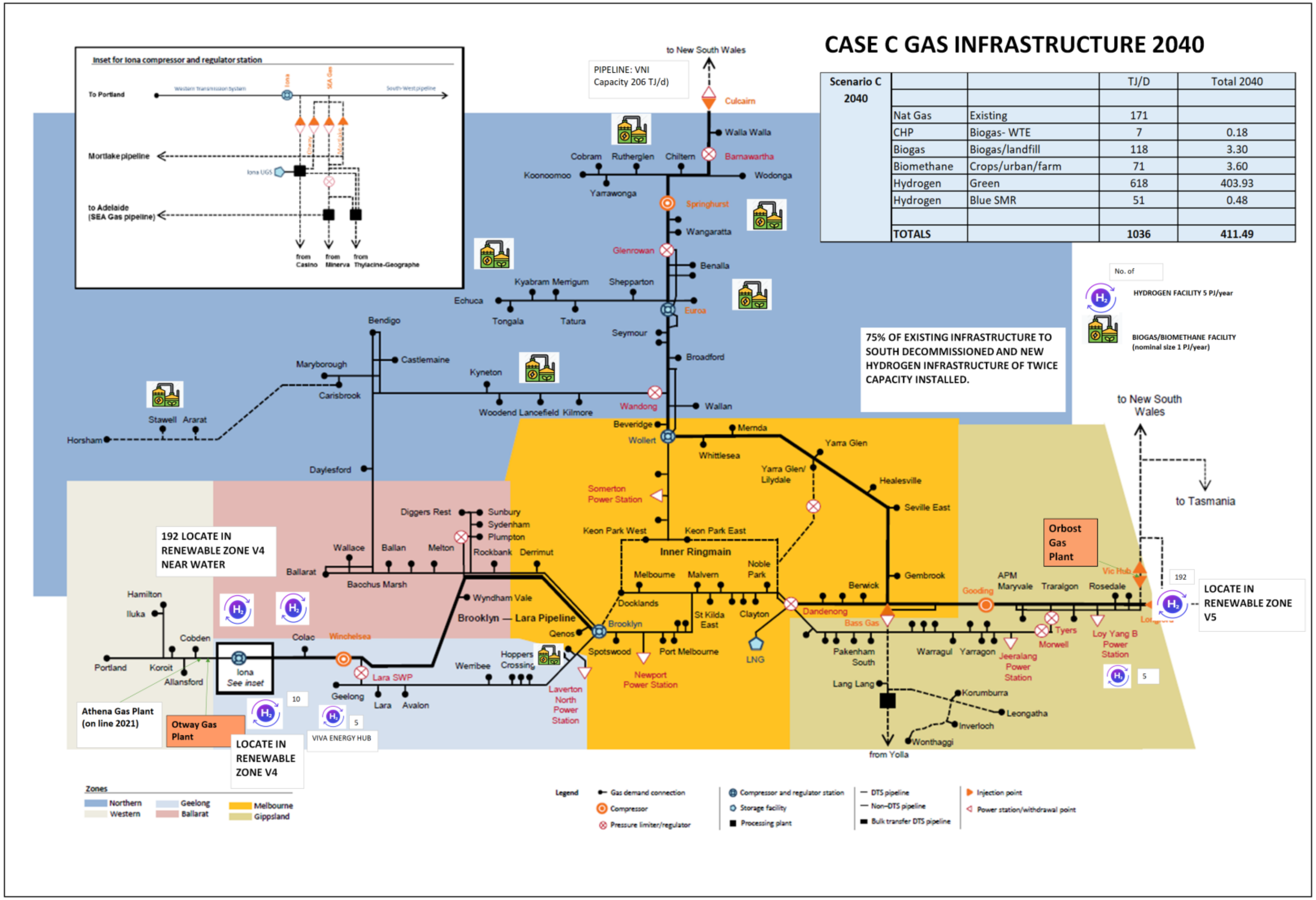
CASE C GAS INFRASTRUCTURE 2030

Scenario C 2030			TJ/D	Total 2030
	Nat Gas	Existing	570	
	CHP	Biogas- WTE	1	0.02
	Biogas	Biogas/landfill	99	2.75
	Biomethane	Crops/urban/farm	59	2.99
	Hydrogen	Green	584	382
	Hydrogen	Blue SMR	39	0.35
	TOTALS		**1352**	**387.84**

HYDROGEN GREATER THAN 10% PARTIAL NEW NETWORK REQUIRED ALONG COAST BY 2030. INCREASED CAPACITY BY FACTOR OF 2 COMPARED TO EXISTING INFRASTRUCTURE

LOCATE IN RENEWABLE ZONE V4 NEAR COAST

Figure 57: Scenario C - Gas Spatial Analysis 2040



CASE C GAS INFRASTRUCTURE 2040

Scenario C 2040			TJ/D	Total 2040
	Nat Gas	Existing	171	
	CHP	Biogas- WTE	7	0.18
	Biogas	Biogas/landfill	118	3.30
	Biomethane	Crops/urban/farm	71	3.60
	Hydrogen	Green	618	403.93
	Hydrogen	Blue SMR	51	0.48
	TOTALS		**1036**	**411.49**

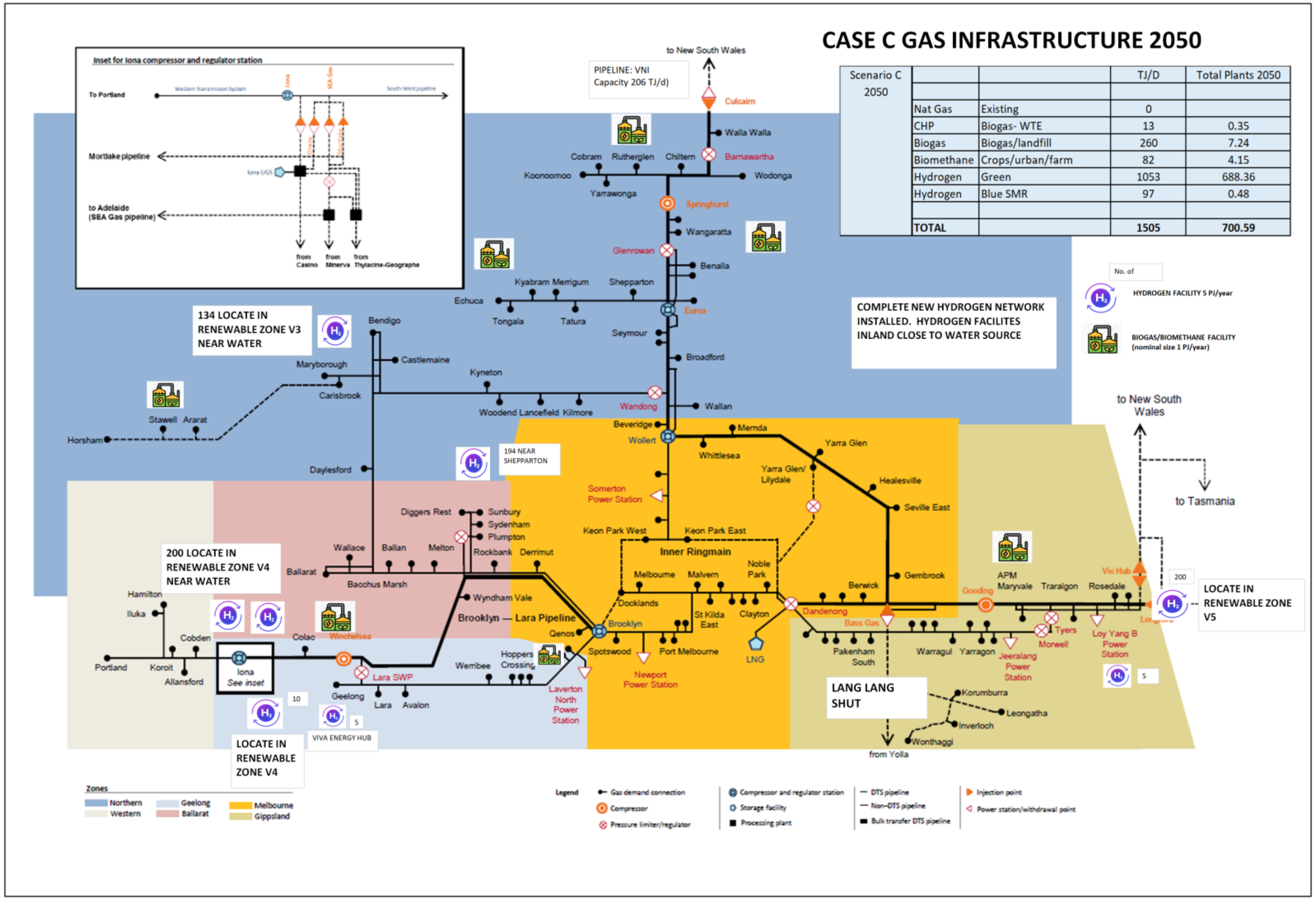
75% OF EXISTING INFRASTRUCTURE TO SOUTH DECOMMISSIONED AND NEW HYDROGEN INFRASTRUCTURE OF TWICE CAPACITY INSTALLED.

192 LOCATE IN RENEWABLE ZONE V4 NEAR WATER

LOCATE IN RENEWABLE ZONE V4

LOCATE IN RENEWABLE ZONE V5

Figure 58: Scenario C– Gas Spatial Analysis (2050)



CASE C GAS INFRASTRUCTURE 2050

Scenario C 2050			TJ/D	Total Plants 2050
	Nat Gas	Existing	0	
	CHP	Biogas- WTE	13	0.35
	Biogas	Biogas/landfill	260	7.24
	Biomethane	Crops/urban/farm	82	4.15
	Hydrogen	Green	1053	688.36
	Hydrogen	Blue SMR	97	0.48
	TOTAL		**1505**	**700.59**

COMPLETE NEW HYDROGEN NETWORK INSTALLED. HYDROGEN FACILITES INLAND CLOSE TO WATER SOURCE

5.3 Natural Gas

Scenario C targets a complete replacement of natural gas and coal relying primarily on the balanced adoption of :

- green and blue Hydrogen
- renewables
- biogas

Subject to careful phasing and blending of biomethane (refined biogas) and Hydrogen, plus the introduction of natural gas to support blue Hydrogen production, Scenario C has the greatest potential to maximise the use of existing natural gas infrastructure.

5.4 Road Vehicle Fuels

The scale of uptake for BEVs and HFCVs was assessed for Infrastructure Victoria's description if Scenario C (Appendix 1) and recorded in Table 77. 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.

Introduction of HFCVs in accordance with Table 77 causes a pro-rata reduction in the amount of kilometres travelled for both hydrocarbon vehicles and BEVs in order to maintain the overall total kilometres travelled for all road vehicles described in the prior analysis [Reference 8]. The selected split of kilometres travelled by vehicle category and fuel type for Scenario C for the three time periods is defined in Table 84, Table 85 and Table 86.

Table 84: Scenario C (2030) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**77,519,730,017 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	48,793,877,737	63%	1,748,986,234	2%
BEVs	21,022,404,359	27%	1,303,277,886	2%
HFCVs	775,197,300	1%	3,875,986,501	5%
Total	**70,591,479,396**		**6,928,250,621**	

Table 85: Scenario C (2040) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**89,147,689,520 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	23,908,321,944	27%	161,554,226	0%
BEVs	56,380,402,466	63%	3,348,549,512	4%
HFCVs	891,476,895	1%	4,457,384,476	5%
Total	**81,180,201,305**		**7,967,488,215**	

Table 86: Scenario C (2050) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**93,411,274,671 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	0	0%	0	0%
BEVs	83,194,507,178	89%	1,809,752,772	2%
HFCVs	1,868,225,493	2%	6,538,789,227	7%
Total	**85,062,732,672**		**8,348,541,999**	

Based on typical fuel consumption for each type of vehicle, the GHG Tool estimated the fuel requirements, with results provided in Table 87, along with emissions.

Table 87: Scenario C – Total Fuel Consumption by Road Vehicle Type

Year	**All Road Hydrocarbon Vehicles**	**All Road BEVs**	**All Road HFCVs**
	Gasoline & Diesel (PJ / yr)	**Electricity (PJ / yr)**	**Hydrogen (PJ / yr)**
2030	163	13	53
2040	69	30	71
2050	0	37	86

5.5 Biogas

Biogas production together with waste to energy is ramped up to approximately 100 PJ/yr by 2050 through significantly increased use of anaerobic digestion plants in agricultural and food waste management. Waste to energy is assumed to consume 1,000,000 tpa by 2050, but could be expanded further if the current policy settings are relaxed due to community support and comfort with the technology and greater drive for renewable energies to displace fossil fuels.

Higher biogas production offers the opportunity to produce biomethane to substitute for natural gas. In Scenario C, biomethane production is ramped up to over 100 PJ/yr which is at the upper end of the potential for anaerobic digestion in Victoria as estimated by Bioenergy Australia. By 2050, new technologies such as gasification of wastes and biomass could also be used to produce biomethane (renewable natural gas) complementing production from anaerobic digestion facilities.

The results from this part of the analysis support consideration for making policy recommendations to :

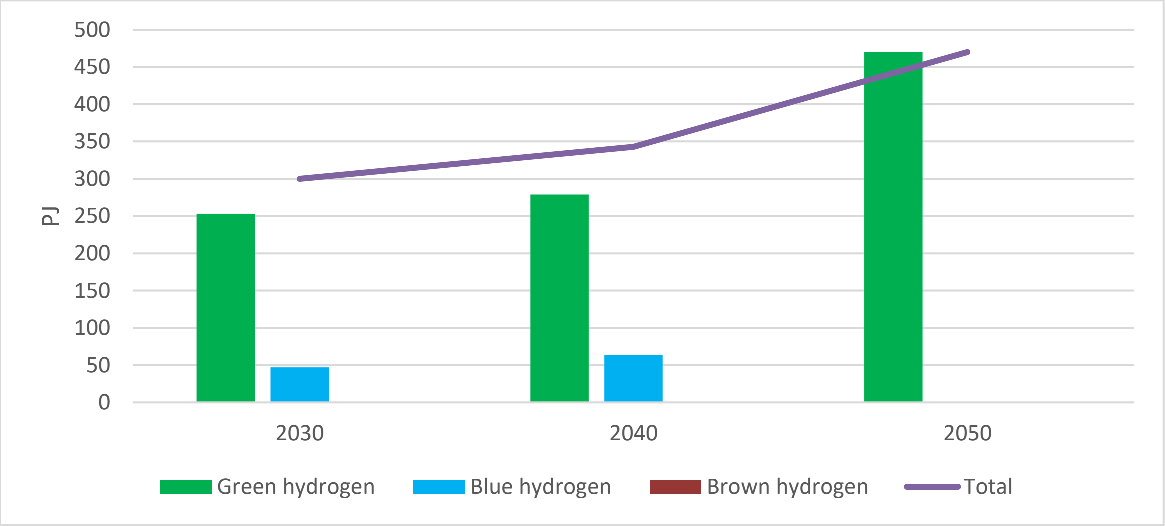
- Ensure local planning regulations allow the construction and operation of biogas, waste-to-energy and combined heat and power facilities, including their logistical requirements and 24 x 7 operation.

- Review the existing limitations on waste-to-energy, recognising only waste that cannot be otherwise recycled will be processed by such facilities.

5.6 Hydrogen

Scenario C has the largest production of green hydrogen over the study period, as shown in Figure 59.

Figure 59: Hydrogen Generation for Scenario C



Green hydrogen production is ramped up very significantly to around 450 PJ/yr by 2050, while blue hydrogen production is rather minimal due to declining natural gas production. Some biomethane could be used as the feedstock to make carbon negative hydrogen by 2050 using blue hydrogen infrastructure built in earlier decades. The expansion in hydrogen production is driven by the use of hydrogen for energy, chemical feedstock and transport applications. The green hydrogen production will require about 15 GW of new renewable electricity generation with a 100% availability. Equivalent to around 30 – 50 GW of new solar PV and wind generation.

5.7 Carbon Capture & Storage

Whilst the definition of Scenario C calls for no CCS, the loading to cater for blue Hydrogen was estimated to determine manageability if it were utilised.

The CCS technology is described in Section 2.3.7. All three major components of the CCS system are considered to be mature technologies with a TRL of 9 (see Section 2.1.9 for details).

In Scenario C, CO_2 emissions from the production of blue Hydrogen is captured and stored.

In this scenario the amount of CO_2 required to be captured and stored is reaches 2 Mtpa in 2040 and would be supported by the initial phase of the CarbonNet project.

5.8 Geothermal Energy

This scenario also incorporates small scale geothermal heating primarily for commercial use in low density areas as described in Section 2.3.5.

5.9 Energy Efficiency

Scenario C includes moderate-scale energy efficiency improvements including the use of smart meters and smart grids to optimise the use of variable renewable power sources and energy storage systems. Improved insulation standards and energy efficient appliance requirements for new and existing buildings are also imbedded into this scenario.

Scenario C also incorporates ground source heat pumps (GSHP) as an energy efficiency measure for both heating and cooling and hot water supply for commercial and industrial users.

5.10 Social

5.10.1 Hydrogen

Victoria has an extensive gas pipeline network, which could provide a major advantage to the renewable hydrogen fuel industry. Gas distribution pipelines supply gas to 80% of Victorian households. Victoria's gas pipelines, coupled with the gas Mains Renewal Project (MRP) – which converts distribution pipes from steel to polyethylene (Ref 26) – will equip Victoria to distribute hydrogen gas around the state.

The MRP is a five-year pro-active program using an insertion technique to insert a polyethylene pipe inside of existing cast iron or unprotected steel pipes.

The manufacturing sector is not set up for large scale hydrogen, but once the hydrogen supply chains are in place and it becomes cost effective exports, products and services should increase. To support this Victoria is establishing the Victorian Hydrogen Technology Cluster Network (Ref 27).

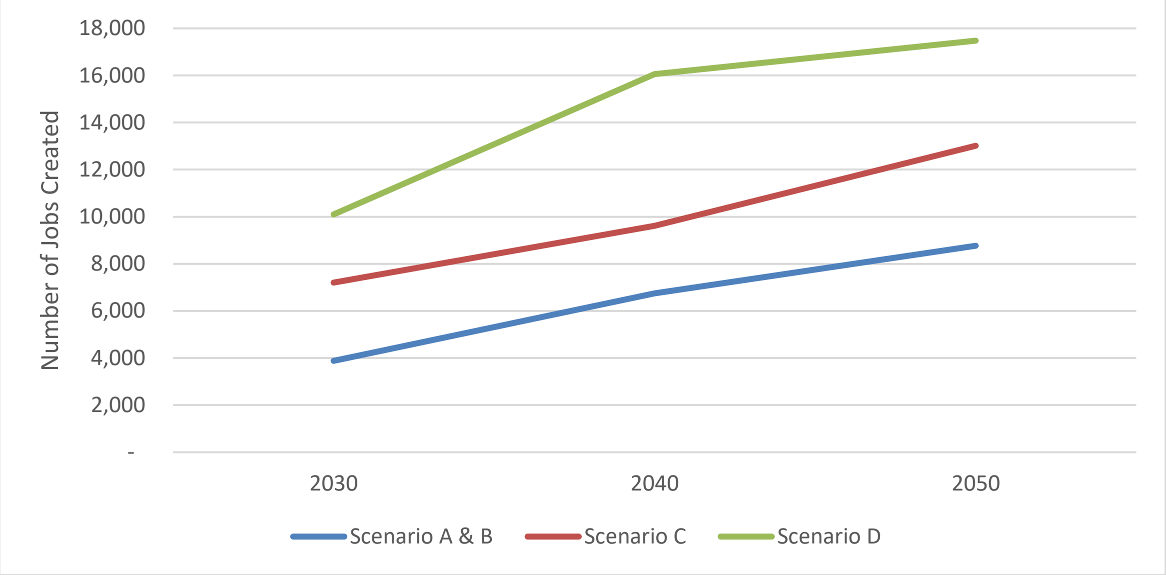
Community confidence in the safety of hydrogen production processes has been deemed a critical success factor for the hydrogen industry. Community understanding is low and will require a coordinated approach to building community understanding of hydrogen technology and the environmental benefits.

5.10.2 Employment

The renewable hydrogen industry is expected to generate between 7,600 and 17,000 jobs in Australia, by 2050 (Ref 28), and more jobs could be found further along the hydrogen supply chain using hydrogen produced in a range of ways. Based upon data obtain from COAG (Ref 28), 1000 jobs could be created for every million tonnes of hydrogen produced.

Figure 60, illustrates the total number of jobs potentially created, both from hydrogen production and conversion to renewable energy sources. Scenario C will create the second largest number of jobs.

Figure 60: Potential Job Creation



Victoria's extensive gas distribution and transmission networks support a workforce with critical expertise and skills. The industry has established expert communities particularly in regional Victorian areas such as the Gippsland Basin area and the Latrobe Valley (Ref 29).

5.11 Environmental

Scenario C achieves net zero emissions faster than any other scenario. It is anticipated that Victoria will reach net zero emissions before 2040, as shown in Table 88.

Table 88: Scenario C Greenhouse Gas Emissions

Sector	2005 Mt CO_2-e	2030 Mt CO_2-e	Change 2005 to 2030 %	2040 Mt CO_2-e	Change 2005 to 2040 %	2050 Mt CO_2-e	Change 2005 to 2050 %
Electricity generation	67	30	55.2	16	76.1	1	98.5
Direct combustion	15.2	-15	198.7	-28	284.2	-57	475.0
Transport	20.2	11	45.5	5	75.2	0	100.0
Fugitive emissions	2.4	2	16.7	1	58.3	0	100.0
LULUCF (land use, land use change and forestry)	-8.7	0	100.0	0	100.0	0	100.0
Total (net emissions)	**104.8**	**28**	73.3	**-6**	105.7	**-56**	153.4

5.12 Risk & Opportunities

Environment

Scenario C is a full electrification scenario similar to A, except that electricity from renewables is also used not just for electricity generation but the manufacture of green Hydrogen. Blue Hydrogen is used as a transition fuel utilising natural gas, however the significant levels of biogas used in the scenario means there is no reliance on carbon capture to meet net zero. The degree of renewable infrastructure required to achieve this scenario has the secondary impacts previously highlighted associated with wind and hydroelectric power and associated transmission line infrastructure.

Societal

The Societal risk associated with Scenario C can again be considered to be similar to Scenario A. This Scenario opens up employment opportunities in the renewable and hydrogen sectors, as described in Section 5.9.

Economics

Scenario C is also susceptible to cost blowouts associated with the installation of the local distribution infrastructure (both electrical and additional gas infrastructure), and the increasing pricing pressure of polysilicon and rare earth material supplies due to global demand.

In this scenario, the gas pipeline infrastructure is initially reused for biogas and hydrogen, and additional hydrogen infrastructure incorporated. Although reuse of an existing asset provides economic benefits it also introduces a degree of technical and therefore economic risk due to the ability of the existing network to deal with the eventual high hydrogen levels in the gas stream. This risk is covered further below, under technical risk. An economic opportunity exists to use the existing gas infrastructure whilst transitioning from a hydrocarbon economy by blending hydrogen into remaining natural gas feedstock. This has the economic advantage of reducing the carbon content of the gas with little expenditure required on transmission infrastructure in the short term whilst the hydrogen infrastructure is being built.

This Scenario requires significant infrastructure in terms of electrical transmission, H2 pipeline networks, production and storage facilities all of which require planning applications, pipeline licence applications, development of Safety Cases. This represents an economic cost to the developer, and to the regulator, in terms of the costs associated with managing the level and speed of development of infrastructure necessary to achieve Net Zero.

Green hydrogen represents an export opportunity with some countries such as Germany preferring to source their power from renewable sources, and as such would provide economic benefit to Australia. It is anticipated that there would be an LNG import terminal in Victoria and this can transition as a hydrogen import/export hub with a commensurate impact on growth and job opportunities both in the hydrogen and supporting electrical infrastructure.

