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Low Emissions Technology Roadmap

Technical Report

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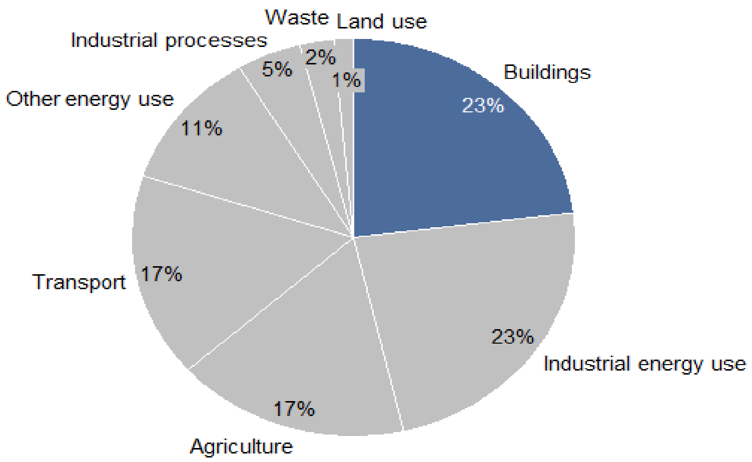
1 Buildings

The building sector is responsible for approximately 23% of Australia's total emissions. However, abatement can be readily achieved using mature technologies such as light emitting diode (LED) lighting, high efficiency heating, ventilation and air conditioning technologies and building envelope improvements. Deployment of these technologies to date has been impeded by cost, motivation and project attractiveness. Implementing a national plan and associated policy frameworks in order to enable these technologies would create significant value from energy savings across the building sector.

- Nearly all areas of energy use in buildings have higher efficiency alternatives. These include including LEDs in lighting, heat pumps and energy recovery in heating, ventilation and air conditioning and improved monitoring and controls.
- Overcoming barriers relating to capability, attractiveness and motivation would allow for widespread adoption of these technologies.
- This could be achieved by implementing a national plan and associated policy frameworks which include mandatory minimum energy standards, appropriate incentives, training and market reform.
- A large opportunity for Australia exists in the energy costs saved by decarbonising the buildings sector. This could be in the order of $20 billion dollars net present value to 2030.
- Other potential opportunity areas for Australian industry exist in the development of 'smart' building control systems and equipment, leveraging integrated sensors and internet connectivity.

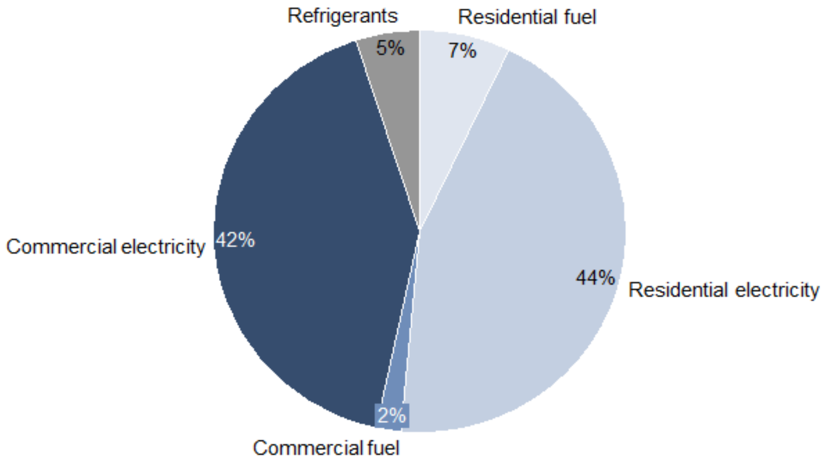
Buildings contribute approximately 23% of Australia's emissions, making the sector one of the largest sources of emissions in Australia (as shown in Figure 1).

Figure 1 – Breakdown of Australian emissions and sector coverage in 2013 (% of total emissions, $MtCO_2e$)
Source: ClimateWorks team analysis based on (OCE, 2016) and (Department of Energy and Environment, 2016)



A breakdown of emissions by building type is set out in Figure 2 below.

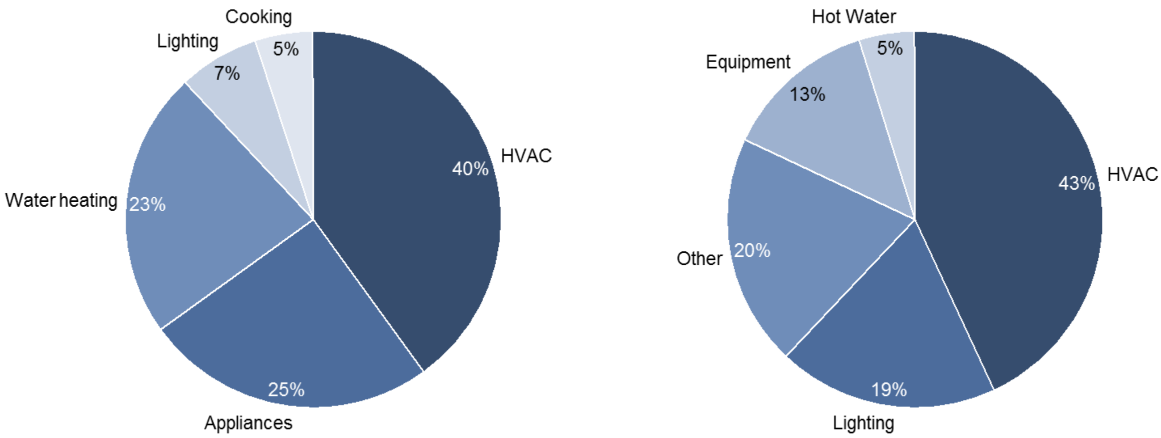
Figure 2 – Breakdown of building emissions by building type 2013 (% of total emissions MtCO2e, 2013) Source: (ASBEC, 2016)



Within the buildings sector, heating, ventilation and air conditioning (HVAC) are responsible for most energy use in commercial (43%) and residential buildings (40%). Other applications such as lighting, hot water, appliances and equipment account for most of the remaining energy use. A high proportion of commercial energy use (approximately 20%) comes from 'other' sources, this reflects difficulties in estimating energy use from existing data sources across the sector.

There are complex interactions between activities, for example, heat released by lighting reduces heating requirements but increases cooling energy use and peak demand.

Figure 3 – Breakdown of residential and commercial energy by end use (% of total energy consumption)



a) Residential **b) Commercial**

Source: (EnergyRating, 2015), (COAG, 2012) and ClimateWorks analysis

1.1 Technology overview

Technology description

Lighting

A range of lighting technologies is used in residential and commercial buildings. These include incandescent, fluorescent and now LED lights. The energy required for different lighting technologies to provide illumination differs significantly due to differences in the amount of heat generated in the process. Incandescent lighting, which includes the more advanced halogen lighting, generally produces large amounts of heat relative to amount of light emitted, thereby making the technologies less efficient.

Fluorescent and LED lights use far less energy per unit of lighting (known as a lumen) and therefore are more efficient sources of light per area illuminated. Other technologies such as organic light emitting diodes (OLED) could provide further opportunities for savings and their thin, flexible structure means they can be applied to a many new applications and designs.

Other techniques designed to improve lighting efficiency include the use of sensors and controls to reduce periods of use as well as building design considerations which maximise the use of natural light. These methods may involve trade-offs such as increasing solar heat gain and consequent cooling loads.

HVAC

HVAC systems take many forms, including burning wood in a fireplace and direct combustion of gas, to modern split system air conditioners driven by efficient heat pump technology and sophisticated chillers.

HVAC energy consumption can be reduced through:

An improved building ‘envelope’ (the structural shell of the building including walls, floors, roofs) - this includes better design, glazing, insulation, sealing and weatherproofing to reduce air and heat/cool leakage and reducing the need for mechanical heating/cooling.

Installation and improved maintenance of more efficient heating and cooling equipment, including equipment that uses more efficient refrigerant gases with lower global warming potential.

In practice, the energy used for space heating and cooling is also influenced by the rate of heat gain or loss from the building (e.g. energy flows through window glazing). Therefore, the performance of the building envelope has a significant impact on total energy use.

Space heating technologies are discussed in more detail in Section 2.

Hot water

Water heating accounts for approximately 22% of energy use in residential buildings and 5% of energy use in commercial buildings.

Water heating can be driven by solar thermal technologies and direct fuels such as gas and biomass. Electricity can also be used to drive off-peak electric resistance heaters and more efficient heat pump technologies for hot water systems. These technologies are discussed in more detail in Section Heating2.

Appliances and equipment

Energy use from appliances has grown as a share of total energy use, a trend expected to continue to 2030 (EnergyRating, 2015). Appliances such as refrigerators, washing machines, dishwashers, and information technology are the primary energy users.

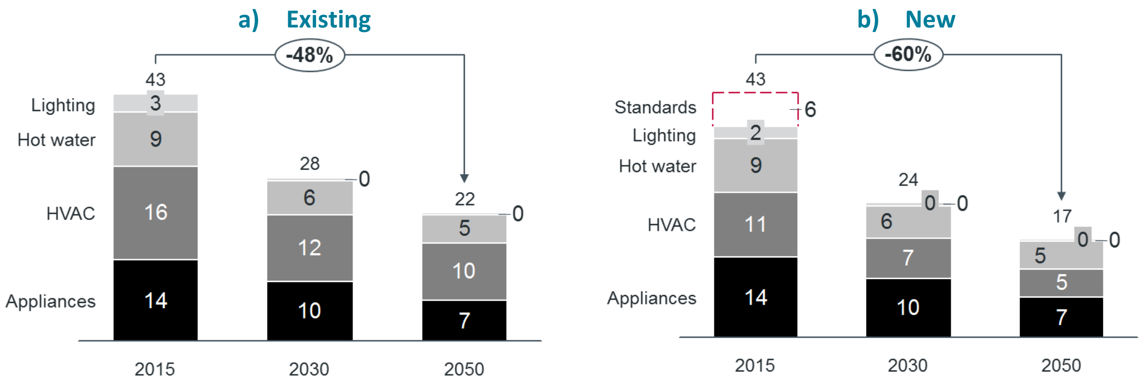
The use of energy from appliances can vary significantly as a result of preferences in consumer electronics. For example, the increase in the average number and size of televisions in households contributed to a large increase in energy use from appliances through the 2000s. More recently however, the energy intensity of appliances has decreased due to improvements in their energy efficiency. This is particularly evident for televisions due to the increased use of energy efficient LED and OLED technology. Improvements in these technologies has contributed to falling energy use per building in recent years (Energy Consult, 2015).

Technology impact

Previous studies have found significant savings potential from the uptake of best available technologies across the buildings stock (ASBEC, 2016). These savings assume conservative rates of improvement for technologies such as LED lighting and heat pump technology.

Figure 4 below shows the potential energy savings from each end use type that has been assessed for new and existing residential buildings. As presented below, there is substantial potential for energy savings with reductions of between 48% and 60% achievable by applying best practice technologies to 2050 for existing and new buildings respectively. These actions generally provide a positive financial return due to energy savings exceeding capital investment in present value terms. Standards refers to the reduction in energy use that a newly built house gains over an existing house due to the continual improvement in buildings standard.

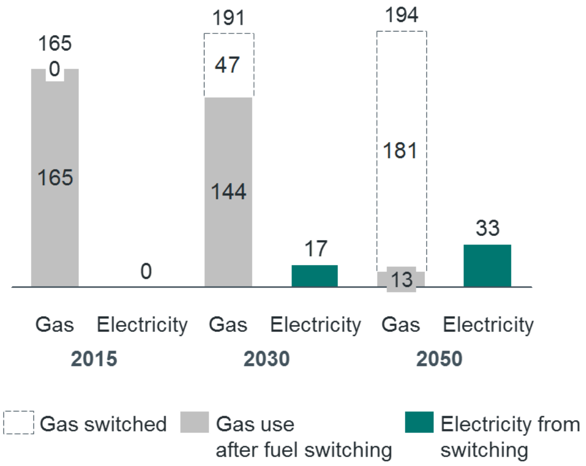
Figure 4 – Residual energy use for existing and new residential buildings after energy efficiency (GJ/household)



Further emissions reductions can be achieved by switching gas to electricity if the grid is sufficiently decarbonised. As shown in

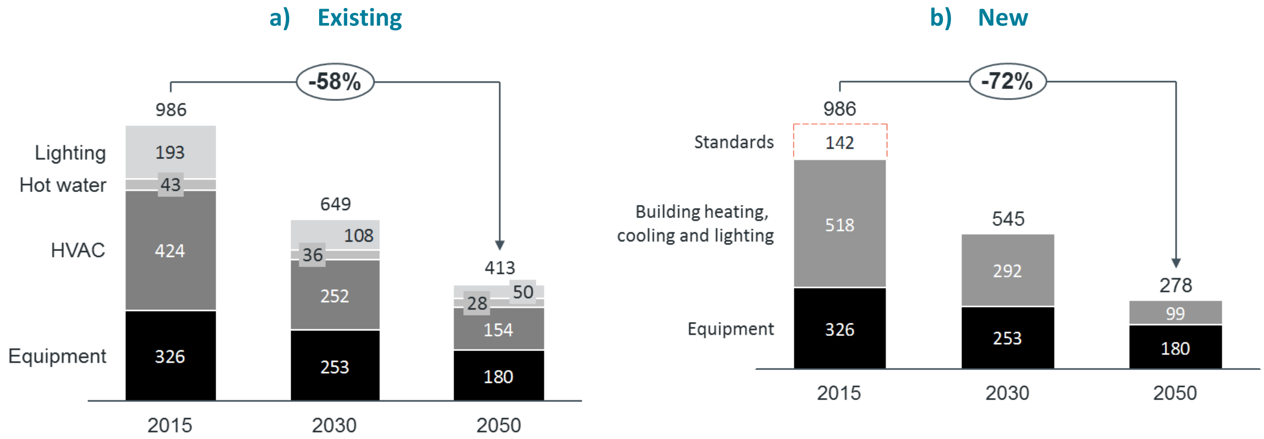
Figure 5 below, almost all gas could be expected to be switched to electricity while achieving cost savings.

Figure 5 – Potential for fuel switching from gas to electricity in residential buildings (PJ)



Even greater savings could be expected in commercial buildings with 58% savings potential in existing buildings and 72% savings in new buildings achievable to 2050 relative to 2015 levels as shown in Figure 6 below.

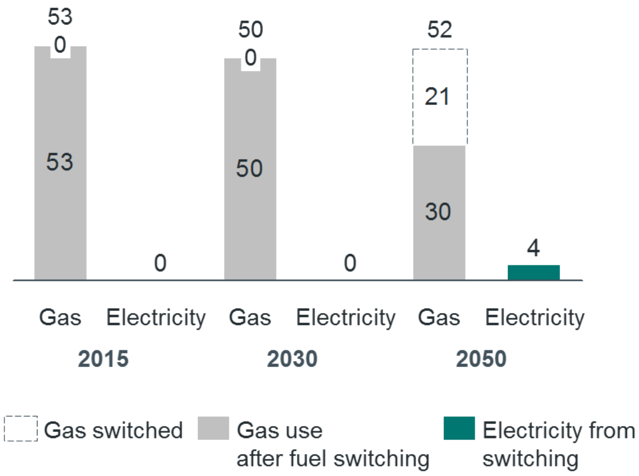
Figure 6 – Residual energy use for existing and new commercial buildings after energy efficiency (MJ/m^2)



Commercial buildings use proportionally less gas than residential buildings and it is more often used for higher temperature heating in buildings such as hospitals and universities. These applications can be more challenging to switch to electricity than hot water and HVAC systems in residential buildings. As shown in

Figure 7, it is estimated that just over 40% of gas use could be electrified cost effectively in commercial buildings for emissions savings if the grid is sufficiently decarbonised.

Figure 7 – Potential for fuel switching from gas to electricity in commercial buildings (PJ)



Limited availability of data relating to energy and technology use in buildings limits more detailed analysis. Data on appliances and equipment energy use in commercial buildings has been particularly problematic. Where data is limited, no savings beyond the historical rates of energy efficiency has been assumed. This is likely to substantially underestimate potential savings.

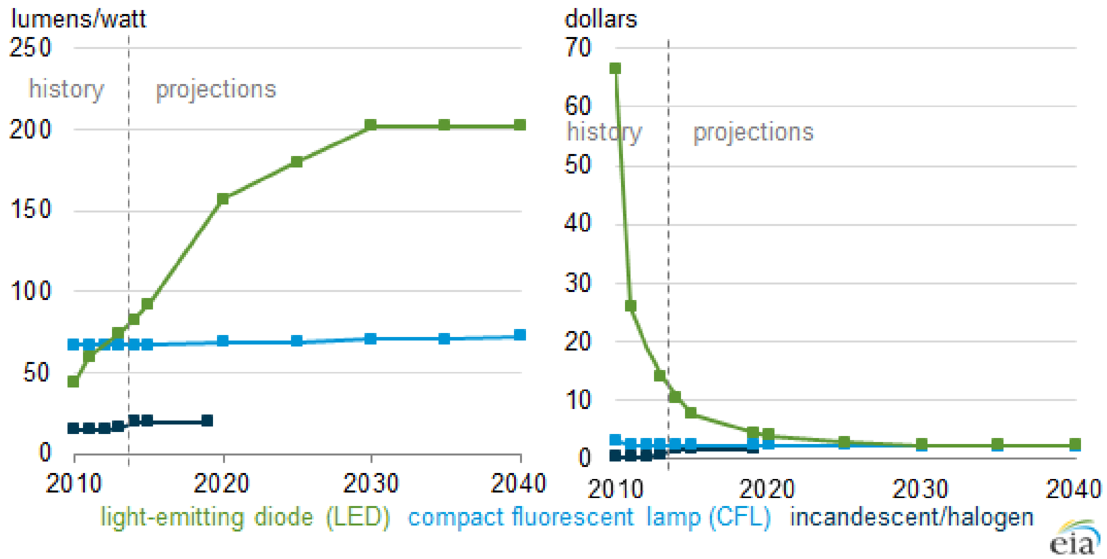
In modelling energy efficiency in buildings, it has been assumed that the rebound effect will ultimately reduce the impact of efficiency on energy demand. The rebound effect is a phenomenon whereby an increase in energy efficiency may lead to less energy savings than might be expected, due to behavioural changes in response to lower costs of operation. A rebound rate of 20% is assumed for this modelling which is consistent with the range of estimates presented by previous studies (S.Nadel, 2016). The evidence of rebound rates is not conclusive and so including this assumption may understate the potential reductions from energy efficiency.

1.2 Technology status

Lighting

The performance and cost effectiveness of LED lighting in particular has improved dramatically in recent years and can now deliver more lighting per watt than fluorescent technology. Costs per LED bulb are projected to decrease exponentially at the same time as energy efficiency improves, as shown in Figure 8 below. Note that these figures may underestimate the cost effectiveness of LEDs as this technology generally has a longer life than other technology types.

Figure 8 – Average efficiency (lumen/watt - light output per unit of energy consumed) (left) and cost per bulb (dollars) (right)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2014 Early Release (EIA, 2014)

OLED technology is expected to continue growing in display applications, with expectations of a near tripling of the market by (by revenue) 2022 (IHA Markit, 2017). Currently the main application of OLED panels are however in mobile phone, tablet and wearable electronic screens, although future applications are expected to include automotive and aerospace displays (IDTechEx, 2016). This could improve the efficiency of appliances and equipment (such as televisions) as OLED becomes more widespread.

HVAC

The efficiency of air conditioners has increased substantially through the use of heat pumps that provide both cooling and heating. Heat pumps can use differences in ambient temperatures to deliver greater energy cooling and heating outputs and improve the coefficient of performance (COP: the energy output of either heating or cooling compared to the energy input)[1]. Technological development could see further improvement in the performance of heat pumps and already some systems are claiming a COP of up to 11 under moderate temperature differences (Pears & Andrews, 2016)

Hot water

The most efficient technologies for providing hot water are heat pumps and solar thermal technologies. The performance of both of these technologies varies depending on the temperature and radiant heat and so their relative performance will depend on their location.

[1] Best available technology has a COP of between 6 and 7 under a variety of operating conditions meaning 6 to 7 times more energy is delivered to heating and cooling than the energy inputs (IEA, 2013)

Appliances and equipment

There are numerous technologies, categorised under appliances and equipment, which demonstrate varied potential for energy savings (e.g. heat pump clothes dryers).

Current policies set minimum performance standards for much of the equipment used in residential and commercial buildings and prevent the use of highly inefficient equipment. Recent improvements in technology such as the emergence of efficient LED televisions shows that overall energy use from equipment can decrease even when more of the technologies are used (for example two efficient screens per house can use less energy than one inefficient screen.

Technological and commercial readiness

The TRL and CRI associated with the key energy efficient buildings technologies is shown in Table 1 below.

Table 1 – Technological and commercial readiness for building technologies

(ENERGY EFFICIENT) BUILDINGS	TRL	CRI	COMMENTS
Lighting	9	6	Significant uptake of energy efficient lighting (LEDs) has occurred in Australia.
Space conditioning and hot water	9	6	There is wide commercial availability of solar water heating, heat pumps and efficient higher COP air conditioning.
Appliances and equipment	9	6	Innovative developments in the electronics industry have resulting in wide availability of energy efficient appliances and equipment
High tech efficient building envelope design (BIPV[2] roof, Low SHGC[3] windows, high insulation and passive heating)	9	4	Present regulations require moderate levels of these solutions and rating schemes encourage leaders to achieve high standards.
Buildings control systems	9	5	Highly intelligent building control systems have been developed but adoption is low.

1.3 Barriers to development and potential enablers

A range of barriers was identified in (ASBEC, 2016) affecting the uptake of energy efficiency opportunities in the buildings sector. Many barriers to energy efficiency in buildings result from the split incentives that exist between landlords and tenants. The split incentive exists where the landlord makes decisions around the purchase of equipment and upgrades to building envelope, while the benefits of energy efficiency flow to the tenant who pays the energy bill.

[2] Building Integrated Photo Voltaic (BIPV)

[3] Solar Heat Gain Coefficient (SHGC)

A variety of other barriers such as access to information, lack of capital, supply chain issues and market failures also impede the uptake of energy efficiency in the sector.

Table 2 – Barriers and potential enablers in the buildings sector

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	>Cost benefits of energy efficiency often go to the tenant while capital costs must be paid by the owner (split incentive)	>Financial instruments such as Environmental Upgrade Agreements can help tenants and owners co-finance energy efficiency	>Government >Industry	2017-2020
Revenue/ market opportunity	> High market fragmentation and transaction costs >Energy market doesn't appropriately value energy efficiency's value to the market/network	>Improve the data availability to reduce transaction costs in the development, delivery and verification of energy efficiency projects. >Continue to develop and improve standardised approaches to rating and measuring the energy performance of buildings to support scaling up of solutions. >Energy market reform to remove barriers (e.g. variable, difficult technical standards for grid connection) >Provide a level playing field for EE and distributed energy with centralised generation	>Government >Academia	2017-2020
Regulatory environment	>Minimum standards of buildings envelope and equipment lags behind most cost effective technology	>Increased minimum standards that keep pace with international best practice and increase in line with a clear future goal and trajectory (rather than ad hoc), to stimulate innovation and help building owners and developers prepare.	>Government >Industry	2017-2020
Technical performance	>Cutting edge equipment and appliances are often energy intensive (e.g. first generation flat screen television). Energy efficiency follows in subsequent generations (e.g. OLED flat screens). > Slow adoption of new technology in Australia due to lagging minimum standards	>Further research can improve the energy performance of all energy end use categories in buildings.	>Government >Industry >Academia	2017-2020

Category	Barrier	Potential enablers	Responsibility	Timing
Stakeholder acceptance	>Consumers value equipment and appliances in buildings in generally based on factors other than energy productivity (e.g. screen resolution in televisions) >Energy costs for buildings are often a small proportion of overall costs for the stakeholders in the built environment	>Mandatory disclosure of performance can increase the likelihood that energy efficiency is considered with new buildings or new appliances and equipment >Incentives to help stimulate early action when the market is still immature, and be phased out over time >Non-regulatory option – industry-led initiatives to better value and market the non-energy benefits	>Government >Industry >Academia	2017-2020
	>Energy costs for buildings are often a small proportion of overall costs for the stakeholders in the built environment	>Develop methods of valuing 'multiple benefits' such as improved staff productivity and health	>Government >Industry >Academia	2017-2020
Industry and supply chain skills	>Best available technology, equipment and materials often not available at low cost in Australia - e.g. Most efficient window glazing >Professionals throughout the building design and construction supply chain do not currently see EP as part of their job and are not trained to identify or implement EP opportunities	>Improvement in minimum standards will drive the supply chain to import the most efficient technology > Training and awareness programs for professionals and customers	>Government >Industry	2017-2020

1.4 Opportunities for Australian Industry

Cost savings from reductions in building energy use present the largest opportunity for Australia. These could be in the order of $20 billion dollars of net present value (ASBEC, 2016). Other opportunities for Australian industry include the development and installation of 'smart' building control systems and equipment, leveraging sensors and connectivity.

Table 3 – Summary of opportunities for Australian industry

	Technology development	Technology manufacturing	Technology supply and installation	End use of technology
Description	>R&D of technologies (sensors and controls)	> Manufacture of efficient appliances > Manufacture of sensors & controls	> Marketing, distribution and install	> Value of increased productivity as a result of implementing the technologies
Australia's comparative advantage	Medium +Existing expertise -Incumbent global companies	Low -Appliance, sensors manufactured overseas	High +Must be done locally	High +Value returns to Australian households and businesses
Size of market	High	High	High	High
Opportunity for Australian industry	High	Low	High	High
Jobs opportunities	High	Low	High	High
Main location of Opportunity	Urban	Urban	Urban/regional	Urban/regional
Difficulty of capture / Level of investment required	Medium	High	Low	Low/medium

2 Heating

Heat derived from combustion of fossil fuels is used in many homes, businesses and industrial processes and contributes to a significant proportion of Australia's emissions. While many of the technologies designed to improve efficiency and reduce emissions in heating are mature, there is currently a lack of knowledge and desire to implement them. This could be overcome by providing appropriate incentives and/or stable regulatory drivers. Energy and (consequently) cost savings can be achieved by implementing efficient heating technologies, and this presents as a significant opportunity for Australia. Australia may also have a role to play in the development of more nascent technologies, particularly high temperature renewable heat.

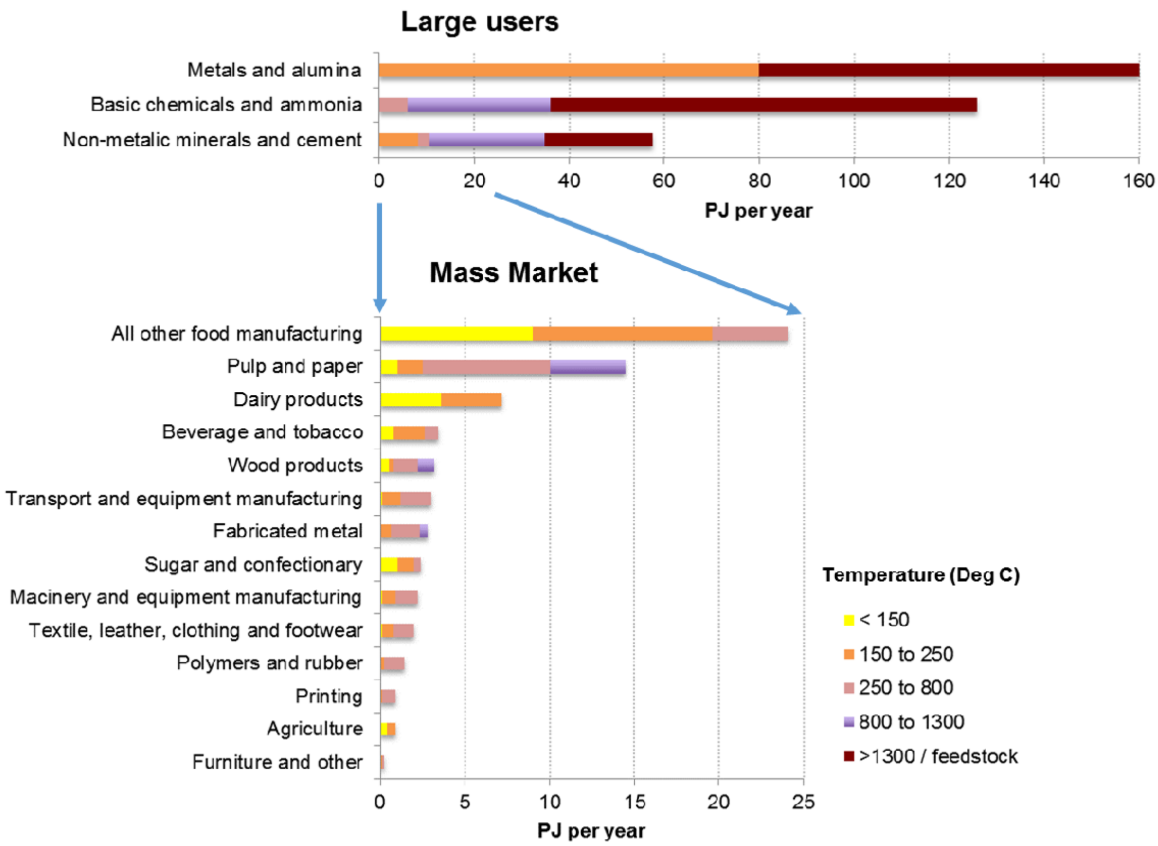
- The most promising technologies for reducing emissions in process heating include high-efficiency boilers, more efficient heat distribution and point-of use heat production for manufacturing. There are also a range of other electric heating technologies that work across industry and buildings. Renewable heat from solar and/or biomass can also be used, depending on the specific location and heating application. Heat pumps are widely available and cost effective in many applications of low and medium temperature heating.
- In many cases heat is provided at higher temperatures than actually required. This leads to significant energy waste, but also creates the perception that solar and heat pump options, which have more limited temperature ranges, are not viable.
- Implementing low emissions heating technologies has to date been a low priority for many Australian companies. Other key barriers include higher upfront capital costs, potentially higher fuel costs, and the technical ability to reach very high temperatures (>600°C).
- Appropriate policy and incentives would therefore be required to enable the uptake of these technologies.
- Further technological development may improve the economic performance of renewable heating technologies, particularly solar thermal.
- Some heating technologies such as drained wetted cathode for aluminium smelting have not been demonstrated commercially but may have significant potential for emissions reductions.
- By expanding upon existing capability, another area of opportunity for Australian industry is in the development of high temperature (>600°C) renewable heating technologies. Additionally, reduced energy costs from more efficient technologies will create value for end-users.