Technical

The major technical risk with Scenario C is the ability to supply power reliably for electricity generation and hydrogen production.

The major technical risks are associated with hydrogen transportation due to the potential for pipeline embrittlement, particularly at the higher pressures required for the transmission network where the use of polyethylene replacement is not currently possible as is the case for the distribution network. This means that limited sections of the transmission network may only be usable for biogas/hydrogen mixtures for industrial and commercial scale heating systems until a technical solution is found. However, for green hydrogen this may represent an opportunity in comparison with brown or black hydrogen, in that the economies of scale for electrolysis are less of an issue, meaning that small scale electrolysis plants can be distributed throughout the network close to end users. This means hydrogen would not be required to be transported at high pressures and embrittlement can be managed.

Although the production of hydrogen through electrolysis is a known technology - it is inefficient, but as worldwide interest in the hydrogen economy grows there is an opportunity for Victoria to capitalize on any developments in this field.

Safety

In addition to the increase in uptake of batteries in homes with their commensurate fire risks, the main safety risk associated with Scenario C is the presence of hydrogen. Hydrogen is well managed in an industrial setting, due to the experience of the Operators, training of workers in the Industry, codes and standards for design, and the presence of regulations which manage Major Hazard Facilities, pipelines, and the storage and handling of dangerous goods, amongst others. This scenario considers the presence of hydrogen in the home for cooking, and as a fuel source for transportation. Unlike natural gas, hydrogen is not odorised (Ref 35) due to its molecular weight in comparison with typical odorants used in Industry, resulting in drop-out of the odourant in piping. In addition, odourants damage transport fuel cells. Hydrogen also has a very large flammable range (2 to 70%, in comparison with natural gas of approximately 4 to 16% presence in air). This means that gas leaks inside the home have a higher potential to be undetected and ignite resulting in damaging explosions in confined spaces. Hydrogen use in the home is subject to trials currently in Scotland, however one simple risk reduction measure is to consider hydrogen for heating where piping remains external to the home, and replace gas cooking appliances with electrical appliances (as per Scenarios A and B), or use of biogas sources. Due to the level of International interest in the development of H2 as a replacement fuel, it is anticipated that these risks can be managed with familiarisation by consumers, ongoing development of detection techniques and appropriate equipment design.

It is expected that at refuelling stations, the presence of hydrogen storage can be managed in a similar manner to the management of LPG bullets at fuel stations currently. Risk associated with any large scale hydrogen storage facilities at Industrial sites can be managed under the Victorian MHF regulations.

5.13 Comparative Cost Index

The cost estimate for each scenario is presented as a “cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The example of the “comparative cost index” illustrates the general intent and mandate of this study being a comparative analysis of scenarios to identify trends, drivers, risks and opportunities in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050. The development of classed cost estimates for each scenario is beyond the scope of this study.

The comparative cost index for Scenario C was calculated to be 1.0 using the method described in Section 2.2.2, and this value is used as input to the Scenario Screening described in Section 7.

6 SCENARIO D

Scenario D is summarised as "large brown Hydrogen / large CCS / no gas”. Based on the detailed description provided in Appendix 1 the scale of uptake of new energy, offset mechanisms and new energy road vehicles is defined in the following tables using the qualitative scale in Table 89.

Table 89: Uptake Scale

🟩	Large upscale / transfer of energy is made to this energy type Large uptake of new energy vehicles
🟧	Medium upscale / transfer of energy is made to this energy type Medium uptake of new energy vehicles
🟥	Small upscale / transfer of energy is made to this energy type Small uptake of new energy vehicles
🟦	No upscale / transfer of energy is made to this energy type No uptake of new energy vehicles

Table 90: Scenario D - Uptake of New Energy

🟧 **Renewable Elec**			🟥 **CHP**	🟥 **Heat**	🟥 **Gas**	🟥 **Gas**	🟥 **Gas**	🟦 **Gas**	🟩 **Gas**	🟥 **Efficiency**		
solar	wind	hydro	biogas	geotherm	biogas	biometh.	H2 green	H2 blue	H2 brown	heat pump	insul.	smart grids

Table 91: Scenario D – Uptake of Offset Mechanisms

🟩 **CCS**			🟥 **Agro-Forestry**			🟥 **Trading**	
Onshore	Offshore	Chemical	Forestry	Marine	Soil	Aus C-Credit	Internat. C-Credits

Table 92: Scenario D – Uptake of New Fuel Vehicles

🟩 **Vehicle**	🟩 **Vehicle**
BEV	HFCV

6.1 Energy-Emissions-Offsets

The energy-emissions-offset flows for each time period for Scenario D demonstrating a path to net zero carbon emissions by 2050 were calculated using the GHG Tool, with results summarised in Table 93.

Schematic representations “Sankey diagrams” of the flows of energy, emissions and offsets leading to the net emissions position for each time frame are provided Figure 61 (overleaf).

These illustrations are intended to provide a simplified, graphical representation of the complex, interconnected data provided in Table 93.

It is important to note that both the “Table of Results” and “Sankey Diagrams” present exactly the same set of results, but on a slightly different basis : Table 93 assumes coal on a thermal basis; whilst Figure 61 reports coal on an electrical basis (applying a 30% conversion factor assumed for a typical brown coal power plant) in order to more clearly illustrate the scale of energy flows relating to electricity consumption, emissions and required offsets.

The basis and build-up of these results, along with a discussion thereof is provided in the following sections.

Table 93: Scenario D – Energy-Emissions-Offset Results

(Coal reported on thermal basis)

Energy Consumed (PJ)	**2030**				**2040**				**2050**			
Overall Demand (Victoria)	**1,492**	**Coal**	**Vehicle**	**Gas**	**1,716**	**Coal**	**Vehicle**	**Gas**	**1,973**	**Coal**	**Vehicle**	**Gas**
Total (Scope of this Study)	**1,550**				**2,020**				**2,444**			
coal	300				150				0			
vehicle fuel (gasoline, diesel)	163				69				0			
natural gas	233				70				0			
solar (replace HC's)	43	13	19	11	109	22	54	33	158	31	73	53
additional solar to balance demand	67				139				216			
wind (replace HCs)	40	30	2	8	85	57	6	22	131	84	9	38
additional wind to balance demand	80				170				260			
hydro (replace HCs)	4	0	2	2	21	9	6	6	37	18	9	10
additional hydro to balance demand	10				20				30			
CHP (WTE / biogas / biomass) (replace HCs)	1	0	0	1	6	0	0	6	9	0	0	9
geothermal (replace HCs)	1	0	0	1	5	0	0	5	3	0	0	3
biogas / landfill gas (replace HCs)	1	0	0	1	6	0	0	6	9	0	0	9
additional biogas / landfill gas to balance gas demand	10				25				45			
biomethane (replace HCs)	1	0	0	1	6	0	0	6	9	0	0	9

additional biomethane to balance gas demand	10				25				45			
green H2 (replace HCs)	3	0	3	1	13	0	7	6	22	0	13	9
additional green H2 to balance gas demand	10				25				45			
blue H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional blue H2 to balance gas demand	0				0				0			
brown H2 (replace HCs)	64	0	51	13	113	0	64	49	140	0	73	67
additional brown H2 to balance gas demand	510				960				1,280			
eff. Improvements (replace HCs)	1	0	0	1	3	0	0	3	6	0	0	6
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			
Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**366**	**Coal**	**Vehicle**	**Gas**	**565**	**Coal**	**Vehicle**	**Gas**	**715**	**Coal**	**Vehicle**	**Gas**
coal	28				14				0			
vehicle fuel (gasoline, diesel)	11				5				0			
natural gas	13				4				0			
fugitive emissions (4% of total HC)	2				1				0			
CO2 (nat gas processing)	1	0	0	1	0	0	0	0	0	0	0	0
solar (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional solar to balance elec demand	0				0				0			
wind (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0

additional wind to balance elec demand	0				0				0			
hydro (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance elec demand	0				0				0			
CHP (WTE / biogas / biomass) (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
geothermal (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
biogas / landfill gas (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
additional biogas / landfill gas to balance gas demand	-3				-8				-14			
biomethane (replace HCs)	0	0	0	0	-1	0	0	-1	-1	0	0	-1
additional biomethane to balance gas demand	-3				-8				-14			
green H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional green H2 to balance gas demand	0				0				0			
blue H2 (replace HCs)	0	0	0	0	0	0	0	0	0	0	0	0
additional blue H2 to balance gas demand	0				0				0			
brown H2 (replace HCs)	35	0	28	7	27	0	0	27	37	0	0	37
additional brown H2 to balance gas demand	283				532				709			
eff. Improvements (replace HCs)	0				0				0			
grid elec imported (to balance demand)	0				0				0			
LNG imported (to balance demand)	0				0				0			
Carbon Offsets	**2030**				**2040**				**2050**			

(Mill Te CO2-e)												
Total	-300	Coal	Vehicle	Gas	-532	Coal	Vehicle	Gas	-715	Coal	Vehicle	Gas
CCS	-297	0	-26	-271	-523	0	0	-523	-698	0.0	0.0	-698.4
agro-forestry	-2	-1	-1	-1	-6	-2	-2	-2	-10	-4.0	-2.0	-4.0
trading	-1	0	0	0	-3	-1	-1	-1	-7	-2.7	-1.5	-2.7
Net Carbon Emissions (Mill Te CO2-e)	**2030**				**2040**				**2050**			
Total	**67**				**33**				**0**			
Energy Storage (GWh)	**2030**				**2040**				**2050**			
Total	**63,931**	**Coal**	**Vehicle**	**Gas**	**136,274**	**Coal**	**Vehicle**	**Gas**	**212,463**	**Coal**	**Vehicle**	**Gas**
battery	12,034	3,563	5,325	3,147	26,896	6,063	11,629	9,204	43,801	8,563	20,413	14,826
additional solar to balance demand	18,611				38,611				60,000			
pumped hydro	11,063	8313	666	2085	23,545	15,813	1,661	6,071	36,439	23313	2552	10575
additional wind to balance demand	22,222				47,222				72,222			
chemical	0	0	0	0	0	0	0	0	0	0	0	0
additional hydro to balance demand	0				0				0			

Figure 61: Scenario D – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

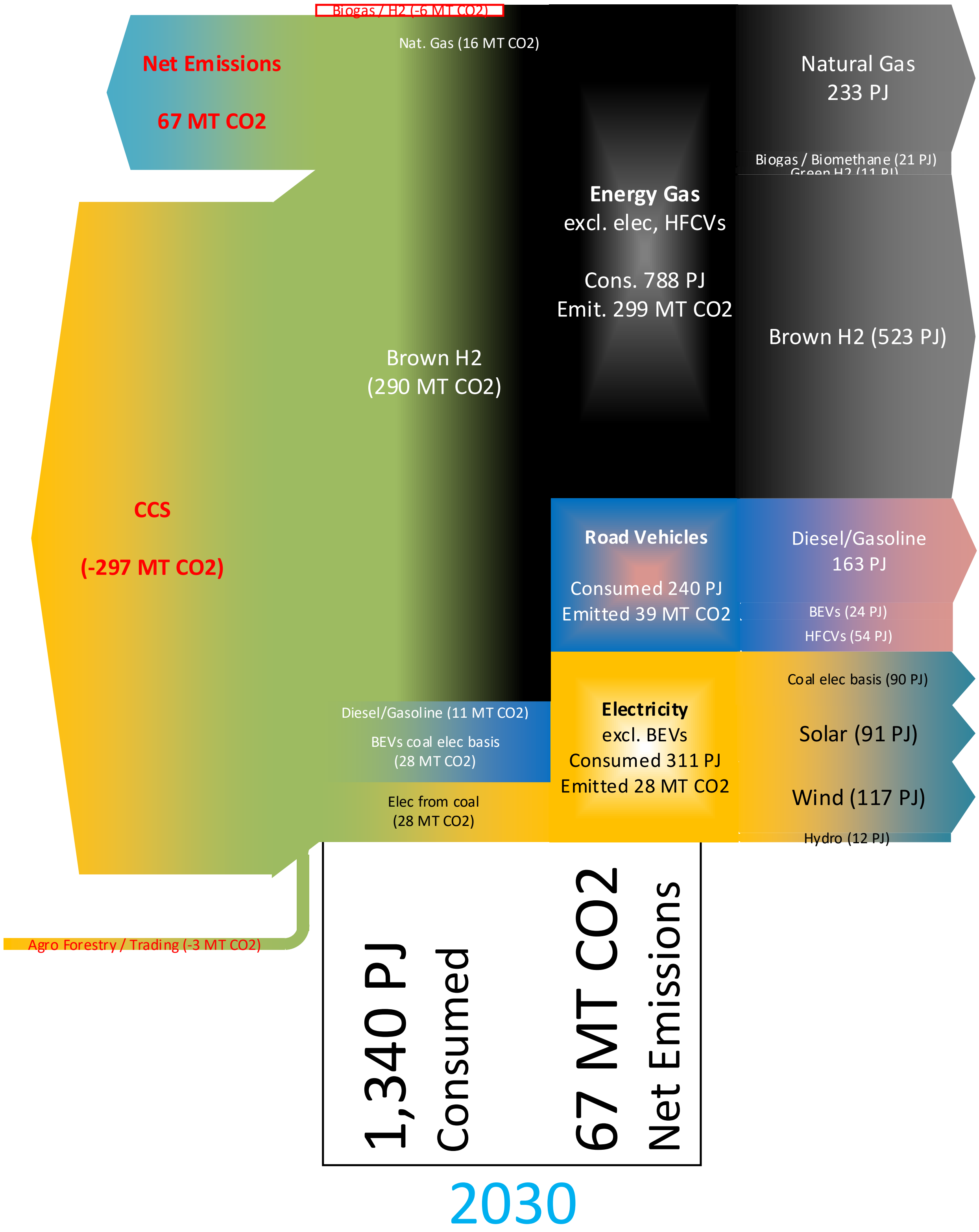


Figure 62: Scenario D – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).

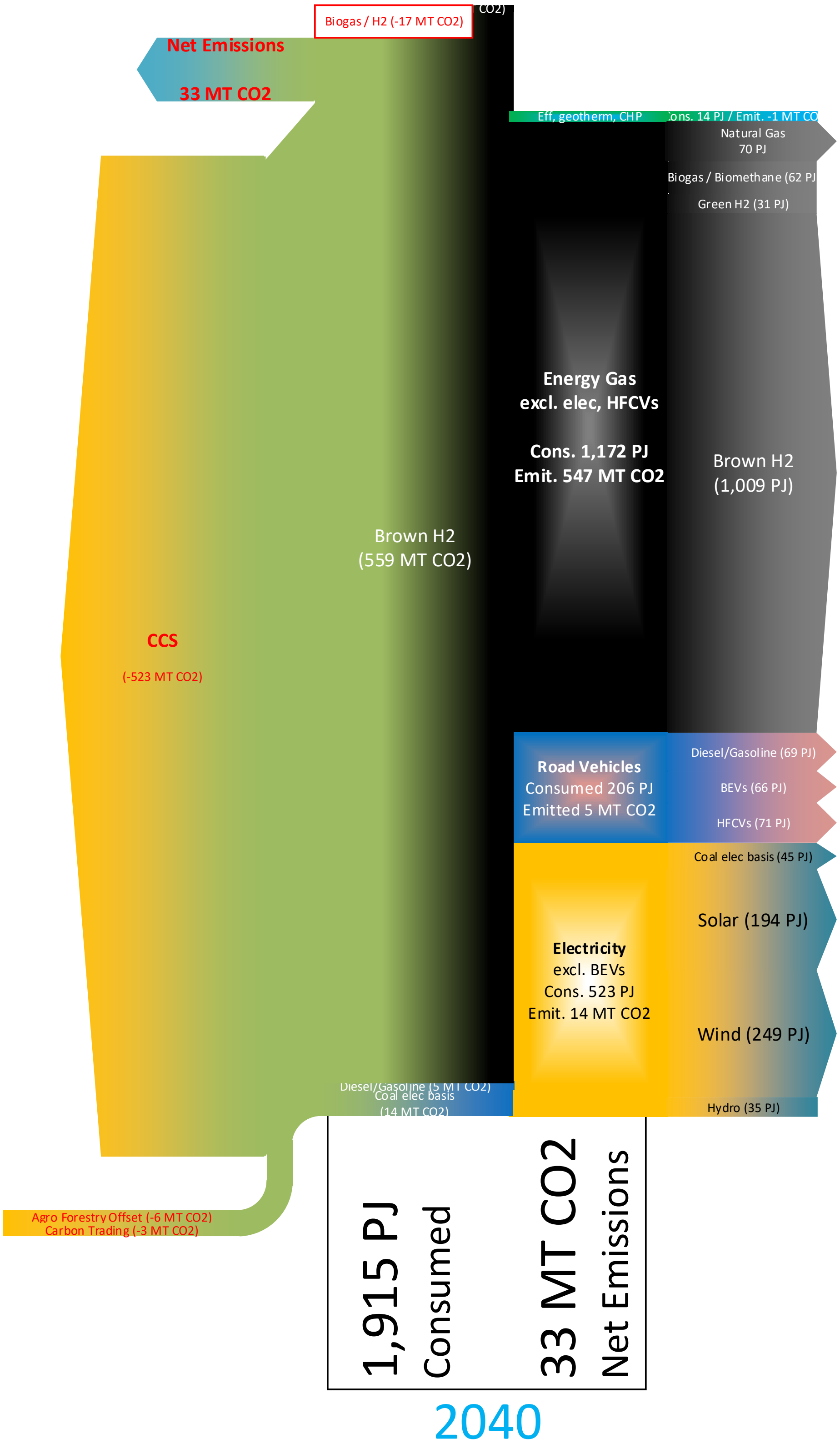
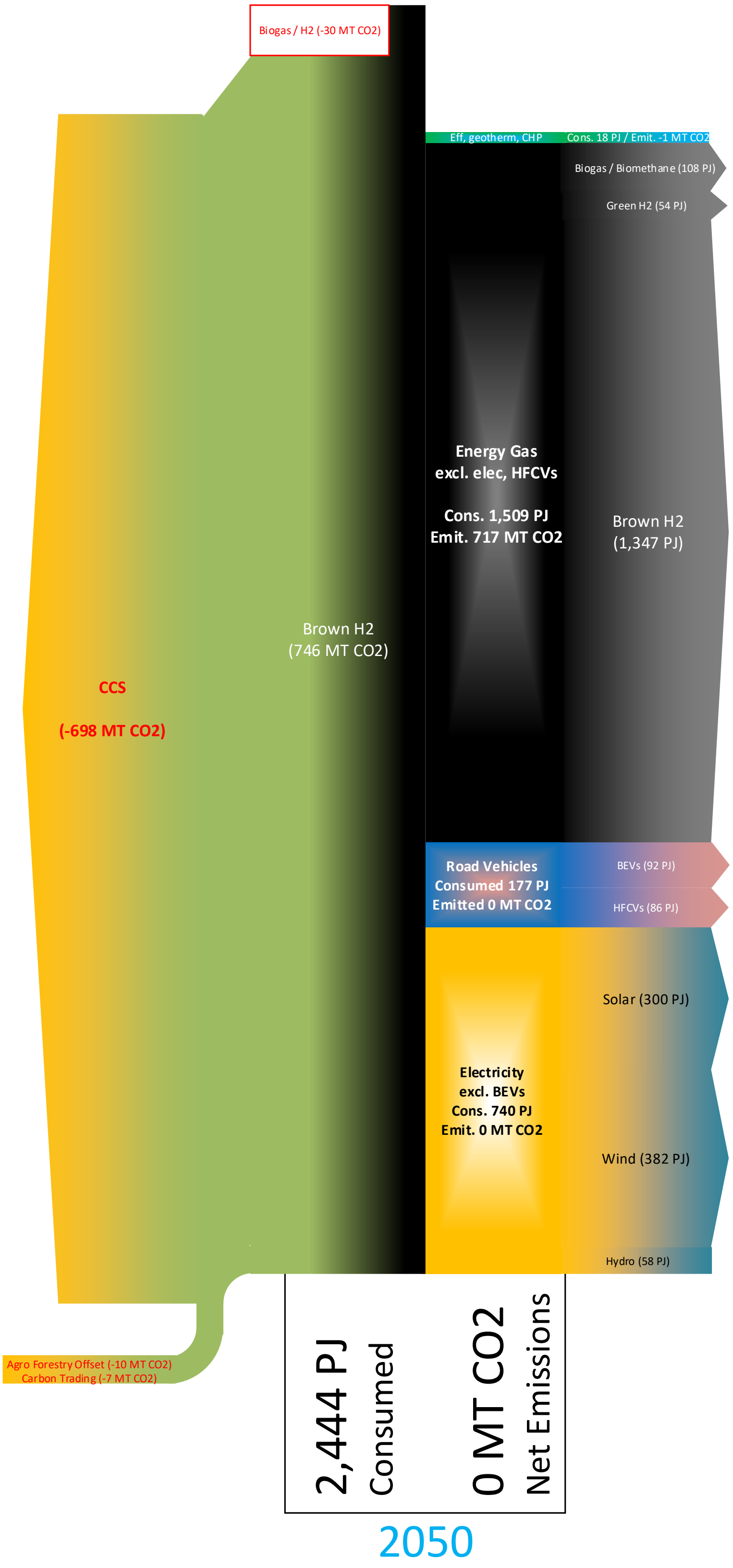


Figure 63: Scenario D – Energy-Emissions-Offset Flows

(Coal reported on electricity basis. Colour scheme is notional aims to distinguish the energy-emissions offset flows for the three key energy classes : gas, vehicles and electricity).



6.1.1 Forecast Demand for Electricity & Hydrocarbon Fuels

The forecast demand for electricity and hydrocarbon fuels was defined for Scenario D, recorded in Table 94 and used as key input to the GHG Tool.

Given the study scope excludes some energy sources (e.g., aviation fuel, LPG, other petroleum liquids) the forecast energy demand for the study will be lower than the overall energy demand for the State of Victoria as defined in Table 18.

Where forecast energy demand for the scope of the study exceeds the overall energy demand for the State of Victoria, then energy export is predicted. For Scenario D a significant level of brown Hydrogen export is defined.

Table 94: Scenario D - Forecast Demand for Electricity & Hydrocarbon Fuels

		2030	**2040**	**2050**
Total	**PJ**	**1,716**	**2,291**	**2,800**
Grid Elec **(adjust to suit Scenario D)**	PJ	300	500	700
Non Elec Energy Gas **(adjust to suit Scenario D)**	PJ	800	1,200	1,500
Road Vehicle Fuels (gasoline, diesel)	PJ	163	69	0
Other Energy e.g., Petroleum Liquids, etc **(Excluded from the scope of the analysis)**	PJ	454	522	600

6.1.2 Energy Generation Mix

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each new energy source was categorised using the qualitative scale in Table 89, the energy mix was defined per guidance notes below and results recorded in Table 95, Table 96, and Table 97 (overleaf). When the energy splits were "balanced" with additional loads to match the energy demand forecasts defined in Table 18, the amount of energy for each time period was calculated using the GHG Tool and summarised in Table 93.

Selection Notes

A broad description of the general approach to defining the energy mix required to match Infrastructure Victoria's Scenario Descriptions (Appendix 1) is provided below and should be read in conjunction with the tables that follow. Unless a timeframe is quoted, values stated will refer to an approximate average during the transition. The new energy *generation* sector may not necessarily correspond to the new energy *consumption* sector for instance industrial generation of green Hydrogen may be consumed (partly) by the residential sector.

Natural Gas Replacement Mix (reference Table 95)

- Residential & Commercial Generation

  - Totals<100% due to scenario D requiring <100% of nat gas replaced by renewable electricity given the major energy stream is Brown H_2
  - Renewables dominant proportion with only solar (wind & hydro not allocated / consumed)
  - Geothermal not allocated / consumed
  - Energy gases not allocated / consumed
  - Efficiency very low proportion growing to approximately 5% of the mix over time
- Industrial Generation
  - Renewables very low proportion of the mix in given the major energy stream is brown Hydrogen.
  - Geothermal low proportion building to over 5% of the mix over time
  - Energy gas building to approximately 70% of the mix over time, predominantly brown Hydrogen at approximately 40% of the mix with moderate loading of biogases including combined heat and power building to approximately 20% over time. Small proportion of green Hydrogen building to almost 10% over time.
  - Efficiency not allocated in this scenario.
- Offsets
  - Large requirement for all offset mechanisms including CCS (predominantly offshore), agro-forestry and trading certificates.