2.1 Process description

Heating is responsible for a large proportion of energy use and emissions in the industrial sector. Emissions from heating is highly concentrated in three sub-sectors: non-ferrous metal manufacturing (alumina and aluminium), chemicals and non-metallic mineral product manufacturing. The iron smelting and steel manufacturing, food production and pulp and paper manufacturing also have notable process heating emissions. As discussed in the buildings appendix, space and water heating is also a very large source of emissions.

To give an indication of the temperatures generated and magnitude of energy consumption from heating, temperatures used in each subsector and their gas energy use is presented in Figure 9. Note that additional energy consumption from other fuels such as coal, oil and bioenergy is not shown, and this shows the temperatures at which heat is supplied, not the temperature actually required to drive processes, which may be much lower.

Figure 9 – Quantity of gas consumption by heat range, by sector (IT Power, 2015)



Devices

The device used to generate heat depend on the temperature of heating required as well as the specific industrial processes. There are four key devices used in heating:

- Furnaces, kilns and electrolytic cells - used for processes with a temperature range over ~400^{o}C. Includes specific industrial processes (E.g. Hall–Héroult, Basic-Oxygen Furnace)
- Ovens - used for processes with a temperature range ~100^{o}C-400^{o}C
- Boilers - used for generating steam with a temperature range from 100^{o}C
- Hot water systems and space heating - mainly residential and non-specialised commercial with temperatures below ~100^{o}C

Furnaces, kilns and electrolytic cells

In Australia, four sectors are responsible for the majority of energy from furnaces, kilns and electrolytic cells. The greatest uses of heating from this technology are alumina (from bauxite using the Bayer process), aluminium (using the Hall–Héroult process), steelmaking (blast furnace or electric arc furnace), as well as non-metallic mineral product manufacturing. The primary fuels used for alumina and steelmaking blast furnaces are coal and gas, with electricity used primarily for aluminium production or steelmaking using electric arc furnaces.

Ovens

Ovens are used for medium grade heat in a wider range of industries than industrial furnaces. While the primary applications are in the food, beverage and fibre industries, ovens may also be used in metal and chemical industries where lower grade heat is required.

Boilers

Boilers are the primary means of generating steam, which is widely used in manufacturing due to its low toxicity, high efficiency and high heat capacity. It is also easily transported and relatively low cost. Key industries include chemicals, food and pulp and paper (US Department of Energy, 2014).

Hot water systems and space heating

Residential and non-specialised commercial sectors use significant amounts of energy on heating, ventilation, air-conditioning (HVAC) and hot water systems which require heating at temperatures below boiling (100^{o}C). Various technologies are used for these purposes including gas combustion, electric resistance and electric heat pumps. These technologies are also discussed in the Buildings appendix.

2.2 Technology overview

Energy savings and emissions reductions of heating processes can be achieved via a range of technologies. The energy and emission savings technologies may be grouped into four main categories:

- Equipment upgrade – implementing higher efficiency equipment using the same/similar heating process and fuel
- Electrification and fuel switching – replacing fuel-powered heat generation equipment with equipment powered by electricity or substituting fuels with low emissions alternatives
- Ambient or waste heat utilisation – utilising heat pump technologies, or capturing, upgrading and re-using waste heat from other processes or electricity generation equipment (e.g. cogeneration)
- Renewable heat – utilising solar, geothermal or bioenergy for heating

There are also technologies available to reduce or replace the need for heat, e.g. microfiltration or alternative sterilisation technologies, although these were not a focus of this report given they are covered as part of the 2XEP ‘The Next Wave’ report (2XEP, 2016).

Technology options are presented for furnaces, kilns, boilers, space heating and water heating – the devices contributing to the largest amount of emissions.

2.3 Technology description

Specific technologies in each of the four categories of energy and emission savings technologies introduced in Section 2.2 are detailed below.

Equipment upgrade

Installing high efficiency equipment can result in substantial savings for particular applications as presented in Table 4 below.

Table 4 – Equipment upgrade heating technologies

EXISTING DEVICE/PROCESS	LOW EMISSIONS TECHNOLOGY	DESCRIPTION OF TECHNOLOGY
Aluminium smelting	Drained Wetted Cathode	An improvement to the Hall–Héroult process, a wetted cathode allows the anode-cathode distance to be lowered, reducing the voltage required and thus leading to significant energy savings. (Cecilia Springer, 2016).
Boilers	'Super boiler'	A high efficiency boiler with a fuel-to-steam efficiency of 94% - approx. 20% increase over existing equipment (U.S. Department of Energy, 2007). It recovers heat from condensation of the water vapour in the flue gases and minimises heat loss from flue gases. The concept packages a suite of enabling technologies—such as a forced internal recirculation burner, high-intensity heat transfer packed media, an advanced transport membrane condenser, and a smart, integrated control system.

Electrification and fuel switching

Electrification and fuel switching technologies that offer emissions savings are presented in Table 5 below.

Table 5 – Electrification and fuel switching heating technologies

Existing device / process	Low emissions technology	Description of technology
Boilers	Electric boilers	Use of electric heating elements to achieve higher fuel-to-heat efficiency. Additional benefits include zero flue losses and ability to be scheduled to take advantage of off-peak prices.
Furnaces	Electric induction melting	Conductive metals are melted via electromagnetic induction, where resistance from the generated eddy currents melts the metals via joule heating effect at very high efficiency (Gandhewar, Bansod, & Borade, 2011)
	Plasma arc melting	In plasma arc melting, an arc formed between the materials to be melted and a plasma torch creates an anode and cathode synergy between the material to be melted and the torch with an inert gas (plasma) passing through the arc. (U.S. Department of Energy, 2007)
	Electrolytic melting	The Hall–Héroult process is an example of electrolytic melting, whereby a product is dissolved into an electrolyte medium that is kept molten by the resistive heating from an electrical current passed through it. A potential future application is molten oxide electrolysis, the production of pig iron from iron ore using electrolysis instead of needing coking coal as a reductant (American Iron and Steel Institute, 2010).

Ambient or waste heat utilisation

Table 6 describes heat pumps, heat recovery methods and cogeneration technologies that utilise extra heat or capture latent heat from the surroundings. Note that recovery of latent heat in exhaust water vapour is a key factor in achieving high overall heat recovery efficiency in many processes (2XEP, 2016).

Table 6 – Ambient or waste heat utilisation heating technologies

Existing device/process	Low emissions technology	Description of technology
Space and water heating	Heat pumps	Heat pumps use principles of thermodynamic refrigeration to transfer heat to and from source and sinks at very high efficiency. In some cases, heat pumps are able to offer up to 7 units of output for each unit of input. By recovering low temperature waste heat, it can be converted it into more useful high temperature heat. The heat recovered is conventionally used for space and water heating purposes in both commercial and residential buildings. Prototype heat pumps capable of producing industrial steam have been developed in Japan. (IEA, 2014)
	Waste heat recovery	Highly efficient thermal conductive heat exchangers are used to recover heat and use it for both low and high grade heating applications.
	Combined heat and power (CHP) or 'cogeneration'	CHP offers higher energy efficiency by utilising the heat created as a by-product of generating electricity, which would otherwise be wasted. The overall system efficiency of a CHP system ranges from 75-90% depending on the fuel source (IEA, 2011).

Renewable heat

Significant emissions reductions can be achieved by replacing or augmenting direct-fired heating equipment with renewable sources. Examples are presented in

Table 7 below. Note that concentrated solar thermal technologies, namely parabolic trough, linear fresnel, power tower and dish thermal, can also be used for electricity generation and are discussed further in the CST appendix.

Table 7 – Renewable heating technologies

Existing device/ process	Low emissions technology	Description of technology
Water heating and steam	Flat plate collectors (FPC), evacuated tube collectors (ETC)	In both FPC and ETC, sunlight heats water flowing through tubes with high absorptivity and low thermal conductivity (IEA-ETSAP and IRENA, 2015). Energy storage is needed for periods of low solar radiation.
	Parabolic trough, linear Fresnel	Parabolic trough and linear Fresnel collectors (mirrors) focus solar thermal heat onto a heat receiver which in most of the cases is an evacuated glass tube or a steel tube. They can satisfy heating demands as high as 400°C (IEA-ETSAP and IRENA, 2015).
	Heliostat & tower	Solar tower technology generates high temperature heat using a ground-based, computer controlled field of heliostats (mirrors) that reflects sunlight

Existing device/ process	Low emissions technology	Description of technology
		onto a heat receiver on top of a central tower. The temperature obtained mainly depends on the number and size of the heliostats and the molten salts used as heat receivers (IEA-ETSAP and IRENA, 2015).
	Dish	A parabolic reflector dish uses reflecting mirrors on the dish to concentrate solar light onto the focal point in front of the dish. The heat output mainly depends on the aperture area and optimised solar tracking.
High-heat (e.g. alumina calcination)	Direct solar radiation	DNI can be concentrated directly on the material being heated. For example, in alumina calcination, a Fresnel lens of very high optical efficiency positioned on an aluminium installation could achieve heat in excess of 1200°C (IEA-ETSAP and IRENA, 2015).
Boilers, electricity generation	Bioenergy	There are a number of processes through which bioenergy can be utilised for industrial heat, such as combustion, gasification, pyrolysis or anaerobic digestion. This topic is covered in detail in the bioenergy appendix.
Water heating	Geothermal	Uses water circulating in drilled wells to draw heat from depth within the earth's crust. These resources are able to produce 24/7 heat on demand. Geothermal energy can be a cost-competitive renewable heat opportunity so long as there is sufficiently large demand and the user is located in an area with a suitable resource. There are two main types: enhanced geothermal systems (~4km depth, 200-250°C) and shallow direct use resources (<2km depth, 60-110°C) The application of geothermal to electricity generation is discussed in the geothermal appendix.

2.4 Technology impact

Implementing the technologies described above to process heating in industry and buildings can result in a significant reduction in energy and emissions. However, this level of abatement is subject to a range of barriers, as discussed in Section 2.6 below. For modelling results, see Appendix A in the main report. For more detailed information of the individual impact of these technologies, see the modelling appendices.

2.5 Technology status

Cost

A detailed assessment and comparison of these technologies is beyond the scope of this report. However, a thorough investigation of renewable heating methods in Australia was recently published (IT Power, 2015). The cost curves for solar, biomass, heat pumps and geothermal derived from that study are provided below.

As shown in the Figures below, renewable heating technologies are already cost effective for certain temperature ranges and scales depending on the relative cost of gas or availability of alternative fuels beyond the gas grid. Heat pumps in particular are already commercial in most situations, particularly when used to replace existing equipment during turnover.

The shift towards point-of use heating can avoid high losses in distribution systems and inappropriately high heat delivery temperatures, thereby improving the cost effectiveness of heat pump technologies.

Apart from biomass, renewable technologies tend to be less competitive at higher temperatures. Higher temperature renewable heating is an active area of research and further technological development is required before it is commercially available.

There are a range of factors that contribute to the cost of the technologies presented below. These vary depending on the process and location. Factors include:

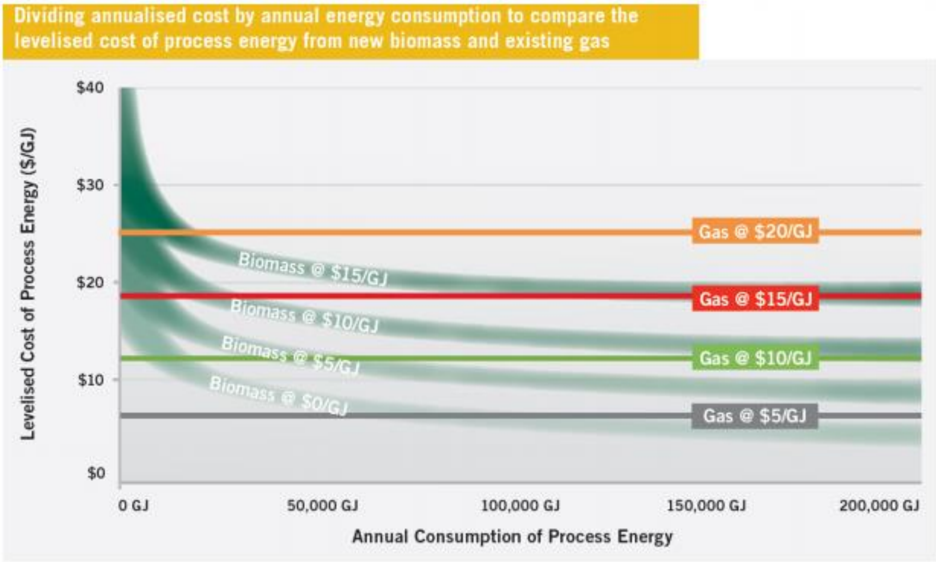
- The required temperature - lower temperature heat is generally cheaper and more efficiently produced from renewable technologies and heat pumps.
- Scale - renewable heating projects benefit from economies of scale which can improve their relative economic and technical performance.
- Location and climate - the cost and performance of renewable heating technologies is dependent on proximity and availability of suitable resources (e.g. biomass supply or solar and geothermal resources).

Biomass

The cost of biomass varies depending on the type of feedstock and pre-treatment and transport requirements. In many cases, biomass is more expensive than traditional fuels. Conversely, biomass costs can be close to zero in sectors where organic waste products are in close proximity to the point of use. This is represented in

Figure 10.

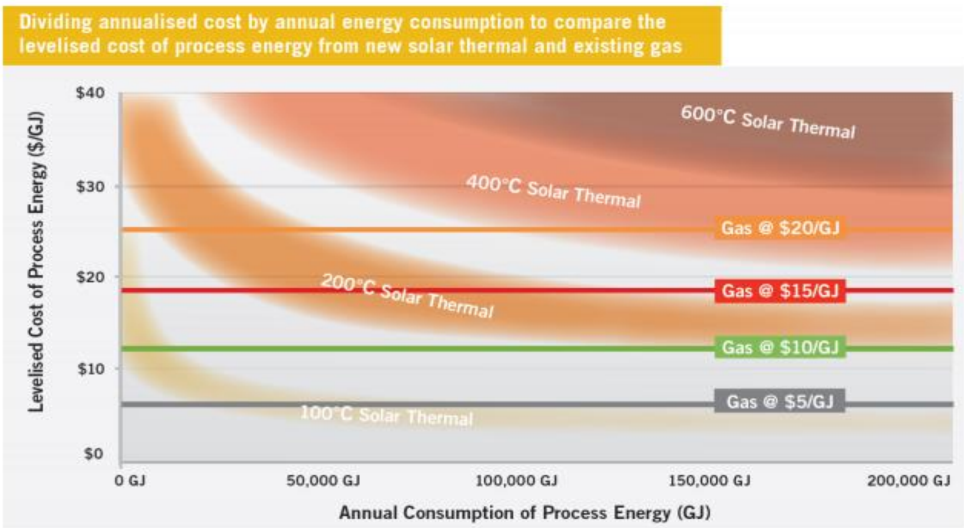
Figure 10 – Assessment of biomass heating economics (IT Power, 2015)



Solar Thermal

The cost effectiveness of solar thermal heating is highly dependent on the temperatures required for different applications and the solar irradiance at a specific location. As shown in Figure 11 below, solar thermal is generally economical for lower temperature heating (i.e. 100°C to 400°C). For application of solar heating at temperatures above 400°C, further research and development is required before this technology will be economically attractive. Further, given that solar thermal on its own is intermittent, the need for consistent provision of heat can add extra costs for energy storage and/or coupling with other energy sources (e.g. gas).

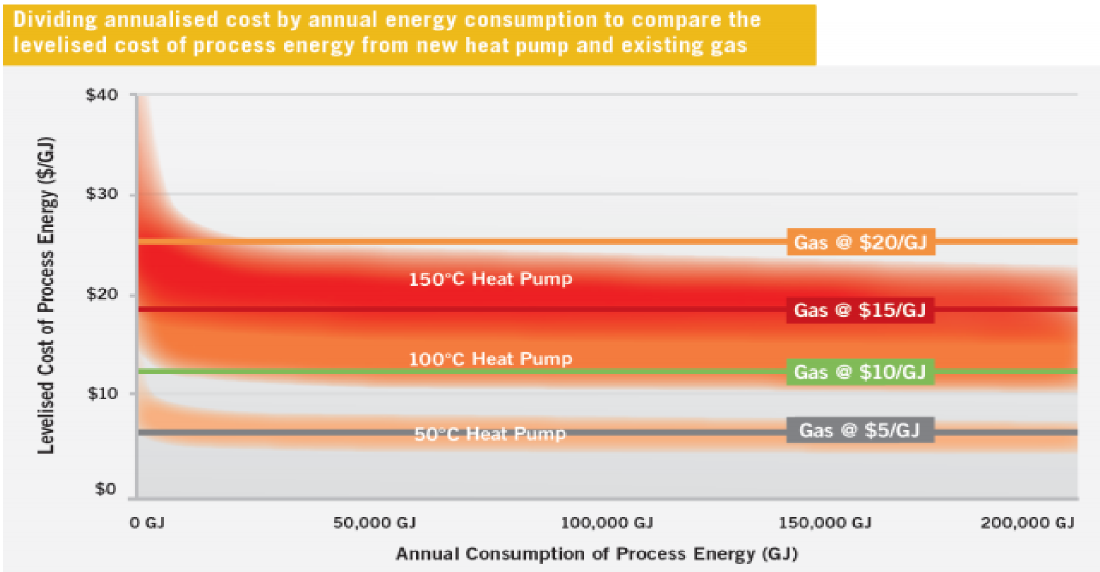
Figure 11 – Assessment of solar thermal heating economics (GJ) (IT Power, 2015)



Heat Pumps

Heat pumps are also more efficient when lower temperature heat is required. As shown in Figure 12 below, although the technology may be used at temperatures up to about 150°C, they become less cost effective relative to gas as the temperature increases. However, by using waste heat or renewable heat as the heat source, provision of higher temperature heat can be made more efficient.

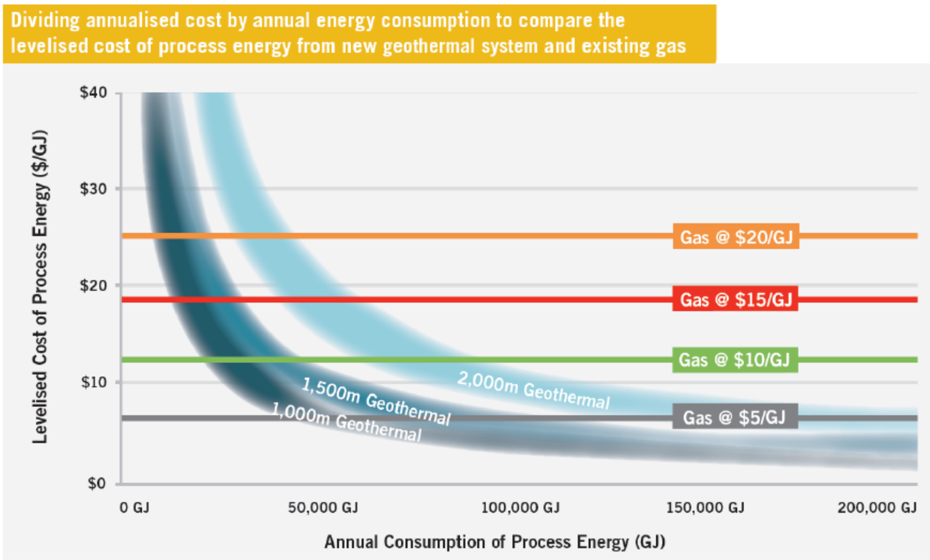
Figure 12 – Assessment of heat pump heating economics (IT Power, 2015)



Geothermal

This source can be cost effective against gas for large consumption at the temperature range obtained from shallow direct use resources, given a suitable resource is located within proximity to the user.

Figure 13 – Assessment of geothermal heating economics (IT Power, 2015)



Technology and commercial readiness

Low emissions technologies discussed here are at various stages of technological and commercial development. The TRL and CRI associated with each of these technologies is shown in Table 8 below. In nearly all cases, low emissions heating technologies are technologically mature, but vary widely when it comes to commercial readiness (CRI).

Table 8 – TRL and CRI assessment of heating technologies

TECHNOLOGY	TRL	CRI	COMMENTS
Equipment upgrade			
Drained wetted cathode	9	2	Conducting commercial trials.
'Super boiler'	9	2-3	Completed small scale commercial trials, scaling up.
Electrification and fuel switching			
Electric boilers	9	6	Commercially mature for smaller applications.
Electric induction melting	9	4	Commercially available, not widespread.
Plasma arc melting	9	4	Commercially available, not widespread.
Electrolytic melting	9	4	Commercially available, not widespread.
Ambient or waste heat utilisation			
Heat pumps	9	4-6	Commercially mature for lower temperatures; further development of higher temperature applications.
Waste heat recovery	9	6	Commercially mature with existing support industries.
Combined Heat and Power (CHP)	9	6	Commercially mature with existing support industries.
Renewable heat			
Flat plate collectors (FPC), evacuated tube collectors (ETC)	9	6	Commercially mature with existing support industries.
Parabolic trough, linear Fresnel	9	6	Commercially mature with existing support industries.
Heliostat & tower	9	4	Less commercially available with support industries mainly overseas.

TECHNOLOGY	TRL	CRI	COMMENTS
Dish	9	4	Less commercially available with support industries mainly overseas.
Direct solar radiation	6-9	1-2	Conducting small scale commercial trials.
Bioenergy	9	6	Commercially mature with existing support industries.
Geothermal – Shallow direct use resources	7	2-4	Past prototyping stage, utilise mature component technologies.
Geothermal – Enhanced geothermal systems	5	1	Active research area. Yet to demonstrate plant at or close to utility scale electricity in Australia.

2.6 Barriers to development and potential enablers

The uptake of the technologies described above is subject to a range of barriers which will require a range of measures to unblock. The costs of unblocking the barriers should be considered given the magnitude of savings potential. Key barriers include a lack motivation, high financial barriers as well as a lack of knowledge. These and other barriers and enablers are described in Table 9 below.

Table 9 – Heating barriers and potential enablers

Heating	Barriers	Potential enablers	Responsibility	Timing
Costs	>Business case – requirement for short payback period (~1-2 years) >Tax incentive to replace 'like with like' equipment instead of high efficiency equivalents	>Incentives to consider and adopt higher efficiency equipment > Address asymmetry, allow equal (or higher) incentives for high efficiency equipment	>Government >Industry	2017-2020
Revenue / market opportunity	n/a	n/a	n/a	n/a
Regulatory environment	>No requirement to reduce emissions from heating	>Introduce policy to recognise and limit emissions and/or increase efficiency	>Government	2017-2020
Technical performance	> Maximum temperature limits > Reliability / continuity of supply (e.g. solar) > Practical issues with installation	>Continue R&D of energy storage technologies and hybrid systems >Educate industry on current and future energy storage options	>Government >Industry >Academia / research group	Ongoing
Stakeholder acceptance	>Lack of knowledge about new technologies >Lack of awareness around benefits of electrification >Lack of internal capability >Technology maturity: Unlikely to be adopted unless widely accepted/demonstrated in a similar industry	>Improve knowledge sharing initiatives >Support demonstration projects	>Government >Industry >Non-Profits	2017-2020 / ongoing

Heating	Barriers	Potential enablers	Responsibility	Timing
Industry and supply chain skills	>Lack of skills around energy efficient and renewable based heating operations	>Introduce certifications and accreditations in the relevant skill sets	>Industry >Government	2017-2025

Table 10 – Opportunities for Australian industry

	Technology development	Technology manufacturing	Technology supply and installation	End use
Description	Research and development of renewables based and efficient heating systems, and systems that avoid or reduce need for heat	Local component and system manufacturing	Supply and installation of low emissions heating systems in local industries	Use of low emissions heating systems
Australia's comparative advantage	High +Established research organisations and facilities for the development of the technologies such as solar thermal	Medium: -Component manufacture mostly overseas. +Some system components could be manufactured locally	High	High
Size of the market	High	High	High	High
Opportunity for Australian Industry	High	Medium	High	High
Jobs opportunity	Medium	Medium	High	Low
Main location of Opportunity	Urban	Urban	Urban / Regional	Urban / Regional
Difficulty of capture/ level of investment	Medium: >Further funding is required to promote research and local development	Med-High	Low: >Already an established market	High

3 Mining

The size and scale of mining operations in Australia results in significant emissions from material handling and comminution. Consequently, there is large scope for energy efficiency improvements by implementing technologies that leverage ore properties, mine design, and local knowledge in optimising loading and hauling operations and new crushing and grinding processing techniques. A key barrier to uptake of these technologies is the focus on production yield and risks of interruption to operations. Australia has the opportunity to develop and potentially export technologies and operational know-how, as well as capture productivity benefits locally from reduced energy consumption.

- Reducing emissions from mobile material handling equipment and comminution (crushing and grinding), the two most emissions-intensive processes in iron ore and coal mining, can be achieved through operational improvements and by implementing technologies that improve efficiency.
- Larger, more efficient or hybrid haul trucks can reduce emissions from mobile material handling equipment. Operational improvements, including route and load optimisation offers further abatement.
- At some sites, haul trucks and loaders could be replaced with electric conveyors, offering greatly improved energy intensity while avoiding diesel fuel consumption.
- Vertical mills and high pressure grinding rolls are technologies currently under development that could greatly increase energy efficiency of comminution.
- These technologies face barriers to uptake including lack of company motivation due to focus on yield and risks of interruption. Unless low-emissions technologies also offer substantial additional benefits such as safety, they will require policy support to drive uptake.
- Opportunities for Australian industry exist in research and development and the end-user productivity benefits of operating more efficient technology.

3.1 Technology overview

Process description

Mining operations involve multiple sequential processes, as shown in Figure 14. This appendix discusses technologies available to reduce energy consumption and emissions in all steps of the process, but focusses on the two most energy-intensive processes: haulage and comminution. Fugitive emissions from coal mining is discussed in the fugitive emissions appendix.

Haulage is the process of transporting ore from the point of extraction to processing facilities ('Truck & Shovel' step in Figure 14). In an open-cut mine, this process typically uses diesel-powered off-road dump trucks - the largest of which have carrying capacities of up to 500 tonnes.

Comminution involves reducing the size of mined materials to small, usable chunks through crushing and grinding (from 'Primary Crusher' step onwards in Figure 14). The grinding process typically involves a rotating cylinder partially filled with a grinding medium such as steel balls or rods in a ball mill, to grind material using impact and friction.

Figure 14 – Comparison of a typical (top) and optimised (bottom) mining process (Valery, 2015)

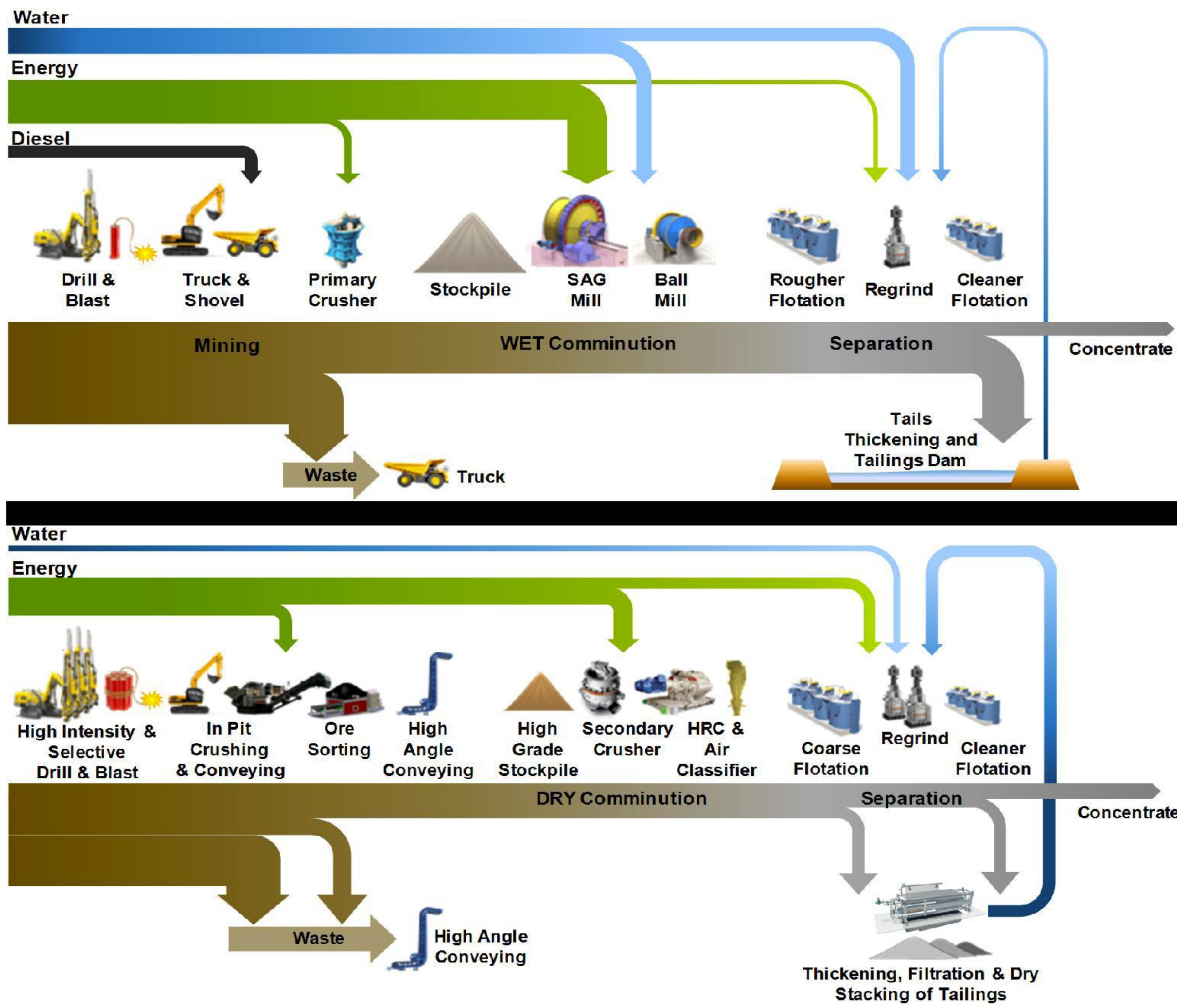


Figure 14 summarises the differences between a typical (top) and optimised (bottom) process. Focussing on the green 'Energy' arrow, it shows the replacement of diesel energy in early process 'Mining' steps with electricity, and a reduction in energy consumption of the middle 'comminution' steps. Changes and optimisation in up-stream activities (e.g. strata blasting) reduces the amount of material processed in subsequent processes, leading to compounded reductions in both energy and water consumption.

Technology description

This section is structured according to mining process (from left to right) in Figure 14, and discusses the technologies used to reduce energy consumption and emissions in each step of the optimised process.

High intensity selective drill and blast

High intensity and selective drilling and blasting is an opportunity that could reduce energy by minimising the amount of material handled and energy required during a mining operation.

Novel blast designs using electronic initiation systems offers flexibility to achieve high intensity selective blasting with no threats of increased dilution or wall damage. The blast is designed such that it increases finer ores with micro-fractures along the mineral grain which reduces the comminution energy and increases mineral recovery (M.Daniel, 2010). These techniques may be less relevant where lump products like iron ore and metallurgical coal are more valuable than fine products.

Haulage

A range of opportunities to improve the energy efficiency of diesel haul trucks was identified, including (eex, 2015):

- Larger haul trucks – reducing the amount of energy required per tonne of material hauled,
- Payload optimisation – filling the haul truck to an optimum amount, and
- Improved driver practices - such as smooth acceleration and braking.

Additionally, autonomous haulage offers the potential to increase efficiency whilst providing safety benefits and reduced maintenance cost. The University of British Columbia suggests that automation in haulage could potentially increase productivity by 20%, reduce fuel consumption by 15% and decrease the maintenance cost by 8% (J.Perriera, 2013). Furthermore, there are cost and emissions benefits from the reduced demand for air travel to bring in drivers to operate on remote mine sites.

Hybrid electric truck haulage

In comparison to diesel, hybrid electric trucks reduce the risk of underground diesel storage, move faster, reduce dust and smoke and have lower operating costs. The minimal demands on ventilation systems is a key impact, given ventilation costs are a large contributor to total underground mining costs. Electric trucks may be powered with by batteries, from a trolley electric line or an electric cable. However, for transporting material over long distances in mines, electric cable and batteries are not feasible (Salama, 2014).

Hybrid systems may involve a combination of power sources. For example, the green line family of trucks are powered up and down the ramp by an overhead, electrified trolley rail during normal operation. Where there is no access to an overhead trolley rail, for example at the loading and dumping station, the truck disengages itself from the trolley and automatically activates a small, on-board diesel engine (Atlas Copco, 2011).

In-pit crushing and conveying (IPCC)

In-pit crushing and conveying has been identified as an alternative to conventional truck haulage and shovel operations. In IPCC operation, a mobile, semi-mobile or a stationary in-pit crusher is coupled with conveyors to remove the material from an open pit. The most efficient system of conveying is 'high angle conveying' (HAC) which offers the shortest route on elevated conveyors, offering substantial savings in energy (T.Norgate, 2013).

Ore-sorting pre-concentration

Excluding worthless gangue material earlier in the process using ore-sorting pre-concentration processes can reduce downstream comminution energy requirements. Depending on ore properties, different technologies of pre-concentration are applicable, such as screening and sensor-based bulk ore sorting (SBOS).

Screening

Where valuable minerals are easily crushed because they are softer than the gangue material, the minerals can concentrate in a fine size fraction after initial breakage from which they are separated from the gangue. This screening technology is limited to certain ores.

SBOS

Electromagnetic, photometric, X-rays and radiometric sensors are used to measure the difference in the properties between the gangue and the ore materials. For bulk mining operations, the SBOS is applied to the bulk quantities of ore loaded on the conveyors or the truck trays. Generally, SBOS are considered too slow for the bulk sorting operations but the magnetic resonance sensors developed by the CSIRO have demonstrated the ability to sort ores on large rapid production conveyors (Kristy-Ann.D, 2015).

Gravity separation

Gravity floatation separation is an ore-sorting technology that can be utilised in a typical wet comminution process to improve efficiency. Gravity separation makes use of the difference between the density of the gangue and ore material to separate the two at a fairly coarse size. This improves efficiency of downstream comminution steps by reducing the amount of material processed. Heavy medium separation (HMS) or dense medium separation (DMS) are the efficient concentration options for a wide variety of ores and offer very large cost and energy efficiency improvements (Legault, 2016).

Comminution

Comminution is the most energy intensive process in mineral processing operations. Conventional wet circuit comminution uses grinding media fed to the tumbling mills or autogenous grinding mills. Replacing wet comminution milling with dry comminution processes such as high pressure grinding rolls (HPGR) and vertical roller mills (VRM) offers both energy and water saving potentials.

HPGR and VRM

HPGR and VRM could substantially improve the performance of the conventional grinding circuits. HPGRs utilize two counter-rotating tires or rollers through which the ore feed passes, under very high pressure applied by hydraulic cylinders. VRMs are used for fine grinding, operating by passing the feed between a grinding table and grinding rollers that are pressed onto the table under hydraulic pressure. These technologies offer low energy intensities compared to conventional mills, as well as operating without grinding media or water.

Technology impact

Mining accounted for around 9.1% of total Australian energy consumption in 2015, with more than half of this energy consumed in the transportation of ore (haulage) and subsequent crushing and grinding (comminution) (Department of Industry and Science, 2015).

The technologies discussed above have the capability to deliver significant energy savings in mining if the barriers to implementation are overcome. The corresponding emissions savings will depend upon the emissions intensity of the electricity generation source.

The largest energy reduction opportunities could be realised through optimisation of the entire mining process, enabled by the implementation of a suite of technologies such as high intensity selective blasting (HISB), IPCC and HPGR.

For detailed information of the assumed impact of these technologies, see the modelling appendices. For modelling results, see the Appendix A in the main report.

3.2 Technology status

Cost

It was beyond the scope of this project to undertake economic modelling of the different technologies discussed. In practice there are numerous factors that affect the business case of these technologies, not least access to capital and internal hurdle rates that would differ by company and by site. Presented in Table 11 below are indicative values of the operational and capital cost of these technologies compared to typical processes. It can be seen that in general there are operational cost reductions available, but capital costs are higher. The exact costs and savings would depend greatly on individual factors.

Table 11 – Indications of operational and capital cost differences compared to conventional processes

TECHNOLOGY	OPERATIONAL COST	CAPITAL COST
High-intensity and selective drill and blast (Kristy-Ann.D, 2015)	Lower 30%-40%	Higher 10%
Efficient haulage (W.Jacobs, 2013)	Lower up to 20%	Higher 20%
In-pit crushing and conveying (Kristy-Ann.D, 2015)	Lower 20%-60%	Higher 25%-35%
Efficient comminution (dry circuit) design (Kristy-Ann.D, 2015)	Lower 30%-40%	Higher 30%-50%
Gravity separation (M.Daniel, 2010).	Cost savings associated with the energy savings	Higher 30%-50%
Pre-concentration (N.J.Grigg)	Lower 10%	Higher 15%-20%

Technological and commercial readiness

The TRL and CRI associated with the key mining technologies is shown in Table 12 below.

Table 12 – Mining technologies: current technological and commercial readiness

	TRL	CRI	COMMENTS
Efficient haulage	9	6	Mature technologies commercially available.
In-pit crushing and conveying	9	4-6	Uses commercially available technologies; depends on site-specifics.
Pre-concentration	9	3	Lacking proper knowledge of ores inhibits utility in large scale operations.
Efficient comminution circuit: efficient classification	9	6	Mature technologies commercially available.
Efficient comminution: dry circuit design	9	2	Technologies demonstrated, ready to be commercialised.
High intensity selective drilling and blasting	9	4	Technologies demonstrated, running at pilot-scale.

3.3 Barriers to development and potential enablers

A summary of the key barriers and enablers is provided in Table 13.

Table 13 – Mining barriers and potential enablers

Mining	Barriers	Potential enablers	Responsibility	Timing
Costs	> Increased capital costs	>Implementation of low interest capital access schemes >Further research focused on cost reduction of the efficient technologies. >New mine design methodologies that consider energy productivity and emissions reduction - not just tonnes processed or capex	>Government >Industry >Academia	2017-2020 / ongoing
Revenue / market Opportunity	> Intensive focus on yield > Limited focus on energy savings > Cyclic booms and busts	>Improve the data availability to clearly identify the potential of cost effective and energy efficient opportunities. > Inclusion of strong energy productivity and emissions considerations when designing new mines to capture maximum benefit > Overall flowsheet for mine to metal evaluation to quantify benefits for industry	>Government >Academia >Mining companies >Industry service providers	2017-2020 / ongoing
Regulatory environment	> Lack of KPI targets for industry to reduce water consumption and energy	> Implement standardised uniform codes acceptable for all >Establishment of an industry/govt body to set targets and oversee the progress towards them	>Government >Industry >Research	2017-2020 / ongoing
Technical performance	>Applicability of some cutting edge technologies to certain mines/ores	>Further research to capitalise on the potential saving opportunities available	>Academia	Ongoing
Stakeholder acceptance	> Low motivation and drive for lower emissions	>Stable long term industry-wide emissions reduction signal >Education and training of Directors and	>Government >Not for profit >Industry	2017-2020

Mining	Barriers	Potential enablers	Responsibility	Timing
		Executives in their corporate responsibilities to consider climate change transition risks		
Industry and supply chain skills	> Lack of expertise and skills to adapt with new cutting edge technologies	>Implementation of trainings for the adaptation to modern technologies	>Government >industry	2017-2030

3.4 Opportunities for Australian Industry

Table 14 – Opportunities for Australian industry

	Technology development	Technology distribution and manufacturing	Technology supply, installation and operation
Description	Research and development of energy efficient technologies and processes in mining	Manufacture of efficient equipment	Procurement, installation and operation of technologies for more efficient mining operations
Australia's comparative advantage	High +Rich and diverse minerals endowment +Existing research and development capability with a history of innovations +Strong support industries	Low -Most of the equipment manufacturing is done abroad.	High +Installation and commissioning of technologies done on-site +More efficient mining operations can increase global competitiveness
Size of the market	High Mining and associated services account for ~8% of Australia's GDP	High Mining and associated services account for ~8% of Australia's GDP	High Mining and associated services account for ~8% of Australia's GDP
Opportunity for the Australian Industry	High +Potential to locally develop energy efficient material handling measures	Low	High +Size of mining industry offers large potential benefits +Potential to support local and int'l (particularly Asian) markets
Jobs Opportunity	High	Low	High
Main Location of Opportunity	National	National	National
Difficulty of capture/ level of investment	Low Existing research and development capability	High: High level of difficulty associated with building electric trucks, IPCCs, comminution equipment in Australia	Low: Huge market potential and investments available in mining industry – although can be cyclic due to commodity prices

4 Motor driven equipment

Motor driven equipment is used extensively across the economy. Key applications include pumps, fans and compressors. While this type of equipment consumes large quantities of electricity, significant energy savings can be achieved by implementing new technologies, improving operations and reducing waste in existing installations. Although many of these technologies offer net financial and productivity benefits, to date there has been a general unwillingness on the part of Australian industry to embrace these opportunities.

- Efficiency improvements on the order of 40% are thought to be achievable in motor driven equipment.
- The majority of the efficiency gains can be achieved through operational improvements, including reducing demand for compressed air, fixing leaks/seals and through maintenance activities.
- A significant share of savings can be achieved by incorporating variable speed and variable frequency control systems that allow for motor performance to be matched to demand. Efficiency of the electric motor itself can be improved through rotor and magnet developments, increasing the efficiency of all equipment using this technology.
- Adoption of energy efficiency has been slow due to high upfront costs and a lack of internal capabilities and motivation at a company level.
- Significant value may be derived from the implementation of efficient motor technologies, primarily as a result of reduced energy use. Other opportunities exist in the development of integrated control systems and process optimisation.

4.1 Technology overview

Globally, electric motors are estimated to consume over 40% of all electricity generated, more than double that required for lighting, which is the next largest end use (International Energy Agency, 2011).

Motor driven equipment systems consist of two key sub-systems as shown in

Figure 15: the core motor system and the end use system. The core motor system comprises the electric motor and the associated control and transmissions systems. The end use system is typically broken into three main classes:

- Pumps - used to transfer and pressurise liquids and gases for processing. They also have applications in cooling, heating, lubrication, power hydraulic systems and sewage processing.
- Fans - used widely in industrial and commercial applications, for ventilation, cooling, heat distribution, blowing and drying.
- Air compressors - use electrical energy to bring air to a high pressure to drive tools and run equipment (UNIDO, 2011).

The end use system also includes ducting/piping systems and attached equipment like compressed air tools.

Figure 15 – Motor driven system components (Anibal T. de Almeida and Joao Fong, ISR, 2011)

Technology description

A range of technologies exist to improve the energy efficiency of motor driven equipment, with continual improvements under development. Technologies designed to improve efficiency of the core motor, pumping, fan and compressed air systems are discussed below.

Electric Motors

Although electric motors are a mature technology, improvements in energy efficiency are still expected. Appropriate matching of motors to loads can improve efficiency. In Australia, 'High' and 'Premium' efficiency classes (IE2[4] and IE3, respectively) of motors are typical and also mandated under the Minimum Energy Performance Standards (MEPS) for three-phase motors between 0.73kW and 185kW (Energyratings, 2016).

A new generation of motors, under the 'Super Premium' efficiency class (IE4), increases efficiency by several percentage points in comparison to NEMA[5] premium and IE3 standards in Australia. This improvement is enabled by technologies such as brushless permanent magnets and synchronous-reluctance technology. (Siemens, 2016) The IE4 standard equates to a minimum efficiency of between 94.6 - 96.7% for a 500-100kW motor. (ABB, 2014)

In the long term, superconductivity may reduce losses in electric motors even further and thus reach efficiency levels of around 99 percent. However, this technology will only be cost-effective for very large motors (or generators) >1000hp in applications with high annual running hours (Mecrow, 2008).

[4] International Efficiency (IE)
[5] National Electrical Manufacturers Association (NEMA); American efficiency standard

Variable speed drives (VSDs) and variable frequency drives (VFDs)

This technology forms part of the motor control and can greatly improve motor system efficiency by better matching the motor speed with the required output. The motor speed and torque is altered by varying the input voltage and/or frequency. Doing so in this manner avoids the need for mechanical flow control devices such as throttles and valves that induce losses in the system (Anibal T. de Almeida and Joao Fong, ISR, 2011).

End Use Systems- Pumps, fans and air compressors

In addition to the implementation of high efficiency motors and variable speed drives, energy efficient technologies and operational optimisation of the end use systems offer savings opportunities. As shown in the Figure 16 below, the saving opportunities from the replacement of the electric motor in a pumping system are in fact quite modest. Larger saving opportunities exist in the implementation of speed controls (VSDs/VFDs) and overall system approach with optimised load management design, optimised sizing of pipes and efficient ancillary equipment energy. For highly variable loads, a parallel system can be installed alongside a large constant load system, with efficient impellers and propellers. Such an arrangement allows both the larger constant load system and smaller, variable system to operate at higher overall efficiencies.

Figure 16: Energy saving techniques for pumps (UNIDO, 2010)

Energy Savings Method	Savings
Replace throttling valves with speed controls	10–60%
Reduce speed for fixed load	5–40%
Install parallel system for highly variable loads	10–30%
Replace motor with a more efficient model	1–3%
Replace pump with a more efficient model	1–2%

Operational, system and technical design improvements of air compressors and compressed air systems offer substantial potential energy reductions. For example, reducing the demand for compressed air by substituting air tools with alternatives where appropriate, can greatly reduce energy use. Examples of alternatives are shown in

Figure 17. Similarly, operational improvements such as minimising leaks and continued maintenance have a very large potential for energy reduction.

Figure 17 – Compressed air uses and potential substitutes (Sustainability Victoria, 2009)

Compressed Air Use	Equipment Used	Solutions
Blowing or Cleaning	Nozzle/gun	Air knife, Induction nozzle, low pressure blower, broom/brush
Cooling	Cooling induction system	Air conditioning systems, chilled water, fresh air ventilation, fans
Drying of water on product	Nozzle/gun	Solenoid control, air knife, induction nozzle

Technology impact

Research undertaken by United Nations Industrial Development Organisation (UNIDO, 2010) suggests that the technical potential reduction in energy consumption in pumps, fans and compressed air is up to 40%; 4-12% of which comes from equipment replacement. Non-technical improvements that do not rely upon application of a specific technology, but rather process improvement, such as fixing leaks/seals, repair of worn belts, predictive maintenance and isolating non-essential equipment account for the remainder of the savings

4.2 Technology status

Cost - current state and projections

The cost of the equipment itself is a fraction of lifetime operating costs, typically accounting for only 12-15%. There is often net cost benefits offered from implementing technologies that reduce energy consumption over the operational lifetime of the equipment, despite requiring a capital investment that is typically higher than for less efficient equivalents.

While this work did not undertake financial analysis of opportunities, previous studies have found that between 70-75% of the total technical potential (up to 40% reduction of energy use in fan, pump and compressed air) is cost effective in both the US and Europe through installing variable speed drives and a wide range of operational optimisations (UNIDO, 2010). This is corroborated with estimates that energy savings in the order of 20-30% of energy are cost effective by implementing more efficient motor and drive equipment (International Energy Agency, 2011).

Technological and commercial readiness - current state

The TRL and CRI associated with the key motor-driven systems is shown in

Table 15 below.

Table 15 – Motor Driven systems technological and commercial readiness

TECHNOLOGY	TRL	CRI	COMMENTS
Motor and Motor Driven Systems			
'Super Premium' efficiency motors (IE 4)	9	5-6	Available for purchase from suppliers.
IE 2/3 motors	9	6	Current standard in Australia, required by current MEPS
Variable Speed/Frequency drives	9	6	Available to purchase from suppliers.

4.3 Barriers to development and potential enablers

The uptake of the technologies described above is subject to a range of barriers which will require a range of measures to overcome. Key barriers include the diversity of applications and stakeholders, as well as financial barriers and lack of detailed monitoring and feedback to operators. These and other barriers and enablers are shown in Table 16 below.

Table 16 – Motor Driven systems barriers and potential enablers

	Barriers	**Potential enablers**	**Responsibility**	**Timing**
Costs	>Higher upfront cost >Low financial attractiveness/weak business case (e.g. long paybacks periods) > Tax incentives available for 'like for like' replacements, but not high-efficiency equipment	>Incentives to consider and adopt higher efficiency equipment > Address asymmetry, allow equal (or higher) incentives for high efficiency equipment	>Government	2017-2020
Revenue / market opportunity	> Least cost preferences of the original equipment manufacturers (OEM's).	>Higher Minimum Energy Performance Standards (MEPS) > Aligned incentives throughout the value chain to manage full life-cycle costs	>Government	2017-2020
Regulatory environment	> Lower minimum standards when compared with the other OECD countries, regulating overall industrial system efficiency.	>Ensure standard efficient industrial operations aided by energy audits	> Service providers > Government bodies	2017-2020
Technical performance	>Different physical size >Tendency to oversize to reduce risk of overloading	>Optimise system efficiency so smaller capacity motor can be specified >Install smart monitoring to avoid overloading	> Industry	2017-2020 / ongoing
Stakeholder acceptance	>Lack of information and knowledge >Throughput focus	>Strengthen awareness through educational efforts	>Government >Industry groups	2017-2020 / ongoing

	Barriers	Potential enablers	Responsibility	Timing
Industry and supply chain skills	>Installation complexity	>Standardise system requirements (e.g. bolt patterns, equipment size) to allow more general application of most efficient equipment	>Industry	2017-2020 / ongoing

4.4 Opportunities for Australian Industry

Table 17 – Opportunities for Australian industry

	Technology development	Technology distribution and manufacturing	Technology supply and installation	End use
Description	Research and development of efficient motor, drive and control systems	Manufacturing of equipment used in the motor driven systems	Supply and installation of high efficiency equipment for motor driven applications	Productivity impacts on the end users from the energy efficient measures
Australia's comparative advantage	Low/Medium -Incumbent international manufacturers leading development	Low/Medium -Manufacturing of motors likely to be done overseas. +Balance of system may be designed and fabricated locally	High +Installation must be done locally	High +Operations are in Australia
Size of the market	High	High	High	High
Opportunity for Australian industry	Medium >Opportunities for development of systems and controls	Low/Medium	High	High
Jobs opportunity	Low	Low	High	Medium
Main Location of Opportunity	Urban/Regional	Urban/Regional	Urban/Regional	Urban/Regional
Difficulty of capture/ level of investment required	Medium	High	Low	Medium

5 Oil & gas

Multiple technologies are available for energy productivity improvements in energy production, particularly in LNG plants. LNG production is the focus of this paper given the large proportion of current and projected emissions. Opportunities are available for existing plants, however due to production dynamics and the need for technologies to be incorporated at the design stage, the window for uptake of the most efficient technologies is limited.

- The most significant energy efficiency improvements in LNG trains can be achieved through the use of higher-efficiency “aero-derivative” gas turbines to drive the liquefaction process instead of conventional gas turbines. Turbines are a key piece of equipment and are therefore decided upon early in the plant design change.
- Electric motors can also be utilised in some applications in order to reduce emissions, especially when drawing suitably low-carbon electricity.
- The scope for replacing the main liquefaction turbine on an LNG train is limited due to a range of technical, economic and operational factors.
- Besides new LNG plant construction, there is scope for energy and emissions reductions opportunities in operating LNG plants, particularly older plants that are no longer operating at maximum throughput due to field production decline.

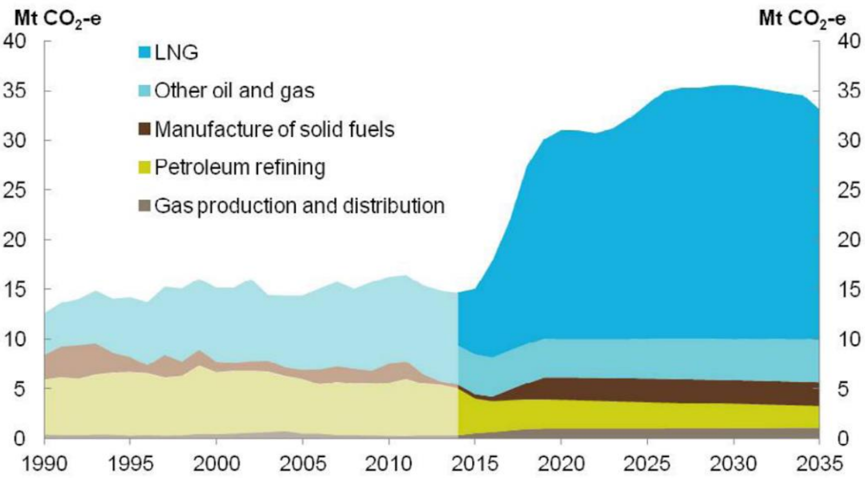
5.1 Emissions overview

Since 2012, liquefied natural gas (LNG) production in North Western Australia and Queensland has ramped up significantly. As shown in

Figure 18 below, LNG production is currently responsible for the majority of GHG emissions from direct combustion in the oil & gas sector in Australia. The additional emissions from electricity consumption is also a consideration, particularly in Queensland, however this is not covered in this appendix.

Australia's crude oil production peaked in 2000 and has since declined substantially to about 300,000 barrels a day (APPEA, 2016). LNG process emissions are much higher than those associated with oil production due to the need to compress and refrigerate gas for export. It is therefore the focus of this appendix – particularly the direct combustion component of LNG emissions. Fugitive emissions from LNG are assessed in the fugitives appendix, with results presented in Pathway 1.

Figure 18 – Direct combustion energy emissions 1989-90 to 2034-35 (Department of Environment, 2015)



Australia has seven LNG projects in operation, most of which were constructed in the last decade. Three more are currently under construction and are listed in Table 18. Additional LNG trains (the main liquefaction and purification unit in an LNG plant, of which there may be more than one) and other projects are also being considered.

Table 18 – Liquefied Natural Gas Projects in Australia
Sources: (Woodside, 2015), (ConocoPhillips, 2012) and (APPEA)

Project/plant	LNG plant location	Date production started	Production (Mtpa)	Current number of trains	Estimated emissions[6] $MtCO_2e$ p.a.
North West Shelf Venture	WA	1989	16.3	5	6.1
Darwin LNG	NT	2006	3.7	1	1.6
Pluto LNG	WA	April 2012	4.3	1	1.02
Queensland Curtis LNG	QLD	December 2014	8.5	2	2.4 (C-General, 2010)
Gladstone LNG	QLD	September 2015	7.2	2	2.5
Australia Pacific LNG	QLD	December 2015	9	2	2.7
Gorgon LNG	WA	March 2016	15.6	3	4.0
Prelude FLNG	WA	Under construction	3.6 LNG 1.3 condensate 0.4 LPG	1	2.3 (Shell, 2009)
Wheatstone	WA	Under construction	8.8	2	5 (EPA, n.d.)
Ichthys	NT	Under construction	8.9	2	5.5 (INPEX)
Browse FLNG	WA	On hold	n/a		
Greater Sunrise FLNG	Timor Gap	On hold			

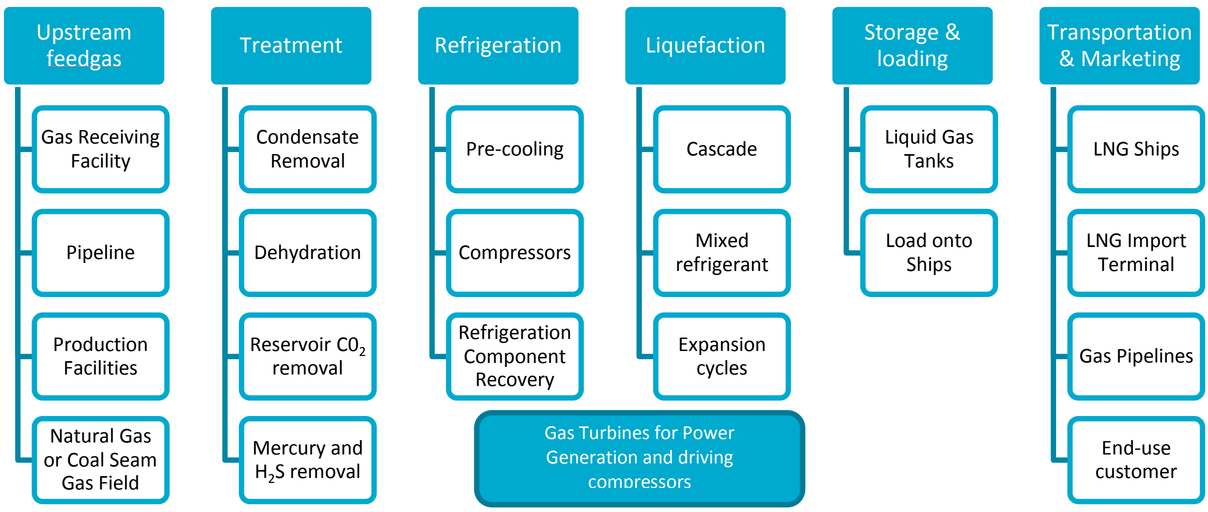
[6] includes venting of reservoir CO_2e, flaring and fugitives from onshore LNG plants

Project/plant	LNG plant location	Date production started	Production (Mtpa)	Current number of trains	Estimated emissions[6] $MtCO_2e$ p.a.
Equus LNG	WA	No Final Decision yet			
Scarborough LNG	WA	No Final Decision yet			
Bonaparte FLNG	WA	No Final Decision yet			
Cash-Maple FLNG	WA	No Final Decision yet			

5.2 Process and application description

LNG is produced through the cooling of natural gas below its condensation temperature of -162ºC. In a liquid state, the gas volume is one six hundredth of its volume in gaseous form and can therefore be efficiently stored and transported in tanks and carriers. Figure 19 describes the common process steps in the LNG production process, from input feed gas streams though to the final end-use customer.