<u>Coal Replacement Mix (reference </u>Table 96<u>)</u>

- 100% allocation of energy generation to industrial renewables, predominantly wind.
- Offsets
  - Whilst offsets were allocated, none were required due to the use of zero emissions energy production (renewables).

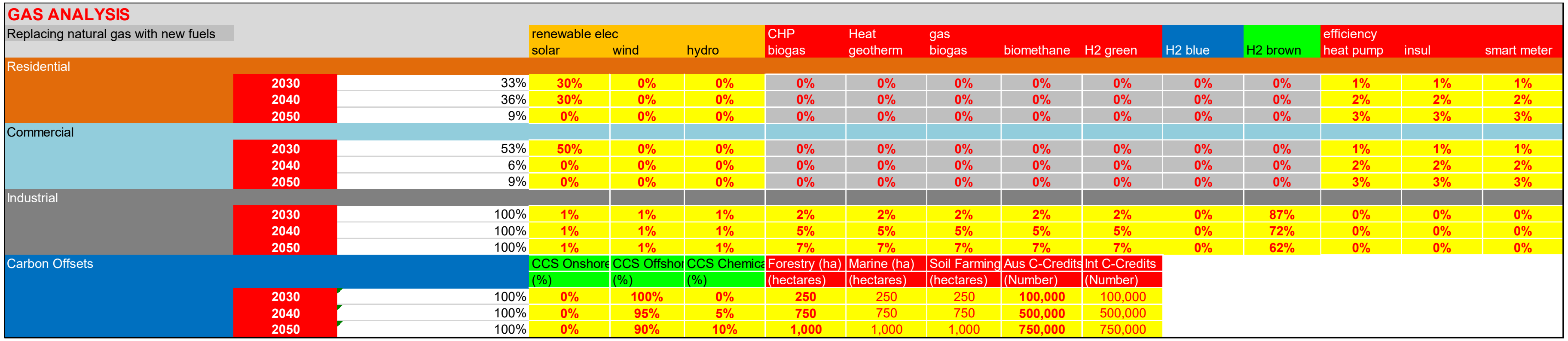
<u>Vehicle Hydrocarbon Fuel Replacement Mix (reference </u>Table 97<u>)</u>

- Electricity for BEVs was generated by renewables with 70% allocated to residential & commercial, and the remainder to industrial generation.
- Hydrogen generation for HFCVs was allocated primarily to industrial brown Hydrogen with over 80% of the mix, and remainder to green Hydrogen climbing to 15% in 2050.
- Offsets
  - All offset mechanisms including CCS (predominantly offshore), agro-forestry and trading certificates were allocated, though the requirement was far less

than for natural gas replacement due to the higher level of zero emissions energy production (renewables).

Table 95: Scenario D – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Natural Gas

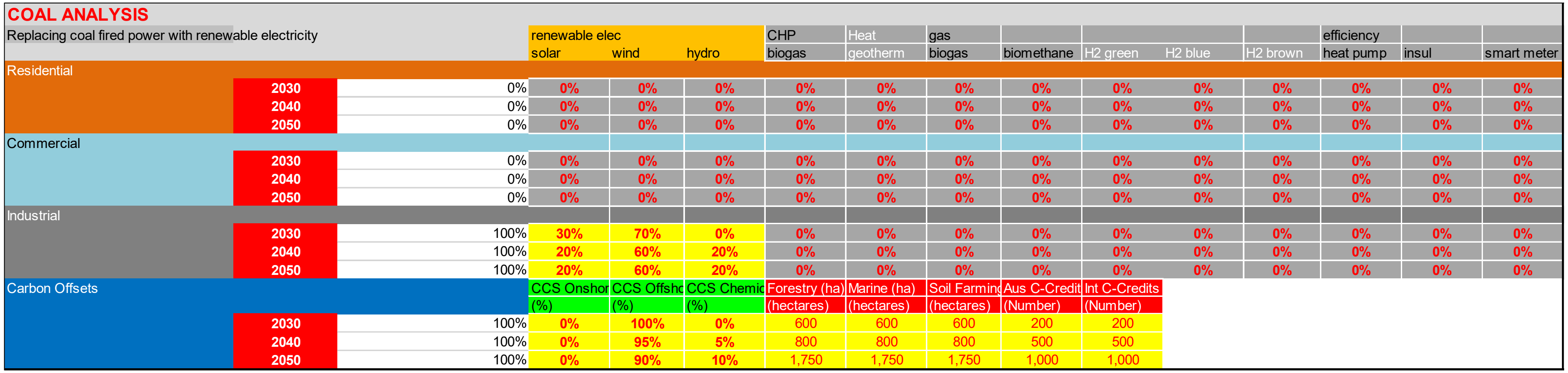
(Yellow fields are active, grey fields are not relevant to the Scenario. Residential & commercial totals < 100% due to medium uptake of renewables, with no other forms of residential / commercial energy generation allotted. Additional energy to replace Natural Gas from Industrial Brown H2).



GAS ANALYSIS															
Replacing natural gas with new fuels			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	33%	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%
	2040	36%	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
	2050	9%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%
Commercial															
	2030	53%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%
	2040	6%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	2%	2%
	2050	9%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%
Industrial															
	2030	100%	1%	1%	1%	2%	2%	2%	2%	2%	0%	87%	0%	0%	0%
	2040	100%	1%	1%	1%	5%	5%	5%	5%	5%	0%	72%	0%	0%	0%
	2050	100%	1%	1%	1%	7%	7%	7%	7%	7%	0%	62%	0%	0%	0%
Carbon Offsets			CCS Onshore	CCS Offshor	CCS Chemica	Forestry (ha)	Marine (ha)	Soil Farming	Aus C-Credits	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	100%	0%	100%	0%	250	250	250	100,000	100,000					
	2040	100%	0%	95%	5%	750	750	750	500,000	500,000					
	2050	100%	0%	90%	10%	1,000	1,000	1,000	750,000	750,000					

Table 96: Scenario D – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Coal

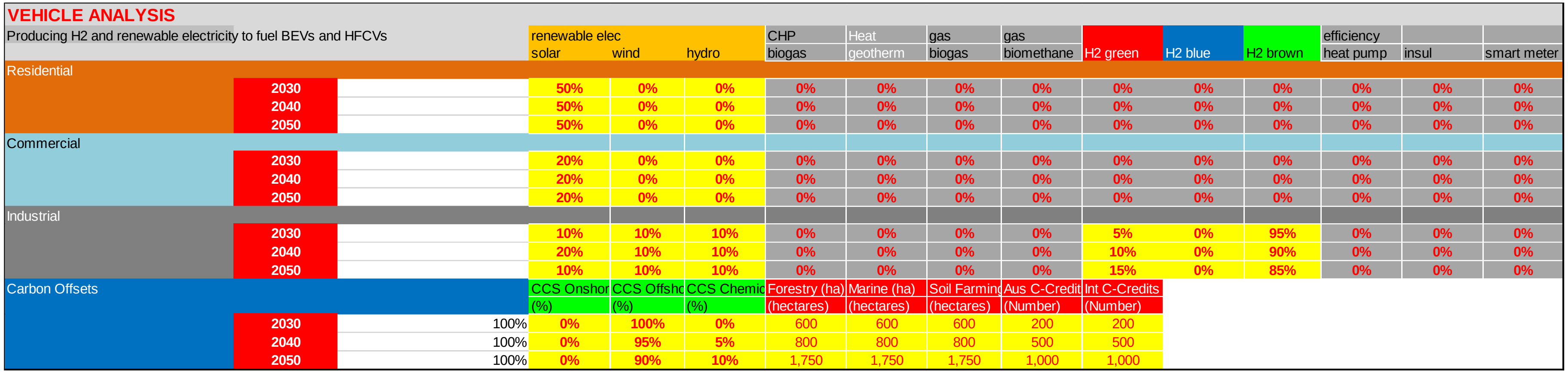
(Yellow fields are active, grey fields are not relevant to the Scenario)



COAL ANALYSIS															
Replacing coal fired power with renewable electricity			renewable elec			CHP	Heat	gas					efficiency		
			solar	wind	hydro	biogas	geotherm	biogas	biomethane	H2 green	H2 blue	H2 brown	heat pump	insul	smart meter
Residential															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030	100%	30%	70%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050	100%	20%	60%	20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Carbon Offsets			CCS Onshor	CCS Offsh	CCS Chemic	Forestry (ha)	Marine (ha)	Soil Farmin	Aus C-Credit	Int C-Credits					
			(%)	(%)	(%)	(hectares)	(hectares)	(hectares)	(Number)	(Number)					
	2030	100%	0%	100%	0%	600	600	600	200	200					
	2040	100%	0%	95%	5%	800	800	800	500	500					
	2050	100%	0%	90%	10%	1,750	1,750	1,750	1,000	1,000					

Table 97: Scenario D – Split of New Energy Generation Sources and Emissions Offset Mechanisms to Replace Hydrocarbon Fuels for Road Vehicles

(Yellow fields are active, grey fields are not relevant to the Scenario)



VEHICLE ANALYSIS															
Producing H2 and renewable electricity to fuel BEVs and HFCVs			renewable elec solar	wind	hydro	CHP biogas	Heat geotherm	gas biogas	gas biomethane	H2 green	H2 blue	H2 brown	efficiency heat pump	insul	smart meter
Residential															
	2030		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Commercial															
	2030		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2040		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2050		20%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Industrial															
	2030		10%	10%	10%	0%	0%	0%	0%	5%	0%	95%	0%	0%	0%
	2040		20%	10%	10%	0%	0%	0%	0%	10%	0%	90%	0%	0%	0%
	2050		10%	10%	10%	0%	0%	0%	0%	15%	0%	85%	0%	0%	0%
Carbon Offsets			CCS Onshor (%)	CCS Offsho (%)	CCS Chemic (%)	Forestry (ha) (hectares)	Marine (ha) (hectares)	Soil Farmin (hectares)	Aus C-Credit (Number)	Int C-Credits (Number)					
	2030	100%	0%	100%	0%	600	600	600	200	200					
	2040	100%	0%	95%	5%	800	800	800	500	500					
	2050	100%	0%	90%	10%	1,750	1,750	1,750	1,000	1,000					

6.1.3 Carbon Emissions

The Carbon emissions associated with energy consumption was calculated in the GHG Tool based on the emissions factors listed in Table 22, with results summarised for each time period in Table 93.

6.1.4 Carbon Offsets

Based on Infrastructure Victoria's Scenario Descriptions (Appendix 1) the scale of uptake for each Carbon offset mechanism was defined and documented in Table 91 and the split of Carbon offset mechanisms to abate emissions associated with energy production was defined and recorded in Table 95, Table 96, and Table 97.

The amount of Carbon offsets were adjusted over time to provide a schedule of net emissions reaching zero by 2050. These calculations were undertaken in the GHG Tool and the results summarised in Table 93.

6.1.5 Energy Storage

Energy storage required to support renewable electricity generation (solar and wind) was calculated in the GHG Tool using the basis described in Section 2.3.2, and results summarised in Table 93.

6.1.6 Discussion of Results

Scenario D targets a complete replacement of natural gas relying primarily on the adoption of brown Hydrogen (gasification of brown coal), with some contribution from

- renewables
- biogas
- green H2

Extremely large scale CCS is adopted to offset emissions.

A comparison of the energy-emissions-offset results for Scenario D against the other scenarios identified the following observations:

- Very large scale Carbon emissions with estimated levels growing from 366 Mill Te CO_2 equiv. in 2030 to 715 Mill Te CO_2 equiv. in 2050.
- Rapid installation of large scale Hydrogen transportation infrastructure given the specific location of the brown coal resource meaning this Scenario is constrained to a centralised energy production model.
- Rapid installation of extremely large scale CCS required with estimated storage levels growing from 297 Mill Te CO_2 in 2030 to 698 Mill Te CO_2 in 2050. These large reservoir storage volumes are as yet unidentified.

Potential refinements to Scenario D could include:

- Define the brown Hydrogen export levels to match the scale and timing of international markets.

6.2 Spatial Analysis

6.2.1 Electrical

The number of renewable energy installations and type allocated per region is indicated in Table 95 below. These have been allocated as per the methodology described in Section 2.3 and balanced to minimise the impact on the transmission system for the demand flow case. The increased requirement for renewable energy for each of the time horizons is shown in Figure 67, Figure 68, and Figure 69. The technical modelling includes for additional transmission capacity and storage to cover generator downtime, short-term peaking demand, and night or poor weather conditions. The figures have been produced for comparison purposes only and demonstrate the increase in renewable installations over the time zones. For clarity, the storage requirements are not shown on the spatial schematics. Every solar farm includes battery storage locally and additional hydro installations have been allowed for in the estimate as storage for areas serviced by wind turbines. It is assumed these are located in V1. The comparison of storage requirements for each scenario is covered in section 6.3.

The significant amount of hydrogen produced from coal gasification introduced into Scenario D compared to Scenario A significantly reduces the electrical consumption. This can be seen by a significant reduction in renewable installations over the three-time horizons. The scale for hydro has been reduced in the figures for Scenario D due to the significant reduction in number of units required for this scenario.

The analysis still indicates some transmission augmentation for the section from Renewable Energy Zone V2 to Melbourne from 2040 and augmentation of the transmission line from Renewable Energy Zone V1 to draw from storage during peak demand or poor wind days from 2030. The augmentation from V2 is less than half that identified for Scenario A and the augmentation of the transmission lines from V1 is approximately half of that for Scenario A. The scenario still indicates significant under-utilisation of the infrastructure from Renewable Energy Zone V5 and underutilisation of renewable energy in Zones V2 and V3.

Refer Scenario A discussion for a comparison of Scenario D against other scenarios.

Table 98 Scenario D Renewable Installations by REZ

Year	Renewable Energy	V1 Ovens Murray	V2 Murray River	V3 Western Victoria	V4 South West Victoria	V5 Gippsland Note 1	V6 Central North Victoria
2030	Hydro	4					
	Solar		78				19
	Onshore Wind			50	48	0	
	Offshore Wind					1	
2040	Hydro	9					
	Solar		84				25
	Onshore Wind			50	48	12	
	Offshore Wind					1	
2050	Hydro	17					
	Solar		100				29
	Onshore Wind			50	48	50	
	Offshore Wind					4	

Figure 64: Scenario D – Electrical Spatial Analysis (2030)

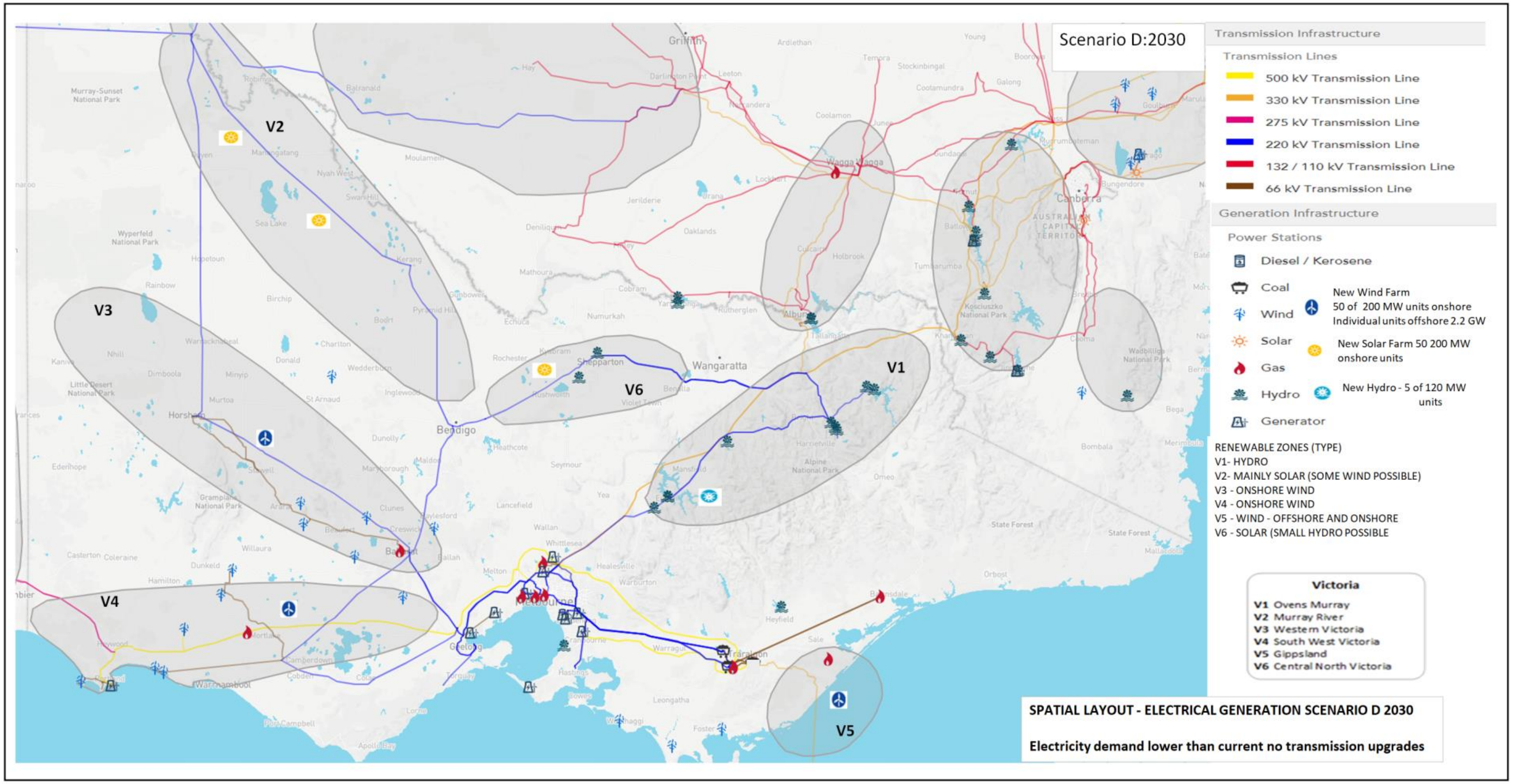
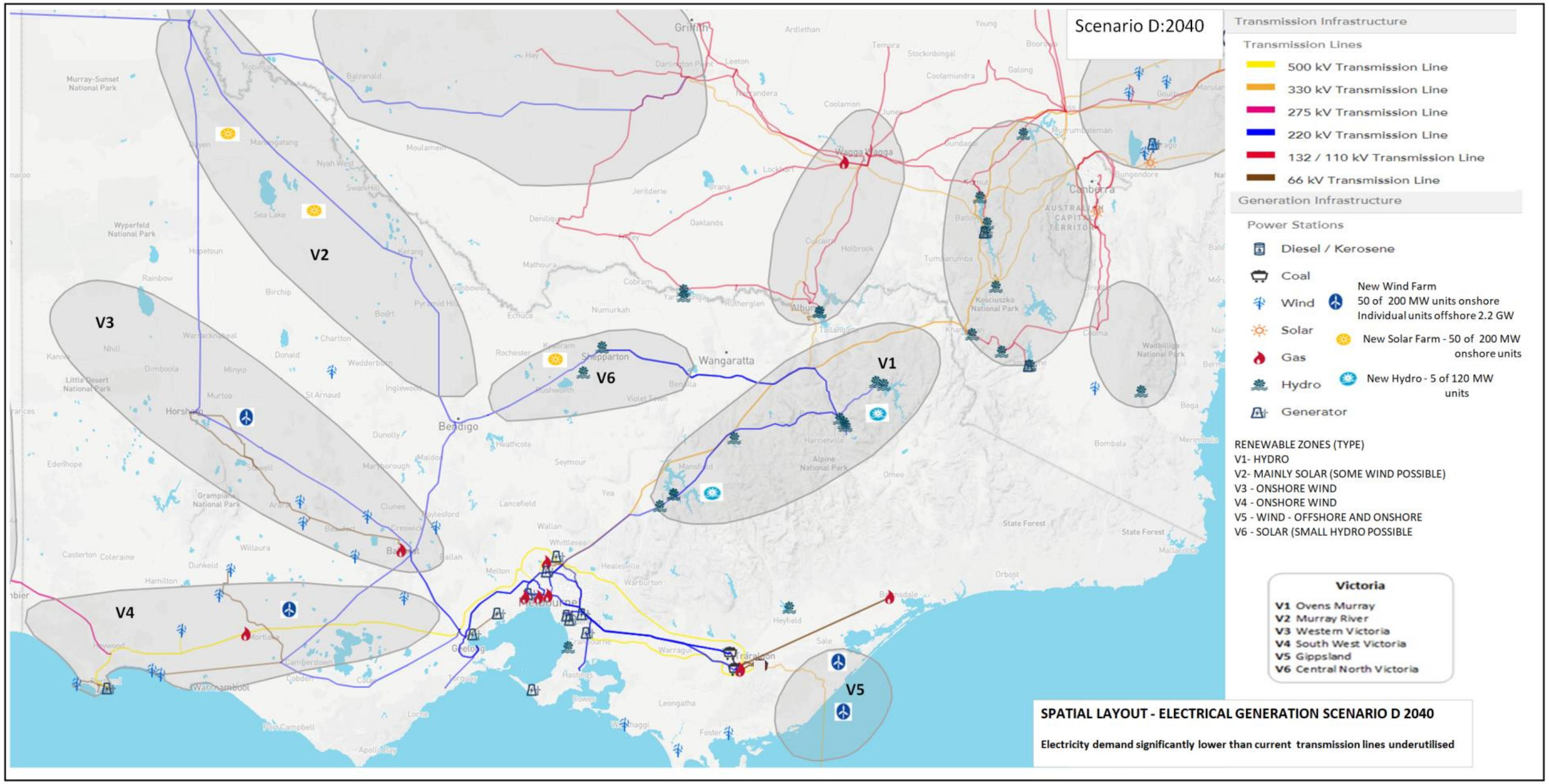


Figure 65: Scenario D – Electrical Spatial Analysis (2040)



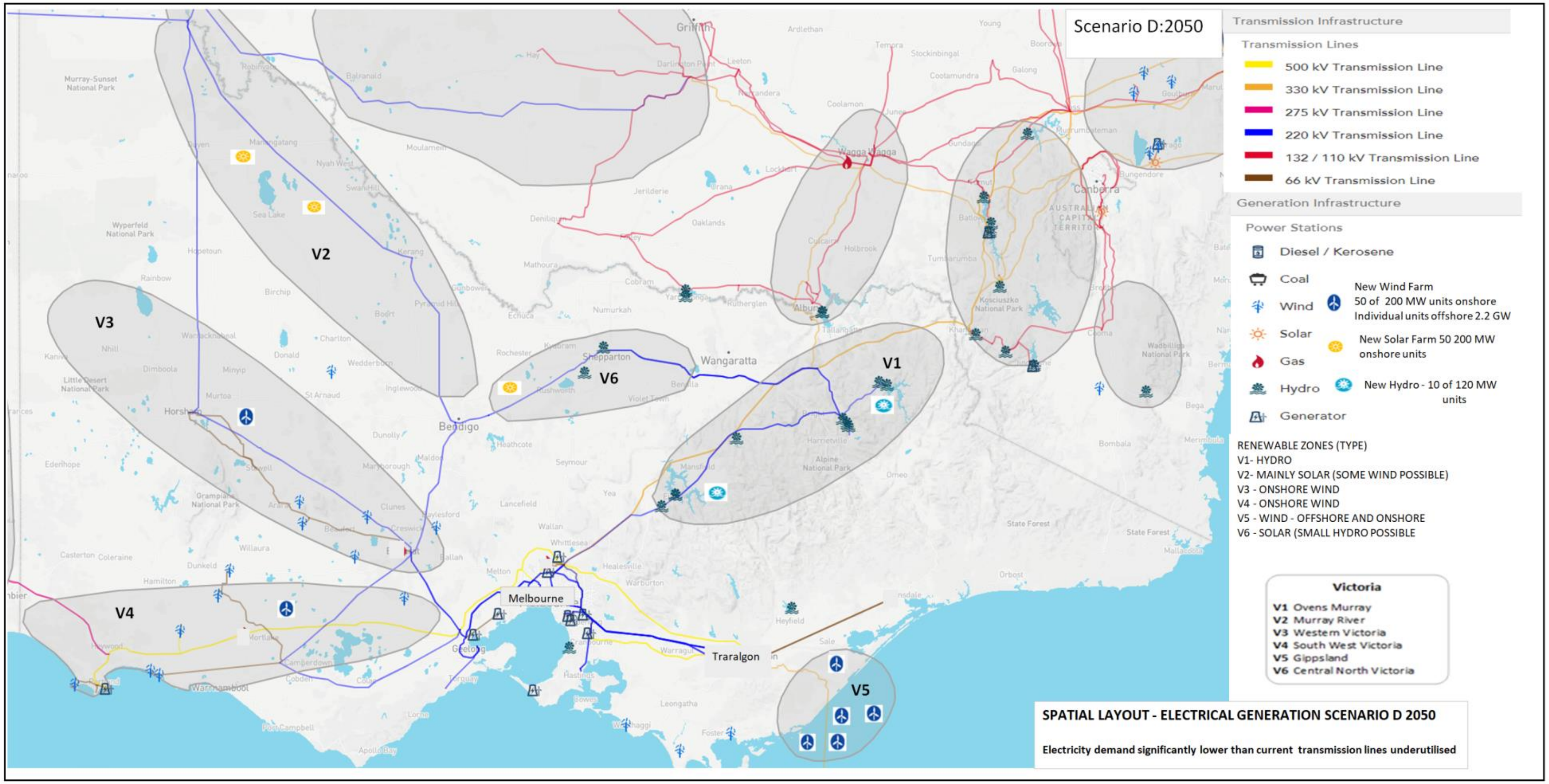


Figure 66: Scenario D – Electrical Spatial Analysis (2050)

6.2.2 Gas

For Scenario D there is significantly more hydrogen production than Scenario C. This is hydrogen produced by the gasification of coal and the production facilities have all been located in the Latrobe valley local to the coal supply. Refer to Figure 67, Figure 68 and Figure 69.