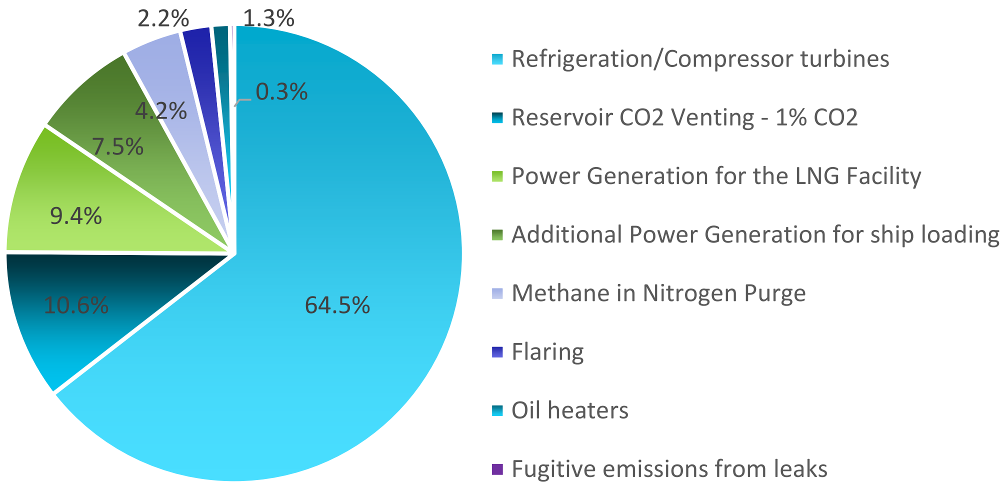
Figure 19 – Generic LNG production process



As shown in

Figure 20, ~65% of the emissions produced by a LNG production facility is driven by the refrigeration/compressor turbine for the liquefaction process. Power generation, both for the LNG facility itself and additional generation for ship loading, are the next most significant sources of lifetime emissions, accounting for 7.5% and 9.4% respectively (Woodside, 2011). Many of the factors that affect the energy and electricity consumption of the facility are decided during the design phase of the project and are very difficult to change later during operations.

Figure 20 – Example LNG plant lifetime emissions
Adapted from (Woodside, 2011)



Reservoir CO_2 gas that is separated from the natural gas during treatment and vented is a significant source of emissions. For example, the Prelude reservoir vents 0.97 Mtpa of CO_2 (Shell, 2009). The Gorgon LNG project is the first in Australia to apply CCS to reduce these emissions. CCS developed at this project has the potential to reduce GHG by approximately 40% by capturing and storing the reservoir CO_2 underground. Here, 3.4 - 4 Mtpa are injected into deep sandstone formations under Barrow Island – one of the largest CCS projects in the world (Chevron). Fugitive emissions of vented CO_2 is discussed further in the fugitive emissions appendix.

5.3 Technology description

Liquefaction Process

Liquefaction and refrigeration are the main process components of the LNG train. The refrigeration system is powered using large gas turbines and a series of cryogenic heat exchangers. Given that liquefaction is the most carbon intensive process in LNG production, a number of technologies are being developed to reduce its emissions profile.

The composition of the feed gas impacts the design and emissions of the LNG plant:

- CO_2 – CO_2 must be removed from the feed gas stream prior to the liquefaction process to prevent it from solidifying and blocking the process. For reservoir gas with higher concentrations of CO_2, the removal process generally requires more energy and larger quantities of CO_2 are then vented into the atmosphere. Coal seam gas typically contains lower concentrations of CO_2, than conventional gas deposits.
- N_2 - higher nitrogen content increases the liquefaction energy requirement.
- LPG - higher LPG fractions in the natural gas stream reduces the liquefaction energy requirement (not applicable to CSG).
- Heavier components - extra condensate yield requires more energy for stabilisation (not applicable to CSG).

Critical to the efficiency of the overall design of the plant is the choice of liquefaction technology. Technologies include a simple nitrogen cycle, cascade refrigeration, propane or ammonia pre-cooled mixed refrigerant, and more complex dual or triple mixed refrigerants like the ConocoPhillips Optimised Cascade technology listed in Table 19. These liquefaction technologies are very mature so significant liquefaction process breakthroughs are not expected. Thus, gains in equipment efficiency and operating effectiveness are expected to play a bigger role in improving efficiency and reducing emissions.

Table 19 – Train efficiencies of the LNG processes

Liquefaction Technology	**Fuel Efficiency (%)** (K.J.Vink)
Propane/Mixed Refrigerant	92.9
Cascade	91.2
Dual Mixed Refrigerant	92.7
Single Mixed Refrigerant	91.6
Pre-cooled Nitrogen Expansion	90.4
Optimised Cascade (Conoco-Phillips)	92 – 94 (with Aero-derivative gas turbines) (ConoccoPhillips, 2007)

Compressor/driver combination

Compressors use mechanical drivers such as reciprocating engines, steam turbines, industrial gas turbines or electric motors. Until the mid-1980s, the centrifugal compressors used in the liquefaction process were mainly driven by steam turbines which are costly and energy intensive. Gas turbine drivers are more powerful, more efficient and less costly options for driving the refrigeration compressors. Optimised compressor and driver combinations offer greater operating flexibility over a wide range of operating temperatures. Implementing efficient refrigeration turbines is the most effective way of reducing direct combustion emissions. This may include upgrading old gas-powered turbines to more efficient models or replacing them with electric drive motors where appropriate, so long as low-carbon electricity is available.

Recently, aero-derivative gas turbines have been used to directly drive compressors due to the fact that they are 25% more fuel efficient and require less maintenance, thereby increasing LNG production by ~3%. Aero-derivative gas turbines can also be used indirectly to produce electric power for electric motors that drive the compressors. High torque output and the inclusion of Dry Low Emission technology substantially reduces the energy input requirement and therefore also reduces emissions (Chen-Hwa, 2012). However, these types of turbines require high quality fuel gas and also may not be available at the scale necessary for some plant.

The Queensland Curtis LNG plant was one of the first in the world fitted with aero-derivative low emissions turbines. These were found to have reduced greenhouse emissions by 27% (QGC, 2015). Other literature (D.J.Bergeron, 2015) states that aero-derivative gas turbines offer a sizeable opportunity for emissions reduction, in the order of 24% of total greenhouse gas emissions.

Electric motors operate at higher efficiencies and produce zero GHG emissions at the operating station and less emissions overall when electricity is drawn from a low emissions electricity source. Electric motors require minimal maintenance and are an attractive option in applications where uptime is paramount. Adjustable speed drives allow for flexible start up and optimal plant flow balance across a wide temperature range, allowing them to be used as a dedicated driver solution for refrigeration. (ConoccoPhillips, 2005).

Process design

Poor process design and operation reduces reliability and increases the amount of flaring that may take place due to unplanned shutdowns. Flaring can be reduced by improved standard operating procedures to reduce plant shutdown times – e.g. rapid start up and recovery from upset conditions (Woodside, 2015).

Advanced process control can optimise equipment operations and realise significant improvement in production, plant reliability and process stability. This may also lead to fewer process upsets that require flaring (ConocoPhillips, 2011) that causes emissions.

Waste heat recovery applications

Further utilisation of waste heat from refrigeration turbines, onsite power generation turbines and other sources of facility heating such as hot oil, water and steam, can provide additional energy gains and thereby emission reductions. By way of example, the use of combined cycle gas turbine (CCGT) using both a gas and a steam turbine together can produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates the extra electricity.

Separate or integrated natural gas liquids recovery with LNG process:

Traditionally LNG facilities have separate plants that enable separate LPG and condensate product streams which can then be sold. Integration of natural gas liquids (NGL) recovery processes with the liquefaction processes significantly reduces the power required to produce the LNG. For example, a turbo expander LPG recovery system could be integrated with a liquefaction process to increase LNG production while maintaining the same process power requirements (Chiu, 2012).

Cryogenic liquid expanders:

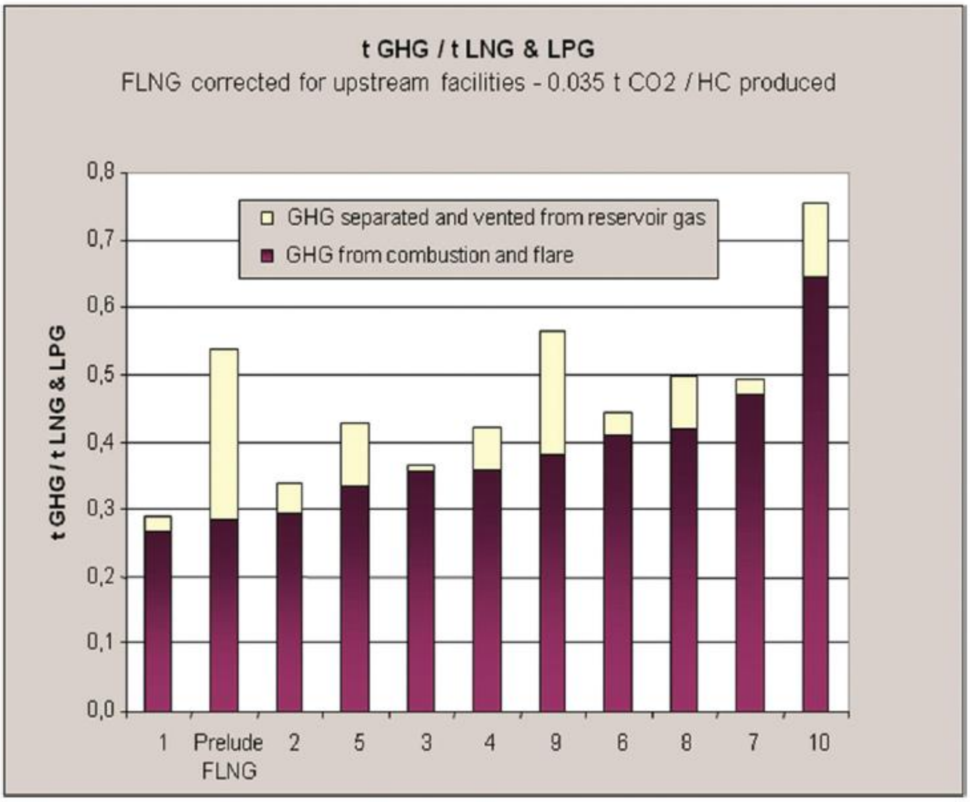
Using liquid expanders instead of traditional Joule-Thomson valves to convert the available high pressure energy into useful electrical energy and low pressure gas offers energy efficiency improvements. They can also act as a variable speed control valve when installed between a cryogenic heat exchanger and the storage tank to improve the overall system efficiency.

Floating liquefied natural gas (FLNG):

In recent years, there has been increasing interest in developing floating LNG (FLNG) facilities that can liquefy the offshore gas for transportation. A floating LNG facility can be positioned adjacent to an offshore natural gas well to liquefy the gas as it is being loaded onto a tanker, which eliminates the need for energy-intensive pipelines to transport the gas onshore prior to liquefaction in a conventional facility. By positioning FLNG facilities alongside the reservoir, they can rely on a direct high pressure feed gas which reduces the need for compression and raises process efficiencies. Access to cold seawater for cooling can also reduce refrigeration-related emissions. Furthermore, direct FLNG to LNG Ship transfer minimises LNG boil-off with short loading lines (Shell, 2009).

Figure 21 shows that FLNG combustion and flare GHG emissions intensity (0.28) compares favourably to other benchmark plants (0.27-.64).

Figure 21 – GHG Intensity Comparison (Shell, 2009)



5.4 Technology impact

LNG plant overall efficiency is driven by the process design, the main compressor drivers (i.e. gas turbines and/or electric motors) and power generator equipment types. It also depends on the extent to which venting and flaring are minimised and waste heat is recovered. Benchmarking of LNG plant costs has shown low-cost design can achieve low CO_2 emissions (ogj, 2003).

Implementation of the technologies required to reduce emissions is easiest during the design stages of new LNG plants (i.e. it is much more expensive to integrate new technologies on existing plant). However, given that the plants typically have construction timelines of 5 to 10 years, they are unlikely to be relying on the best available technology once in operation.

Following the significant increase in LNG plants over the last decade (as shown in Table 18), there is likely to be limited opportunity for new plants, at least until prices stabilise and demand is more certain. That said, there is still scope to add new LNG trains to existing plants or retrofit new technologies when trains are shut down for major scheduled maintenance. The relevant technology opportunities are therefore highly site-specific in nature and will depend upon a range of factors particular to the given operation. Across the industry there will be gradual uptake of these technologies and consequent improvements in efficiency of equipment replaced at end of life.

While Australian LNG associated GHG emissions are high, LNG can also significantly cut emissions in overseas export markets. For every tonne of greenhouse gas emissions generated by LNG production in Australia, between 4.5 and 9 tonnes are avoided in Asia when natural gas is substituted for coal in electricity generation (APPEA).

For modelling results quantifying the impact of these technologies, see the Appendix A in the main report. For more information about the assumed the impact of these technologies, see the modelling appendices.

5.5 Technology status

Australia is now a leading nation for LNG production with most of the recent plants built by global contractors such as Bechtel. The local technology status is therefore a good reflection of the global status of the industry.

Table 20 – Current technology costs and emissions benefits

Technology	Cost	Emissions Benefits
Aero-derivative gas turbine	-5% to +70% variation in the upfront capital cost	Up to 30% reduction in emissions p.a. (13%-15% increase in thermal efficiency)
Electric motors	Lower capital cost than gas turbine with starter/helper motor. Lower spare parts and maintenance cost. (Higher overall cost if power plant has to be built)	Drive & motor have no emissions. Electricity supply emissions depend on emissions factors
Advanced process control	Site specific – generally only a small fraction of total process control systems and software budgets	Emissions reduced through less flaring due to process upsets and shutdowns
Waste heat recovery applications (combined cycle heat recovery)	6%-10% increase in upfront capital cost, with significant fuel cost savings	Up to 19% reduction p.a. in emissions
Integrated natural gas liquids recovery with LNG process	Overall integrated process reduces combined capital (-5%) and operating costs, with 7% LNG production increase (Elliot, 2005)	Reduced emissions due to improved thermodynamic efficiency
Cryogenic liquid expanders	2% increase in capital	3-6% improvement in the production efficiency and corresponding reduction in emissions due to energy recapture for electricity production.
Floating liquefied natural gas (FLNG):	20% increase in the facilities capital cost, but enables production from fields that cannot be exploited using conventional approach of pipeline to a shore-based LNG plant	~ 20% decline in emissions from combustion and flaring, compared to benchmarks. Additional benefits from elimination of long pipelines and use of seawater for cooling.

The TRLs and CRIs of each of the energy productivity technologies applicable to LNG is set out in Table 21 below.

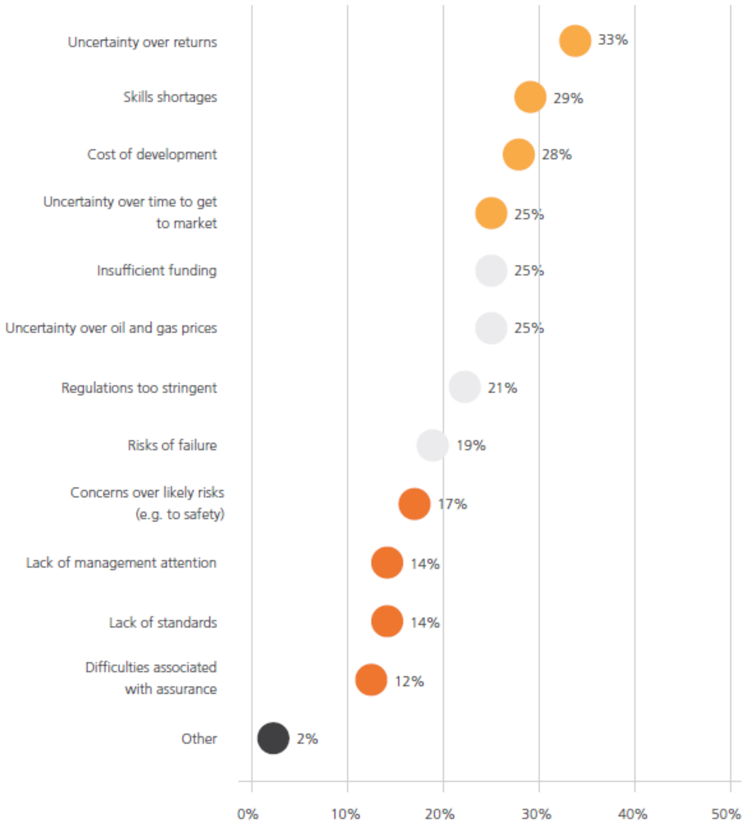
Table 21 – Technological and commercial readiness

ENERGY PRODUCTION	TRL	CRI	COMMENTS
Aero-derivative gas turbines	9	4	Major uptake is witnessed in newly developed facilities.
Electric motors	9	6	See the motor-driven equipment appendix for electric motor developments.
Process design	9	5	Automated Process Control can also be retrofitted to existing plants.
Waste heat recovery applications (combined cycle heat recovery)	9	4	Longer pay back periods have negative impacts on the economic viability of the waste recovery projects.
Integrated natural gas liquids recovery with LNG	9	3	Successful pilot projects. Further development is anticipated in the near future.
Cryogenic liquid expanders	9	5	Turbine-generator expanders are more mature than axial impulse expanders. Further optimisation is underway to improve the thermodynamic efficiencies of the production process.
Floating liquefied natural gas (FLNG):	8	3	Prelude FLNG plant is under construction in South Korea with potential Australian production starting in 2018. Exmar FLNG barge and Petronas PFLNG projects due to start production in 2017. Rapid uptake is anticipated with the increasing demand in LNG, which can be partially met by conversion of liquefied natural gas carriers into a floating liquefaction vessels.

5.6 Barriers to development and potential enablers

Figure 22 presents results from a recent oil & gas industry survey which indicate the main global barriers currently facing the potential enablers industry in bringing new technology to market. The top three are: uncertainty over returns, skills shortages, and cost of development. These barriers demonstrate the competing company priorities and motivations that make it challenging for the implementation of low emissions technologies to compete for funding and consideration amongst other concerns.

Figure 22 - Survey Results to question "What are the biggest barriers your business faces in bringing a new technology or innovation to market?" Source: (Lloy'd register, 2016)



In the Australian context of low emissions technologies, the significant barriers and possible solutions are listed in Table 22.

Table 22 – Barriers to development and potential enablers

Potential enablers	Barriers	Potential enablers	Responsibility	Timing
Costs	> High upfront capital costs make retrofitting a challenging business case > Opportunity cost of lost production revenues due to shut down for retrofit	>Implementation of low interest capital access schemes >Further research focused on cost reduction of the efficient technologies	> Government >Industry >Academia	2017-2020 / ongoing
Revenue / market opportunity	>Limited window during design phase to put in lower emission technologies in new plants >Less incentive to improve existing plant if production is in decline phase of lifecycle	>Improve data availability/education to clearly identify the potential of cost effective and energy efficient opportunities >Focus on lower emissions designs in early phases of design cycle and environmental impact statement approvals	>Government >Academia >Industry	2017-2020 / ongoing
Regulatory environment	> No minimum energy efficiency standards for the overall production process of	>Introduce policies to encourage optimisation of operations for lowest emissions	>Government	2017-2020

Potential enablers	Barriers	Potential enablers	Responsibility	Timing
	LNG	> Avoid policies with restrictive short payback periods		
Technical performance	>Substantial thermodynamic losses in gas turbine >Synchronous electric motors lack essential load flexibility >Limited capacity of aero-derivative engines	>Further research to continue to reduce turbine thermal losses >Use full-rated power variable frequency drive (VFD) electric motors >Encourage adaption of newer, larger aero turbines as they're developed	> Academia > Industry	2017-2020 / ongoing
Stakeholder acceptance	> Low motivation and drive for lower emissions > Limited focus on energy savings or increased production	>Shift focus/attitude from "LNG is lower emissions than coal" to "LNG is largest direct combustion GHG emitter in Australia and those emissions can be reduced cost-effectively while increasing LNG production" >Policy to drive GHG abatement in LNG sector	> Government >Not for profits >Industry	2017-2020
Industry and supply chain skills	> Lack of in country expertise and skills to adapt with new cutting edge LNG technologies	>Implementation of trainings for the adaptation to modern technologies > Understand licensing and trade secret impacts reducing innovation appetite	>Government >Industry	2017-2020

5.7 Opportunities for Australian industry

Table 23 – Opportunities for Australian industry

	Technology development	Technology distribution and manufacturing	Technology supply and installation	End use
Description	Research and development of energy efficient and low carbon production of LNG	Manufacturing of equipment used in the production processes	Low carbon LNG production, supply and technical support both locally and international (Asian) markets	Benefits of efficient technologies to LNG production
Australia's comparative advantage	High: +World leader in LNG production +One of first FLNG facilities is in Australia	Low: -Local manufacturing of equipment like aero-derivative gas turbine and ancillary systems unlikely -Likely to be imported	High +Substantial increase in the LNG production is expected +New LNG trains will offer opportunity to adopt efficient production practices	High +Improved efficiency increases throughput and cost competitiveness
Size of the market	High	High	High	High
Opportunity for Australian Industry	High	Low	High	Low
Jobs opportunity	High	Low	High	Low

	Technology development	Technology distribution and manufacturing	Technology supply and installation	End use
Main location of opportunity	Urban	Urban	Urban/Regional	International
Difficulty of capture/ level of investment required	Medium >Further funding for research and development	High >Local manufacturing of equipment unlikely	Low >Already established market (higher commercial readiness for the uptake of efficient and low carbon LNG production systems)	Low

6 Transport

Reducing CO_2 levels across the transport sector can contribute significantly to Australia's overall emissions abatement task. The transport sector has a multitude of technological and non-technological options available across all modes of transport. These include fuel substitution, improved vehicle efficiency and demand reduction. To date, the uptake of low emissions technologies has been impeded by a lack of policy drivers and incentives. However, if successfully deployed, they create opportunities for Australian consumers to derive significant value (e.g. reduced fuel costs) and allow for the emergence of new systems and business models.

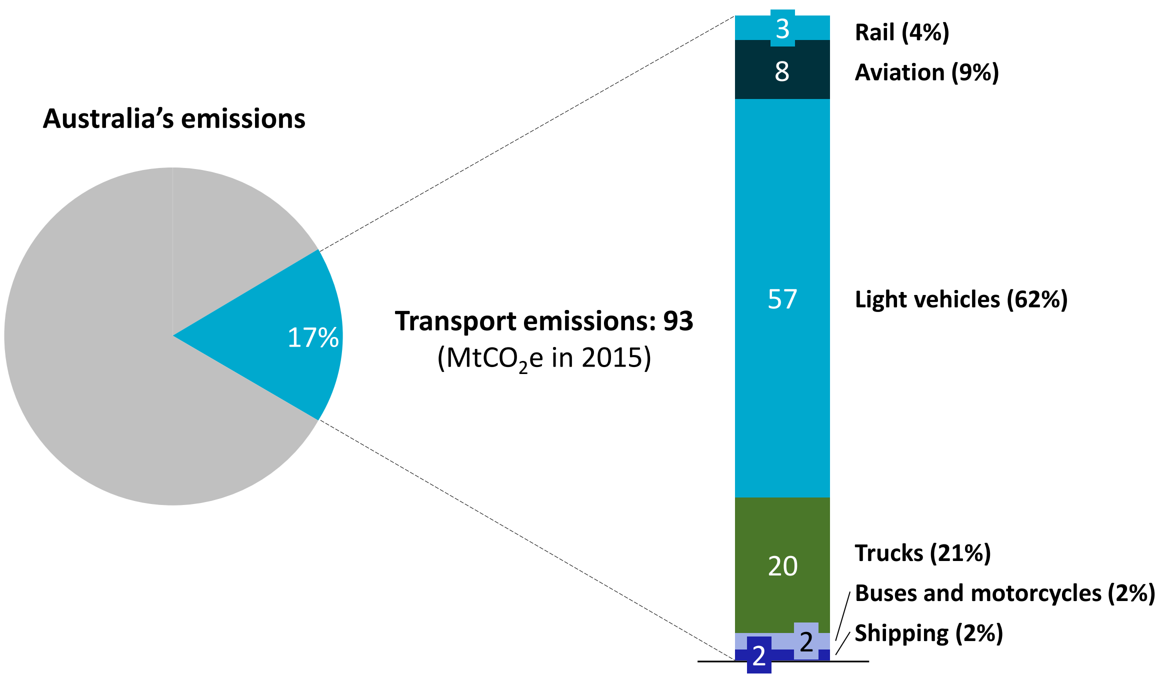
- The emergence of electric vehicles and other alternative drivetrain technologies like hydrogen fuel cells could significantly reduce the emissions profile of Australia's current vehicle fleet. In heavy road vehicles, alternative fuels such as natural gas could also play a role.
- Biofuels are expected to remain the largest opportunity for significant long term emissions abatement in the aviation sector. Incremental technological improvements, driven mainly through fleet renewal, are also expected to continue to deliver abatement.
- Road vehicle emissions can be reduced through technologies that improve the efficiency of the engine, transmission and other vehicle systems. These technologies are being implemented elsewhere around the world.
- In passenger transport, demand reduction from shifting to alternative modes of transport and a trend away from private vehicle ownership are already being observed and are expected to continue. Demand reduction and operational improvements in freight, through improved logistics and routing, mode shifting, improved urban design and innovative business models will also offer abatement.
- Electric drivetrain technologies are being introduced with increasingly advanced autonomous driver assistance systems. The share of these systems is expected to grow as electric vehicles become more prominent. While autonomous and shared mobility systems that make use of the internet of things could disrupt the mobility landscape, the impact these trends will have on emissions is highly uncertain.
- Barriers to uptake of high efficiency light vehicles include the lack of policy that accounts for the externalities from transport emissions and increased upfront costs. Policy support with appropriately ambitious limits on emissions is required to drive uptake in Australia of existing technologies, and to ensure future technologies are available in the market.
- Without appropriate policies to create a 'level playing field', the competitive freight industry has little incentive to spend on new technology or implement innovative operational practices.
- In addition to policy support for limits on emissions, appropriate incentives and improved infrastructure could drive uptake of vehicle efficiency technologies and enable further demand reduction and operational improvements.
- The largest opportunity for Australia exists in the value saved from reduced fuel consumption as a result of the implementation of high efficiency technologies.
- An additional opportunity area for Australia may exist in the development of technologies and systems that increase operational efficiency in both passenger and freight transport.

6.1 Technology overview

Sector emissions overview

Transport accounts for a high proportion of Australia's emissions, accounting for 17% of total emissions in 2014-15 (Department of the Environment, 2015). Nearly two-thirds (62%, or 57 $MtCO_2e$) of transport emissions come from 'light vehicles', which are made up of passenger and light commercial vehicles. Trucks and buses account for an additional 23% (22 Mt) of road transport emissions. Of the remaining transport modes, comprising rail, aviation and shipping (collectively referred to as 'non-road'), aviation is the most significant and also fastest growing, accounting for 9% (8 Mt) of emissions.

Figure 23 – Breakdown of transport emissions by mode ($MtCO_2e$)
Note: totals do not sum due to rounding



Technology description

There is a range of technologies, at varying stages of maturity that could be deployed in order to reduce emissions across all modes of transport. These include:

- **Electric vehicles (EVs)** – rely on battery power to drive an electric motor (detailed further in the EVs appendix)
- **Hydrogen fuel cell vehicles (FCVs)** – rely on hydrogen powered fuel cells in order to drive the motor (discussed further in hydrogen appendix)
- **Biofuels** - Fuels derived from organic biomass via a range of different conversion methodologies (discussed further in bioenergy appendix)
- **Improved vehicle efficiency** – reducing the amount of fuel required per unit of distance travelled. The technologies required in order to achieve this vary by mode, but typically involve improved combustion, reduced drag and minimised frictional losses.

Another means by which emissions reductions may be achieved is through demand reduction and operational improvements. These opportunities are common to all modes of transport and are not always technology-related.

This appendix covers vehicle efficiency and demand reduction technologies. EVs, FCVs and biofuels are covered in detail in the respective appendices.

6.2 Vehicle efficiency

Road vehicles

There is a range of available technologies designed to improve fuel economy and reduce emissions associated with road vehicles. These technologies, synthesised from a number of sources[7], are discussed further below. It is important to note that some of these technologies, while available for vehicle manufacturers to deploy, may not be available for a consumer to explicitly choose from when purchasing a vehicle.

Engine Technologies

Some of the key technologies that may deployed to improve engine efficiency are set out in Table 24.

Table 24 – Engine technologies

TECHNOLOGY	DESCRIPTION	EXAMPLE	APPLICATION
Variable valve timing; Cam-less valve actuation	Valve train improvements reduce pumping losses and optimise performance and volumetric efficiency	Honda "VTEC"; Audi "Valvelift"; BMW "VANOS"; Koenigsegg "freevalve"	All internal combustion vehicles, passenger & freight
Turbocharged, downsized engines	Turbocharging provides increase airflow and specific engine power, allowing smaller engines to deliver equivalent performance	Ford "EcoBoost"	
Gasoline direct injection	Increases thermodynamic efficiency by allowing increased compression ratios	GM "Ecotec"; Mazda "SkyActiv"; Ford "EcoBoost"	
Cylinder deactivation	Selectively cuts fuel supply to some cylinders under certain conditions (typically low-load) to improve efficiency	GM "Cylinder on Demand"; Honda "Variable Cylinder Management"	
Low friction lubricants and engine friction reduction	Improves overall engine efficiency by reducing energy losses from friction	Nissan "Mirror Bore Coating"	
Idle reduction	Stop-start and neutral idle technologies that minimise time spent in idle	Mercedes "ECO Start/Stop"; Mazda "i-stop"	

Transmission technologies

Transmission efficiency improvements are presented in Table 25. These focus on maximising efficiency by better matching the useable power band of the engine to achieve the desired level of performance, and decreasing the power lost in transmitting power to the wheels.

Table 25: Transmission technologies

[7] (EPA N. , 2010) (ICCT, 2016) (Department of Infrastructure and Transport, 2011) (Oscar, 2016) (ClimateWorks Australia and Future Climate Australia, 2016) (ALCTF, 2012)

TECHNOLOGY	EXAMPLE	APPLICATION
6+ speed transmissions	(Jeep Cherokee (9 speed); Lexus RC (8 speed))	All internal combustion vehicles, passenger & freight
Dual-clutch transmissions	(Ford "Powershift"; VW "DSG (Direct-Shift Gearbox)")	
Continuously variable transmissions (CVT)	(Toyota, Nissan, Honda hybrids; Jeep; Subaru)	

Vehicle technologies

Technologies that involve changes to both the vehicle system and the vehicle as a whole, are presented in Table 26 below.

Table 26: Vehicle technologies

TECHNOLOGY	DESCRIPTION	APPLICATION
Light-weighting	Application of lighter, high-strength materials such as carbon fibre and high-tensile steel as well as improvements in component design and integration.	All vehicles
Aerodynamics	Improvements to reduce drag through streamlining of external surfaces and reducing losses in internal flows (like through radiators). For heavy freight vehicles this includes tractor and trailer drag reduction through appendages like fairings.	
Ancillary systems	Optimisation or electrification of alternators, power steering and air conditioning so as to reduce drive losses.	
Low rolling resistance tyres	Reduced frictional losses between the tyres and the road	
Automatic tyre inflation systems	Maintaining correct tyre pressures reduces energy losses between the tyres and the road	Freight vehicles particularly
Hybrid drivetrains	Combination of electric motor and battery system alongside an internal combustion engine. Hybrid vehicles are generally more efficient than non-hybrid vehicles, due in part to the ability to recovery kinetic energy during deceleration that would otherwise be lost and re-deploy it to assist other phases of driving. Hybrid vehicles charge their battery from regenerative braking (during deceleration) or from the on-board engine. Some hybrid systems allow the combustion engine and electric motor able to power the wheels directly, either separately or together, in a parallel configuration. In some systems the electric motor alone maintains a physical connection to the driven wheels, with the engine acting as a generator to provide electrical energy only, as in a series configuration. There are permutations of these configurations that see combinations of the two, as in Toyota's series-parallel 'hybrid synergy drive', or 'mild-hybrid' applications where a small motor and battery system is used to augment the internal combustion engine by providing power to auxiliary systems.	Light vehicles, rigid freight trucks
Plug in Hybrid Vehicles (PHEVs)	Plug-in hybrid electric vehicles (PHEVs) differ from normal hybrids by having the facility to be charged from an external source. They also typically have larger batteries and more powerful electric drive systems to allow the use of electric power more often.	Light vehicles
Alternative fuels	Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) can provide a lower-carbon fuel alternative for heavy vehicles, but the benefit depends on the engine technology used. These fuels also offer reduced carbon monoxide,	Freight vehicles

	nitrogen oxides and particulate emissions compared to diesel (Energy Supply Association of Australia, 2014). Both CNG and LNG are used in an internal combustion engine and consist primarily of methane, unlike LPG that is a mixture of propane, propylene, butane, and butylene. The share of CNG/LNG in heavy road freight vehicles is expected to be small.	

Aviation

There are five key groups of technologies designed to improve energy efficiency in the aviation sector, as presented in Table 27.

Table 27 – Technologies for aircraft efficiency improvement (Tecolote Research, 2016)

TECHNOLOGY AREAS	TECHNOLOGIES
Aerodynamics (Non-Viscous)	• Improved transonic design • Wingtip technologies • Variable camber • Increased wing span • Adaptive compliant training edge
Aerodynamics (Viscous)	• Natural laminar flow on nacelle, wings • Hybrid laminar flow on wings and empennage • Laminar flow coating/riblets • Low-friction paint coating
Structures	• Composite materials • Advanced metal alloys • Advanced structural joining techniques • Structural health monitoring • Net-shaped components • Multifunctional materials and structures
Engines	• Geared turbofan • Advanced turbofan • Open rotor
Aircraft System	• More electric aircraft • Electric landing-gear drive

Rail (freight) and shipping

There is a range of energy efficiency technologies available for the rail and marine transport sectors.

For rail freight, the technologies include improved locomotive efficiency, fuel injection, heat recovery, weight reduction, double stacking and anti-idling devices. Electrification offers an opportunity for emissions abatement when using renewable energy sources. It is worthwhile to note that most existing electric trains are for used for public transport and are a relatively small contributor to emissions compared to freight locomotives.

Alternative fuels and drivetrain technologies such as hybrids, CNG/LNG and hydrogen could also be deployed (eex, 2016). Furthermore, Australia’s locomotive fleet is one of the oldest in the developed world. Upgrading locomotives could yield significant fuel, CO_2 and pollution reductions.

For shipping, more efficient hull design and propulsion systems should also be considered (ALCTF, 2012). Also, the use of wind power as a supplementary power source when conditions are favourable is a large area of research that could improve efficiency of conventional engines.

6.3 Demand reduction

Road vehicles

Light vehicles

Reductions in demand for travel can improve transport sector efficiency as a whole. Identified opportunities (ALCTF, 2012) include:

- Increased mode shifting to public transport
- Substituting car travel with cycling, walking and telecommuting
- Changes in urban form/design (e.g. where housing, amenities and workplaces are close by and connected by transit hubs)

Further, the emergence of autonomous vehicles threatens to significantly reshape the transport sector. It is unclear however whether widespread adoption will achieve significant levels of abatement. One perspective suggests that the uptake of autonomous vehicles could increase emissions due to a higher number of vehicle kilometres travelled (vkt), additional demand for car travel and further congestion. Alternatively, autonomous vehicles that are connected with other nearby vehicles and infrastructure could improve the efficiency per kilometre travelled. Further, if paired with ride- and car-sharing services, vkt could drop as a result of route optimisation and higher vehicle utilisation (Alexander-Kearns, Peterson, & Cassady, 2016) (McKinsey and Company; Bloomberg New Energy Finance, 2016).

Freight vehicles

Emissions from road freight vehicles can be reduced by improving freight logistics through activities such as:

- Reducing empty running
- Using route/planning optimisation
- Higher vehicle utilisation

Development of a small number of freight and logistics precincts to combine multiple deliveries into metropolitan areas could also significantly reduce demand. There is also the opportunity for mode shifting, particularly from road-freight to rail, as well as the implementation of eco-driving practices and/or driver information systems (ALCTF, 2012).

Australia is a world leader in the use of higher productivity vehicles (HPVs) such as multi-trailer combination (B-Doubles and road trains) and other unique configurations that are approved under performance based standards (PBS). These vehicles provide a fuel and emissions saving when measured in productivity terms (L/tkm); but their main benefit is in reducing the number of trips required, and therefore the number of vehicles on the road (clearly a demand reduction measure).

An emerging area that could reduce emissions further is the use of big data and the Internet of Things (IoT) to match spare load capacity in trucks with customers shipping small loads, particularly in urban areas. This could simultaneously address fleet underutilisation and reduce congestion by reducing (demand for) partially loaded trucks on the road.

Aviation

Beyond technical improvements to the aircraft itself, there are also opportunities to reduce energy and emissions through improved operational practices and infrastructure. These include reduced auxiliary power unit usage, more efficient flight procedures and planning, and weight reduction (Tecolote Research, 2016).

Greater use of telecommuting to reduce discretionary business travel is a large potential demand reduction opportunity, as is mode shift to a high speed rail or hyperloop network along the east coast of Australia.

Rail (freight) and shipping

For rail freight, operational improvements include driver assistance software and improved logistics. Many of the technical and operational measures also offer other benefits such as increased throughput and reduced maintenance costs which can help improve operating margins.

For shipping, operational efficiencies are being achieved through reducing ship speeds, optimising routes to account for weather and streamlining port logistics and maintenance (e.g. hull cleaning, propeller polishing) (ALCTF, 2012).

6.4 Technology impact

For modelling results of the emissions impact of the technologies discussed above, see the Appendix A in the main report. For information about the assumptions, see the Transport modelling appendix.

While efficiency improvements in ICE vehicles are the largest source of abatement to 2030, alternative drivetrain technologies (e.g. EVs and FCVs), provide the best opportunity for long term abatement, particularly if they are run on low or zero-emissions energy sources. However, the share of these vehicles is expected to be limited to 2030 due to the projected rate of uptake and vehicle turnover (around 10 per cent of vkt).

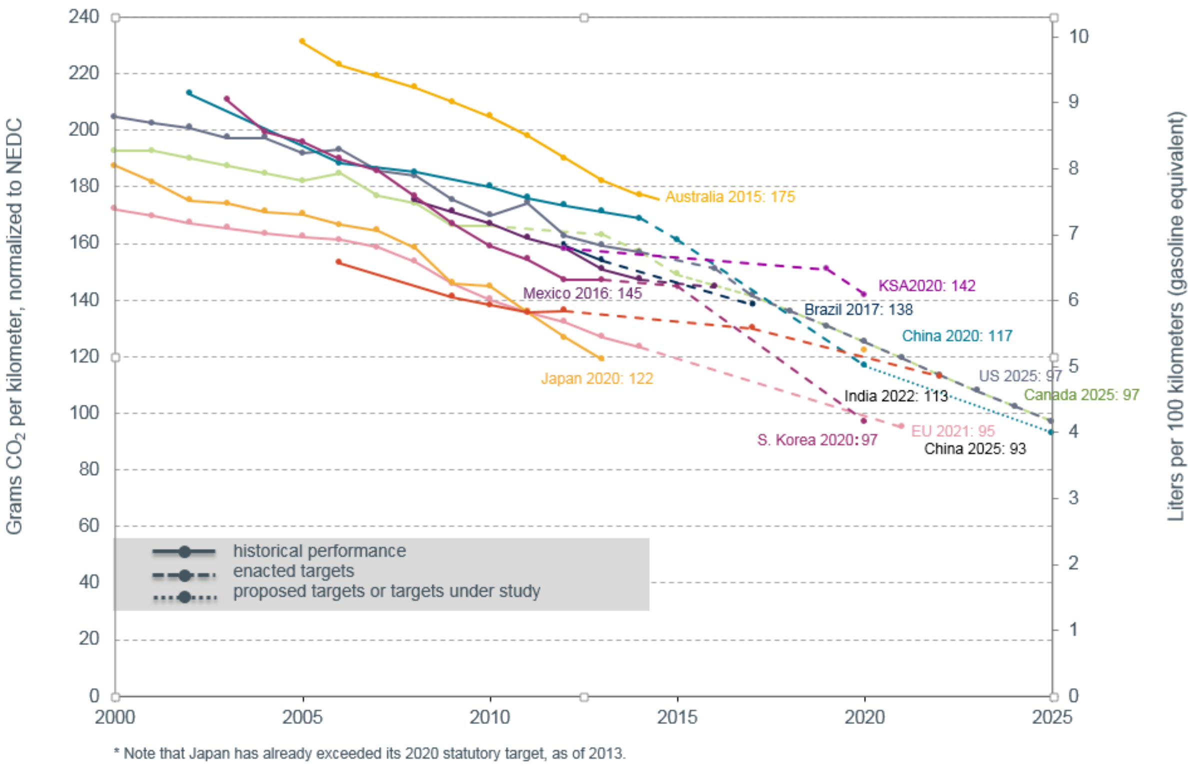
Abatement from demand reduction and operational improvements is expected to be significant over the period to 2050.

Biofuels are most applicable in aviation, given the lack of alternative propulsion technologies and other options to fully decarbonise. That said, aviation, like other modes of transportation including rail and shipping, will continue to achieve abatement from energy efficiency technologies and demand reduction.

The current and historic emissions performance of the light vehicle fleet in Australia is much poorer than other countries – as shown in yellow in

Figure 24. This leaves significant room for improvement to meet current best practice. Into the future, global standards are proposed to continually tighten, requiring the widespread implementation of low emissions technologies, such as those discussed above, for them to be met. The barriers to Australia reaching a better performance (such as fuel quality), are discussed below in Section 6.6.

Figure 24 – Global comparison of CO_2 emissions and fuel consumption standards for passenger vehicles Adapted from (International Council on Clean Transportation, 2016)



6.5 Technology status

Technological and commercial readiness

Many of the technologies required to achieve substantial vehicle efficiency improvements in the road transport sector are available in vehicles currently on sale in Australia, although these vehicles currently make up a small share of the fleet. Where vehicle technologies and demand reduction techniques are not available or in use in Australia, they are generally available and in use elsewhere around the world, particularly in jurisdictions with emissions standards for light vehicles.

Other technologies for the non-road sector, such as open-rotor fans in aviation and sails in shipping are still in the RD&D phase, although pilots of alternative fuels and drivetrains in rail and heavy vehicles are underway.

6.6 Barriers to development and potential enablers

Considering that many of the vehicle technologies are available, the key to achieving improved energy efficiency is in overcoming the barriers currently impeding uptake. A summary of the key barriers and potential enablers is provided in

Table 28.

Table 28 - Transport barriers and potential enablers

Transport	Barriers	Potential enablers	Responsibility	Timing
Costs	>Light vehicles: Increased upfront cost of low emissions technologies >Road-rail freight mode shift: High expense of loading and unloading	>Incentives > Dedicated freight routes or improved separation from passenger rail congestion; high speed rail; better/more intermodal terminals	>Government >Academia >Industry	Ongoing
Revenue / market opportunity	>Lack of a 'level playing field' in the freight sector to encourage innovative operational practices or expenditure in new technology	>Pricing of externalities >Incentivising full loading/mandating against empty running of road freight >Congestion charges	>Government >Industry	2017-2020
Regulatory environment	>Lack of regulations that account for the externalities from transport emissions (CO_2) >Conservative limits on infrastructure (e.g. truck and rail axle loads) >No flexibility to account for weight/dimension penalty of EVs and other alternatives	>Vehicle emissions standards (new vehicles) >Existing vehicle turnover/ retirement scheme >Weight/dimension concessions for alt fuel vehicles	>Government	2017-2020
Technical performance	>Limited internet outside cities, inhibiting the use of IoT >Rail freight: gauge difference, intra-national customs, track degradation	>Enhanced tailpipe emissions standards (e.g. EURO VI) >Improved internet coverage >Streamlined rail systems >Improved rail infrastructure	>Academia >Industry research >Government	2017-2020 / ongoing
Stakeholder acceptance	>Real/perceived risk of public transport and cycling >Location, availability and frequency of public transport and connections	>Improved cycling routes and end-of-use facilities (bike racks, showers, etc) >Connectivity for group travel or real-time tracking for concerned passengers >Improved public transport	>Government >Industry	2017-2020 / ongoing
Industry and Supply chain skills	n/a	n/a	n/a	n/a

6.7 Opportunities for Australian Industry

Table 29 - Opportunities for Australian Industry

	Technology development	Technology distribution and manufacturing	Technology supply and installation	Technology end use
Description	R&D of vehicles, in-vehicle technologies, connectivity technologies, business models	Manufacturing and distribution of low carbon transport vehicles	>Installation of connectivity technologies >Provision of demand reduction and optimisation techniques (including urban form/design)	Cost savings from operating high efficiency vehicles
Australia's comparative advantage	High +Existing vehicle R&D capability +Diverse automobile market	Low -Most vehicles are imported	High + Provision must occur locally	High + Provision must occur locally
Size of the market	High >High per capita transport requirement	High	High	High
Opportunity for the Australian Industry	High	Low	High	High
Jobs Opportunity	Medium	Low	High	Low
Main location of Opportunity	Urban	Urban/regional	Urban/regional	Urban/regional
Difficulty of capture/ level of investment	Low: >Existing vehicle R&D capability	High	Low: >Major potential of local uptake and infrastructure development	Low: >Enablers (such as vehicle emissions standards) are well known due to application overseas and are low cost to implement

7 Electric vehicles (EVs)

The substitution of ICEs with EVs is a key enabler of emissions reduction in road transport. While Australia has started to see some level of adoption, it is estimated that by 2030, around 50% of all new light vehicles could be electric. Uptake will be driven by consumer preferences as the vehicle cost continues to decrease. Before cost parity with mass market ICEs is achieved, uptake will likely be driven by consumer preference. However, this may be accelerated through regulations that impose emissions standards on new vehicles, subsidies and support for an accelerated roll out of required infrastructure (e.g. charging stations). While likely to remain an importer of EVs, new opportunities for Australia could be realised in relation to building local charging infrastructure and support services as well as the development and integration of other complementary technologies (e.g. home energy management systems)

- EVs are critical to achieving widespread emissions reductions in the road transport sector (i.e. most likely for passenger vehicles and light trucks).
- Significant abatement is achieved via the removal of direct combustion of fossil fuels but also through the use of more efficient drivetrains (i.e. reduced energy losses associated with EVs when compared to ICEs).
- With the current electricity generation mix, EVs are already 50-70% less emissions intensive than ICEs. This factor will improve with electricity sector decarbonisation or if charging infrastructure is powered directly by renewable energy.
- Australia has already seen some uptake of EVs in urban areas. However, these vehicles are still purchased at a premium and are not yet competitive with mass market ICEs. It is estimated that by 2030, approximately 50% of all new light vehicles could be electric.
- The capital cost of EVs is expected to be significantly reduced via improvements in the cost and performance of batteries addressed further in Section 14. By 2026, parity in terms of the total cost of ownership (TCO) between sedan ICEs and EVs is expected to be achieved, with SUVs to follow soon after (˜2027).
- Uptake of EVs could be accelerated via the implementation of vehicle emissions standards or through other incentives (e.g. rebates, lower stamp duty, low cost registration).
- EVs require supporting infrastructure. Recharging codes and standards should be prioritised along with home/work recharging facilities. Commercial charging stations should also continue to be deployed in order to accommodate long distance travel (i.e. > 400km).
- As uptake continues to increase, charging of vehicles from the network is limited during periods of peak energy demand in order to ensure grid security and avoid increased network expenditure. This risk may be mitigated by incentivising customers to charge during off peak periods as conditions of sale (e.g. enable EV charging to be controlled by the network in return for discounts on purchase price).
- While there are some niche manufactures already established locally, it is likely that Australia will continue to import EVs in order to service the broader domestic market. New opportunities also exist in the development of batteries as well applications such as home energy management systems. Consumers will also benefit from additional cost savings (e.g. fuel and maintenance) once the TCO of EVs is less than ICEs.

7.1 Technology overview

Technology description

EV

In contrast to internal combustion engine (ICE) vehicles, EVs rely on battery power to drive an electric motor. The batteries recoup some energy from braking systems but require an external electricity source in order to recharge. In this respect, they differ from fuel cell electric vehicles (FCVs), which use hydrogen powered fuel cells to charge the battery and/or drive the motor.

Plug-in hybrid vehicles (PHEVs), in addition to the battery, retain an ICE and are therefore less dependent on recharging infrastructure.

Charging Infrastructure

EV charging infrastructure is twofold:

- Home/work – relies on the availability of converters in order to draw power from standard power outlets. Another key development is in relation to DERs (e.g. smart meters) and DER management systems (refer to Section 13.2) which can signal optimum times for recharge (e.g. off-peak) as well as enable export of energy back to the grid.
- Public charging infrastructure (i.e. commercial charging stations)

Technology impact

EVs are critical to achieving widespread emissions reductions in the road transport sector (i.e. most likely for passenger vehicles and light trucks). Significant abatement is achieved via the removal of direct combustion of fossil fuels but also through the use of more efficient drivetrains (i.e. reduced energy losses associated with EVs when compared to ICEs).

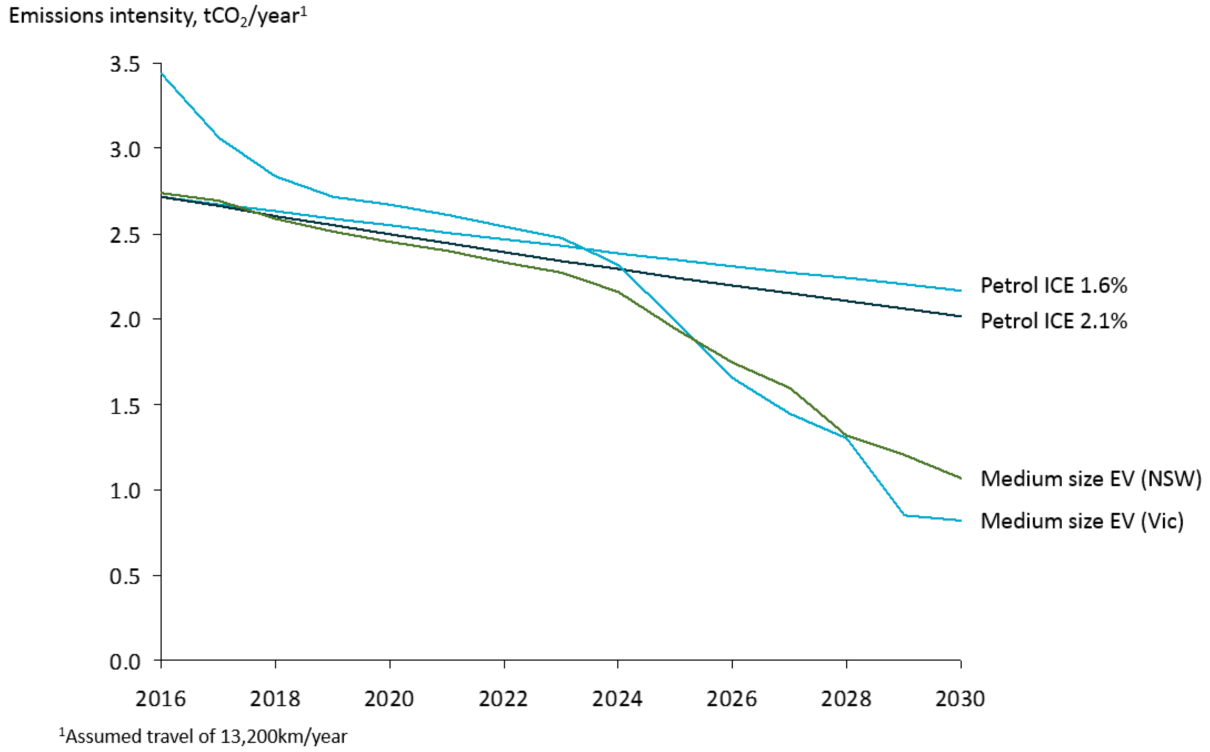
Australia has already seen some uptake of EVs in urban areas. However, these vehicles are still purchased at a premium and are not yet competitive with mass market ICEs. It is estimated that by 2030, approximately 50% of all new passenger vehicles could be electric.

EVs charged from the grid are already less emissions intensive than ICEs (on average in Australia; EVs charging from the grid in Victoria are more emissions intensive than similar ICE vehicles). The emissions intensiveness will continue to improve with electricity sector decarbonisation or if charging infrastructure is powered directly by renewable energy. For instance, by 2030, assuming that ICE efficiencies improve by 1.6% annually, they will have an emissions profile that is two and a half times more CO_2 than EVs charging from the Victorian grid, with the decarbonisation of the grid as assumed in Pathway 3.

The decreasing emissions intensity (tCO_2/year) associated with EVs charging from the grid in Victoria and NSW based on network decarbonisation to 2030 in Pathway 3 is represented in

Figure 25 below. Also shown are the emissions of similar ICE vehicles, with improvements in efficiency as assumed by the pathways (1.6% p.a. for P2&3, 2.1% p.a. for P1&4).

Figure 25 - Comparison of medium sized EV emissions intensity to 2030 for Victoria and NSW



Deployment of EVs creates a series of benefits over and above emissions reductions, one of which will include reduced TCO for consumers. Of similar importance is the twofold benefit provided to the electricity network. Firstly, the increasing electricity demand associated with EV charging loads could help offset the reductions caused by increasing energy efficiency and the uptake of rooftop solar PV. Second, by incentivising charging during periods where there is likely to be excess VRE, utilities can create new markets for otherwise unused electricity and flatten out the overall demand profile of the network. This added utilisation will help integrate higher share of VRE into the grid.

Further, EVs will have the benefit of localising the fuel supply (i.e. electricity) as compared with ICEs that rely on petrol/diesel derived from mostly imported crude oil. By 2030, EV uptake could lead to 6.76TWh of additional electricity in the NEM and the displacement of ~11,000 barrels of gasoline per day[8].

7.2 Technology status

Cost - current state and projections

A comparison of the current and projected levelised cost of transport (LCOT) for medium sized passenger EVs and ICEs is set out in Table 30. The capital cost of EVs is set to be steadily reduced with improved cost and performance of batteries and as shown below, mass market EVs become cost competitive with ICEs on a TCO basis at or around 2025.

Table 30- LCOT ($/vkm) comparisons for EVs and ICEs

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[8] This calculation is based on CSIRO modelling undertaken for Pathway 1 and a conversion factor of 1.68 TWh per million barrels of oil equivalent as derived from (BP Approximate conversion factors: Statisitical review of world energy). It was also assumed that barrels of oil were used entirely for petrol.

	2015	2020	2030
EVs (from grid)	1.7-2.0	0.75-0.90	0.60-0.70
ICEs	0.70-0.85	0.65-0.80	0.65-0.80

Technological and commercial readiness – current state

EVs are technologically and commercially mature. Specific improvements will stem from cost reductions and performance of the battery.

7.3 Barriers to development and potential enablers

As shown in Table 30, EVs currently have a high capital cost and are therefore limited to the high end market. However, these costs will continue to decrease with improvements in battery technology, economies of scale, and the creation of a competitive market.

Government and private sector entities with large vehicle fleets should continue to be encouraged (e.g. via direct funding as is already the case with the CEFC (BNEF, 2016) to act as 'early adopters' of EVs. In many cases, this has already proven to be more cost effective for businesses and also has a positive impact on overall sustainability performance.

Currently, there is minimal policy in place to encourage widespread adoption of EVs. In order to increase the rate of uptake, emissions standards on new vehicles could be imposed together with various incentives that may include, removal of taxes or charges, free or lower cost for parking and registration, and access to transit lanes (BNEF, 2016). This will also help increase acceptance amongst the automobile industry who currently derive more revenue from ICEs for services such as maintenance.

It is also important for EV targets to be set so that the required infrastructure can be deployed accordingly. This should involve ongoing coordination between the automobile industry, utilities, and government.

In order to ensure grid security, it is also critical that EV recharging is limited during peak energy demand. This risk may be mitigated by incentivising customers to charge during off peak periods as conditions of sale (e.g. enable EV charging to be controlled by the network in return for discounts on purchase price) or through time-of-use tariffs.