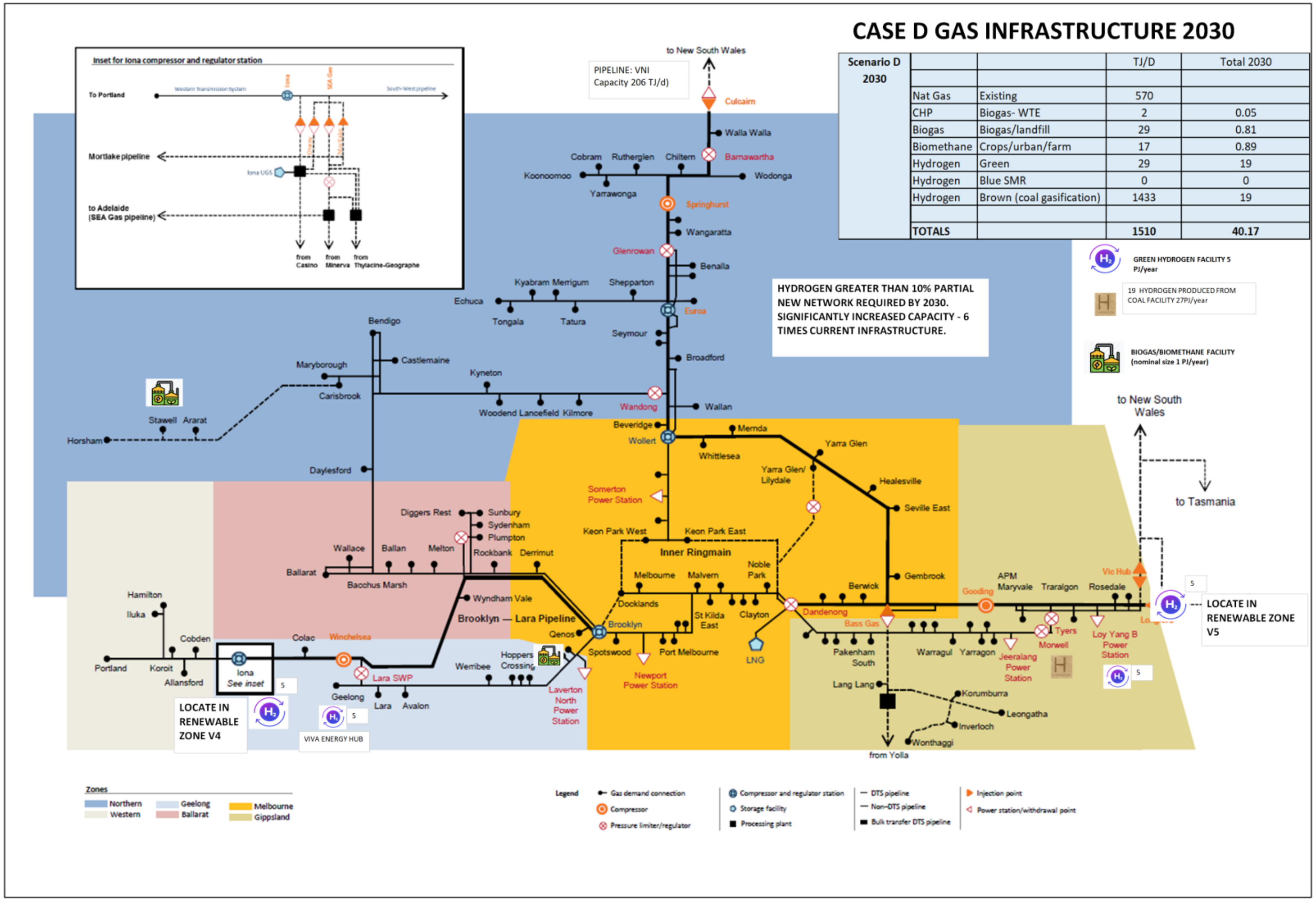
The scenario is supplemented by a small amount of bio-gas production and some green hydrogen production. Scenario D has the same natural gas depletion profile as Scenario's A and C allowing some use of the existing infrastructure. The bio-gas facilities have been located in the north of the state to take advantage of the existing infrastructure in these areas. As there are less green hydrogen facilities than Scenario C it is anticipated that these can all be located in the coastal regions as indicated in Figure 67, Figure 68, Figure 69.

This scenario is intended to offer larger hydrogen export potential. The Viva Energy hub is located close to a suitable port, the Port of Geelong, but further work needs to be completed to access the suitability of the ports local to the higher capacity hydrogen production facilities in the Latrobe valley. The use of the Port of Hastings is possible, although this is an environmentally sensitive subject to strong public opinion following the stoppage of the ALG LNG import terminal due to public outrage around environmental issues. Suitable alternative ports would need to be identified and would require extensive modification.

Similar to scenario C some of the hydrogen ready infrastructure needs to be in place prior to 2030. Due to the amount of hydrogen in this scenario the infrastructure will need to be sized for approximately six times the capacity (pipeline diameter wise) to transport the required amount of energy in hydrogen form. Given the additional capacity for both the hydrogen gas infrastructure and the CCS collection infrastructure there is unlikely to be sufficient time for planning and scheduling the extensive infrastructure modifications required. Reuse of gas infrastructure to support CCS collection is not considered viable due to the age of the installed infrastructure and requirement for the CO2 to be transported in dense phase. The design pressure of the CarbonNet transport system, at 20 MPa exceeds the current maximum allowable design pressure of the gas transmission system.

Refer Scenario A discussion for a comparison of Scenario D against other scenarios.

Figure 67: Scenario D - Gas Spatial Analysis Scenario 2030

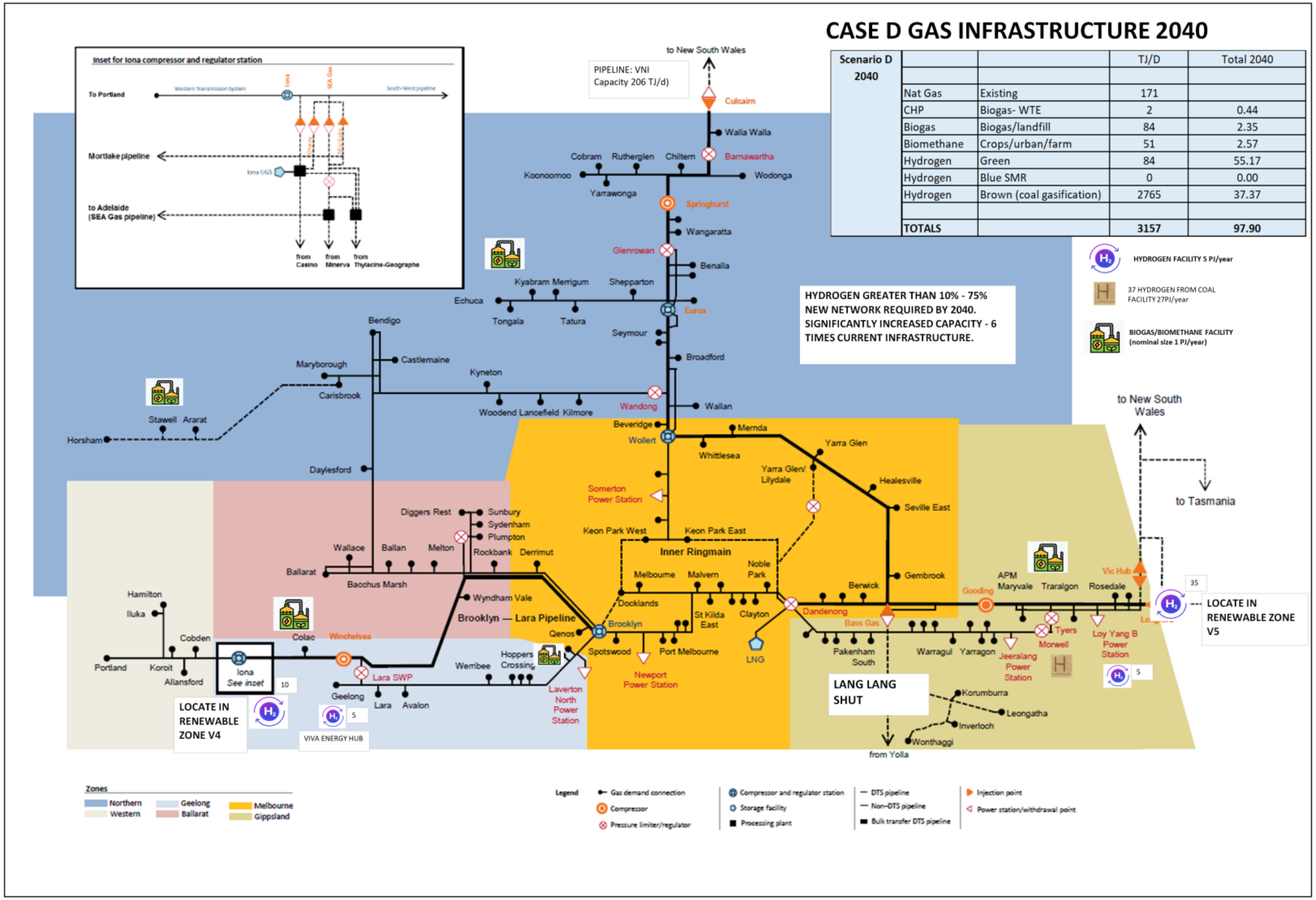


CASE D GAS INFRASTRUCTURE 2030

Scenario D 2030			TJ/D	Total 2030
	Nat Gas	Existing	570	
	CHP	Biogas- WTE	2	0.05
	Biogas	Biogas/landfill	29	0.81
	Biomethane	Crops/urban/farm	17	0.89
	Hydrogen	Green	29	19
	Hydrogen	Blue SMR	0	0
	Hydrogen	Brown (coal gasification)	1433	19
	TOTALS		**1510**	**40.17**

HYDROGEN GREATER THAN 10% PARTIAL NEW NETWORK REQUIRED BY 2030. SIGNIFICANTLY INCREASED CAPACITY - 6 TIMES CURRENT INFRASTRUCTURE.

Figure 68: Scenario D - Gas Spatial Analysis 2040

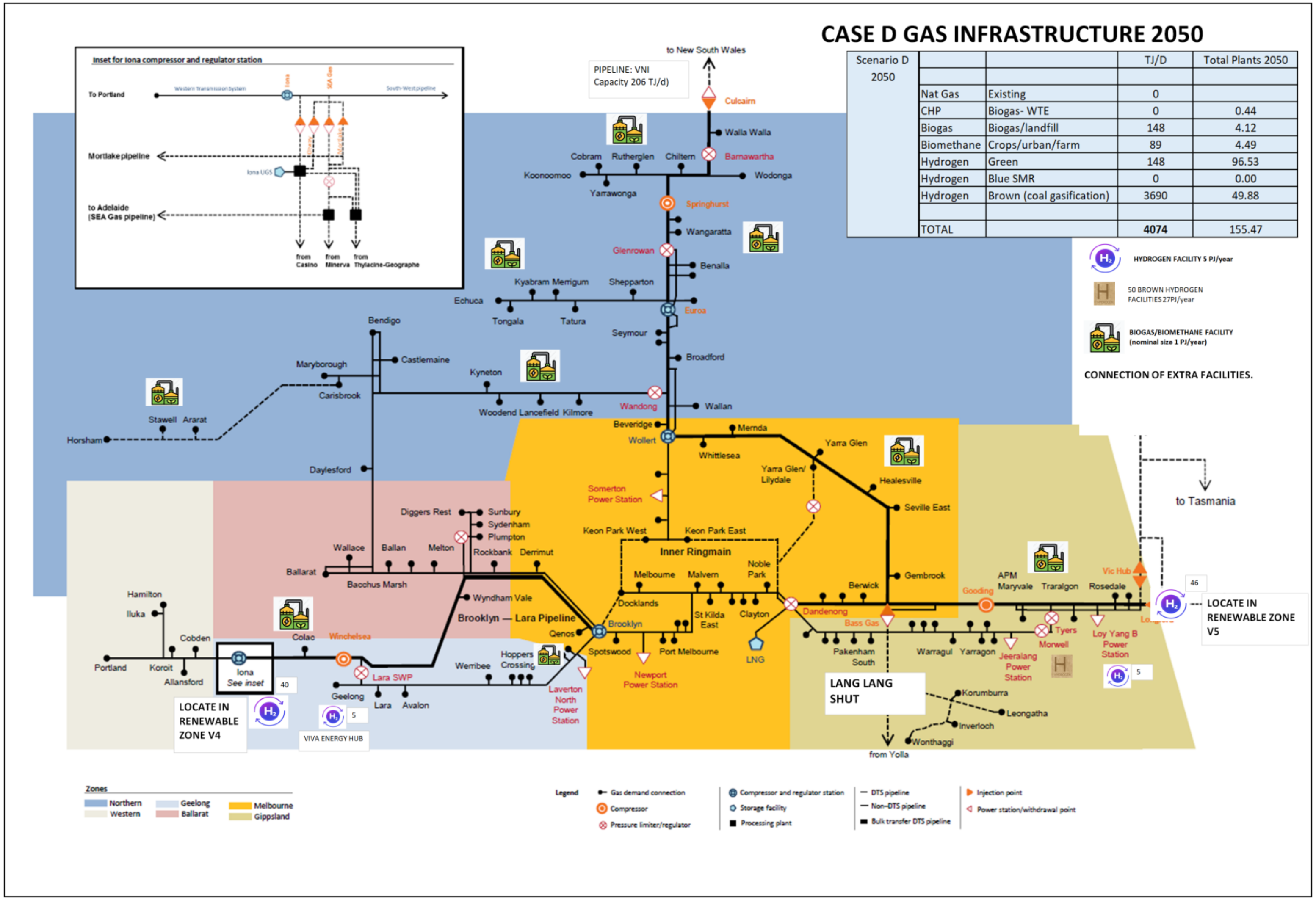


CASE D GAS INFRASTRUCTURE 2040

Scenario D 2040			TJ/D	Total 2040
	Nat Gas	Existing	171	
	CHP	Biogas- WTE	2	0.44
	Biogas	Biogas/landfill	84	2.35
	Biomethane	Crops/urban/farm	51	2.57
	Hydrogen	Green	84	55.17
	Hydrogen	Blue SMR	0	0.00
	Hydrogen	Brown (coal gasification)	2765	37.37
	TOTALS		3157	97.90

HYDROGEN GREATER THAN 10% - 75% NEW NETWORK REQUIRED BY 2040. SIGNIFICANTLY INCREASED CAPACITY - 6 TIMES CURRENT INFRASTRUCTURE.

Figure 69: Scenario D– Gas Spatial Analysis (2050)



CASE D GAS INFRASTRUCTURE 2050

Scenario D 2050			TJ/D	Total Plants 2050
	Nat Gas	Existing	0	
	CHP	Biogas- WTE	0	0.44
	Biogas	Biogas/landfill	148	4.12
	Biomethane	Crops/urban/farm	89	4.49
	Hydrogen	Green	148	96.53
	Hydrogen	Blue SMR	0	0.00
	Hydrogen	Brown (coal gasification)	3690	49.88
	TOTAL		**4074**	155.47

6.3 Natural Gas

Scenario D targets a complete replacement of natural gas relying primarily on the adoption of brown Hydrogen (gasification of brown coal), with some contribution from

- renewables
- biogas
- green H2

Utilisation of the existing natural gas infrastructure would be limited in Scenario D given the potential materials incompatibility issues with transporting Hydrogen in carbon steel pipelines. Instead, it is likely that rapid installation of large scale Hydrogen transportation infrastructure would be required given the specific location of the brown coal resource i.e., this Scenario is limited to a centralised energy production model.

6.4 Road Vehicle Fuels

The scale of uptake for BEVs and HFCVs was assessed for Infrastructure Victoria's description of Scenario D (Appendix 1) and recorded in Table 92. 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.

Introduction of HFCVs in accordance with Table 92 causes a pro-rata reduction in the amount of kilometres travelled for both hydrocarbon vehicles and BEVs in order to maintain the overall total kilometres travelled for all road vehicles described in the prior analysis [Reference 8]. The selected split of kilometres travelled by vehicle category and fuel type for Scenario D for the three time periods is defined in Table 99, Table 100, and Table 101.

Table 99: Scenario D (2030) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	**77,519,730,017 KM**			
	Light Vehicle (km) / (% Grand Total)		**Heavy Vehicle (km) / (% Grand Total)**	
HC Vehicles	48,793,877,737	63%	1,748,986,234	2%
BEVs	21,022,404,359	27%	1,303,277,886	2%
HFCVs	775,197,300	1%	3,875,986,501	5%
Total	**70,591,479,396**		**6,928,250,621**	

Table 100: Scenario D (2040) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	89,147,689,520 KM			
	Light Vehicle (km) / (% Grand Total)		Heavy Vehicle (km) / (% Grand Total)	
HC Vehicles	23,908,321,944	27%	161,554,226	0%
BEVs	56,380,402,466	63%	3,348,549,512	4%
HFCVs	891,476,895	1%	4,457,384,476	5%
Total	**81,180,201,305**		**7,967,488,215**	

Table 101: Scenario D (2050) - Selected Split of Kilometres Travelled by Vehicle Category and Fuel Type

GRAND TOTAL ALL VEHICLES	93,411,274,671 KM			
	Light Vehicle (km) / (% Grand Total)		Heavy Vehicle (km) / (% Grand Total)	
HC Vehicles	0	0%	0	0%
BEVs	83,194,507,178	89%	1,809,752,772	2%
HFCVs	1,868,225,493	2%	6,538,789,227	7%
Total	**85,062,732,672**		**8,348,541,999**	

Based on typical fuel consumption for each type of vehicle, the GHG Tool estimated the fuel requirements, with results provided in Table 102, along with emissions.

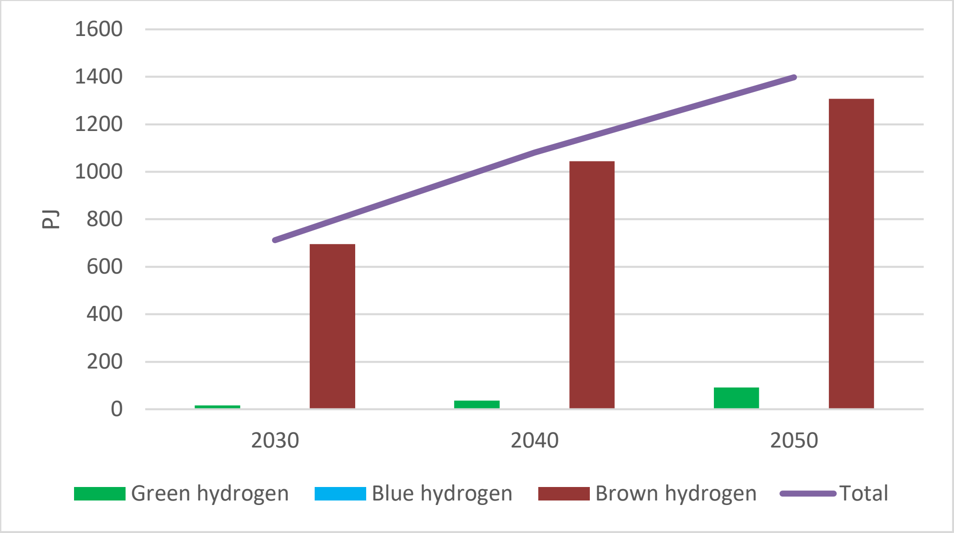
Table 102: Scenario D – Total Fuel Consumption by Road Vehicle Type

Year	**All Road Hydrocarbon Vehicles**	**All Road BEVs**	**All Road HFCVs**
	Gasoline & Diesel (PJ / yr)	**Electricity (PJ / yr)**	**Hydrogen (PJ / yr)**
2030	163	13	53
2040	69	30	71
2050	0	37	86

6.5 Hydrogen

Scenario D is the only option to utilise brown coal, with a large uptake in 2030 increasing over the study period. There is also a small amount of green hydrogen production, as shown in Figure 70.

Figure 70: Hydrogen Generation for Scenario D



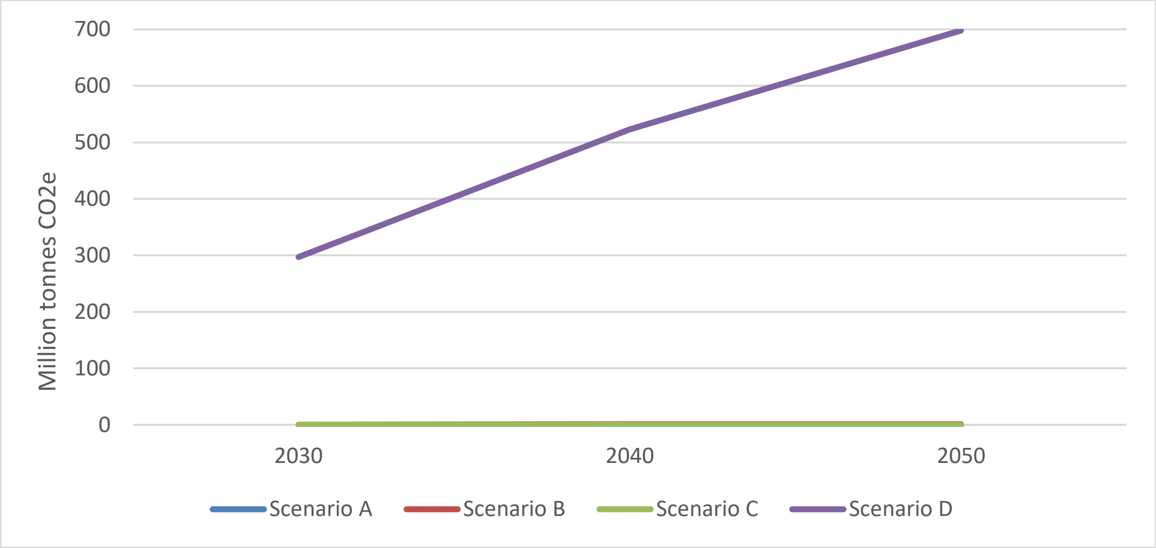
In Scenario D a massive upscale of brown hydrogen from coal is forecast to be required. By 2030, 696 PJ/yr of hydrogen from brown coal is required. This is equivalent to around 6 Mtpa of hydrogen requiring 80 Mtpa of coal to be converted via brown coal gasification. To put that in context the largest coal gasification plant in the world in China converts about 20 Mtpa of coal into syngas and has over 24 individual gasification trains. The capital cost for a world-scale 5 Mtpa coal gasification to hydrogen plant would likely be in the range $5 to 10 billion, excluding CO_2 compression, transport and sequestration. Such a project will require about 3 to 5 years for planning, permitting and engineering and another 3 years to build. The development of brown coal to hydrogen also requires certainty on the CCS and this will also take time. The partners in the HESC project say that brown coal to hydrogen could reach 500,000 tpa of H_2 by 2030. Therefore, it would not be possible to build brown hydrogen infrastructure to achieve 6 Mtpa in the time available between now and 2030. Further increases in production to over 1250 PJ/yr of hydrogen production from coal will require enormous investment, certainty regarding the sequestration of enormous volumes of CO_2 which both seem unlikely.

6.6 Carbon Capture and Storage (CCS)

Scenario D has the largest volume of CO_2e captured and stored, as shown in Figure 71.

In Scenario D, hydrogen production primarily from gasification of Latrobe Valley brown coal is assumed to ramp up massively to develop a large-scale low-carbon hydrogen export industry. The CO_2 by-product from the hydrogen generation plants is captured and stored with large-scale CCS offshore Gippsland.

Figure 71: Carbon Capture and Storage



In this scenario the amount of CO_2 required to be captured and stored reaches 698 Mtpa and would need to be supported by a significant expansion of the CarbonNet project and development of numerous other large-scale CCS projects. This would be equivalent to 35 expanded (20 Mtpa) CarbonNet projects which is considered to be unrealistic.

Due to the advanced age of the existing natural gas pipeline network, new purpose-built pipelines will be required for the transport of CO_2 to multi-user storage sites, such as CarbonNet.

The results from this part of the analysis support consideration of making policy recommendations to develop a method for the treatment of CCS as an eligible activity for earning ACCUs is required to enable CCS projects to proceed.

6.7 Energy Efficiency

Scenario D includes small-scale energy efficiency improvements including the limited use of smart meters and smart grids to optimise the use of variable renewable power sources and energy storage systems since electrical power playing only a minor role. Improved insulation standards for new buildings are also imbedded into this scenario.

Scenario D also incorporates ground source heat pumps (GSHP) as an energy efficiency measure for both heating and cooling and hot water supply for commercial and industrial users.

6.8 Social

The potential for the use of coal to generate hydrogen has a large degree of support in the Latrobe Valley, with the hope that job losses resulting from the closure of coal fired power plants should be reversed as Victoria transitions to the use of Hydrogen, . The recent announcement of the decision to fast track the closure of the Yallourn power station, which employs around 500 people, emphasises the social impact in this region. Currently the

Hydrogen Energy Supply Chain project, a Japanese-Australian consortium, is in pilot phase, and should the technology move to the commercial phase the generation of around 8000 jobs and an $11 billion boost to the economy is predicted. The project has broad government support. As shown in Section 5.9.1, showed that Scenario D has the largest potential for job creation thanks to the high dependence on Hydrogen production and other renewables included in the energy mix.

Conversely, the use of coal for hydrogen generation has many detractors outside of the traditional coal producing regions, and the technology, including the amount of CCS required is yet to be proven on a commercial scale. The developing hydrogen certification schemes reflecting the provenance of hydrogen may serve to disadvantage this production method as customers turn to 'greener' forms of hydrogen.

For this Scenario, as the production of hydrogen needs to be centralised close to the source of coal and CCS, the technical challenges of transporting high pressure Hydrogen to an appropriate export facility also require surmounting.Environmental

6.8.1 Emissions

Under Scenario D, Victoria will reach net zero emissions by 2050, as shown in table below.

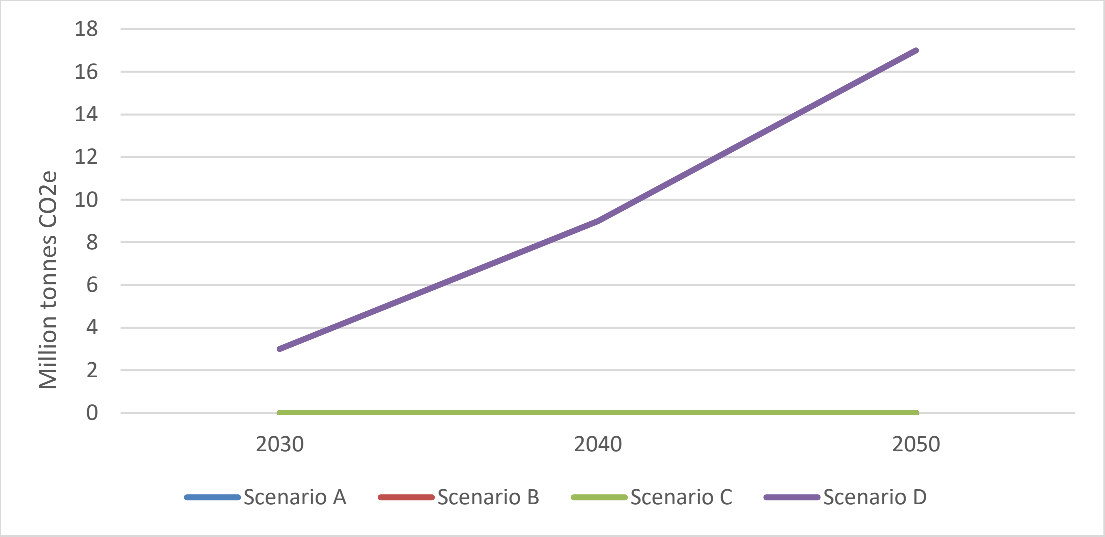
Table 103: Scenario D Greenhouse Gas Emissions

Sector	2005 Mt CO_2-e	2030 Mt CO_2-e	Change 2005 to 2030 %	2040 Mt CO_2-e	Change 2005 to 2040 %	2050 Mt CO_2-e	Change 2005 to 2050 %
Electricity generation	67	49	26.9	50	25.4	48	28.4
Direct combustion	15.2	8	47.4	-15	198.7	-31	303.9
Transport	20.2	11	45.5	5	75.2	0	100.0
Fugitive emissions	2.4	2	16.7	1	58.3	0	100.0
LULUCF (land use, land use change and forestry)	-8.7	-3	65.5	-9	-3.4	-17	-95.4
Total (net emissions)	**104.8**	**67**	36.1	**33**	68.5	**0**	100.0

6.8.2 Land Use, Land Use Change and Forestry

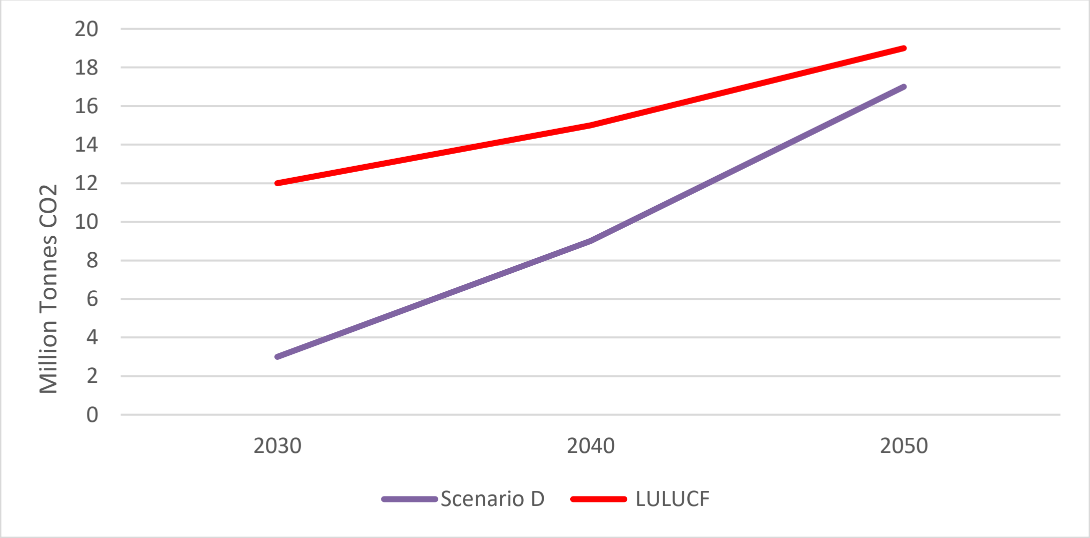
Scenario D is the only scenario in the study to utilise the use of agriculture-based sequestration of CO_2e (forestry, marine environment, soil farming) (refer to Figure 72).

Figure 72: Carbon Dioxide Equivalents Sequestered through Agricultural Activities



The Interim Emissions Reduction Targets (Ref 30) has predicted that carbon sequestered as a result of land use, land use changes and forestry (LULUCF) values will increase by approximately 25% by 2030, from a 2018 level of 9.7 million tonnes of CO_2 sequestered. None of the other scenarios show LULUCF emissions being reduced to the same extent as that predicted by the Independent Expert Panel. Figure 73 illustrates the CO_2 sequestration achieved in Scenario D as compared to the Independent Expert Panel's predictions.

Figure 73: Scenario D Agriculture Based Sequestration compared to predicted LULUCF Values



6.9 Risk & Opportunities

Environment

As Scenario D uses coal for hydrogen production, the quantity of CCS required represents a risk of not meeting net zero as the predicted capacity of the only CCS facility currently under investigation, CarbonNet, is inadequate to capture the amount of CO_2 produced in this scenario.

Hydrogen in this scenario is used as an energy store, reducing reliance upon hydroelectric power for peak shaving with its associated secondary environmental impacts.

Societal

One of the main risks associated with the use of coal in Scenario D is the lack of support from the general public outside of Victoria’s traditional coal producing regions. Conversely, the approach would be strongly supported in regions such as the Latrobe Valley, where the potential use of coal will be seen as positive due to the potential for job opportunities.

A societal risk associated with this Scenario is the global desire for hydrogen from renewable sources, making Victorian hydrogen less attractive than green alternatives.

Economics

The main economic risk associated with Scenario D is the potential for cost blowouts associated with the quantity of carbon capture infrastructure development required to support this scenario. This is somewhat offset by the economic advantages of large-scale hydrogen export hubs and the potential impact this has on jobs and growth in Victoria.

The same comments regarding costs associated with dealing with the risk of hydrogen embrittlement in high pressure gas pipelines, and the regulatory burden associated with the degree of infrastructure development required for this scenario is even greater due to the degree of infrastructure required. Although the electrical transmission development work is lower, the degree of pipeline infrastructure required is significant, tripling the expected capacity of the hydrogen pipelines required for Scenario C.

Technical

The major technical risks are associated with the ability to find and develop adequate CCS infrastructure, and the challenge of high-pressure hydrogen distribution though the transmission network due to the potential for embrittlement. As hydrogen production relies on coal in this scenario, a centralized production facility would be required resulting in the need for high-pressure hydrogen lines to feed export hubs and Victorian end users. As hydrogen has a lower volumetric heating value than natural gas, the size or number of pipelines required to deliver the same quantity of energy is approximately tripled.

In addition, it is expected that it will be unlikely to be able to reuse existing pipelines for CO_2 at the pressure required to allow injection into offshore carbon capture locations such as CarbonNet.

Safety

Similar Safety risks apply to Scenario C, which consist of the potential for battery fires in the home, and explosion risk due to the presence of unodorised, and therefore undetected hydrogen leaks within homes resulting in explosion risk. It is expected that at refuelling stations, the presence of hydrogen storage can be managed in a similar manner to the management of LPG bullets at fuel stations currently. Risk associated with any large scale hydrogen storage facilities at Industrial sites can be managed under the Victorian MHF regulations.

6.10 Comparative Cost Index

The cost estimate for each scenario is presented as a “cost index” rather than a dollar value to allow the cost trends across all scenarios to be identified, rather than supporting a cost benefit analysis of each scenario, being beyond the scope of this work. The example of the “comparative cost index” illustrates the general intent and mandate of this study being a comparative analysis of scenarios to identify trends, drivers, risks and opportunities in support of drawing conclusions regarding the most affordable, reliable pathway to Net Zero Emissions by 2050. The development of classed cost estimates for each scenario is beyond the scope of this study.

The comparative cost index for Scenario D was calculated to be 4.3 using the method described in Section 2.2.2, and this value is used as input to the Scenario Screening described in Section 7.

7 SCENARIO SCREENING

7.1 Objectives

The Scenario Screening activity is the final step in the analysis workflow, as it uses all of the prior work as input including technical analysis, spatial analysis, cost estimation, risk & opportunity assessments, etc. The analysis undertaken will typically align to the screening parameters, for example the energy and emissions modelling informs to the environmental parameter, the cost estimation work informs the cost parameter, the social assessments inform the social parameter so on. The output of the Scenario Screening activity provides key input to the conclusions and recommendations, and hence the location of this section matches the workflow by being located after the technical and cost analysis, but before the conclusions and recommendations.

The objective of the Scenario Screening is to identify the strongest scenario(s) to take forward for more detailed analysis. The Scenario Screening activity provides structured, informed decision support information that will be used by the contractor to form its recommendations to the client regarding the strongest scenario(s).

The Scenario Screening Workshop forms one part of the overall Scenario Screening activity, and the outcome of the Screening Workshop represents a “consensus case” developed by the entire project team (client and contractor). The Screening Workshop will be preceded by contractor’s preparations to pre-populate the Screening Analysis. Along with development of a consensus case comes the need to identify “consensus variants” relating to screening parameter weighting, and scenario rankings. It is not intended for the “consensus case” to represent a unanimous project position, and a post workshop assessment activity will be undertaken to analyse the “consensus variants” and estimate sensitivity and robustness of the “consensus case”.

7.2 Scope

The scope of the Scenario Screening activity has been limited in line with the notes below.

- Four scenarios defined in Appendix 1.
- State of Victoria with interconnections to other States being noted but not analysed.
- Energy gas and electrical generation and distribution infrastructure requirements rather than the ultimate user.
- (Reference 5 : Minutes, Scenario Screening Workshop Minutes) in line with Client advice, the Stakeholder / Regulatory / Political parameter should be removed from the scope of the Scenario Screening.

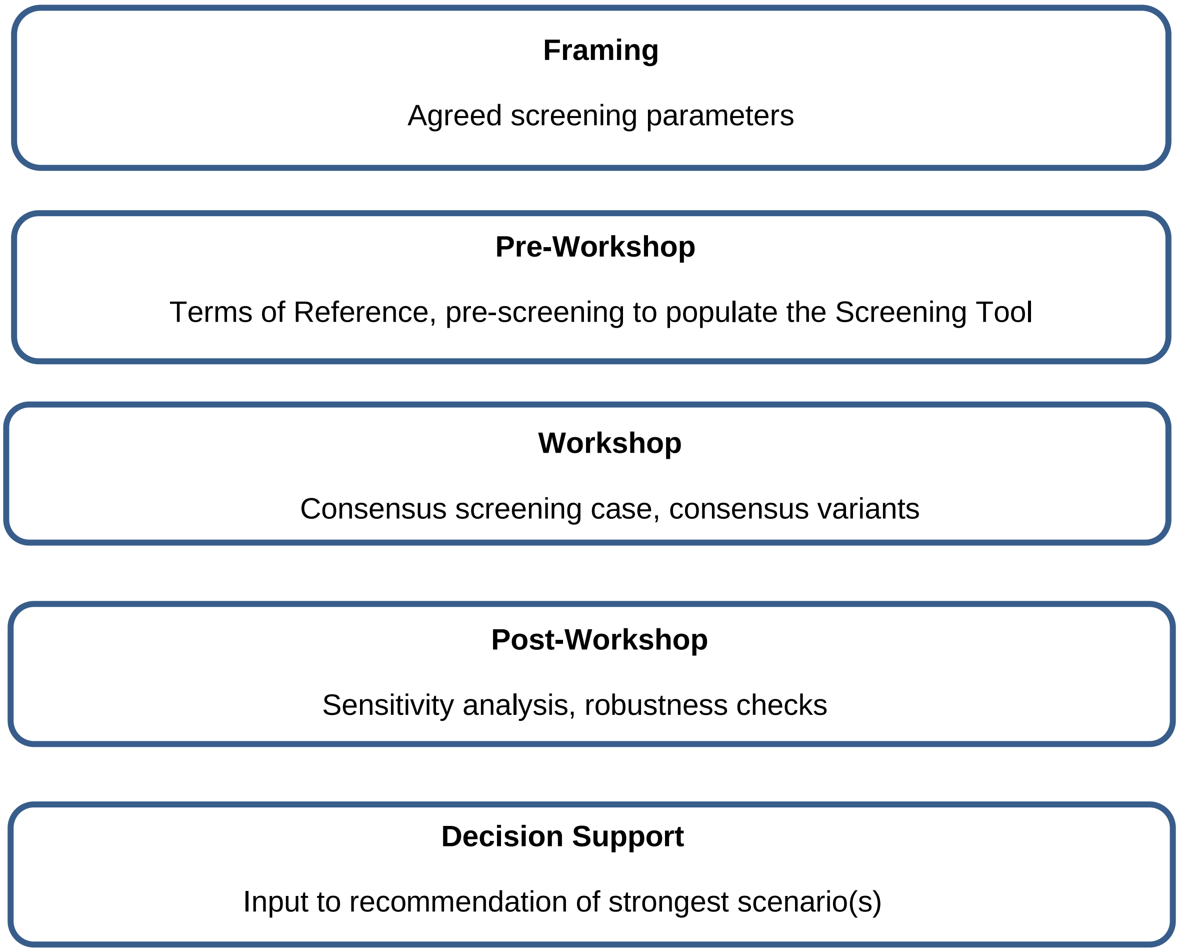
Consistent with the qualitative, comparative screening methodology being utilized it is not required to have quantified data available for each of the screening parameters to undertake the scenario ranking. Instead, informed opinions, supported by consensus, will be used to rank the scenarios, referencing the knowledge gained during the analysis and the highly qualified and experienced Study Team members.

7.3 References

Ref.	Document Reference	Title
1	N/A	Technical Analysis of Energy Generation and Carbon Offsets
2	N/A	Spatial Analysis of Energy Infrastructure
3	N/A	(Infrastructure Victoria) Scenario Descriptions (Appendix 1)
4	210301-GEN-MOM-001	Minutes, Inception Meeting, 30-APR-21
5	210301-GEN-MOM-005	Minutes, Scenario Screening Workshop, 22-APR-21

7.4 Methodology

Figure 74 : The Scenario Screening Process



Given the combination of limited study time and expansive analysis scope a qualitative, a comparative screening methodology will be utilized based on high level screening parameters. This approach has proven to be effective where a highly qualified and experienced Study Team is engaged in the Screening which is deemed to be the case.

The Scenario Screening Workshop forms one part of the overall Scenario Screening activity as illustrated in Figure 74. The outcome of the process is support to the decision of which is the strongest Scenario(s) to brought forward for more detailed assessment.

Each of the key stages of the Scenario Screening process is covered in following sections of this report.

7.5 Screening Parameters and Preliminary Weighting

The Screening Parameters listed below were identified at the Inception Meeting [Ref 4].

The preliminary weightings are arbitrary values required by the Screening Tool algorithm to identify the relative importance of the parameters. The typical “logic” for selecting weightings is to firstly ask “what is the most important parameter” and assign this is relatively large number. Then ask “which is the least important parameter: and assign this a relatively low number. Then ensure that all other parameters have a number somewhere between the high and low, depending on its relative importance. The weightings are not intended to be fixed and will be varied as part of the sensitivity analysis in the post workshop processing activity.

[WEIGHTING] Primary Parameters

- **[100]** Environment
    - o Getting to net zero quicker than 2050
    - o Environmental risk / opportunity balance
- **[50]** Social (acceptable community outcomes)
    - o Community acceptance of transition
    - o Social Risk / Opportunity balance
- **[60]** Economic
    - o Growth & jobs during transition
    - o CAPEX
    - o Economic Risk / Opportunity balance
- **[80]** Technical
    - o Reliability of supply
    - o Technology readiness
    - o Technical Risk / Opportunity balance

[WEIGHTING] Secondary Parameters

- **[30]** Safety
    - o Behind the meter & in the field
    - o Safety Risk / Opportunity balance

7.6 Traffic Light Definition

Colour & Rank Number	Definition
0	(Comparative) non differentiated / cannot be compared
🟩 1	(Comparative) Better / Good / Preferable
🟨 2	(Comparative) Mid-Range Low / Few Issues but Manageable
🟧 3	(Comparative) Mid-Range High / Numerous Issues but Manageable
🟥 4	(Comparative) Worse / Unacceptable / Not Preferable / Issues Unlikely Manageable

7.7 Process Description

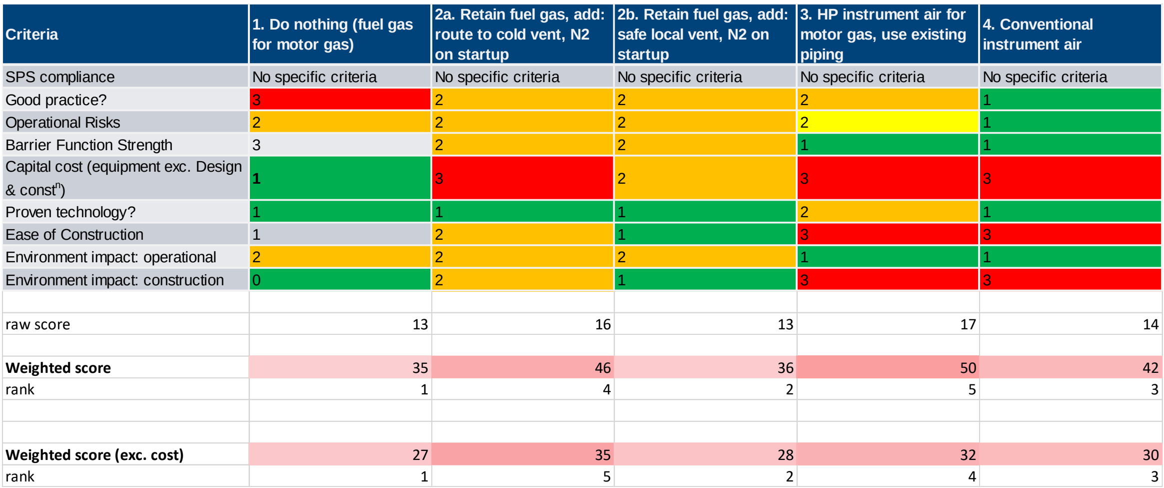
The knowledge and data gained from analysis of the four Net Zero Scenarios, including key risks and opportunities identified during the (contractor) Risk & Opportunity Workshop will all feed into the Scenario Screening activity aimed at identifying the strongest Net Zero Emission 2050 scenario for the State of Victoria. A qualitative comparative screening methodology will be utilized based on high level screening parameters.