Table 31 - EV barriers and potential enablers

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	> High capital cost of EVs as compared with ICEs	> Support international collaborations to improve battery performance and reduce battery costs across the supply chain > Implement incentives designed to increase uptake (e.g. exemption from luxury car tax, reduced fringe benefit tax, free/reduced parking, access to transit lanes) > Explore and encourage alternative EV ownership models (e.g. leasing, battery exchange) > Allow for customers to sell electricity from the EV into the grid (requires new market platforms)	> Industry > Government > Research organisations	Ongoing

Category	Barrier	Potential enablers	Responsibility	Timing
Revenue/market opportunity	Less incentive for widespread adoption for EVs given that the car industry derives more revenue from ICEs (as a result of maintenance etc.)	> Set EV deployment targets as well as coordinated strategies for achieving targets (e.g. timing, funding requirements) > Continue to encourage business/government fleets to serve as early adopters (e.g. through direct funding) > As per regulatory environment	> Industry > Government	2017-2020
Regulatory environment	Lack of favourable regulations for EVs	> Impose emissions standards on new vehicles	> Government	2017-2020
Technical performance	Insufficient infrastructure supporting roll out of EVs	> Establish appropriate codes and standards for recharging, electricity supply and smart metering > Support roll out of home/work recharging infrastructure (e.g. ensure smart metering technologies etc. are readily available) > Collaborate locally and globally on best practice recharging and site location > Plan for and implement charging infrastructure on highways to enable inter-city travel	> Industry > Government	2017-2020
	Electricity network may not be able to accommodate increasing demand due to EV charging loads	> Incentivise customers to charge off peak via customer sign-up conditions (e.g. allowing EV charging to be controlled by the network for discount on purchase price) or TOU tariffs > Conduct modelling to understand the impact to the electricity network and determine appropriate times for recharge in order to avoid additional network spend > Ensure that government, automobile industry regulators, utilities continually coordinate their efforts in order to refine roll out strategies	> Utilities > Government > EV distribution companies	2017-2020
Stakeholder acceptance	Consumer reluctance to accept EVs due to belief it will require adjustments in behaviour (e.g. 'range anxiety', limited selection of vehicles, longer recharge times)	> Communicate continual improvements in driving ranges achieved as well as reductions in charging periods > Improve infrastructure along highways > Incentivise imports from a range of different manufacturers	> Government > Industry bodies	Ongoing
Industry and supply chain skills	n/a	n/a	n/a	n/a

*Key barriers highlighted

7.4 Opportunities for Australian Industry

As compared with the global market, Australia retains a comparatively small ICE and niche EV manufacturing and battery industry. As such, it is likely to continue to import EVs. However, increasing the penetration of EVs will lead to greater demand for batteries and increase the scope for participation along the relevant supply chain (discussed in Section 14). There may also be niche vehicle manufacturing opportunities. As an example, 'SEA Automotive' are a Geelong (Victoria) based company currently involved in the retrofit of light trucks with electric drive-trains. 'Tomcar Australia' is another Victorian based off-road EV manufacturer that utilise 60% Australian-made componentry in their vehicle design. They are currently exploring export opportunities for applications in underground mines.

Further, there is much that can be done locally in order to support deployment. This includes opportunities associated with the development of commercial recharging infrastructure as well as marketing and distribution of EVs. Australia also has considerable expertise in management and integration of DERs (e.g. home energy management systems).

Table 32 - Opportunities for Australian Industry Summary

	Charging infrastructure development and operation	**EV manufacture**	**Marketing and distribution**
Description	Development of DERs (e.g. smart meters) for charging at home/work as well as design and procurement of charging stations	Manufacture of EVs including batteries	Marketing and distribution of EVs
Australia's comparative advantage	High + Infrastructure development must occur locally + Established companies with expertise in smart metering, DER control	Low - Small car and battery manufacturing industry in Australia + Niche manufacturing opportunities (e.g. SEA Automotive, Tomcar Australia) + Strong IP in improving battery performance and rich natural resources (refer to battery supply chain analysis in Section 14)	High + Marketing and distribution of EVs must be done locally
Size of market	High - Service of local market	High	High
Opportunity for Australian industry	High	Low	High
Jobs opportunity	High	Low	Low - Likely transition for current industry
Main location of opportunity	Urban	Urban/regional	Urban/regional
Difficulty of capture/level of investment	Low - Commercial charging stations may require some Government investment before high level uptake is reached	High - difficulty associated with creating car or battery manufacturing industry in Australia	Low - Likely transition for current industry

8 Bioenergy

Bioenergy provides a low emissions option for fuel switching in heat, electricity and transport fuels. In Australia, waste biomass feedstocks are expected to continue to be utilised in niche, distributed applications for heat/electricity. However, fuel substitution for the aviation, freight (road) and shipping industries is more likely to be the basis for a local bioenergy industry. For this to occur, national regulatory frameworks are required to incentivise use, but also ensure sustainability standards are maintained. If a biofuels industry is successfully established, it can create new opportunities for farmers by creating a market for waste feedstocks and use of under-utilised land. It could also allow for new processing and production supply chain opportunities in regional areas.

- Biomass can be used to produce heat/electricity and transport fuels via a number of different processes. While new conversion pathways using different feedstocks are continually being developed, the technologies required to produce these products (e.g. co-firing, gasification, pyrolysis) are generally well understood. Many are already commercial with the key challenge being to achieve higher yields at lower cost.
- In Australia, waste biomass will continue to be utilised for heat and electricity generation in niche, distributed applications (e.g. biogas from landfills). There may also be scope for biomass co-firing in existing power stations provided no significant upgrades are required and biomass transport costs are minimal.
- The key use however will be in the production of 'drop-in' fuels for the aviation, freight (road) and shipping industries. Use of biofuels in passenger road transport is unlikely given consumer reluctance to accept ethanol blended-fuels and the emergence of electric and hydrogen fuel cell vehicles.
- Given the higher cost of dedicated energy crops and possible competition with food, the primary source of biomass feedstock is likely to be waste, including agricultural and forest residues.
- Australia has an abundance of waste feedstocks (i.e. ~1000PJ) (Climateworks, 2014) but spread out over large distances. Bio-refineries should therefore be deployed strategically, in areas with high concentrations of biomass in order to limit transport of feedstocks.
- A national regulatory framework that governs use of biomass, imposes widespread sustainability criteria and imposes effective economic incentives is critical to the development of the biofuels industry. Ideally this should align with international standards. It is also important to implement stable policies that enable project developers to secure long term feedstock supplies and offtake agreements.
- The creation of a sustainable biofuels industry would provide Australian farmers with a means of generating revenue from waste feedstock and underutilised land. Processing of biofuels is likely to occur locally, thereby providing additional job opportunities in regional areas.

8.1 Technology overview

Technology description

Bioenergy involves the conversion of organic feedstocks (i.e. biomass) into either heat, electricity or transport fuels. Feedstocks typically include sugars, lignocellulose, triglyceride oils and waste (e.g. sewage and municipal waste).

Depending on the nature and end use of the biomass, the feedstock may be treated using a variety of methods (e.g. pelletisation, hydroprocessing) to remove impurities and improve energy density.

Treated biomass may then be converted to heat/electricity using a range of techniques (e.g. biomass co-firing, gasification) or further processed in order to produce biofuels. Biofuels include products that may be blended with petrochemically derived fuels up to certain concentrations (e.g. ethanol, biodiesel) or 'drop-in' fuels which can be used directly in existing engines.

Biomass Feedstocks

Australia has access to a variety of different bioenergy feedstocks. These are set out in Table 33 below.

Table 33 - Australian biomass feedstocks (Farine, 2012)

BIOMASS	DESCRIPTION
Starch	Wheat, sorghum, barley, oat and triticale grain
Sucrose	C-Molasses and sugarcane
Oil	Canola, animal tallow, waste oil mixture, algae, Pongamia seed,
Lignocellulose	Stubble from annual crops, bagasse, sugarcane (whole plant) products and residues from native forest, hardwood and softwood plantations, wood waste mixture and coppice eucalypt (e.g. oil mallee)
Waste	Organic components of municipal solid waste (MSW), sewage etc.

Feedstock pre-treatment

Depending on the end use, biomass may be treated to enhance the energy density and remove impurities. Some of the key techniques are set out in Table 34 below:

Table 34 - Biomass pre-treatment technologies (IEA, 2012)

BIOMASS TREATMENT	DESCRIPTION
Drying	Reduces the high moisture content in many untreated biomass feedstocks
Pelletisation/briquetting	Involves compacting bulky biomass in order to improve energy density
Torrefaction	Involves heating biomass in the absence of oxygen to between 200˚C - 300˚C and turning into char. This is then typically pelletised
Pyrolysis	This process treats biomass to temperatures of ~290-500°C for various lengths of time in the absence of oxygen to produce chars, combustible gases and pyrolysis liquids (including bio oils). The process can be tuned to produce more biochar, which is suitable for combustion or for soil carbon (Bridgwater, 2012)
Hydrothermal upgrading	Involves the removal of oxygen content from biomass to produce a bio oil

Conversion technologies

Various bioenergy products can be made via a number of technology based conversion pathways. Biofuels in particular may be classified as either:

- First generation - conventional pathways derived from sources such as starch, sugar, animal fats
- Second generation - advanced pathways derived from various types of non-food biomass including waste
- Third generation - more advanced pathways that require a significant amount of R&D before they can be commercial (GEA , 2012)

While not an exhaustive list, those technologies that are most relevant for Australia are set out in Table 35 below.

Table 35 - Key bioenergy conversion technologies

PROCESS	KEY FEEDSTOCK	PROCESS
Ethanol from fermentation of sugar	Starch, sucrose	This is a mature process whereby sugars and starches are fermented using yeast or bacteria to produce ethanol. This is the current method of production of ethanol in Australia.
Biodiesel from transesterification of oils	Canola oil, tallow, waste oil	Currently in Australia, biodiesel is produced using tryglyceride oils. Dedicated energy crops such as pongamia or algae can be grown and have their oils extracted and converted into biodiesel via transesterification.
Jet fuel from hydro-processed esters and fatty acids (HEFA)	Canola oil, tallow	Involves hydroprocessing of triglyceride oils to produce a 'drop-in' jet fuel. Unlikely to be available in Australia due to scarcity of feedstock and competition with food (Graham, et al., 2011).
Electricity/heat from biogas via anaerobic digestion of waste	Wastes (e.g. MSW, manure)	Organic wastes can be used as feedstocks in a digester to produce biogas – a mixture of mostly methane and CO_2. This technology is currently used in Australia at waste management facilities to produce electricity for onsite consumption.
Drop-in fuels from fast pyrolysis of lignocellulosic biomass	Lignocellulose	Fast pyrolysis of biomass (i.e. thermal decomposition of biomass in the absence of oxygen at ~500°C for ~1 second). This produces liquid bio-oil (as well as char and gas) which can be further refined into a drop-in fuel (Hayward, et al., 2015).
Drop-in fuels from hydrothermal liquefaction (HTL) of lignocellulosic biomass	Lignocellulose	HTL is the thermal decomposition of biomass using supercritical water at elevated pressures to produce liquid bio-oil. Further refining is needed (e.g. hydroprocessing) to convert to a drop-in fuel but the amount of refining required is less than with fast pyrolysis (Xiu & Shahbazi, 2012) (Hayward, et al., 2015).
Electricity from biomass gasification	Lignocellulose, waste	As with coal, lignocellulosic biomass can be gasified, i.e. reacted at high temperatures without combustion in the presence of oxygen to produce syngas. The syngas is then combusted to produce heat/steam and then electricity (Bridgwater, Toft, & Brammer, 2002)
Drop-in fuels from hydrotreatment/ gasification + Fischer Tropsch (FT)	Lignocellulose	As above, however syngas produced from gasification of biomass can be converted using the FT process into various products, including 'drop-in' fuels.
Heat/electricity from combustion of lignocellulosic biomass	Lignocellulose	The most common feedstocks are treated chipped biomass, pellets or biochar which are combusted directly to generate heat or electricity.
Electricity from co-firing biomass	Lignocellulose, waste	This is where untreated biomass is fired with coal at around 5-10% of total volume in an existing coal-fired power station. This represents the upper limit at which co-firing may occur without significant upgrades to existing boilers or pre-treatment of biomass (e.g. torrified chars). Chipped biomass, pellets or biochar are the most common feedstocks.

Technology impact

Bioenergy provides a low emissions and dispatchable option for fuel switching in heat, electricity and transport fuels. This is due to the fact that biomass processing operates in a 'closed carbon cycle' and therefore can create marginal net CO_2 emissions (Clean Energy Council, 2008) (i.e. the CO_2 emitted when biomass from plants and trees is burned is offset by the CO_2 absorbed during growth). However, given the use of energy in upstream processing as well as potential for other greenhouse gases (e.g. NOx) and environmental impacts (e.g. water use), it is important that the emissions associated with each bioenergy conversion pathway are assessed on a whole of life-cycle basis.

As shown in Section 8.1, there are a range of different biomass feedstocks that can be treated and then converted to various products. Depending on the conversion pathway, feedstocks may constitute up to 70% of total costs (IEA, 2009). The need to reduce costs, combined with tensions over food and land security would suggest that waste (including agricultural and forestry residue), rather than energy crops, would be the primary source of biomass. Recent studies have suggested that Australia's waste feedstock could provide up to 1000PJ of energy annually.[9] There is also potential for greater use of underutilised land via plantation of short-rotation-trees (i.e. trees that can be continually grown and cut) that are easy to grow and have comparatively low water requirements (Murphy, et al., 2015).

In Australia, waste biomass is expected to continue to be utilised for heat and electricity production in niche, distributed applications (e.g. biogas from landfills). Currently this represents approximately 0.9% (~800MW) of electricity generation. However, with a series of projects currently under consideration, there is considerable scope to double bioenergy generation by 2020 (CEFC, 2015).

Biomass co-firing in existing power stations is also likely to progress provided no extensive upgrades are required and the cost of the biomass (including feedstock, pre-treatment and transport) is not prohibitive. For example, Vales Point power station in NSW currently replaces between 2-5% of coal with biomass without modifications (Office of Environment and Heritage, 2014).

Large-scale new build/retrofit combustion and gasification plants that run on 100% biomass are unlikely to be required or cost competitive (refer to Table 36). This may change however should there be a need for negative emissions to be achieved in order to reach 2050 targets. This could be achieved via BECCS but is also likely to depend on whether a carbon storage network is already in place.

Rather, the key application for biomass in Australia is most likely fuel substitution, or 'drop-in' fuels for the aviation, shipping and heavy vehicles (road) sectors. For aviation, this is particularly important given the lack of alternatives for real decarbonisation. Based on CSIRO modelling for the projected uptake of biofuels, it is estimated that the aviation industry would require approximately ~20% of Australia's total waste biomass in 2050.

For light commercial vehicles, substantial uptake is unlikely given the emergence of EVs and consumer resistance towards blended fuels (e.g. ethanol) to date.

[9] Refer to SKM study in (ClimateWorks Australia, 2014)

8.2 Technology status

Cost – current state and projections of key pathways

Assuming transport costs are minimal, bioenergy costs depend on both the feedstock and technology. The cost of each of the key conversion pathways are set out in Table 36 below.

Table 36- levelised cost of fuel/energy for key conversion pathways for Australia in $/GJ for fuels and $/MWh for electricity

	2015	2020	2030
Ethanol from fermentation of sugar ($/GJ)	70-85	65-80	70-85
Biodiesel from esterification of waste oils ($/GJ)	35-45	35-40	30-40
Electricity from biogas via anaerobic digestion of waste ($/MWh)	130-160	130-160	130-160
Drop-in fuels from fast pyrolysis of lignocellulosic biomass ($/GJ)	35-40	30-40	30-35
Drop-in fuels from HTL of lignocellulosic biomass ($/GJ)	35-40	30-40	30-35
Drop-in fuels from hydro-treatment/gasification + FT ($/GJ)	45-55	40-50	40-45
Electricity from biomass combustion ($/MWh)	110-140	110-140	110-140
Electricity from biomass gasification ($/MWh)	200-250	190-230	180-220
Electricity from co-firing biomass [10]($/MWh)	30-40	30-40	30-40

Technological and commercial readiness – current state

As shown in

[10] Short run cost only

Table 37 below, while all conversion pathways are largely known, they vary significantly in terms of commercial readiness. Key developments to be prioritised include the production of 'drop-in' fuels from waste feedstocks at higher yields and lower cost.

Table 37 – Technological and commercial readiness 2016

CONVERSION TECHNOLOGY	TRL	CRI	COMMENTS
Ethanol from fermentation of sugar	9	6	Currently in operation in Australia.
Biodiesel from esterification of waste oils	9	6	Currently in operation in Australia. This technology can also use algal oil but the process to grow and extract algal oil is in its infancy for this type of application. It is also possible to use canola or other plant-based oils but these are more expensive.
Biogas from anaerobic digestion of waste	9	6	Mature and commercial process currently used in waste management facilities for onsite power production.
Drop-in fuels from fast pyrolysis of lignocellulosic biomass	6-8	1	This technology is being developed globally for production of drop-in biofuels.
Drop-in fuels from HTL of lignocellulosic biomass	6-8	1	This technology is being developed globally for production of drop-in biofuels. There is currently a pilot/demonstration plant in operation in Australia but it is only producing a bio oil which needs further refining.
Drop-in fuels from hydro-treatment/gasification + FT	8-9	2	There are currently 7 small-scale commercial plants operating globally. RD&D is ongoing into developing FT channel reactors which are more suited to small-scale feedstock applications **Invalid source specified.**
Electricity from biomass combustion	9	6	Currently operating in Australia
Electricity from biomass gasification	6-8	1-2	Technology is similar but not as mature as coal gasification (requires different feedstock preparation and has different impurities).
Electricity from co-firing biomass	9	6	Currently in operation in Australia.

8.3 Barriers to development and potential enablers

In relation to biofuels, the most significant barrier to widespread development in Australia is the high cost (refer Table 36) as compared with conventional petrochemically derived fuels (e.g. petrol, diesel, jet fuel). For a number of the conversion pathways, costs can be significantly reduced by incentivising R&D programs and by providing financial support for demonstration plants.

Favourable policies that mandate sector targets for biofuel use may also enable bio-refinery proponents to attract further investment by obtaining secure long term biomass feedstock and biofuel offtake agreements. It is important that policies do not inadvertently favour other forms of renewable generation or preference conventional biofuels (e.g. ethanol) over more advanced 'drop-in' fuels.

A local biofuels industry is also unlikely to be realised in the absence of a national regulatory framework that governs use of biomass, imposes widespread sustainability criteria and well recognised tools for conducting life-cycle analyses over various processes. Governing standards should be internationally consistent where possible in order to simplify procurement for the aviation and shipping industries and enable export of biofuels and related technologies.

Incentives and increased stakeholder awareness are critical to encouraging further use of biomass in the generation of heat/electricity. Key measures include regular community consultations, implementing favourable FiTs and ensuring that bioenergy plant gate fees are more cost effective than landfill levies.

Table 38 - Bioenergy barriers and potential enablers

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	High cost of biorefineries and biofuels as compared with fossil fuel alternatives (e.g. petrol)	> Provide financial support (e.g. through grants and loan guarantees) to advanced bio-refineries and incentivise shared learnings > Ensure that bio-refineries are strategically deployed in areas with high concentrations of feedstocks to limit transport costs > Encourage mapping and modelling of feedstock types, land availability and potential scale-up options > Explore opportunities to retrofit existing refineries	> Government > Councils > Industry	2017-2020
Revenue/market opportunity	Uncertain market (e.g. price volatility) and revenue opportunities for biofuels	> Implement stable policies that favour the use of biofuels (e.g. fuel tax credits) and enable project developers to secure long term biomass supply and fuel offtake agreements > Communicate other financial/non-financial impacts of biofuel use (e.g. local supply so no price hedging, reputational benefit, carbon benefit)	> Government	2017-2020
	Lack of incentives for further development of waste-to-energy plants	> Raise awareness amongst community stakeholders of associated opportunities (e.g. burning MSW for cheaper electricity) > Implement favourable FiTs for electricity from waste > Ensure that bioenergy plant gate fees are cheaper than landfill levies	> Government > Local councils	2017-2020
Regulatory environment	Bioenergy is governed by a range of different types of regulations (e.g. agricultural, transport regulations)	> Create a single stable, long term national policy framework for bioenergy production and consumption that is aligned to international standards > Implement clear national sustainability criteria (e.g. LCA assessment tools)	> Government > Local councils	2017-2020
	Regulations that preference other forms of renewable generation over bioenergy or incentivise conventional biomass conversion methodologies (e.g. ethanol) over advanced 'drop-in' fuels	> Review current policy and ensure future regulations do not inadvertently favour other forms of renewable electricity over bioenergy or prioritise other uses of biomass	> Government	2017-2020
Technical performance	As compared with conventional fossil fuels, greater technical challenges associated	> Increase demonstration projects > Support retrofitting existing infrastructure to accommodate different feedstocks (e.g. biocrude	> Government > Industry	Ongoing

Category	Barrier	Potential enablers	Responsibility	Timing
	with biomass given different characteristics of feedstocks and higher levels of impurities	refineries) > Support R&D in efficient low cost pre-treatment methodologies		
Stakeholder acceptance	Concern over biomass competition with food resources	> Communicate widespread use of waste feedstock as opposed to dedicated energy crops	> Government > Industry	Ongoing
	Other environmental concerns such as non-CO2 emissions, air & soil quality, water use	> Further improve and encourage national adoption of life-cycle assessment methodologies for bioenergy to account for all impacts on land-use > Communicate long term GHG emissions impacts of bioenergy schemes	> Government > Research	Ongoing
Industry and supply chain skills	n/a	n/a	n/a	n/a

*Key barriers highlighted

8.4 Opportunities for Australian Industry

Development of a sustainable biofuels industry in Australia will bring significant new opportunities. This is particularly the case for the agricultural sector whereby farmers may be able to derive new revenue streams from waste residues or otherwise underutilised land. Widespread deployment could also lead to the development of a local, low emissions fuel industry, and provide EPC and O&M job opportunities for bio-refineries, particularly in regional areas.

Table 39 - Opportunities for Australian Industry Summary

	Technology manufacture	Biomass cultivation/extraction and pre-treatment	Biofuel production
Description	> Manufacture/construction of biomass processing equipment (e.g. pre-treatment, biorefineries)	> Cultivation of various feedstock crops as well as extraction of waste products and other plant residues > Pre-treatment and upgrading of biomass to improve efficiency of handling, transport and conversion (e.g. drying, pelletisation)	> Processing of biomass (e.g. Fischer Tropsch, hydrotreatment) to produce biofuels (e.g. biocrude)
Australia's comparative advantage	Medium + Strong IP in relation to certain manufacturing methods (e.g. HTL, microbial conversion) - Larger and more mature bioenergy markets overseas	High + Skilled agricultural/farming industry + Abundant logistically accessible biomass feedstocks	High + Skilled oil & gas workforce with declining local oil refining industry

	Technology manufacture	Biomass cultivation/extraction and pre-treatment	Biofuel production
	(particularly Europe) + Well established co-firing industry	+ Existing pelletisation projects	
Size of market	High - service of local market and export of IP to share of global market	High - service of local markets and possible export opportunities	High + Established aviation and shipping industries in Australia as well as possible export
Opportunity for Australian industry	Medium	High	High
Jobs opportunity	Medium	High > Can support existing enterprises such as farms, forestry and associated processing industries	High > Opportunity to build a local oil industry
Main location of opportunity	Urban/regional	Regional/remote	Regional
Difficulty of capture/level of investment	Medium > Likely to only develop if local industry exists and therefore requires appropriate policy and incentives	Medium > Requires appropriate policies and incentives	Medium > Requires appropriate policies and incentives

9 Fugitive emissions from fossil fuels

9.1 Sources of fugitive emissions

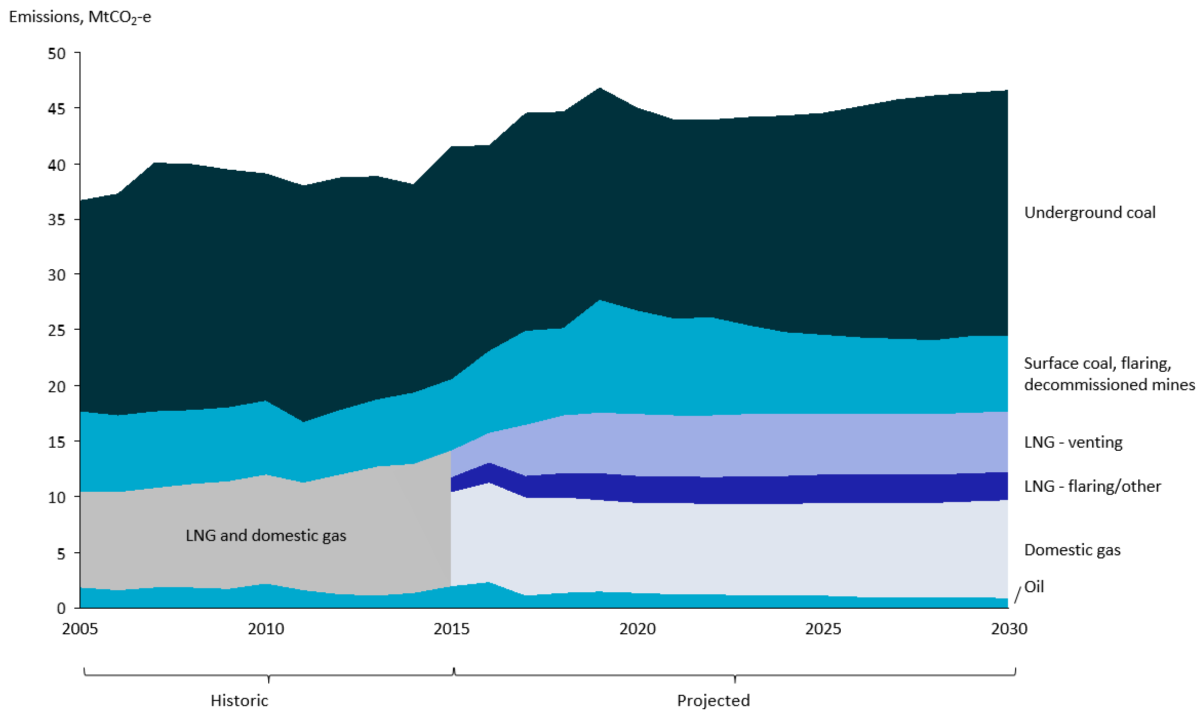
Fugitive emissions in the energy sector include carbon dioxide and methane (and small amounts of other greenhouse gases) released during exploration, extraction, processing and transport of fossil energy commodities (Australian Government Department of the Environment and Energy, 2016). Key sources or emissions are (numbers given for 2016):

- Coal
  - Coal seams contain methane and carbon dioxide that can be released into the atmosphere during or after mining.
  - 65% of fugitive emissions from coal consist of ventilation air methane (VAM) from underground coal mines.
  - Some methane is also released from above ground and decommissioned mines.
- Export gas (e.g. LNG)
  - Venting: Some gas reserves contain CO_2 at relatively high concentrations. This CO_2 is removed from the gas during processing and vented into the atmosphere. Around 2.7 $MtCO_2e$ p.a. of emissions from export gas comes from venting.
  - Flaring: Gas may be released during production to help manage pressures in processing equipment. This gas is combusted to reduce its emissions intensity. This accounts for around 1.8 $MtCO_2e$ p.a. of GHG fugitive emissions from export gas.
- Domestic gas
  - 31% of domestic gas fugitive emissions (2.8 $MtCO_2e$ p.a.) result from gas lost from the transmission and distribution network due to leaks.
  - Around a quarter of emissions are from venting and similar quantity is from flaring.
  - The remainder of emissions occur during exploration and production.
- Oil
  - Emissions result from production and refining.

Historical and projected emissions by sources are shown in

Figure 26.

Figure 26 – Historic and projected fugitive emissions from coal mining and oil and gas (Australian Government Department of the Environment and Energy, 2016)



9.2 Fugitive emissions abatement opportunities in coal

Within coal, the greatest opportunity for abatement exists in reducing VAM emissions from underground coal mines. There appears to be less opportunity for abatement in surface coal mines, although at least one miner is investigating potential options.

Ventilation air from underground mines contains methane that seeps into the air from the coal beds being mined. Methane is explosive at concentrations between 5 and 15% and so for safety reasons the methane concentration at mine ventilation air shafts is kept well below this, typically < 1%. This is achieved by extracting air from the mines using fans, typically at hundreds of cubic metres per second.

There are three main types of technologies for VAM abatement:

- **Regenerative thermal oxidation (RTO):** RTO works by passing VAM over a regenerative bed of ceramic beads or structured blocks, which are heated to over 1000°C, oxidising the methane to carbon dioxide, which has lower global warming impact than methane. Also, depending on methane concentration at some mines, the oxidation heat can be recovered to generate steam for power generation.
- **Catalytic oxidation:** Catalytic systems work at lower temperatures of 450-800°C, and use a catalyst to oxidise the methane, converting it to carbon dioxide.
- **Lean fuel gas turbines:** Lean fuel gas turbines combust methane at low concentrations, driving a turbine and generating power.