To conduct the Scenario Screening with maximum efficiency, DORIS will utilise an in-house tool based on a **"Traffic Light"** scoring system using weighted screening parameters identified at the Inception Meeting and documented in the Terms of Reference. DORIS considers this approach to be well suited to the Net Zero Emissions Scenario Analysis as it is an intuitive and transparent process that has demonstrated itself to be reliable and robust having been used many times over the years for similar concept select studies.

The Screening Tool calculates a weighted sum for each scenario by adding the product of the assigned rank number and the parameter weighting calculated for all parameters. Because the rank number increases as the comparative favourability decreases, the strongest option will have the lowest weighted sum and the weakest option will have the highest weighted sum.

Figure *75* shows an example comparison table of criteria ranked for each option from a previous study.

Figure 75 : Typical « Workshop Input » to the Traffic Light Option Screening Tool



Criteria	1. Do nothing (fuel gas for motor gas)	2a. Retain fuel gas, add: route to cold vent, N2 on startup	2b. Retain fuel gas, add: safe local vent, N2 on startup	3. HP instrument air for motor gas, use existing piping	4. Conventional instrument air
SPS compliance	No specific criteria	No specific criteria	No specific criteria	No specific criteria	No specific criteria
Good practice?	3	2	2	2	1
Operational Risks	2	2	2	2	1
Barrier Function Strength	3	2	2	1	1
Capital cost (equipment exc. Design & const^{n})	**1**	3	2	3	3
Proven technology?	1	1	1	2	1
Ease of Construction	1	2	1	3	3
Environment impact: operational	2	2	2	1	1
Environment impact: construction	0	2	1	3	3
raw score	13	16	13	17	14
Weighted score	35	46	36	50	42
rank	1	4	2	5	3
Weighted score (exc. cost)	27	35	28	32	30
rank	1	5	2	4	3

7.8 Pre-Workshop

Preparation for the Workshop will commence by informing all Workshop participants, with a priority on the Company's Project Team, to review and understand in advance the methodology, process, and parameters to be used. Reviewing these Terms of Reference and resolving clarifications with DORIS ahead of the Workshop is a suitable way of preparing.

- **Traffic Light Definitions** - refer Section 7.6
- **Comparative Ranking** - not absolute. This requires only that each Scenario be ranked in comparison to the other for each screening parameter, and not on the basis of absolute parameter values. By way of hypothetical example, for the Cost Parameter, and with the knowledge gained from the preliminary analysis results that a significantly larger degree of new electrical generation systems will be required for Scenario A (in addition to reduced availability of carbon offsets) driving overall costs higher than other Scenarios then Scenario A can be ranked "worse" (more expensive) *compared* to the other Scenarios, without having to reference *absolute* calculated cost estimates.
- **Screening Parameters & Weighting** – primary and secondary parameters, generally specified during the Inception Meeting. A preliminary specification of weightings is provided in Section 7.5.

The Screening Tool will then be pre-populated with the Scenario cases and the weighted criteria, and a pre-screening will be by Contractor's Study Team to check all input data, confirm the outputs are logical and explainable, and generally ensure the process is ready for involvement of the Company's Project Team at the Workshop.

The key outcomes of the Preparation stage are:

- Workshop Terms of Reference.
- Option Screening Tool pre-populated.

7.9 Workshop

The Net Zero Emissions Scenario Screening Workshop was held on Thursday 22-APR-21, see Appendix 2 for Minutes (Reference 5).

7.9.1 Objective & Outcomes

The Scenario Screening Workshop forms one part of the overall Scenario Screening activity, and the outcomes of this forum will be to identify the:

- **"Consensus Case"** - developed by the entire project team (client and contractor). It is not the purpose of the "consensus case" to represent a unanimous project position, and a post workshop assessment activity will be undertaken to analyse the "consensus variants" and estimate sensitivity and robustness of the "consensus case".
- **"Consensus Variants"** - relating to any input to the "consensus case" typically screening parameter weighting, scenario rankings, etc. In an ideal Screening Workshop, the "consensus variants" will result from informed debate and constructive challenges amongst the team regarding values for weightings and rankings. Once the consensus and its variant have been documented the team can progress.

An experienced Facilitator will lead the session, and a Scribe will be in attendance to support administration. Antony Loane will facilitate and Andrea Hosey will scribe.

The "Review Team" will comprise key members of Contractor's Study Team and Company's Project Team. These have been identified and included in meeting invite.

7.9.2 Process

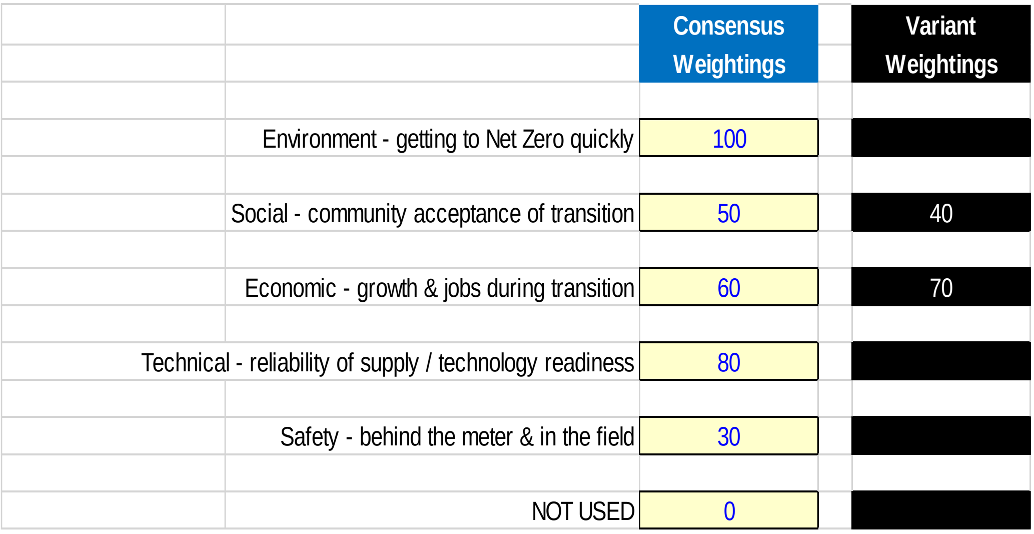
- State aim: "Identify Optimum Net Zero Emission Scenario".
- Review the ranking process: case comparative (not absolute), differentiating criteria only.
- Understand traffic light grading definitions.
- Review criteria (already agreed during pre-workshop preparation).
- Review weighting (already agreed during pre-workshop preparation).
- Undertake ranking. Depending on the familiarity of the Review Team with the Screening Process it may be useful to commence with an "intuitive" screening parameter such as Cost. Once the Scenarios have been ranked against the first parameter the process becomes clear and progress through to more complex parameters can be made.

- As the Workshop requires attention and engagement of all participants the duration of the session is generally limited to 45 minutes before a rest period.
- Whilst a creative and constructive environment is encouraged, any ideas that modify or re-structure the pre-agreed scope will not be assessed, but rather noted and, if necessary, analysed in a post workshop session. Any subsequent results that may influence the Workshop outcomes will be assessed during the Post Processing exercise.
- The workshop is not a design review and so working up solutions to issues identified will not be carried out during the workshop but instead noted and, if required, assessed separately. Any subsequent results that may influence the Workshop outcomes will be assessed during the Post Processing exercise.

7.9.3 Consensus Screening Case (Updated for Final Results)

The Consensus Screening Case developed during the Scenario Screening Workshop is summarised in the following sections (see also Ref 5).

7.9.3.0 Consensus Weightings



	Consensus Weightings	Variant Weightings
Environment - getting to Net Zero quickly	100	
Social - community acceptance of transition	50	40
Economic - growth & jobs during transition	60	70
Technical - reliability of supply / technology readiness	80	
Safety - behind the meter & in the field	30	
NOT USED	0	

7.9.3.1 Consensus Rankings – Updated for Final Results

			Scenario A	Scenario B	Scenario C	Scenario D
			Full Electrification	Partial Electrification	Green & Blue H2 with Offsets & Electrification & Medium Level Biogas	Brown H2
			No Gas	Some Gas	No Gas	No Gas
			No CCS	Some CCS	No CCS	Full CCS
			Consensus Ranking	**Consensus Ranking**	**Consensus Ranking**	**Consensus Ranking**
Environment - getting to Net Zero quickly		**100%**				
101	Getting to Net Zero before 2050	50%	🟨	🟨	🟩	🟥
102	Environmental Risk / Opportunity balance	50%	🟩	🟨	🟩	🟧
Social - community acceptance of transition		**100%**				
201	Community acceptance of transition	50%	🟩	🟩	🟨	🟧
202	Social Risk / Opportunity balance	50%	🟨	🟩	🟨	🟧
Economic - growth & jobs during transition		**100%**				
301	Growth & jobs during transition	34%	🟨	🟧	🟨	🟩
302	CAPEX	33%	🟩	🟩	🟩	🟥
302	Economic Risk / Opportunity balance	33%	🟨	🟩	🟨	🟧
Technical - reliability of supply / technology readiness		**100%**				
401	Reliability of supply	34%	🟧	🟩	🟨	🟨
402	Technology readiness	33%	🟩	🟨	🟧	🟧
403	Technical Risk / Opportunity balance	33%	🟨	🟩	🟨	🟧
Safety - behind the meter & in the field		**100%**				
501	Behind the meter & in the field	50%	🟨	🟩	🟨	🟧
502	Safety Risk / Opportunity balance	50%	🟩	🟩	🟨	🟧

7.9.3.2 Ranking Logic – Updated for Final Results

Table 104 : Ranking Logic Statements

Parameter		Ranking			
		Sc. A	Sc. B	Sc. C	Sc. D
Environ.	Quicker to Net Zero	**REVISED FOR FINAL RESULTS** Achieves Net Zero Slightly before 2050	**REVISED FOR FINAL RESULTS** Achieves Net Zero Slightly before 2050	**REVISED FOR FINAL RESULTS** Achieves Net Zero well before 2050	**REVISED FOR FINAL RESULTS** equires v. large CCS to hieve Net Zero by 2050
	Risk / Opp Balance	Hydrocarbon use minimised	Risk of not capturing all CO2	Hydrocarbon use minimised	Risk of not capturing all CO2 (largest volumes)
Social	Community Acceptance	Comm. happy with solar & wind	Comm. happy with solar & wind	Concern of ongoing nat gas (blue H2)	Concern of ongoing coal (brown H2)
	Risk / Opp Balance	Public opposition to dams (hydro power)	Minimum change	ıblic opposition to dams (hydro power)	Brown coal and public opposition
Economic	rowth & Jobs	**REVISED FOR FINAL RESULTS** Lower jobs potential mpared to H2 scenarios	Lower jobs potential ɔmpared to H2 scenarios	**REVISED FOR FINAL RESULTS** Higher jobs potential for H2 industry	Higher jobs potential for H2 industry
	CAPEX	**REVISED FOR FINAL RESULTS** Significantly lower cost than Sc D	Significantly lower cost than Sc D	**REVISED FOR FINAL RESULTS** Significantly lower cost than Sc D	**REVISED FOR FINAL RESULTS** Significantly higher st than other scenarios
	Risk / Opp Balance	Gas network stranded set – write off, miss out n H2 economy, cost of istributed power asset grade blow out. Li/rare	Parts of gas network tranded asset – write off , niss out on H2 economy	ɔst of distributed power sset upgrade blow out. Li/rare earth cost risks	CCS cost blowouts. pportunity LNG export.
Technical	Reliability of Supply	most complex power supply with “amateur anagement” (behind the meter)	Minimal change	H2 storage & distribution efficiency	H2 storage & distribution efficiency
	Technology Readiness	Solar, wind, hydro proven	Mixed bag	2 technology at scale	2 technology at scale
	Risk / Opp Balance	Concentrated solar opportunity	Less new technology	portunities concentrated solar, H2 production cost / scale red’n.	CCS and H2 ıbrittlement risks in high pressure lines
Safety	Behind the Meter / In Field	More complex behind the meter	Least change / most understood	H2	H2 (largest volume)
	Risk / Opp Balance	Household battery fire	Household battery fire	Household battery fire, ydrogen risks (storage / piping / cars)	Household battery fire, ydrogen risks (storage / piping / cars)

7.9.3.3 Results – Updated for Final Results

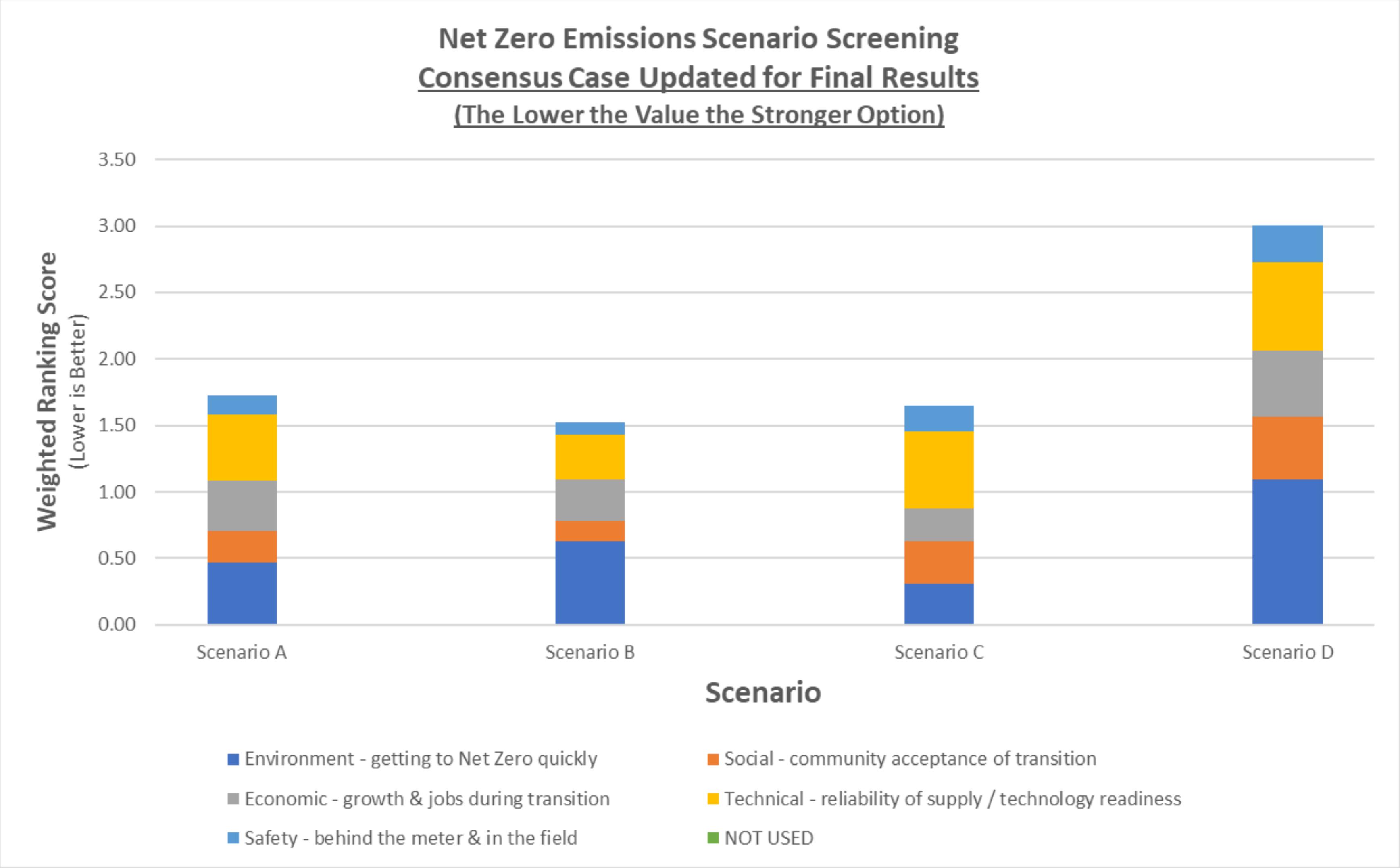
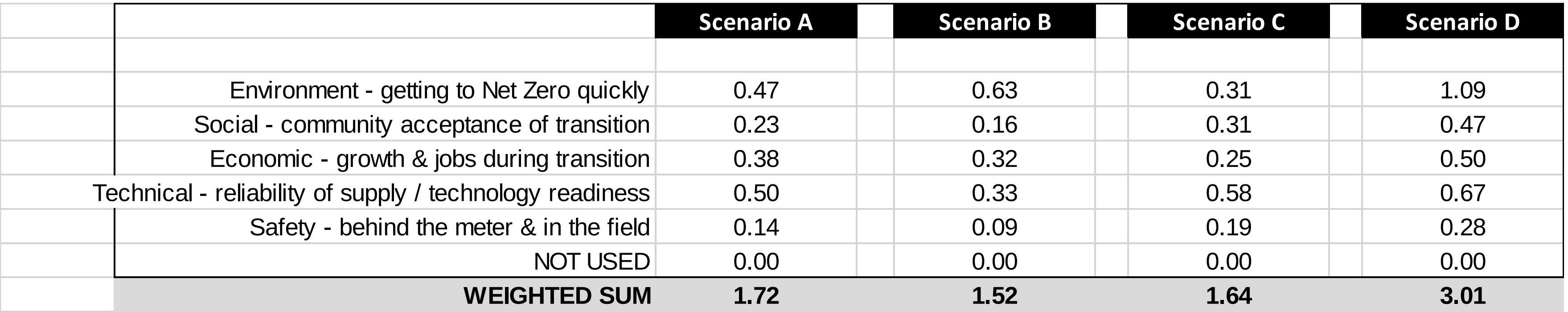


Figure 76: Weighted Screening Sums for Each Scenario – Revised for Final Results



	Scenario A	Scenario B	Scenario C	Scenario D
Environment - getting to Net Zero quickly	0.47	0.63	0.31	1.09
Social - community acceptance of transition	0.23	0.16	0.31	0.47
Economic - growth & jobs during transition	0.38	0.32	0.25	0.50
Technical - reliability of supply / technology readiness	0.50	0.33	0.58	0.67
Safety - behind the meter & in the field	0.14	0.09	0.19	0.28
NOT USED	0.00	0.00	0.00	0.00
WEIGHTED SUM	**1.72**	**1.52**	**1.64**	**3.01**

7.9.3.4 Conclusion – Updated for Final Results

The Consensus Screening Case (updated for final results) identified the following key outcomes:

- **Strongest Cases : Scenario A, B, C (very little difference)**
- **Weakest Case : Scenario D**

Refer Section 7.10 (Post Processing) for an assessment of the robustness of the consensus outcomes.

7.10 Post Processing

In this activity the “consensus case” is tested for sensitivities and its robustness to unexpected events checked.

7.10.1 Objective

Test the “consensus case” for sensitivities and determine its robustness to unexpected events.

7.10.2 Process

Post processing of the Screening Workshop outcomes is a vital exercise when utilising the “Traffic Light” option screening tool, ensuring that uncertainty in the input data and any variation in the judgement of the Review Team typically relating to ranking values, criterion weighting, etc. is accounted for in the subsequent recommendations to support the decision as to which Scenario(s) to bring forward for further analysis and assessment.

The process requires that each “consensus case variant” is systematically tested and results recorded, noting any change to the consensus case outcome. General sensitivities can also be checked during this analysis such as a modification to the extent of Carbon Capture and Storage, CCS, adoption in Scenario D, or the speed of uptake of Hydrogen Fuel Cell Vehicles, HFCVs, in Scenario C. This mode of assessment is considered to be “sensitivity analysis”.

Another mode of post processing deals with cases such as un-planned future events that may affect key underlying case assumptions. A hypothetical example may be a completely novel technology breakthrough that obviates the need for the proposed systems, on the basis of either energy generation, or carbon utilisation. “Break-point analysis” may be carried out as part of this activity to determine which conditions would be required to change a scenario from strong to weak. This mode of assessment is considered a “robustness check”.

7.10.3 Sensitivity Analysis

In this assessment all variants to the consensus case that were identified during the Screening Workshop will be run through the screening tool and any change to the consensus screening outcomes, namely change in scenario relative rankings, will be highlighted.

7.10.4 Weightings

Changing the consensus case for the weighting variants (both separately, and combined) was found to make no change to the consensus screening outcomes, namely all cases retained the same comparative ranking, with results recorded in the table below.

Table 105 : Weighting Sensitivities

Case	Change	Value	Strongest Case
Consensus			A, B, C
4.2.1.1 – Wso	Weighting Social	40	A, B, C
4.2.1.2 - Wec	Weighting Social	70	A, B, C
4.2.1.3 – Wall	Weighting all Variants	Above	A, B, C

7.10.5 Rankings

Changing the consensus case for the ranking variants (both separately, and combined) was undertaken with results recorded in the table below.

Table 106 : Ranking Sensitivities

Case	Change	Value	Strongest Case
Consensus			A, B, C
4.2.2.1 – Ren102D	Ranking Enviro – Risk Opp (Sc D)	RED	A, B, C
4.2.2.2 – Rso201A	Ranking Social – Comm Acc (Sc A)	YELLOW	A, B, C
4.2.2.3 – Rso201B	Ranking Social – Comm Acc (Sc B)	YELLOW	A, B, C
4.2.2.4 – Rso201D	Ranking Social – Comm Acc (Sc D)	GREEN	A, B, C
4.2.2.5 – Rso202D	Ranking Social – Risk Opp (Sc D)	RED	A, B, C
4.2.2.6 – Rec301A	Ranking Econ – Jobs Grow (Sc A)	GREEN	A, B, C
4.2.2.7 – Rec301D	Ranking Econ – Jobs Grow (Sc D)	YELLOW	A, B, C
~~4.2.2.8 – Rec302D~~	~~Ranking Econ – CAPEX (Sc D)~~ None (consensus case for final results)	~~RED~~	A, B, C

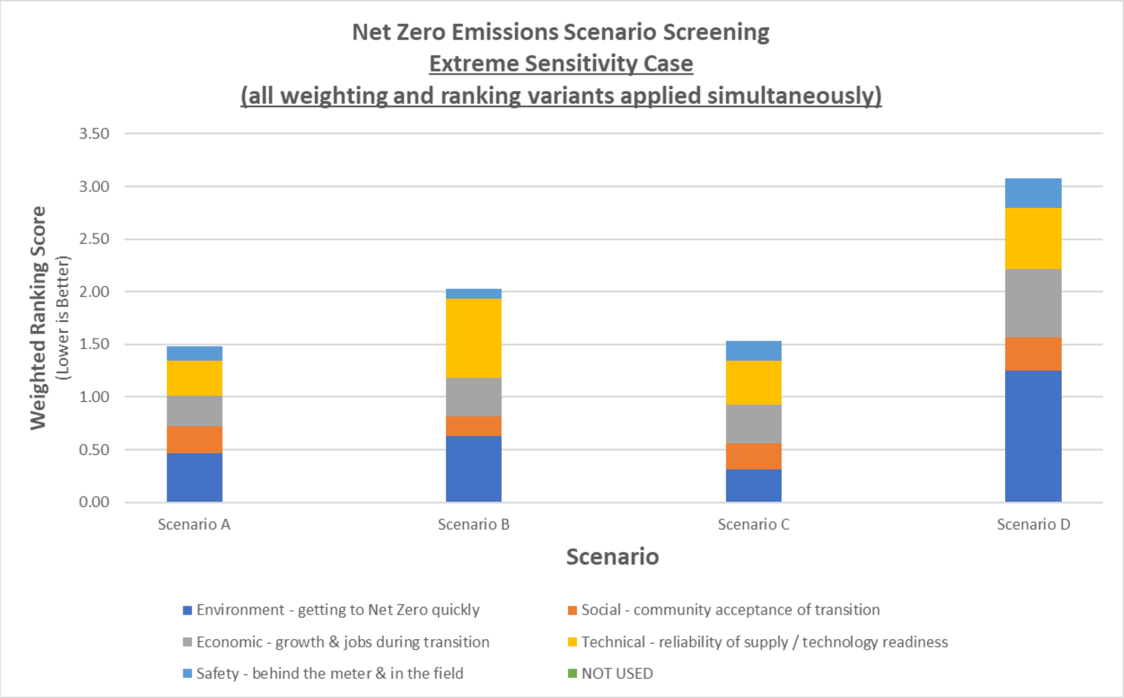
4.2.2.9 – Rte401A	Ranking Tech – Rel Sup (Sc A)	GREEN	A, B, C+
4.2.2.10 – Rte401B	Ranking Tech – Rel Sup (Sc B) (“what happens if CCS doesn’t work ?”)	RED	A, B, C
4.2.2.11 – Rte402B	Ranking Tech – Tech Read (Sc B)	RED	A, B, C
4.2.2.12 – Rte402C	Ranking Tech – Tech Read (Sc C)	GREEN	A, B, C
4.2.2.13 – Rte403D	Ranking Tech – Risk Opp (Sc D)	YELLOW	A, B, C
4.2.2.14 – Rall	Ranking all Variants	Above	A, C

7.10.6Conclusion

The consensus screening outcomes were found to match all sensitivity runs based on singular adjustment of weightings or rankings to the variant value.