Demonstration scale thermal systems have been developed in Australia (e.g. Corky's 12 m^3/s VAM RAB® unit at Centennial Mandalong mine (Corky's, 2016) (Australia, 2016). A commercial scale plant at West Cliff mine used the MEGTEC VOCSIDIZER™ to oxidise 20% of the VAM, using the heat to generate steam driving a 6 MW turbine and reducing emissions by 250 ktCO_2e p.a. (Energy Developments, 2016). This project has since been discontinued due to a cease of longwall mining.

The CSIRO has been working on VAM abatement technology for more than 15 years, and has developed three technologies, for which it has international patents:

- VAMMIT: A catalytic reactor that destroys VAM via oxidation at over 99% effectiveness. It can be operated with 0.3% or greater methane concentration and requires ~10x less energy to run than existing thermal technology.
- VAMCAT: A catalytic turbine system that can be operated with 0.8% methane in air for power generation.
- VAMCAP: nanostructured carbon composite adsorbents used to enrich VAM, so that it can be used by the other techniques. This is currently pre-demonstration – another 5-10 years of research may be required before this technology is ready for demonstration.

The University of Newcastle is also active in VAM abatement RD&D. It is developing a catalytic conversion technology known as stone dust looping (SDL). In SDL, methane is catalytically oxidised using limestone dust and the resulting CO_2 is captured. The university's work on this topic is currently at bench scale demonstration stage (ACARP, 2016).

It is estimated that VAM abatement technologies could reduce emissions by ~15 MtCO_2e vs BAU in 2030.

To calculate this figure, it is assumed that technologies to oxidise methane are applied to 80% of VAM in Australia, reflecting the uncertainty in the quantity of methane at concentrations less than 0.3%, which is the minimum concentration required for the higher TRL technologies. (This uncertainty exists due to the lack of published data on VAM concentrations in Australian coal mines.)

It is also assumed that all of this 80% of total methane is converted to CO_2. Converting methane to carbon dioxide is assumed to reduce its global warming impact by a factor of 10.2[11]. It is also assumed that there is negligible emissions from energy used to run the processes.

Technologies such as VAMCAT and VAMMIT are currently at demonstration stage (TRL = 6). Further work is required to scale these technologies to commercial scale. Industry stakeholders identified ensuring safe operation to be a key consideration in deploying commercial scale units. CSIRO has devised a patented safe ducting system to manage safety risk. Demonstration and commercial scale VAM abatement units have previously been deployed safely.

Developing commercial scale units for new technologies would require a commercial partner, and would take an estimated 4-5 years (i.e. potentially by 2022 if started now). Subsequent rollout to remaining underground coal mines in Australia could happen via licensing the technology to EPCs, feasibly within 5-10 years, meaning the technology could be deployed to all suitable mines in Australia as early as 2027.

Aside from scaling up technologies, the key barrier to deployment of VAM abatement technologies has been the lack of a commercial or regulatory incentive. Developing and deploying VAM abatement technologies imposes a net cost to miners, and until recently has offered no source of revenue. The Emissions Reduction Fund has recently been updated to include VAM abatement technologies as eligible projects. No projects have yet been funded via this mechanism however, so it is too early to say whether the ERF will provide a sufficient incentive to drive deployment of VAM abatement technologies in Australian underground coal mines to the full technical potential. The cost of VAM abatement is not expected to be high—it is estimated at only \$1-2/tCO_2e for 0.8% VAM concentrations for the CSIRO

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[11] The EPA estimates methane has a global warming potential of 28-36 over 100 years (i.e. the global warming impact of a ton of methane is 28-36 times that of a tonne of CO_2 over a period of 100 years) (EPA, 2016). Methane is converted to carbon dioxide at ratio of 1:1 in terms of number of molecules, but a molecule of carbon dioxide has 2.75 times the mass as a molecule of methane. Taking the lower end of the EPA's range, a conservative estimate of the reduction in global warming potential achieved by converting methane to carbon dioxide is then 28/2.75 = 10.2

technologies. Should the ERF prove insufficient, uptake of VAM abatement technologies would require policy that imposes a cost greater than the technology cost to miners to continue emitting VAM, or regulation that requires them to abate this methane.

Given the global need for decarbonisation, it is expected that a significant commercial opportunity exists for licensing IP for VAM abatement technology to other countries, particularly China, which accounts for ~45% of coal mine emissions. Similar to Australia, realising this opportunity relies on policy support in potential export markets to drive uptake.

The amount of VAM in underground coal mines can also be reduced via draining the methane from the coal beds. This can either be done prior to mining (pre-draining), or during mining (in situ-draining), and reduces the amount of methane available to enter the ventilation air. The technology required for draining is mature, and as such pre-draining more of an operational issue. Generally pre-draining is required in any case, to reduce the VAM concentrations to low enough levels to allow mining to be carried out safely.

9.3 Fugitive emissions abatement opportunities in LNG

The key opportunity for abatement in export gas is geo-sequestration of CO_2 naturally occurring in some petroleum gas reservoirs in North Western Australia. LNG plants separate a pure stream of CO_2 from the natural gas during processing which is usually just vented into the atmosphere. Besides a pure stream of CO_2, CCS requires access to a suitable geological storage reserve, and the capability to inject the CO_2 into the reserve safely.

Some LNG plants are located near sedimentary basins that can provide potential storage reserves. Potential geological formations for CCS have already been assessed in the Petrel sub-basin in North Western Australia near Darwin (Consoli, 2013). Nearby depleted oil and gas fields in general also make good candidates for CO_2 sequestration while enhancing recovery.

Due to the current high capital and operating costs of CCS, the key barrier to this abatement opportunity is the lack of a regulatory or commercial driver. Regulation would be required to drive uptake. Note that given the widely varying economics of CCS for different projects, a mechanism that allows lower cost abatement from other sources may be preferable. Bio-sequestration using plantings is being pursued as a cheaper alternative in some projects.

An example of CCS in LNG is provided by the Gorgon project in WA, which is set to start injecting 3.4-4 million tonnes per annum of reservoir CO_2 in 2017 (Global CCS Institute, 2016) into a deep aquifer underlying Barrow Island where the LNG plant is located. CCS was required by the WA government as part of the set of requirements for developing the project.

In recent years, the Environmental Impact Statements (EISs) of projects under development all considered geo-sequestration feasibility to varying degrees of detail. The INPEX EIS (INPEX, 2008) for the Ichthys LNG project indicates that "the potential for geo-sequestration is being examined by Inpex" to sequester the initial 2.5 Mtpa of CO_2 emissions from venting, which will increase up to 4 Mtpa later in the development lifecycle. Since the separation of reservoir CO_2 occurs onshore in the Darwin facility, a CCS site near Darwin would be required to minimise transport costs.

With around 0.97 Mtpa of reservoir CO_2, the Shell Prelude EIS (Shell, 2009) states:

> "Overall, the sequestration of reservoir CO_2 has significant cost and technical uncertainties still to be resolved and adds a degree of complexity to the FLNG design. For this first application of the FLNG technology it is therefore proposed to safely vent the reservoir CO_2 up the flare stack once it has been separated from the feedgas. Economic factors will also be significant in a decision whether to sequester the reservoir CO_2 and this will largely be dependent on the design of the Australian CPRS,

> the emerging price of carbon[12] and the overall volume of reservoir CO_2 compared to the capital and operational cost of geo-sequestration. The Prelude field is small and compared to larger gas fields, lacks the volume of reservoir CO_2 and economy of scale to make geo-sequestration economically attractive given the high, upfront capital costs involved."

A similar situation is likely to apply to any other small, remote or marginal fields where Floating LNG plants are considered such as Greater Sunrise, Equus, Scarborough, Bonaparte and Cash-Maple. The current North West Shelf Venture trains at Karratha vent ~1.1 Mtpa CO_2. Woodside and partners assessed the technical feasibility of geo-sequestration for the Browse FLNG Development (Browse FLNG Development, 2014) for extracted reservoir CO_2 as part of the 'Concept Select' phase of the Browse FLNG Development, but this option was not carried forward and the overall project has since been cancelled. The Conoco-Phillips Darwin LNG project vents an estimated 0.6 Mtpa. Similar to the INPEX project, since the separation of reservoir CO_2 occurs onshore in the Darwin facility, a CCS site near Darwin would be required to minimise transport costs.

If a regulatory driver was created for CCS more broadly, this could create a commercial opportunity for LNG producers to make their storage resources available to other producers of CO_2 as is starting to occur in Norway.

For this study we have assumed 33% uptake or 1.8 Mtpa (not counting Gorgon which is counted as part of BAU).

The other main source of fugitive emissions from LNG is flaring. Flaring is mainly an operational issue – for instance if a gas turbine shuts down flaring may be required to avoid dangerous build-up of pressure. As such, opportunities to reduce flaring mainly stem from improved operational practices, enabled by technological solutions such as advanced process control. An annual reduction in emissions from flaring of 0.8% is assumed (see summary of assumptions below). This results in 0.3 $MtCO_2e$ of abatement in 2030.

The major technical challenge in LNG plants is the reduction of direct combustion emissions used to run the plant as described in the Oil & Gas appendix.

9.4 Domestic gas

Unlike LNG, most domestic gas emissions are methane, a potent GHG, so it is important to avoid emissions from venting. Consequently State Laws such as the Queensland Petroleum and Gas Act 2004 requires that gas should be used commercially wherever possible or flared to convert the methane to CO_2 if it is not. Venting gas is only allowed when flaring is not technically possible or for safety reasons. Limited technology solutions exist for reducing emissions from venting and flaring, although process improvements, enabled by technological solutions such as advanced process control. An annual reduction in emissions from venting and flaring of 0.8% is assumed (see summary of assumptions below).

The other main source of emissions from domestic gas is leaks in gas transmission, distribution and storage. These emissions can be reduced through improved maintenance and planning processes (ClimateWorks Australia, 2014). Reductions in emissions from transmission and distribution of 20% and 45% respectively have been assumed (see assumptions below). However, for these reductions to be counted towards Australia's abatement target, changes would need to be made to the emission factors used to calculate emissions from these sources.

[12] Note the CPRS and carbon price are no longer current policies in Australia.

Domestic emissions are driven by domestic consumption, and will drop with declining residential, commercial and industrial gas use. Conversely, more fugitive emissions can be expected if more gas is used for electricity generation, as is the case in some of the scenarios modelled in this report.

9.5 Exploration and production (export and domestic)

Emissions can also occur during exploration and production of domestic and export gas:

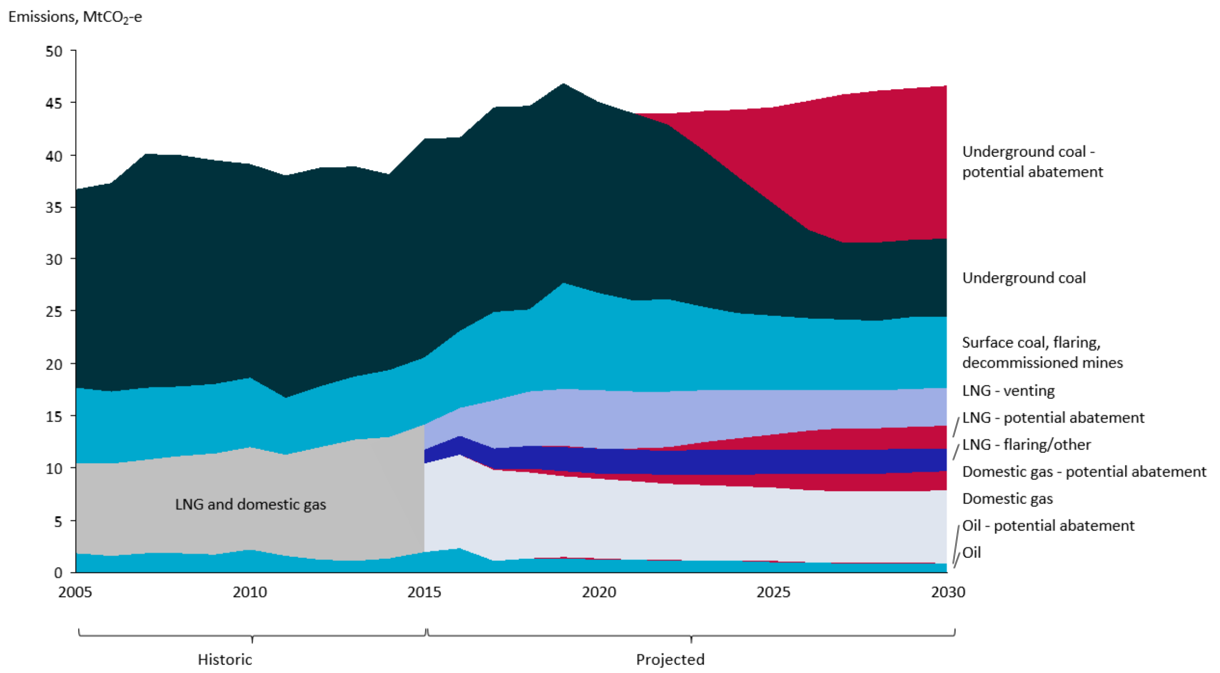
- Exploration: Methane may be vented or flared during gas well drilling, drill stem testing and well completion.
- Production: Emissions may occur between the production well head and the inlet point of the gas processing plant or transmission pipeline. This can result from:
    - Opening and closing new wells: Fugitive emissions can occur if wells are not immediately connected to the pipeline after drilling and pumping in the fracking fluid
    - Leaks at the well head
    - Leaks from pipelines
    - Gas released by gas-powered pneumatic devices
    - Production pilot plants not connected to transmission pipelines.

Abatement of these emissions is primarily an operational issue, requiring improved maintenance to reduce leaks. Gas-powered pneumatic devices can also be replaced by compressed air devices. An annual reduction in emissions of 0.8% is assumed (see summary of assumptions below).

With BAU gas use, the measures identified for domestic gas and exploration and production result in 1.8 $MtCO_2e$ abatement in 2030.

Total abatement potential of fugitive emissions from coal mining and oil and gas production is shown in Figure 27.

Figure 27 – Total fugitive emission abatement potential
Assumes BAU gas consumption—domestic gas consumption, and hence fugitive emissions, increases or decreases depending on pathway.



9.6 Uncertainties in reported and projected emissions

The emissions shown in

Figure 26 and Figure 27 are estimated based on reported emissions and on projections of activity in the respective sectors. For this report, abatement potential has been calculated based on these estimates. Potential sources of errors in the estimates include:

Activity levels differing from projections: For most of the sources listed above, fugitive emissions scale with the production of the respective commodity. For instance, changing demand for domestic gas would proportionally change the amount of vented and flared methane and the methane leaking from the distribution network. The amount of gas vented from underground mines will scale with production, which is largely export driven. As such, reduced demand from trading partners such as China and India would reduce Australia's fugitive emissions.

Changes in emissions intensity of the respective sectors: Fugitive emissions are impacted by, for example, exploiting gas reserves with higher or lower CO_2 concentrations, mining coal with a lower methane content or by improving operations to reduce emissions intensity, such as by reducing flaring in domestic and export gas.

Incorrect emission factors being used to calculate emissions: There is large uncertainty in fugitive emissions in particular from unconventional gas production:

- Rather than being directly measured, emissions are estimated for the National Greenhouse Gas Inventory using factors applied to production volumes. Furthermore, factors developed using US measurements are used, and there is high uncertainty in their applicability to Australia. Initial measurements carried out in Australia suggest factors being used in Australia are appropriate but further work is required (Day, 2014).
- Measurements made in the US indicate that a majority of fugitive emissions for gas production and distribution result from a small number of 'super-emitters' (Brandt, 2014), i.e. operators or point sources producing a large quantity of emissions. While the industry in Australian is better regulated in the US, with fewer, large operators, and hence likely better operating practices, it is not clear the degree to which there are super-emitters.
- There is limited data on background methane to establish emissions baselines.
- Migratory emissions may occur due to depressurisation of coal seams resulting in gas migrating through existing geological faults, water bores, exploration wells or the soil, but limited data on this currently exists (Lafleur, 2016).

More work is therefore required to better understand fugitive emissions from gas production. This is particularly important if gas production is to be scaled up for electricity generation. It is important to establish baselines and to carry out direct measurements of emissions, to establish appropriate emission factors and to ensure that no super-emitters are going unnoticed.

9.7 Summary of modelling assumptions

SUBSECTOR	EMISSIONS SOURCE	ASSUMPTIONS	SOURCE
Coal	Underground	80% of VAM converted to CO_2 in 2030, ramped up from 0% from 2022 to 2027	CSIRO expert and industry consultation
	Open cut	No abatement	CSIRO expert and industry consultation
	Abandoned coal mines	No abatement	CSIRO expert and industry consultation
LNG	Venting	CCS applied to 33% of vented emissions in 2030 (not counting sequestered emissions from Gorgon); Ramped up from 0% from 2022 to 2027	Industry stakeholder consultation; Project EISs;

SUBSECTOR	EMISSIONS SOURCE	ASSUMPTIONS	SOURCE
	Flaring and other	0.8% p.a. improvement in emissions intensity (consistent with CWA number of 7% improvement from 2010-11 to 2019-20)	(ClimateWorks Australia, 2013)
Domestic gas	Exploration, production, flaring and venting	0.8% p.a. improvement in emissions intensity (consistent with CWA number of 7% improvement from 2010-11 to 2019-20); Emissions scaled by change in total domestic consumption	(ClimateWorks Australia, 2013)
	Transmission and storage	20% abatement achieved between 2017 and 2027 due to reduction in leaks, scaled by change in total domestic consumption	(ClimateWorks Australia, 2010)
	Distribution	45% reduction (based on a 1.2 $MtCO_2e$ abatement opportunity in gas maintenance, off a 2010 baseline of 2.84 MtCO2e (DoEE numbers for T&D), factoring in contribution of 20% abatement in transmission) Emissions scaled by change in buildings consumption	(ClimateWorks Australia, 2010)
Oil	All	0.8% p.a. improvement in emissions intensity (consistent with CWA number of 7% improvement from 2010-11 to 2019-20)	(ClimateWorks Australia, 2013)

10 Solar PV

Rapidly declining costs and improving efficiencies is likely to see large-scale and rooftop solar PV systems become the most widely deployed form of renewable energy generation out to 2030. Given that solar PV is already a mature technology, the rate of uptake will most likely be dictated by the presence of a favourable regulatory framework and tariff regime designed to encourage investment. These technologies present a range of opportunities for Australian industry, particularly in relation to local EPC and O&M, exportable IP and niche solutions for the local and global markets.

- Solar PV is on the verge of displacing wind as the preferred technology for large-scale renewable generation. Improvements in asset procurement are key to achieving further reductions in cost. Key enablers of this include repeatability, shared learnings and regulatory reform that incentivises utilities to efficiently connect solar PV to the grid.
- While uptake of residential rooftop solar PV is steadily increasing, its growth rate is somewhat dependent on the availability of market mechanisms such as peer to peer electricity trading and/or the cost of behind the meter energy storage.
- Commercial/industrial rooftop solar PV, which has experienced slower growth, has been hindered by higher costs as well as existing ownership structures (e.g. landlord pays upfront cost but does not realise the benefits of reduced energy bills). Regulatory reform and new business models that enable landowners to generate revenue from rooftop solar PV will drive further adoption.
- It is unlikely that Australia will be able to compete in the manufacture of silicon cells. Opportunities exist however in licencing of IP designed to improve manufacturing processes and cell efficiencies.
- Given that EPC and O&M will need to occur locally, increasing uptake will mean new industry opportunities for Australia, particularly in remote regions for large-scale solar. There will also be opportunity to export niche solutions (e.g. analytics, racking).
- Less mature thin-film PV technologies are continuing to develop. With potentially lower manufacturing costs and higher efficiencies, they threaten to significantly disrupt the silicon industry. There may therefore also be an opportunity to produce thin-film locally by drawing on existing printing, as well as glass and plastic manufacturing industries.

10.1 Technology overview

Technology description

Solar photovoltaic (PV) systems consist of two primary components:

1. Solar cells / modules
2. Balance of System (BoS)

Solar cells

PV solar cells create energy through the absorption of photons (particles of light) that excite electrons within the cell and create a flow of electrons to produce electricity. The cells are semiconductors, which are solid substances that conduct electrical current under certain conditions (CO2CRC, 2015). The conducting properties may be altered by creating controlled impurities in their structure through a process known as ‘doping’ (MIT, 2015). The energy required to excite electrons within the semiconductor is known as the ‘bandgap’.

PV cells can be classified as either (MIT, 2015):

1. Wafer-based: A ‘thin slice’ semiconductor that does not require an additional base material or substrate
2. Thin-film: A semiconducting material that is required to be deposited onto an insulating substrate (e.g. glass or plastic)

Solar cells are combined to create modules. These can be aggregated into series or in parallel depending on the particular application. In this section, both large-scale (typically greater than 1 MW) and rooftop solar PV (i.e. commercial/industrial and residential) are considered.

While there are a diverse range of cell technologies either in the market currently or undergoing development, six have been recognised as having significant potential. These are detailed in Table 40 below:

Table 40 – Summary of solar PV technologies

SOLAR CELL	TYPE	DESCRIPTION	RECORD LAB CELL EFFICIENCY	ADVANTAGES	DISADVANTAGES
Crystalline silicon	Wafer-based	May be either single crystalline (c-Si) or multi-crystalline (mc-Si). c-Si is more expensive but has greater conversion efficiencies	25.6%	Most mature of all PV technologies	Weak light absorption and so requires thick wafers Stringent material purity requirements Approaching theoretical efficiency limit Unable to operate at high temperatures
Cadmium telluride (CdTe)	Thin-film	Leading thin-film technology in terms of worldwide installed capacity	21.0%	Strong absorption across the solar spectrum Low cost Able to operate at higher temperatures	High toxicity (but relatively safe when bound in product) Lower efficiencies than silicon
III-V multijunction (MJ)	Wafer-based	Uses a stack of cells with different band-gaps to absorb light across the solar spectrum. These are used in concentrated PV arrays (i.e. concentrated light from heliostats is focused onto a multi-junction panel)	46.0%	High efficiency High radiation resistance Low temperature sensitivity	Prohibitively high material costs Complex manufacturing processes Poor long term reliability and cell uniformity
Copper indium gallium diselenide (CIGS)	Thin-film	Mainstream thin-film PV, manufactured by depositing copper, indium, gallium and selenide on glass	21.7%	High radiation resistance	High variability in cell properties Low voltage Scarcity of indium

SOLAR CELL	TYPE	DESCRIPTION	RECORD LAB CELL EFFICIENCY	ADVANTAGES	DISADVANTAGES
Perovskite	Thin-film	Employs a light absorbing film that is a hybrid organic-inorganic lead halide. It is recognised as having significant potential - lab cell efficiencies have increased from 10.8% to 20.1% in less than 3 years.	20.1%	Low cost Potential for bandgap tuning Maintains efficiency in high temperatures Stable power output	High sensitivity to moisture Use of toxic lead (Currently looking at alternatives)
Tandem silicon/perovskite	Hybrid	Top layer of the cell is an absorbing perovskite which harvests short wavelength light. Bottom layer is a silicon wafer which harvests longer wavelength light	˜22%	Greater potential efficiencies than silicon More stable than perovskite	Silicon wafer/perovskite Interface challenges

BoS

While BoS consists of a variety of component parts (e.g. racking, wiring, electronics), two that have a material impact on system performance include:

1. Inverters: Convert the DC output from the solar panels into AC so that power derived from the panels can be exported to the electricity network. Inverters must be optimally sized for the conversion of DC power from the connecting array (discussed further in Section 13.2.2).
2. Axis-tracking: Single and double-axis tracking allow PV panels to track the position of the sun so as to maximise daily electricity output. This equipment is capital intensive and requires ongoing maintenance. Single-axis tracking is now at the point where the benefit of increased output justifies the additional capex.

Technology impact

Solar PV has existed for over half a century and has seen largely incremental technological developments over that period. Increasing the capacity factor via improvements in components such as cell efficiency and axis tracking have been a continual area of RD&D focus.

In recent times, primarily due to market maturity as well as increased manufacturing capacity and uptake on a global scale, the cost of PV systems has been significantly reduced. For instance, the average decline in the cost of large-scale solar PV globally was 65% between 2010 and 2015 (IEA, 2016). Over the same period, global solar capacity increased from less than 5 GW to over 60 GW.[13]

Market maturity, increased uptake and construction experience will continue to push down the cost of financing and EPC. Improved solar cell efficiencies will also have a material impact by reducing BoS costs per unit of system power.

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[13] http://wiki-solar.org/library/public/160307_Utility-solar_2015_figures_top_60GW.pdf (accessed 11 August 2016)

Competitive tension exists between mature silicon wafer-based cells and emerging thin-film technology. The former, which is predicted to have greater efficiencies and a comparatively lower cost of manufacture, has the potential to significantly disrupt the silicon industry.

In Pathway 2, for the centralised scenario, annual capacity additions of rooftop and large-scale solar PV to 2030 were 1.3 GW/year and 1.2 GW/year respectively. Under the decentralised scenario, annual additions of rooftop solar PV reach 7.8GW/year in 2030. While this is a relatively large increase, as compared with the 0.9 GW/year of rooftop solar PV installed in Australia from 2011 through 2015 (Australian PV Institute, 2016), it does appear feasible as long as the long the local market can continue to develop.

10.2 Technology status

Cost - current state and projections

Whole of PV system LCOEs are set out in Table 41 below. The LCOE ranges represent possible system sizes, PV cell types and configurations (e.g. fixed or single axis tracking).

Table 41 – Projected large-scale solar PV system LCOE ($AUD/MWh)

SOLAR CELL	2015	2020	2030
Large-scale solar PV	100-120	75-95	55-70
Rooftop solar PV	120-150	100-120	70-85

Technological and commercial readiness - current state

The TRL and CRI associated with each of the solar PV technologies discussed in Section 10.1 is outlined in

Table 42 below.

Table 42 – Solar cell TRL and CRI

SOLAR CELL	TRL	CRI	COMMENTS
Silicon	9	4-6	• Silicon solar cells are a mature technology • Commercial roll-out for rooftop solar PV • A number of large-scale solar farms exist however still require some level of funding assistance (i.e. government grants) • More international players creating a competitive market • Incremental technology improvements also contributing to improved output and cost
CdTe	9	3-4	• Has been used for large-scale PV systems globally. 3 of the 4 largest solar PV systems in Australia are CdTe, all of which received ARENA funding. Not yet readily available for rooftop solar PV
III-V MJ	8	1-2	• Due to high cost and high efficiency, cells are used in concentrating PV arrays (CPV). CPV have been built as demonstration plants (e.g. Raygen).
CIGS	8-9	2	• Has been used for large-scale PV systems globally. Available through several manufacturers.[14]
Perovskite	6	1	• High efficiencies in laboratory conditions have been recorded. Manufacturing techniques at larger scale are yet to be fully developed (Habibi, 2016)
Tandem silicon/perovskite	4-5	1	• Perovskite tandem is still in developmental phase. Improvements in cell stability are continually being achieved.

10.3 Barriers to development and potential enablers

ARENA recently undertook a refresh of their solar R&D strategy (ARENA, 2016) to be published in 2017. Our findings in relation to the development of solar PV should be read in conjunction with this report.

This report maintains that solar PV will form a significant part of Australia's energy mix and in order to capitalise on Australia's solar resource, there are a number of challenges that need to be solved via further R&D. These include improvements in PV cell efficiency and longevity as well as reductions in manufacturing costs. It was also concluded that R&D funding should be extended to both silicon and thin-film solar PV.

A different set of barriers and potential enablers apply to large-scale and rooftop solar PV respectively. These are presented in

[14] https://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-SOLAR_PV.pdf (accessed 12 August 2016)

Table 43 and Table 44 below. Note that while barriers and enablers relating to the development of less-developed thin-film PV are only included in

Table 43, they apply equally to rooftop solar PV.

For large-scale solar, high EPC costs may be reduced by incentivising collaboration between developers and improving relationships with utilities. Further, the implementation of clear policy post 2020, combined with incentives to accelerate retirement of fossil fuel generation could also improve demand certainty and help project proponents secure investment.

Table 43 – Large-scale solar PV barriers and potential enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• High EPC costs	• Incentivise sharing of connection and other BoS costs between developers • Improve knowledge sharing in relation to EPC and O&M • Implement regulations that encourage utilities to efficiently connect solar PV to the grid • Improve communication and cost allocation between 'network service providers' (NSPs) and developers	• Government	2017 - 2020
Revenue/market opportunity	• Low capacity factors	• Implement incentives for solar farms to invest in energy storage	• Government, AEMC, AEMO	2017 – 2020
		• Continue support of research into silicon PV to improve performance and reduce the rate of degradation	• Government, research organisations, industry	Ongoing
	• Oversupplied electricity market and reduced supply of long term PPAs	• Implement policy/incentives to accelerate the retirement of coal and gas generation • Improve design of PPAs (e.g. direct supply to industry off-taker as opposed to retailer). This may also require regulatory change.	• Government • Industry	2017 - 2020
Regulatory environment	• Lack of policy certainty post-2020 to continue driving uptake	• Establish certain policy framework post-2020 early enough to limit uncertainty and encourage investment	• Government	2017
Technical performance	• Uncertainty over performance of emerging thin-film cells[15]	• Increase support of emerging thin film technologies and partnerships with companies to drive commercialisation[9]	• Government	2017 - 2020
Stakeholder acceptance	• Solar PV still perceived as an unattractive investment	• Implement incentives (e.g. tax) for institutional investors to have a higher proportion of renewables in their portfolio • Increase market confidence and lower perception of investment risk by improving transparency and knowledge sharing (e.g. publication of solar yield forecasting)	• Government	2017 - 2020
Industry and supply chain skills	• Lack of industry depth and breadth along certain parts of the supply chain (e.g. EPC) to	• Maintain clear government support for long term growth of large-scale solar industry (beyond 2020), to give industry confidence to invest in growing capacity • Continue to develop training, accreditation and standards	• Government • Industry bodies, ARENA	2017 - 2020

[15] Also applicable for rooftop solar PV

Category	Barriers	Potential enablers	Responsibility	Timing
	enable rapid uptake			

*Grey boxes represent key barriers and enablers

Residential rooftop solar PV has continued to experience considerable growth. However, the cost of behind the meter energy storage and availability of peer-to-peer electricity trading frameworks is important in ensuring this level of growth is maintained.