Only in the extreme case where all weighting and ranking variants were applied simultaneously was a change to the consensus outcome identified with Scenarios A and C becoming the strongest cases.

Figure 77 : Scenario Screening Results for Extreme Sensitivity Case



7.11 Robustness Check

In this assessment the value of weightings and rankings at which the consensus screening outcomes are changed will be determined. The results of this assessment provide an indication of the robustness of the strongest case identified in the consensus screening.

7.11.1Weightings

Changing the weightings of the consensus case parameters (both separately, and in combinations) was undertaken and results recorded below.

Table 107 : Individual Weighting Adjustments

Parameter	Weighting		Strongest Case
	Consensus	Change	
Environment	100	10	B
		120	A, B, C
Social	50	10	A, B, C
		120	A, B, C
Economic	60	10	A, B, C
		120	A, B, C
Technical	80	10	A, B, C
		120	A, B, C
Safety	30	120	A, B+, C

The robustness checks found the consensus outcomes to be generally robust, noting however that a break point appeared with Scenario B becoming the strongest scenario if the Environment parameter becomes un-important (weighting value dropped to 10).

Figure 78 : Robustness Breakpoint - Scenario B becomes Strongest if Environment Parameter becomes un-important

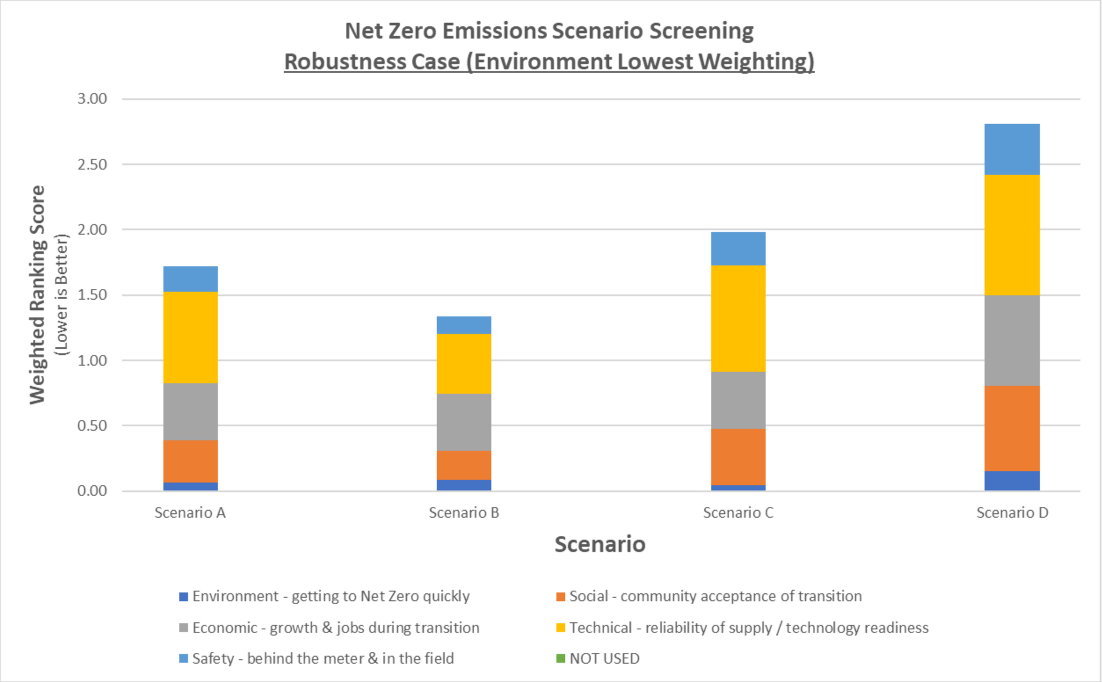
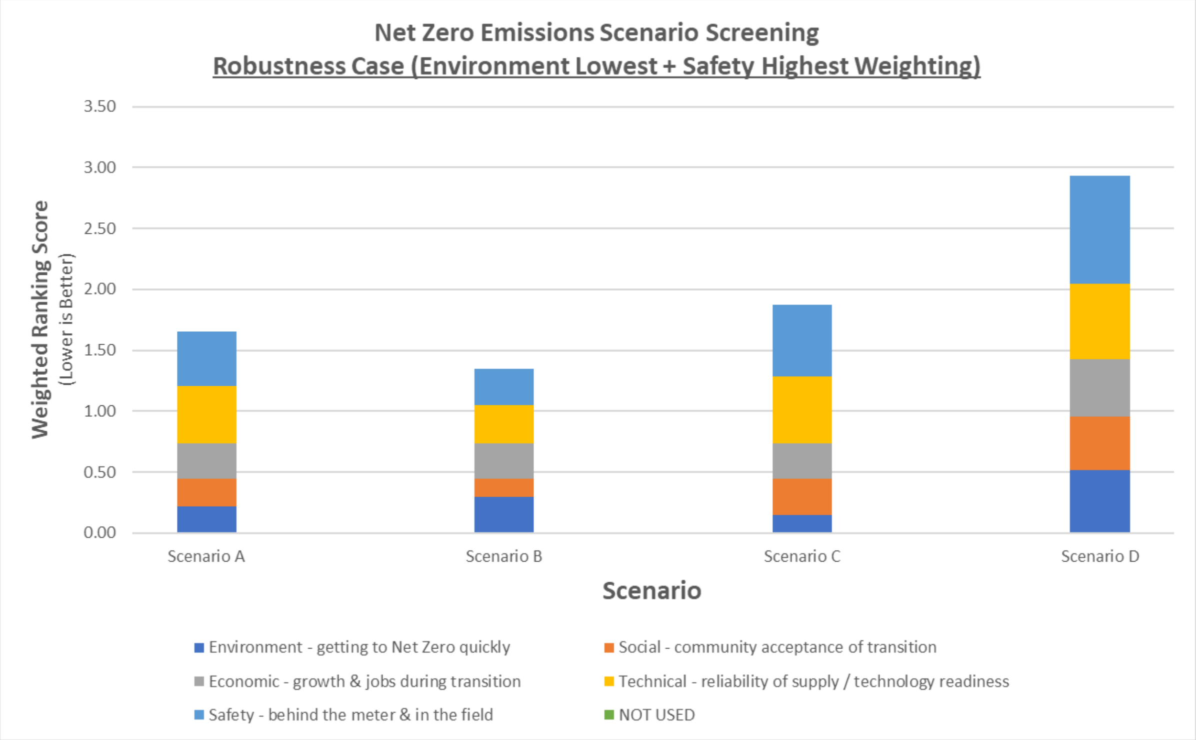


Table 108 : Combinations of Weighting Adjustments

Case	Enviro	Social	Econom	Tech	Safety	Strongest Case
Consensus	100	50	60	80	30	A, B, C
	50	100	Cons.	Cons.	Cons.	A, B+, C
	50	Cons.	100	Cons.	Cons.	A, B+, C
	50	Cons.	Cons.	100	Cons.	A, B+, C
	50	Cons.	Cons.	Cons.	100	B
	50	100	100	Cons.	Cons.	A, B+, C
	50	Cons.	100	100	Cons.	A, B+, C
	50	Cons.	Cons.	100	100	B
	50	100	100	100	Cons.	A, B+, C
	50	Cons.	100	100	100	A, B+, C

Figure 79 : Robustness Breakpoint- Scenario B becomes Strongest if Environment Parameter becomes un-important



7.11.2Rankings

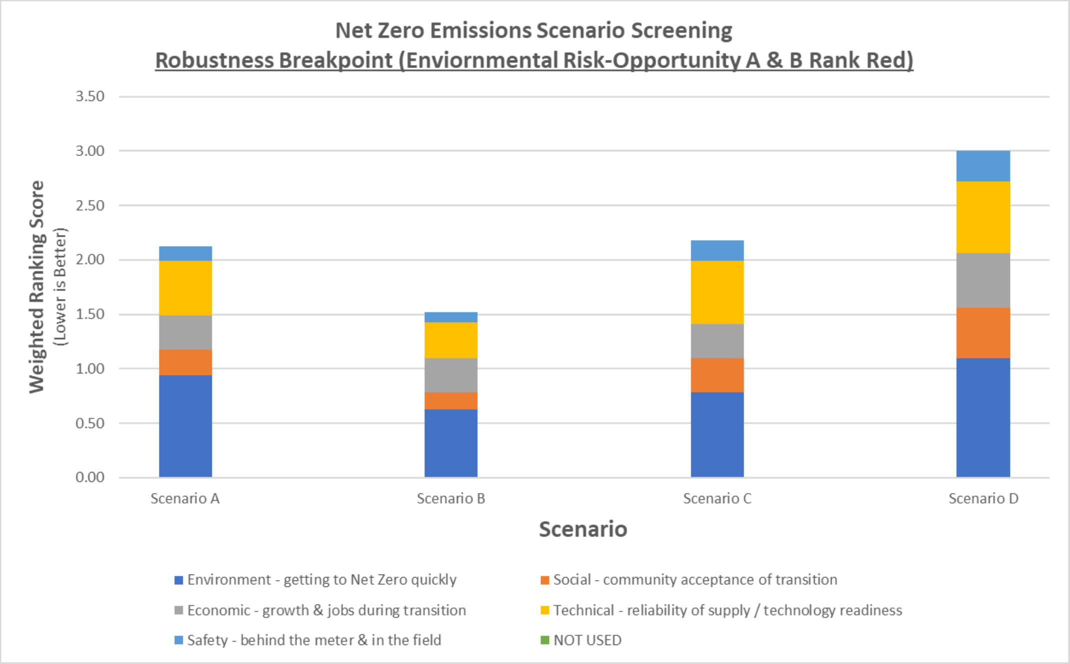
Changing the consensus case rankings by several degrees (both separately, and in combinations) identified two environmental rankings cases, where the consensus outcomes were not matched (see table below for details).

In all other cases Scenarios A, B, C were found to be equivalent strongest cases.

Table 109 : Adjustment of Rankings

Parameter	Sub-Parameter	Case	Ranking				Strongest Case
			Sc. A	Sc. B	Sc. C	Sc. D	
Environ.	Quicker to Net Zero	Consensus	YE	YE	GR	RE	A, B, C
			Cons.	Cons	RE	GR	A, B
	Risk / Opp Balance	Consensus	GR	YE	GR	OR	A, B, C
			RE	Cons.	RE	Cons.	B
Social	Comm. acceptance	Consensus	GR	GR	YE	OR	A, B, C
			RE	RE	Cons.	Cons.	A, B, C
	Risk / Opp Balance	Consensus	YE	GR	YE	OR	A, B, C
			Cons.	RE	Cons.	Cons.	A, B, C
Economic	Growth & Jobs	Consensus	YE	OR	YE	GR	A, B, C
			Cons.	Cons.	Cons.	RE	A, B, C
	CAPEX	Consensus	GR	GR	GR	RE	A, B, C
			RE	RE	RE	GR	A, B, C
	Risk / Opp Balance	Consensus	YE	GR	YE	OR	A, B, C
			Cons.	RE	Cons.	Cons.	A, B, C
Technical	Reliability Supply	Consensus	OR	GR	YE	YE	A, B, C
			Cons.	RE	Cons.	Cons.	A, B, C
	Technology Ready	Consensus	GR	YE	OR	OR	A, B, C
			RE	Cons.	Cons.	Cons.	A, B, C
	Risk / Opp Balance	Consensus	YE	GR	YE	OR	A, B, C
			Cons.	RE	Cons.	Cons.	A, B, C
Safety	Behind Meter / In Field	Consensus	YE	GR	YE	OR	A, B, C
			Cons.	RE	Cons.	Cons.	A, B, C
	Risk / Opp Balance	Consensus	GR	GR	YE	OR	A, B, C
			RE	RE	Cons.	Cons.	A, B, C

Figure 80 : Robustness Breakpoint - Scenario B becomes Strongest if Environment Risk Opportunity Ranking has Scenarios A & B as Unacceptable



7.12 Decision Support

When taken together with the Study Team's judgment, the "consensus case", plus post workshop processing covering sensitivities and robustness checks, the Scenario Screening activity will support a recommendation as to the strongest / optimum Scenario(s) to bring forward for more detailed analysis and assessment.

Recommendations may also identify that further work is required to develop more information before the strongest scenario(s) can be confidently identified.

7.12.1 Conclusions

The following conclusions can be drawn from the post processing analysis:

1. Whilst the consensus screening outcomes are generally robust, there is a mild level of sensitivity to significant changes in the Environmental parameter (weighting and ranking).
2. Under all cases, Scenario B is amongst the strongest outcomes either on its own, or (in almost all cases) alongside Scenarios A and C.
3. Scenario D was always found to be the weakest scenario under all cases.

7.12.2 Recommendations

It is recommended to undertake dynamic, parametric analysis of Scenarios A, B and C to develop more detailed data allowing further differentiation between Scenarios A, B and C. Given the constraints of the static, single point analysis method adopted for this study, it is not considered possible to develop the necessary level of detail to differentiate Scenarios A, B and C. It is further recommended to define the "Optimum Scenario" on the basis of the more detailed data.

8 RISK & OPPORTUNITIES CONCLUSIONS & RECOMMENDATIONS

The evolution of Victoria to a net zero future by 2050 brings many challenges, but it also brings opportunities. A list of some of these opportunities together with recommendations on how these may be capitalised upon is tabulated below.

Issue	Opportunity/recommendation	Scenarios Affected
Decision making on gas infrastructure	As parts of the gas pipeline infrastructure is reaching end of life, certainty around the potential use of and development of an ongoing viable gas network is required to give Operators the confidence to replace aging infrastructure, as necessary. Given the age of infrastructure, this represents an opportunity for rolling replacement of appropriate parts of the network with materials for future use with gas containing higher hydrogen levels should this approach to Net Zero be selected.	Scenario B, C and D
Impact of number of industrial solar farms on environmental and societal landscape values	The societal impact of Industrial scale solar farms can be mitigated by the use of mixed use solar, with panels installed on higher stands to allow grazing or selected cropping beneath. In certain circumstances replacement of monoculture such as a wheatfield with a solar farm can improve the biodiversity of the impacted area (ref: Solar farms, land use and the rise of solar sharing 25th January 2016) (ref: https://www.abc.net.au/news/rural/2020-08-25/parkes-solar-panel-sheep-trial-early-positive-results/12581756) Wind Farms Consider incentives for dual purpose development to allow mixed use infrastructure to be developed.	All
Energy Efficiency Measures	Encouragement of further energy efficiency measures are recommended, measures to be considered include incentivising further uptake of insulation targets and heat pumps for renovations and new builds, increased use of geothermal where technically possible, use of smart technology to reduce heating and lighting in unoccupied rooms, use of remote technology to cool homes in advance of the summer evening peak demand to manage grid loading, smart meters linked to remote timing on appliances for use during periods of low demand, publicity campaign to raise public awareness of energy use. See also recommendations around use of car batteries to assist with peak shaving.	All
Renewable Energy Zone locations	The identification of Renewable Energy Zones provide an opportunity for power infrastructure and job opportunities in regional areas	All
Residential Solar uptake required to meet Net Zero	All Scenarios, but particularly A and C anticipate an even greater uptake of residential rooftop solar. Ongoing incentive schemes should encourage this particularly for households that are non-owner -occupiers to encourage a further depth of take-up. Many systems will require expansion to include battery storage, and incentives to adopt updated technology are recommended. Small business opportunities exist to assist households with services and inspections of solar systems.	All
EV charging requirements	Installation of distributed EV charging infrastructure through metropolitan car parking areas (e.g., rail stations, office car parks) provide installation job opportunities and can be used to charge cars during peak solar production periods reducing peak evening demands. Smart meter installations in residences can be used to charge cars overnight during periods of low demand. Optimise residential meters to allow use of EV batteries as a top up resource	All

	to home power requirement during periods of peak demand. Residents should be able to dial in a minimum km distance EV battery lower limit for safety/convenience, allowing battery to 'top up' during the evening peak and then recharge overnight.	
Concentrated solar power potential for heating, hydrogen manufacture	Track the success of the ARENA funded concentrated solar plant (CSP)(Ref: https://reneweconomy.com.au/world-first-solar-hydro-plant-in-victoria-gets-backing-from-arena-agl-50353/) and other CSPs around the world due to the potential for project costings to drop as the technology develops further	All Scenarios, particularly Scenario C
Biogas development	Use of animal wastes for biogas facilities provide rural employment opportunities, provide gas feedstock for heating and electricity generation, and fertilisers, whilst reducing potential for animal waste contamination of rural waterways in areas of intensive livestock production such as abattoirs	All Scenarios, particularly B
Waste to energy for electricity generation	Waste to energy plant for electricity generation has the ability to reduce demand on landfill, minimise emissions from landfill, and provide either gas or electricity. Consideration of government incentives to encourage power generation companies to develop these types of plants due to the consequential benefits to Victoria	All Scenarios
Impact of bushfire and other weather related events on ability for REZ to supply power to the grid	To minimise the risk of weather related events affecting the electricity grid (e.g., hailstones on solar, high winds, bushfire) it is recommended that farms are distributed through Victoria to minimise the risk of blackouts	All Scenarios
Hydrogen embrittlement risk	Track worldwide developments concerning pipeline transportation of hydrogen to minimise embrittlement risk	Scenarios C & D
Hydrogen safety risk	The use of hydrogen in the home has been identified as a safety risk. Further public information should be developed to assist in public confidence in the uptake of hydrogen. It is noted that natural gas has been used in the home for many years, and the historic incidences of fire associated with gas use is significantly lower than that for electrical fires, and with hydrogen there is no risk of carbon monoxide poisoning. As worldwide interest grows in the use of H2 as a fuel, track developments in the safe use of H2 fuel from pilot studies such as those currently undertaken in Scotland, and any developments in technology to detect hydrogen leak.	Scenarios C & D
Use of gas network for biogas/hydrogen	The Victorian gas network is directly interconnected with NSW, and South Australia. Decisions on increasing hydrogen composition in gas, transition to hydrogen or abandonment of gas pipeline infrastructure altogether cannot be made independently without impacting other States and the decision making on the approach to net zero needs to be unanimous for maximum benefit gained by all states.	All Scenarios
Offshore infrastructure	Victoria has a large number of offshore facilities that are nearing the end of their useful life as reservoirs diminish. Decommissioning of offshore infrastructure is a cost that can be written off against the petroleum resources rent tax (ref ATO TR2018/1). As an alternative, these structures may represent an opportunity for ongoing development as bladeless wind farms, harnessing wave power, or as CCS locations should technology advances allow.	All
Alternative Hydro	Currently modelling assumes hydropower provides the backup to energy supplied into the grid by wind. This requires further development of mountainous regions, a constrained resource in Victoria, or import of power from interstate. Consider further investigation of alternate energy sources such as potential locations for cliff-top hydropower to fulfill Victoria's energy storage needs.	All
Impact on End Users	In Scenario A, two key implications for residential and commercial consumers of transitioning to full renewable electricity are the requirement for extensive replacement of natural gas appliances for	Scenario A

	electrical units, and the need for energy “self reliance” with the high level of behind the meter solar and battery storage systems. Industrial consumers will either continue to rely on grid supplied electricity or install their own renewable electricity generation and storage infrastructure or some combination of the two, particularly to cover the peak demand case.	
	In Scenario B, implications for each consumer type would be similar to those described above for Scenario A, though for residential and commercial consumers a small level of replacement of natural gas appliances with Hydrogen units would also be required. A lower level of energy self reliance would be required compared to Scenario A.	Scenario B
	In Scenario C, implications for each consumer type would be similar to those described for Scenario A, though for residential and commercial consumers a significant level of natural gas appliances would need to be replaced by Hydrogen units. A lower level of energy self reliance would be required compared to Scenario A.	Scenario C
	In Scenario D, implications for all consumers of transitioning to a large proportion of Hydrogen in the energy mix would be extensive replacement of natural gas appliances for Hydrogen units.	Scenario D

Appendix 1 Scenario Descriptions

SCENARIO	A. ZERO EMISSIONS ELECTRIFICATION – NO NATURAL GAS	B. NET ZERO EMISSIONS ELECTRIFICATION SUPPORTED BY NATURAL GAS	C. ZERO EMISSIONS HYDROGEN WITH BIOGAS AND ELECTRIFICATION	D. NET ZERO EMISSIONS HYDROGEN WITH BIOGAS AND ELECTRIFICATION
GENERAL DESCRIPTION	Almost full electrification using renewable sources and lots of storage with very little use of any gas except where it is irreplaceable. No Carbon Capture and Storage (CCS).	Extensive electrification with renewable sources and storage with some natural gas to support the renewable electricity system and some industrial use, made net zero by CCS and offsets.	Hydrogen using renewable sources really takes off as a substitute for natural gas, along with some waste to energy, biogas and renewable electricity sources with some batteries. No natural gas or CCS.	Hydrogen using both renewable sources and coal with CCS, along with some waste to energy and biogas and renewable electricity sources with some batteries. No natural gas.
ELECTRICITY GENERATION	- Renewable energy (mainly solar and wind) generation supported by pumped hydro, waste-to energy - Large upscale of renewables - Utility-scale solar farms and small-scale solar - Utility-scale onshore and offshore farms Smart networks at all scales for grid reliability	- Renewable energy (mainly solar and wind) generation supported by natural gas plants for peak supply (with CCS), waste-to energy - Large upscale of renewables - Utility-scale solar farms and small-scale residential solar - Utility-scale onshore and offshore farms Smart networks ensure grid reliability	- Renewable energy generation supported by green hydrogen, waste-to energy & biogas fired plants - Large upscale of renewables for both electricity and green hydrogen production	- Renewable energy generation supported by hydrogen, waste-to energy & biogas fired plants - Moderate upscale of renewables mainly solar and wind
GASEOUS FUELS	- Small upscale of hydrogen, mainly for industrial feedstock - Major biogas upscale behind-the-meter	- Small upscale of hydrogen, mainly for industrial feedstock - Small upscale of biogas, focus on local use in	- Massive upscale of green hydrogen production, up scale of blue hydrogen to support transition to 2050	- Decreased hydrogen production and associated CCS costs - VIC hydrogen (incl export) hubs

	lessens requirement for centralised generation	farms, WWTP and waste facilities	- Moderate upscale of biogas	- biomethane in gas network for regional use - Combined heat & power
ENERGY STORAGE	- Major improvements in battery technology - Large-scale pumped hydro and battery farms - Networked batteries for large-scale "smart" demand side response	Moderate improvements in battery efficiency and cost meaning more peak generation is required - Small-scale (non-networked) residential batteries for demand side response	Significant improvements in both battery and chemical hydrogen storage, supported by pumped hydro and batteries	- High reliance on hydrogen as energy storage in gas pipelines and gas storage facilities (above- and underground) supported by small-scale batteries and pumped hydro
CARBON OFFSET	- limited offsets - no CCS	- Small-scale CCS for gas fired energy production and suitable heavy industry - Small- scale carbon forestry	Blue and green hydrogen develops extensively – limited offsets required, no blue hydrogen and no CCS after 2050	- Large-scale CCS enables low-carbon hydrogen (SMR & gasification) - CarbonNet is successful (and possibly others) - Large-scale carbon sequestration
TRANSMISSION & DISTRIBUTION	- Moderate upgrade electricity network due to higher demand but lower transmission due to regional-scale generation, storage and networking - Gas network unused	- Major upgrade electricity network due to higher demand - Gas network primarily unused, stranded asset - Select gas pipelines repurposed for transport of CO2	- Major upgrades to electricity network due to higher demand - Conversion of gas networks for hydrogen, CO2 and biogas - LNG terminal(s) become hydrogen hubs	- Smaller upgrades of electricity network - Conversion of gas networks for hydrogen, CO2 and biomethane - LNG terminal(s) become hydrogen hubs
RESIDENTIAL AND COMMERCIAL USE (SPACE AND WATER HEATING, COOKING)	- District combined heat and power in high-density and industrial areas - Electric and small-scale geothermal heating in low-density areas	- High efficiency upgrades and decreased energy demand - Energy-sufficient homes - Upgrades to electric or geothermal appliances - Upgrades to electric induction stoves	- Significant efficiency upgrades (decreased energy demand) - Biogas and hydrogen fired heating with appropriate appliance upgrades	- Small efficiency upgrades (slightly decreased energy demand) - Biogas and hydrogen fired heating with appropriate appliance upgrades - Biogas and hydrogen cooking

	- electric cooking		- Mix of biogas, electric and hydrogen cooking	
INDUSTRIAL USE	- Extensive efficiency and innovation (decreased energy demand) - High intensity electric or biogas heating. - Some hydrogen/biogas for chemical uses	- High industrial efficiency upgrades and decreased energy demand - Upgrades to electric or biogas heating. - Some ongoing industrial use of natural gas where displacement is particularly difficult	- Biogas and hydrogen fired heating - Upgrade of heating tech - Large scale blue and green hydrogen to replace chemical feedstock	- Biogas and hydrogen fired heating - Upgrade of heating tech - Large scale hydrogen (gasification) to replace chemical feedstock
TRANSPORT	- strong uptake of EVs for most transport - renewable fuels for air transport	- Strong uptake of EVs for personal and public transport - Small-scale uptake of hydrogen- for heavy and air transport	- Strong uptake of hydrogen-fuelled transport for personal, public, air and heavy vehicles	- Strong uptake of EVs for personal and public transport - Strong uptake of hydrogen-fuelled transport for air and heavy vehicles
ENERGY EFFICIENCY	- Large-scale energy efficiency improvements (public /private investment)	- Moderate-scale energy efficiency improvements due to large public and private investments	- Moderate energy efficiency improvements	- Small-scale energy efficiency improvements for residential and industrial use
EXPORT	- No energy exports - export of expertise and tech	- No energy exports - International carbon emission certificate trade	Export renewable and hydrogen tech/expertise Hydrogen export	- Global hydrogen export leader

Appendix 2 Risk & Opportunity Matrix

Issue	Consequence	Likelihood	Existing/Planned controls	Risk rating per Scenario								Comparative screening per risk			
				A		B		C		D					
				Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	A	B	C	D
Environment Risks															
CH4 emissions associated with changing water levels in reservoirs not accounted for	Environmental impact - CO2 offsets not assessed appropriately	Understanding of CH4 emissions associated with hydropower is increasing	1. Undertake more research to assess CH4 emissions associated with hydro 2. EIS would address this issue	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟨	🟩	🟩
Waste to energy - potential feedstock contamination and toxic releases to atmosphere	Toxic impacts to environment, potential for loss of public trust in technology, delaying opening of additional infrastructure, etc	Feedstock management reduces likelihood	1. Feedstock control and emission monitoring 2.Currently 14 approx. plants operating in Victoria - no significant issues	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Waste to energy and recycling improvement contributes to circular economy aim and net negative GHG emissions	Reduction in Quantity of material sent to landfill			Opportunity								🟩	🟩	🟩	🟩
Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Potential for piping/pipeline failure due to CO2 corrosion, flange leaks, leaks from reservoir	Release of CO2 to atmosphere	Well understood corrosion mechanism	Monitoring for CO2 releases, known technology	No risk		LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟨	🟩	🟨

Unable to maintain offshore CCS injection facility to fix potential problems due to Waiting On Weather	Extended leak CO2 to atmosphere	Winter weather conditions in Bass Strait - but limitations well understood from Offshore industry		No risk		LOW	UNLIKELY	LOW	UNLIKELY	LOW	LIKELY	🟩	🟨	🟩	🟧
Climate change - inadequate water in reservoirs for hydro	Loss of power /interruptions to supply	Generally, areas for hydropower have adequate rainfall - used for peak shaving	Location selection – use of interconnectors	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟨	🟨	🟩	🟩
Unable to secure adequate CCS or offsets to ensure Scenario meets net zero	Climate change intensifies as a result of failing to meet net zero targets	Higher use of renewable resources reduce likelihood of event	CCS development Forestry and soil farming Ongoing investigation into marine offsets	HIGH	UNLIKELY	HIGH	UNLIKELY	HIGH	UNLIKELY	HIGH	LIKELY	🟩	🟨	🟩	🟧
Geothermal causes localised subsidence	Environmental impact and costs to fix	Unlikely due to surveys required prior to installation	Well understood technology	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	No risk		🟩	🟩	🟩	🟩
Rolled up comparative risk screening – Environment												🟩	🟨	🟩	🟧
Main Risk Driver:- CO2 emissions and degree of carbon capture required															

Issue	Consequence	Likelihood	Existing/Planned controls	Risk rating per Scenario								Comparative screening per risk			
				A		B		C		D					
				Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	A	B	C	D
Societal Risks															
Resistance to development of further hydro schemes due to impact upon wild places and endangered species halts development	Unintended environmental impact project delays	Resistance to hydropower's impact will be almost certain	Early EIA to understand risks	HIGH	LIKELY	HIGH	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟨	🟨	🟩	🟩
Public resistance to the ongoing use of coal to make H2	Loss of social licence, significant disruption to plans	Adani as an example of public interest	Early planning Support from Latrobe Valley	No risk		No risk		No risk		HIGH	LIKELY	🟩	🟩	🟩	🟧
Wind Farms - land area required to meet energy mix is high -Difficulty sourcing enough land for number of wind farms required due to local concerns for bird life, land values, noise etc	Delays to approvals as resistance grows - increasing costs and resulting in interruptions to the grid,	Developing numbers of anti-wind farm groups in UK, elsewhere, Bald Hills SG council taken to high court by locals and lost	1. Start planning processes early 2. Move wind farms offshore 3. Economic benefits to farmers	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟨	🟨	🟨	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
With current schemes, uptake of domestic rooftop solar has occurred from the public who are interested in the technology, owner occupiers, able to manage the technology, interested in cost savings/ environment, etc	Potential for 'market saturation' of domestic rooftop solar uptake as remainder of housing in the hands of the aged, disinterested parties, lack of finances	Across Australia (AIHW) 32% of houses are rented, owner occupiers over 70 assumed to generally not be interested in taking up solar due to payback	Incentivisation schemes with grants	MEDIUM	LIKELY	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	🟨	🟩	🟩	🟩
Difficult sourcing enough land for number of solar farms required due to local concerns for land values, environmental concerns, competition with farming	Project delays, cost blowouts	Assumed land value in high quality solar areas low as drought drives values down	Declared REZs - adequate land available	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	LOW	LIKELY	🟨	🟩	🟩	🟩
Mix solar with grazing land?	Benefit to farmers			Opportunity								🟩	🟨	🟨	🟨
Desire to build up other urban areas outside of Melbourne coincides with development of REZs to power new/upsized towns				Opportunity								🟩	🟩	🟩	🟨
Use of coal for H2 improves job prospects in Latrobe Valley				Opportunity								🟨	🟨	🟨	🟩
Early days of roll out, release of H2 in industrial setting	Fatalities Technology abandoned	Risks associated with H2 well understood	Standards, regulations	No risk		MEDIUM	UNLIKELY	MEDIUM	UNLIKELY	MEDIUM	UNLIKELY	🟩	🟩	🟨	🟨
Resistance to Li/rare earth mining	Cost, availability impact – global demand for rare earth materials		Can import, public perception campaigns	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	🟨	🟨	🟨	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Carbon capture & soil farming - Resistance from some farmers to engage/be the solution to the state's problem	Inadequate quantity of land available for carbon capture	Expectation that there will be adequate land available for A	note 200 km2 required if all soil farming (non-forestry, marine)	LOW	UNLIKELY	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	🟩	🟩	🟩	🟩
Transition from gas appliances and heating in the home to all electric	Social pressure for no change as results in replacement costs to consumer	Impact considered to be low as time to get people used to the change	Manageable over timeframe with plenty of flagging for change, legislation to stop sale of appliances etc - cost borne by others, advances in induction heating	LOW	UNLIKELY	LOW	UNLIKELY	No risk		No risk		🟩	🟩	🟩	🟩
Use of hydrogen/biogas for heating - appliance availability and uptake	Social pressure for no change as results in replacement costs to consumer	Not considered to be an issue due to worldwide anticipated changes	Manageable over time	No risk		No risk		LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
EMF from car batteries either cause a risk to health, or are believed by people to cause a risk to health	International Agency for Research on Cancer has classified ELF magnetic fields as possibly carcinogenic to humans.	Not proven	Public information campaigns if this becomes an issue	LOW	UNLIKELY	LOW	UNLIKELY	No risk – can select H2 fuel car		No risk – can select H2 fuel car		🟨	🟨	🟩	🟩
Costs and lack of understanding - resistance to take up heat pumps	Reduction in uptake of heat pump technology	Expected to be only feasible for new builds	Government schemes to encourage use Can be managed by campaigns and advertising around successful adoption elsewhere (e.g., Sweden)	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Local population resistance to new technology developed/purchased from overseas	Delays to roll out	Not expected to be significant		LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Rolled up comparative risk screening – Societal												🟨	🟩	🟨	🟧
Main risk drivers: Societal resistance to coal use, hydropower development															

Issue	Consequence	Likelihood	Existing/Planned controls	Risk rating per Scenario								Comparative screening per risk			
				A		B		C		D					
				Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	A	B	C	D
Economic Risks															
Offshore wind farm - potential for cost blowouts during the offshore construction phase, WOW, labour costs, suitable vessel hire etc	Project costs increase	Offshore experience o&g sector	1. Delays during construction and impact on costs understood by the Industry - should be allowed for in cost estimating	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟩	🟩	🟩	🟩
Wind Farms - potential for mix of turbines and crops/livestock				Opportunity								🟩	🟩	🟩	🟩
Environmental impact of polysilicon manufacture limits supply of solar panels, world demand soars	Costs increase due to shortage	Costs expected to rise due to world demand		MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟨	🟩	🟩	🟩
Reliance on other states to provide clean hydro	Cost impact	Assumes no hydropower developed instate	Costings agreements interstate?	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟨	🟩	🟩
Increased potential for bushfire/grassfire as a result of climate - potential for damage to solar farms, transmission infrastructure, wind farms	Interruptions to supply, additional costs associated with burial	Low likelihood with fuel management practices & regulation	System redundancy Area housekeeping (fuel management) to minimise fire risks	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
As Natural gas supply reduces, and smaller requirements to meet disparate needs, potential for location of turbine generators & other infrastructure to be sub optimal for dwindling distributed gas network	Stranded asset	Unlikely due to long timeframe and standard project planning	Project Planning - asset location based on gas infrastructure	No risk		LOW	UNLIKELY	No risk		No risk		🟩	🟨	🟩	🟩
Inadequate supplies of lithium and other rare earths to meet global demand - note life cycle of batteries, ongoing replacement But Australia has significant untapped reserves of Li, Co - public resistance to mines - costs of mining in Australia	Project delays, significant cost blowout to guarantee supply	Due to global demand almost certain to impact costs - current low production rates of Li in Aus	Trade deals/partnerships /alternate storage technology	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	LIKELY	🟨	🟩	🟩	🟩
In this scenario power generation and storage moves from the hands of a few to that of many, this has an impact on the reliability of power supply (maintenance, testing, unknown disconnection from gride due to spikes etc)??	Small Businesses - opportunity to manage gen public solar systems			Opportunity								🟩	🟩	🟩	🟩
Distributed power providers - potential for mini drop outs? Requirement to improve local distribution infrastructure?	Increased unexpected costs- As systems expected to be highly complex	Understanding of impact on current infrastructure well understood?	Cost for improved local distribution infrastructure	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	🟨	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
As technology develops further, residential/commercial customers pull out of grid altogether as self-reliant	High infrastructure costs to provide electricity to lower number of consumers	Assumed unlikely that large numbers would uptake full independence from grid		LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Managing all the differing new connections to the grid - step change in connection activity	Increase in Project costs, shortfalls in electricity supply	Current delays to onshore windfarms in Vic	Early installation, allow for delays and performance issues	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	🟨	🟩	🟩	🟩
Transmission lines - Through the bush and associated bush fire risk due to climate change damaging infrastructure	Delays to approvals as resistance grows Or costs for transmission line routing	Routing to avoid minimise these issues having cost impact	Routing of any additional infrastructure	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Significant infrastructure construction - delayed due to union unrest	Significant delays to installation, increased costs and targets not met	Some disruption can be expected over life of roll out	IR, stakeholder engagement	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	LOW	HIGHLY LIKELY	🟩	🟩	🟩	🟩
Cost blowouts associated with development of adequate CCS infrastructure	Significant costs associated with discovery and management of CCS	Likelihood higher for scenario D due to amount of CCS infrastructure required		No risk		MEDIUM	LIKELY	No risk		MEDIUM	HIGHLY LIKELY	🟩	🟩	🟩	🟩
Recently closed down car manufacturing in Victoria and centre of technical/design development	Potential to reopen car manufacturing for EV vehicles in Victoria			Opportunity								🟩	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk	B risk	C risk	D risk	A	B	C	D
Charging of EV's during the day (off peak) (using residential and commercial solar)	Employment opportunity - installation and ongoing management of public charging facilities			Opportunity				🟩	🟩	🟩	🟩
Costs and lack of understanding - resistance to take up heat pumps	Employment opportunities for small business - maintaining heat pump systems			Opportunity				🟩	🟩	🟩	🟩
Australia has gas expertise and hasn't fully taken up the potential for H2 export - missed opportunity?	loss of a potential H2 export market			Opportunity				🟧	🟧	🟨	🟩
As gas industry winds down, lack of employment in sector	80,000 jobs in industry lost	Opportunities in the renewable sector	Less of an issue for Victoria? Retraining for alternative energy industries	LOW UNLIKELY	LOW UNLIKELY	LOW UNLIKELY	LOW UNLIKELY	🟩	🟩	🟩	🟩
Rolled up comparative risk screening – Economic								🟨	🟩	🟨	🟧
Main risk drivers: Cost blowout of CCS, loss of H2 export opportunity,											

Issue	Consequence	Likelihood	Existing/Planned controls	Risk rating per Scenario								Comparative screening per risk			
				A		B		C		D					
				Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	A	B	C	D
Technical Risks															
Offshore wind farm - unavailability due to maintenance requirements and access issues - coincident with high power demand for heating	Demand exceeding supply - power grid drop outs - up to 3 days WOW, resulting in short term drop outs	Offshore - experience - weather conditions limiting access can be expected to occur over project life	1. Redundancy in alternate power sources allowed for in costings 2.Program maintenance in appropriate weather windows. 3. Alternative sources from interstate as backup 4. Additional batteries planned to cover outages	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	🟩	🟩	🟩	🟩
Development of concentrated solar plant	Lower land use reqts, energy storage advantages	Currently 2.3GW in Spain, 1.7GW in US	ARENA currently investing in a number of projects - potential for green H2	Opportunity								🟨	🟩	🟨	🟩
Reliability of solar panel is 30 years, inverters less. Some residential panels have been installed for 10+ years, and will require replacement - Loss of social licence due to replacement of components and use of landfill for failed renewable equipment	Home owners decide not to replace due to costs etc - opt out - and loss of generating capacity	Likely that this would occur, but balanced against (assumed) rising cost of purchasing from grid as alternate	cost driven incentive	LOW	LIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Climate Change - damaging hailstorms/snow/sandstorm put solar panels out of action/poor performance due to weather unpredictability	Loss of power/ interruptions to supply	Significant hailstorms causing damage to solar panels have occurred in QLD (Vic??)	Locate utility sized solar farms in differing REZs to spread climate associated risks Note solar panels have AS std to resist up to 25mm hailstones so majority of hailstorms should not impact	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟩	🟩	🟩
Robustness of electrical supply - given means of provision are climate related (wind, solar) impact of climate change (high winds, cloudy days) and weather predictability	Interruptions to supply	Battery backup allows for weather variation	More back up power - cost weather forecasting	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟩	🟩	🟩
Development of more efficient solar panels	Lower roof area/land use requirements	Almost definite		Opportunity								🟩	🟩	🟩	🟩
In Australia, nuclear energy generation is prohibited by legislation and has high capital cost. Start up and shut down time consuming so normally used as a base load electricity provider.	Small-scale modular reactors have received some attention in recent years - Future potential for nuclear energy in the mix for peak shaving			Opportunity								🟩	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk	B risk	C risk	D risk	A	B	C	D
Use of animal wastes rurally located	Rural employment. Use of unused raw material that may be impacting environment-(if enters water sources - high BOD			Opportunity				🟩	🟩	🟩	🟩
Improved low cost H2 process (Current focus worldwide)				Opportunity				🟨	🟨	🟩	🟨

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Residential battery storage - In this scenario power generation and storage moves from the hands of a few to that of many, impacts on the reliability of power supply (maintenance, testing, unknown disconnection from grid due to spikes etc)?? Potential for over- reliance of supply on general public with no guaranteed provision	Grid dropouts more likely due to blown inverters, etc?? Tendency to buy cheapest technology available, and therefore least reliable, difficult to guarantee power delivery	Almost certain that the reliability of domestic supply to feed into market is lower than industry as currently not a contracted rate	Smart meters. As many local batteries - smoothing effect?	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	🟨	🟩	🟨	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Requirement peaks (last year 5000MW over average demand) places huge demand on system, as evening solar cannot be used, may coincide with still evening, high battery/hydro/? Additional capacity requirement	Cost impact	During peaks likelihood of dropout high	Some battery storage, hydro	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	MEDIUM	HIGHLY LIKELY	🟨	🟩	🟨	🟩
Household EV battery used to power household during peak times when purchasing electricity high cost	Reduces demand on grid, smooths peaks, battery can be recharged overnight when electricity price lower/or next day on solar			Opportunity								🟩	🟩	🟩	🟩
Technical risks associated with ongoing management of CCS	costs & risks associated with ongoing management of CCS	Likelihood increases with amount of CO2	CarbonNet development studies ongoing	No risk		MEDIUM	UNLIKELY	No risk		MEDIUM	LIKELY	🟩	🟨	🟩	🟧
Risk of soil farming not achieving required outcomes - particularly with climate change (mix of humus retention, minimise ploughing etc...)	Release of CO2 to atmosphere	Only required for Scenario D	note 200 km2 required if all soil farming (non-forestry, marine) - may be able to use higher numbers	No risk		No risk		No risk		LOW	UNLIKELY	🟩	🟩	🟩	🟨

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Seaweed farming potential as carbon sink and as use in plastics production				Opportunity								🟩	🟩	🟩	🟩
Impact on existing infrastructure of peak energy flow from solar when demand is low.	High voltage which can damage residential inverters and transformers in the grid.		1. Limits to feeds from residential at when voltage high to manage network stability 2. Smart meters	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟩	🟩	🟩
Single Point Failure of Subsea cables - WOW to effect repair	Shortfalls in electrical supply	Higher potential during winter higher wind, greater waves	Industry mature in Australia and overseas	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Repurposing of network for CO2 transportation	Potential for cost savings	Feasibility questionable due to pressure reqd		Opportunity								🟩	🟩	🟩	🟩
H2 embrittlement	Potential for delays due to high pressure H2 embrittlement issues			No risk		LOW	UNLIKELY	MEDIUM	LIKELY	MEDIUM	LIKELY	🟩	🟩	🟨	🟧
Strong uptake of EVs, home charging conflict with battery storage and overnight to solar??	Peaky demand on system	With no smoothing controls this will have a significant impact on demand spikes in evenings	Can design costing infrastructure to smooth peaks – off peak charging technology	LOW	HIGHLY LIKELY	LOW	LIKELY	LOW	LIKELY	LOW	LIKELY	🟨	🟩	🟩	🟩
Charging of EV's during the day (off peak) (using residential and commercial solar)	Reduces night time peak load requirements		Infrastructure required to be established to allow EV charging in public car parks shopping centres etc	Opportunity								🟩	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk	B risk	C risk	D risk	A	B	C	D
Use of H2 for fuelling heavy transport minimises refuelling times	Not relevant for Scenario A			Opportunity				🟨	🟨	🟩	🟩
Rolled up comparative risk screening – Technical								🟨	🟩	🟨	🟧
Key risk drivers: CCS and H2 embrittlement risk (D) Reliability of power supply (A & C)											

Issue	Consequence	Likelihood	Existing/Planned controls	Risk rating per Scenario								Comparative screening per risk			
				A		B		C		D					
				Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	Consequence	Likelihood	A	B	C	D
Safety Risks															
Concern around turbines shedding blades - safety impact to personnel	Project delays- issues with approvals,	Turbine blades have been shed in past UKHSE studies suggest risks to gen public eqvlt to 2 flights/annum at 2 x hub height dist.	1. Data from overseas and Australia - demonstration of risk to public low	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Pipeline containing H2 fails due to embrittlement	Fatalities Technology abandoned	Risk understood. External release less hazardous than confined as lighter than air easily dispersed	Standard, selection of materials	No risk		MEDIUM	UNLIKELY	HIGH	UNLIKELY	HIGH	UNKIKELY	🟩	🟩	🟨	🟧

Battery fire	House fire, potential for loss of life	Has been known, less well controlled in residential settings	Location of batteries, installation guide, regulations and standards	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟨	🟩	🟩	🟩

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Storage of large quantity of H2 - Industrial setting	potential for release, fatalities, loss of social licence	Based on other MHF facilities and regulatory regime - expected to be low		No risk		HIGH	UNLIKELY	HIGH	UNLIKELY	HIGH	UNLIKELY	🟩	🟩	🟨	🟧
Requirement for more transmission infrastructure, and increased desire for tree planting to provide carbon sink / high environmental/societal value	Potential for transmission lines to cause bush fire (environmental/ safety impacts) (Black Saturday AUS$4Billion, 173 fatalities	Black Saturday - note resulted in legislation change	Fuel management (arborists/engineers) Line routing	MEDIUM	UNLIKELY	MEDIUM	UNLIKELY	MEDIUM	UNLIKELY	MEDIUM	UNLIKELY	🟨	🟨	🟨	🟩
Use of Hydrogen in the home - potential issues with leakage and explosion (very large flammable range)	Potential for fatalities, damage not relevant Scenario A	Non controlled environment	Pilot studies ongoing for use in home	No risk		No risk		HIGH	UNLIKELY	HIGH	UNLIKELY	🟩	🟩	🟨	🟨
Use of H2 for refuelling heavy transport - potential that a traffic accident results in loss of social licence to use H2 refuelling , fatality potential	RTA and fatalities	Unlikely based on LPG experience	Current use of H2 vehicles around the world, and exposure to LPG has shown this risk manageable	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟨	🟨

Issue	Consequence	Likelihood	Controls	A risk		B risk		C risk		D risk		A	B	C	D
Badly installed insulation leading to fire	House fire, potential for loss of life	Previously free attic insulation resulted in fires due to coverage of light transformers	Previous - experience and investigations - lesson learned to minimise likelihood of reoccurrence	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	LOW	UNLIKELY	🟩	🟩	🟩	🟩
Rolled up comparative risk screening – Technical												🟩	🟩	🟨	🟧
Key risk drivers: H2 risks, home battery fire															