Similarly, for commercial/industrial rooftop solar PV to experience the same level of growth as residential, regulatory reform and new business models that enable landowners to generate revenue from rooftop solar PV will drive further adoption.

Table 44 – Rooftop Solar PV barriers and enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• Relatively higher costs on commercial/industrial buildings due to bespoke design	• Continue ongoing learning-by-doing in simplifying PV racks, mounting equipment etc.; moving towards standardised installations	• Industry bodies	Ongoing
Revenue/market opportunity	• Owner pays upfront capital cost but tenants benefit from reduced bills	• Implement technology/market/regulatory improvements that allow landlords to trade electricity directly (i.e. without retailers)	• Industry providers, Government	2017-2020
	• Tenants are prevented from access to rooftop solar PV	• Implement market/regulatory mechanisms that allow/incentivise tenants to lease solar PV directly from a utility provider	• Government	2017-2020
Regulatory environment	• n/a	• n/a	• n/a	n/a
Technical performance	• Reduced energy output from rooftop solar PV over time	• Further education regarding importance of solar panel maintenance	• Industry, Government	Ongoing
Stakeholder acceptance	• Low income households' aversion to high upfront capital costs	• Continue to implement incentives that target low income households • Raise awareness of financial benefits associated with finance leases (e.g. no upfront capital cost)	• Government	2017-2020
	• Cost of electricity is immaterial for many SMEs	• Regulations/schemes that require/incentivise building owners to meet energy usage standards for both 'new build' and 'retrofit'	• Government	2017-2020
	• Consumers have little understanding of tariff arrangements and options	• Improve education on tariffs and opportunities	• Government	2017-2020

Category	Barriers	Potential enablers	Responsibility	Timing
Industry and supply chain skills	• Installation and connection delays	• Continue certification of installers and ongoing training • Regulations providing further incentives for utilities/retailers to efficiently connect rooftop solar PV	• Government, industry bodies	2017-2020

10.4 Opportunities for Australian Industry

There are a number of opportunities for Australian industry to participate in the solar PV supply chain. Australia's vast mineral resources and established mining industry means that it is well placed to provide raw materials for solar PV development. Further, given the lower cost of manufacturing and IP currently held, there is significant scope to produce thin-film solar for local and export markets. While unlikely to produce silicon cells locally, Australia holds significant IP relating to improving manufacturing and operation of the cells which could be licenced globally.

Deployment of solar PV locally will also bring significant EPC and O&M opportunities for both large-scale and rooftop systems. In the latter, there are also a number of companies providing construction and operational solutions (e.g. analytics) that could be exported overseas.

A detailed summary of the supply chain opportunities for solar PV are set out in Table 45 below.

Table 45 – Solar PV opportunities for Australian industry

	Natural resource estraction	Cell and module manufacture	EPC	O&M	Recycling of base materials
Description	Mining of raw materials (e.g. quartzite gravel (sand) for wafer technologies)	Involves processing of raw materials and construction of cells and modules.	Includes resource (i.e. sun irradiance) studies in proposed locations, land leasing, logistics and construction	Ongoing maintenance of solar includes cleaning panels, maintaining inverters and axis tracking where required	Used cells are broken down into their base materials for reuse
Australia's comparative advantage	High + Significant deposits of relevant materials + Established mining industry + Significant mining RD&D	Medium + Thin-film: Strong IP in printing/depositing thin films (e.g. pervoskite and 3D printing) - Silicon: High cost labour and small capacity relative to global industry + Silicon: Strong IP related manufacturing e.g. reducing defects and increasing efficiency	High + Site/rooftop studies, logistics and construction must occur locally + Existing companies with IP in specialised BoS components e.g. Improved mounting, tracking systems	High + O&M of solar must occur locally + Existing companies with IP in specialised O&M (e.g. analytics over output)	Medium + Established recycling industry - High cost of labour in Australia compared to e.g., Asia - High transport cost to Australia
Market size (2030)	High Local and share of global market	High > Global solar market	High Domestic market and global market for specialised components	High Large potential domestic market	Medium Potential domestic market
Opportunity for Australian industry	High Accessible global market	Medium > Potential for export of IP and printed solar cells	High Domestic EPC market and export of specialised components	High Domestic O&M market	Medium Potential global market but likely with strong competition
Jobs opportunity	High	Medium	High	High	Medium

	Natural resource estraction	**Cell and module manufacture**	**EPC**	**O&M**	**Recycling of base materials**
Main location of opportunity	Regional/remote	Urban/regional	Regional (near generation) and near population centres (in distribution network)		Urban/regional
Difficulty of capture/level of investment	Low	Medium Thin-film industry requires further investment	Low	Low	High

11 Wind

Wind energy is a readily available low emissions technology that is continuing to be deployed globally. For the Australian energy sector however, despite its commercial maturity, its rate of growth could slow as a result of increasing competition from large-scale PV.

- Large-scale wind turbines are continuing to be deployed both globally and locally. While already a competitive form of energy generation (~$80/MWh), increased uptake, incremental technology developments, lower financing and improved EPC/O&M will all serve to further reduce cost.
- Due to increasing competition from solar PV, the growth rate of wind energy in Australia could slow within the period to 2030. However it is still expected to form a significant part of the electricity generation by 2050.
- Offshore wind faces additional challenges to deployment such as higher costs and geographical constraints (e.g. narrow continental shelf, rough seas).
- Given the maturity of wind energy, further R&D is likely to be focused on achieving incremental improvements in system operation. This includes turbine components as well grid integration technologies that result in greater energy output and improved grid integration.
- In order to drive further uptake of wind energy, stable policy measures will be required post-2020 to encourage further investment.
- To date, Australian companies have been successful in providing niche solutions along the value chain (e.g. development of control software). However, growth in this area may depend on the extent to which the broader industry continues to develop.

11.1 Technology overview

Technology description

Large-scale wind turbine systems consist of:

1. Wind turbine
2. Balance of system (BoS)

Wind turbine

Energy is extracted from wind through the turbine blades which turn a shaft (the rotor) in order to produce electricity. The rotor, along with the gearbox, drive train and brake assembly are all held inside a casing, known as the nacelle that sits atop of the tower.

Over the course of development, there have been numerous wind turbine designs in the market that have considered variations based on the orientation of the axes, number of blades and generator type. Currently, the preferred and most widely used is the three-blade, upwind, horizontal axis design (CO2CRC, 2015).

A single turbine currently has an average capacity of 3.5MW. For efficient large-scale generation, single turbines in a wind farm are arranged so as to minimise the creation of 'wake turbulence' which interferes with other turbines downwind. Wind turbines may be positioned both onshore and offshore.

BoS

Wind farm BoS encompasses all windfarm facilities outside of the turbine and its various components. This typically includes (but is not limited to) turbine foundations, cabling to substation and grid, transformers, and the 'supervisory control and data acquisition system' (SCADA). The most recent turbines also utilise a power converter to convert AC power to DC, and then back to AC power that is synchronous with the network (AEMO, 2013).

Technology impact

While wind turbine technology is relatively mature, there are a number of areas of development intended to improve the capacity factor of the turbines so they can act more like baseload generation and operate at a high level under variable conditions.

Considerable focus is being directed towards improving the positioning and increasing turbine size (i.e. taller towers and longer blades) in order to maximise capacity (~7-8MW). Other developments have involved replacing gearboxes with magnets to produce 'direct-drive' turbines which reduce friction and increase efficiency. Further improvements in turbine materials and maintenance have also been critical to extending asset life (CO2CRC, 2015).

Many of the challenges around the integration of intermittent renewable generation into the electricity grid exist at the transmission/distribution network level (discussed in Section 13.1). However, there are a series of advanced wind turbine developments that enable greater control over utility-scale energy output. Some of which include (IEC, 2015):

- Fault ride through – The ability for wind turbines to continue to operate at network voltages outside of their optimum range in order to avoid tripping.
- Pitch control or active-stall – Enables the operator to change the output of the turbine by adjusting the angle (i.e. yaw rotation) of the blades against the wind. This allows for greater frequency and reactive power control.
- Use of synthetic inertia - conversion of kinetic energy stored in the rotating mass of the turbine to additional electrical energy using power electronics (e.g. inverters) in order to maintain frequency control.

Other developments with potential for significant impact are set out below:

Centralised control

In areas where there is a strong wind resource and a high concentration of wind farms, multiple assets may be operated as a single unit using a centralised SCADA and dispatch centre (CO2CRC, 2015). This level of coordination allows for greater optimisation of resources and smoother integration into the grid.

Offshore turbines

Offshore wind turbines overcome space constraints and generally provide for a better resource and capacity. They are however more expensive given the need for taller towers to reach the seabed, longer subsea electric cables as well as other modifications designed to withstand the marine environment (CO2CRC, 2015).

Offshore turbines may be floating or fixed. Floating turbines, used in depths between 60-200m, utilise tension-leg platform technology that is typically seen in floating oil rigs (CO2CRC, 2015).

In an Australian context, there is likely to be limited scope for deployment of offshore turbines. While a scenario with a significant increase in the number of wind farms may limit the availability of optimal onshore locations, the higher cost and geographical constraints (e.g. narrow continental shelf, rough seas) are likely to prevent offshore wind from becoming an attractive investment.

Airborne wind

'Airborne wind' represents an emerging class of wind generation in which tethered wings or aircraft are driven by wind at higher altitudes (e.g. 450 meters). The flying pattern of the aircraft causes the tether to repeatedly move in and out. This creates mechanical energy that can then be converted to electricity.

While at early stages of the development, airborne wind has the potential to disrupt the incumbent industry given the expected lower capital and operating cost and ability to utilise greater wind resources at higher altitudes.

11.2 Technology status

Cost - current state and projections

Wind turbine system LCOEs are set out in Table 46 below.

Table 46 – Wind energy LCOE forecast ($AUD/MWh)

WIND ENERGY	2015	2020	2030
Onshore Systems	80-100	75-90	70-85
Offshore Systems (fixed)	150-180	130-160	130-150

Technological and commercial readiness - current state

The technological and commercial readiness of each of the wind turbine technologies discussed in Section 11.1 is outlined in

Table 47 below.

Table 47 – Technological and commercial readiness 2016

WIND TURBINE	TRL	CRI	COMMENTS
Onshore system	9	6	Onshore wind energy systems are commercial technologies
Fixed offshore system	9	2	While it is a mature and commonly used technology in Europe (i.e. CRI 6), no demonstration projects currently exist in Australia
Floating offshore system	6-7	1	A range of floating offshore wind turbine designs are currently undergoing development
Airborne wind	6-7	1	A number of companies such as Australian based Ampyx power and Makani (owned by Google), are currently developing different technology designs

11.3 Barriers to development and potential enablers

The key barrier to further deployment of wind energy relates to the potential unavailability of PPAs as a consequence of an oversupplied electricity network. This makes the task of securing investment in new projects more challenging. Implementation of a clear and stable policy post 2020 that continues to incentivise deployment of wind over other (current or future) emissions intensive energy generation is therefore critical.

Geographical diversity and optimisation of prospective locations for new build wind farms will help ensure that the value of energy produced is not diminished by nearby incumbent generation. Further, incentivising sharing of infrastructure between proponents will also assist in lowering the cost of connection to the transmission network.

Table 48 – Wind energy barriers and enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• High BoS costs (e.g. competition and limited sharing between developers)	• Mechanisms/incentives to allow project developers to share transmission connection costs (e.g. co-location of wind and solar)	• AER, Government	2017-2020
	• Lack of high voltage transmission network near appropriate wind sites	• Incentives for utilities to improve infrastructure in areas where there is a high concentration of wind farms	• Network developers	2017-2020
Revenue/market opportunity	• As more wind turbines are built within a certain area, the value of the energy generated is reduced	• Promote geographical diversity by commissioning further studies for less utilised areas with reasonable proximity to network	• Government	2017-2020
	• Oversupplied electricity market and demand for long term PPAs	• Policy/incentives to accelerate the retirement of coal and gas generation	• Government	2017-2020
Regulatory environment	• Lack of policy certainty post-2020	• Establish stable post 2020 policy to encourage investment	• Government	2017-2020
Technical performance	• Standard wind farm designs do not typically provide inertia	• Implement policy that incentivises wind farms to maintain power electronics required to provide inertia to the network	• n/a	2017-2020

Category	Barriers	Potential enablers	Responsibility	Timing
Stakeholder acceptance	• Public perception of wind turbines as 'eyesores' that devalue land • Perceptions that turbines cause 'wind turbine syndrome'	• Communication of financial benefits to landholders • Improved awareness around 'wind turbine syndrome	• Local Government • Windfarm developers	2017-2020
Industry and supply chain skills	• n/a	• n/a	• n/a	2017-2020

*Grey boxes represent key barriers and enablers

11.4 Opportunities for Australian Industry

While there may be scope for development of certain wind turbine components as the local industry continues to grow, most opportunities will be related to the creation of jobs EPC and O&M for new plant, as well as in the export of niche solutions that improve overall deployment, operation and integration with the grid.

Table 49 – Opportunities for Australian Industry Summary

	Component manufacturing	**EPC**	**O&M**
Description	Key components are blades, towers, nacelles, generators as well as BoS which includes wiring and control systems and software	EPC requirements include resource (i.e.wind) studies in proposed locations, land leasing, logistics and construction	Ongoing maintenance of wind turbines Ongoing SCADA and dispatch control
Australia's comparative advantage	Medium - High labour cost - Established suppliers overseas with greater manufacturing capacity + High transport cost for blades and towers supports local manufacture for domestic market	High + Site studies, logistics , assembling of components and wind farm construction must occur locally + Companies with expertise in niche solutions (e.g. wind mapping)	High + O&M of wind farms must occur locally + Companies with expertise in niche solutions (e.g. wind farm optimisation, IoT)
Market size (2030)	Large > Global and domestic wind market	High > Share of global market and potentially local market	High > Domestic market and share of global market
Opportunity for Australian industry	Medium > Local use of components but possible export of software	High > Wind development in domestic market and export of niche solutions to global market	High > Wind development in domestic market and export of niche solutions to global market
Jobs opportunity	Medium	High	High
Main location of opportunity	Urban/regional	Regional/remote	Regional/remote
Difficulty of capture/level of investment	Medium > Requires industry policy to support domestic industry for hardware components	Low	Low

12 Wave energy

Wave energy is currently significantly more expensive than wind and solar PV. While wave energy does offer the benefit of lower variability, a different variability profile and a small amount of inbuilt energy storage to smooth the power output than wind and solar PV, it is unlikely that costs will decrease fast enough to make the technology competitive at scale in Australia. The technology does have applications in other markets, and Australia's leading wave energy technology R&DD represents a good potential export opportunity.

- Of the different forms of ocean energy (tidal, wave, ocean current, ocean thermal energy and salinity gradients), wave is the most likely to have applicability at scale in Australia (CSIRO, 2012)
- The size of the wave energy resource in Australia is significant; for example the total wave energy at 25m depth along the southern coastline of Australia is five times the country's annual energy use (CSIRO, 2012)
- Supplying 10% of Australia's energy use would require up to 750km of coastline (CSIRO, 2012)and it has been shown that there are a sufficient number of suitable sites for wave farms that will not impact on marine protected areas, marine reserves, shipping and other ocean industries, recreation use zones, habitat protection zones, multiple use zones and other zones, native title and population sensitivity (Behrens, Hayward, Woodman, Hemer, & Ayre, 2015)
- The key benefit of wave energy compared with wind and solar PV is that is it less variable and more predictable (CSIRO, 2012)
- Wave energy faces a number of important challenges:
  - High cost – 2015 LCOE is ~$286/MWh; Further cost reductions are currently difficult as operating in an ocean environment creates significant engineering challenges (e.g. stress and fatigue caused by rough seas, difficulty in carrying out O&M, marine growth and corrosion); furthermore, development is slow and expensive, since large systems are required even at the development and pilot stages (Titah-Benbouzid & Benbouzid, 2015). It is worth noting however the industry is moving to smaller scale pilots reduce costs as well as to exploit niche revenue opportunities. It is estimated that 2030 LCOE could drop to $153/MWh, but this is still higher than current costs of wind and solar PV. Also, given the likely high penetration of intermittent renewables in Australia at this time, the cost including integration is likely to be higher, given storage and other technologies are likely to be need to be needed at high VRE share as discussed in the main report.
  - Social and environmental impact: as this is a new technology these types of impacts are still being understood. Social impacts, depending on the type of technology, can include visual amenity, sea calming (which could also provide a benefit) and competition with commercial fishing and recreational uses. Environmental impacts include the creation of artificial reefs which could have a net positive or negative impact on marine life (CSIRO, 2012).
- Modelling shows that limited uptake of wave energy generation is expected in Australia in the period to 2050.
- There is currently one operating wave array project connected to the grid globally, which is situated off the coast of Garden Island, Perth (ARENA, 2016). This project has moved the TRL of

wave energy from 5 to 7. However, there are marine energy test sites located in Europe and North America (see for example the European Marine Energy Centre http://www.emec.org.uk/).

- Australia is a world leader in wave energy technology development, with several technologies at various stages of development (Carnegie's CETO device, BioPower Systems' BioWave and Bombora Wave Power's mWave device).
- There is good potential for export of wave energy technologies; this type of generation is likely to be best suited to remote coastal areas with limited land and poor solar resources, or where it can be co-located or integrated with other revenue streams.

13 Enabling technologies for VRE

This section discusses the enabling technologies required to allow VRE to reach high share of grid electricity generation.

The existing range of VRE generation has different characteristics than the conventional synchronous generation resulting in different performance under normal and fault conditions. The existing electricity rules evolved over the years and are designed to be technology neutral; however the management of system security recognises more the traditional value of inertia and fault level than the value of fast frequency response and immediate power injection.

In the interim period when VRE generation technology is still maturing and the rules are rectified there can be value in installing additional equipment that enhances performance of VRE generators and this equipment is referred to as the enabling technologies. Improvements in VRE generation technology may make some of these enablers redundant.

Further detail on key enabling technologies, namely energy storage and smart grid technologies, is presented in separate technical assessments.

13.1 Why enabling technologies are required

13.1.1 Key electricity grid requirements

Before discussing the enablers, and why they are required in a scenario of high VRE share, the key requirements of an electricity grid are reviewed:

- **Dispatch and Scheduling:** Proper operation of the grid requires there to be sufficient generation capacity operating at any given time to match total demand while satisfying all operational constraints. In the NEM, this is achieved by dispatching generators at 5 minute intervals. Different types of generation have different lead times before they can be brought online. For instance, it takes longer to start up coal fired power stations than peaking gas turbines or hydro plant. Also dispatched is spinning reserve to provide spare generation capacity required to compensate against load changes and contingencies.
- **Frequency control:** An electricity grid runs at a nominal frequency (50 Hz in Australia). Proper operation of the grid and of the loads connected to it depends on the frequency being kept within defined ranges for normal and contingency conditions. It is also important for the rate of change of frequency (RoCoF) to stay within prescribed limits.

  In the NEM, frequency control is provided by frequency control ancillary services (FCAS). This consists of two types (AEMO, Guide to Ancillary Services in the National Electricity Market, 2015):
    - Regulation FCAS: continuous correction of minor deviations in frequency
    - Contingency FCAS: correction of frequency following a major contingency event (e.g. loss of a generating unit or a major industrial load). This is achieved by activating FCAS reserve. In the case of non-credible contingencies, emergency control schemes may restore supply demand balance by reducing demand (e.g., under-frequency load shedding) or generation over-frequency tripping schemes.

Traditional generators are powered by turbines driving large rotating masses at high speeds. These are known as synchronous generators, since the rotation is synchronised to the grid frequency. The masses of synchronous generators have large mechanical inertia, which limits the rate of change of grid frequency, stabilising the system.

- **Reactive power and voltage control:** Reactive power can be thought of as the power that flows back and forward without doing useful work and its function is to keep all system elements magnetised. Voltage is the force that makes electricity move in a wire. Voltage must be maintained within an appropriate range at each point in the grid, but unlike frequency, there is no one consistent voltage across the grid, with voltages in transmission lines reaching thousands of volts, while voltages in domestic settings are only 240 volts. Voltage and reactive power can be managed continuously by devices such as synchronous condensers, static sources (e.g. SVCs and STATCOMS) or by switched sources such as switching capacitors, reactors and transformers with taps. To maintain high quality of supply it is important that voltage is not subject to excessive harmonics, flicker or step changes.
- **System strength:** System strength is an important characteristic of electricity networks, required for controlling voltage when there are system disturbances, and for protecting the system and its users when there are short circuits.
  System strength is determined by fault level – systems with high fault level have high strength. Fault level is a measure of the ability of the system to provide a fault current. Fault current is the current that flows in response to a short circuit (i.e. a fault). Activating the protection systems that isolate faulty elements and protects the system and its users typically requires a fault current several times higher than the normal or rated current in the network. Due to their use of rotating masses, synchronous generators and synchronous condensers are able to provide this current. Fault level tends to be higher at locations in the network closer to synchronous generators and synchronous condensers.
- **Black start:** This involves restarting the system from complete blackout. This can be done using hydro power, gas turbines and other thermal generators (Piekutowski, 2016). HVDC using voltage source converters is also able to provide black start if appropriately specified.

13.1.2 Characteristics of VRE that need addressing at high share

In relation to the functions listed above, VRE generators differ in a number of important ways from the synchronous generators that have historically powered the grid (AEMO, 2013):

- **Variability:** The output from VRE is variable, i.e. energy supplied depends on the available wind and sun. This represents the key challenge related to reaching high VRE share. Solar PV has greater variability than wind, given that it is only available during the day, with output affected by cloud cover, and less geographic averaging than wind. At high VRE share, variability can lead to supply/demand imbalances. Variability presents additional challenges if there is fast ramping up or down of output, as the system needs to respond more quickly.
- **No or low inertia:** Solar PV and wind lack the inertia of traditional sources (although modern wind turbines can provide some inertial response), and so as VRE share increases and synchronous generators are displaced from the schedule by VRE generators, other means of frequency stabilisation may be required. Reduced system inertia mean the grid frequency can change more quickly in the event of a disturbance such as the loss of a large generator or load (AEMO, Future Power System Security Program - Progress Report, 2016).
- **Low fault current (also referred to as low system strength):** While traditional generators are able to provide the high fault current (typically 6 to 8 times rated current) required to trip system protection, the same is not necessarily true for wind and solar PV. These may be limited by their inverters in how

much current they can export into the network. Typically, inverters can provide up to 1 to 1.3 times their normal current as fault current (Piekutowski, 2016).

- **Fault ride through:** Fault ride through refers to the ability of generators to keep providing power to the system when there is a disturbance such as a sudden change in frequency or voltage. When there is a disturbance in a network, VRE generators may need to disconnect from the networks to protect themselves from damage. Alternatively, they may only be able to provide reactive power and limited active power for several seconds, due to the limited short term overload capability of their inverters. Historically, VREs have been subject to different requirements in the characteristics of faults they need to be able to ride through. At low VRE share, disconnection of VRE and a reduction in active power is an acceptable measure in response to faults. As VRE reaches higher penetration, this loss of energy supplied can further destabilise the system and increase the impact of the largest contingency.

Distributed sources of generation, namely rooftop solar PV, have a number of further characteristics that can create issues at high penetration:

- **Reverse power flows:** Rooftop solar PV can export power back into the distribution network, resulting in power flows that are reversed compared to the flow of power from centralised generators.
- **Lack of observability and controllability:** Unlike centralised generators, rooftop solar PV and other DERs are not currently visible to, or controlled by centralised entities such as AEMO and network operators.

If appropriate mitigation actions are not undertaken, these characteristics of distributed generation may cause unpredictable changes to system dynamics and lead to overloading certain components of the network, reducing their lifetimes (Volk, 2013).

As part of its current work in reviewing system security in light of increasing share of VRE, AEMO has identified the follow priority areas for focus (AEMO, Future Power System Security Program - Progress Report, 2016):

- Frequency control
- Management of extreme power system conditions
- Visibility of the power system (information, data, and models)
- System strength.

13.2 Enabling technologies

From the section above, it is evident that enabling technologies are required in order to ensure that the network continues to operate reliably with high VRE share. These technologies are described below.

13.2.1 Storage

One of the key roles of storage is to manage the variability of renewables, allowing supply to match demand, regardless of available supply from renewables at a given moment. Storage also has the potential to be used together with inverters and smart grid technologies to provide fault current as well as frequency and voltage control. The key storage technologies likely to be important in Australia are batteries and pumped hydro. These technologies have fast ramp rates, and as such are well suited to supporting VRE. Pumped hydro storage can be used for black starts and trials are underway for using batteries for this purpose (Compton, 2016). Batteries can either be grid-scale (deployed by utilities) or behind the meter (deployed by households and other energy users). Given the importance of storage as the key enabler of VRE, these technologies are described in detail in the batteries and other storage technical assessments.

13.2.2 Smart grid technologies

Smart grid technologies represent a large category of related technologies used to control and optimise an electricity grid and the DERs and VRE contained within it. The key technologies are smart appliances, smart inverters, control platforms, market platforms, smart meters, telemetry and sensors, advanced protection systems, system data, characterisation and models, demand forecasting, generation forecasting and secure communications protocols and architectures.

These technologies can:

- Help address the variability of renewables and manage frequency by providing energy from batteries or reducing the load of large numbers of appliances (demand response); fast response times are required for management of frequency
- Inject fault current and protect systems with low fault levels
- Manage voltage in distribution networks
- Provide visibility and controllability of rooftop solar PV and behind the meter batteries.

Smart grid technologies are discussed in detail in the smart grid technologies technical assessment.

13.2.3 Conventional power equipment

There are a number of types of power equipment that are currently deployed in electricity networks to support conventional synchronous generation that may need to be scaled up or adapted to a system with high VRE share. These include:

- Reactive power control technologies, e.g. STATCOMs, synchronous condensers, static VAR compensators (SVCs). These technologies regulate voltage by removing or adding reactive power to the system. They also add inertia to the system (in the case of synchronous condensers) and can provide fault current. Conventional generators can be specified to be able to run in synchronous condenser mode; this may require decoupling or de-watering the turbines (Piekutowski, 2016).
- Transmission and distribution: Additional T&D, including HVDC, can be built or existing lines upgraded to cope with increased renewables share by providing greater interconnection or allowing higher voltages within the distribution network. This is typically an expensive option and technologies that are less capital intensive may be preferred.

13.2.4 Dispatchable generation (non-renewable and renewable)

This includes for example peaking gas and CST with storage. These technologies can be dispatched to help balance supply and demand. They also add inertia to the system and provide fault current, although only when operating. These technologies are described further in the respective appendices.

13.2.5 Other ways of addressing variability

In addition to the enabling technologies listed above, there are several other means of addressing variability:

- Geographical diversity: Different weather conditions exist at any given time across a geographically large network like the NEM, which helps average out the variability of VRE.
- Technology diversity: A mix of wind and solar and potentially other VRE such as wave helps average out the variability.
- Overbuilding wind and solar PV: Enough generation could be built such that there is enough capacity to meet demand during periods of low sun or wind. Excess power curtailed at times of high generation may then be used to power "opportunistic loads" such as load-following electrolysers which produce hydrogen.
- Demand response: Demand response provides and additional way to introduce flexibility into the system to manage VRE variability. Rather than changing generation to match supply and demand, demand response involves reducing or time-shifting demand. Demand response relies on smart grid technologies, as well as markets and commercial and regulatory structures that enable businesses to offer demand response as a service and for energy users to participate and benefit economically.

13.2.6 Other ways of addressing low inertia

Other means of addressing the low inertia are

- Via modern windfarms, which are able to provide synthetic inertia, using the kinetic energy stored in their rotating turbines, and quickly providing it to the grid if there is a sudden dip in frequency. Some markets, such as Quebec (a standalone grid with peak demand of less than 40 GW) require new wind farms to be able to provide synthetic inertia. Inertia-compliant turbines now make up two thirds of Quebec's wind capacity, and provide a similar initial response to contingency events as a similar capacity of synchronous generation (although taking longer to return the grid to its normal frequency). Wind farm developers are further improving the ability of wind turbines to provide synthetic inertia (Fairly, 2016).
- An alternative to providing additional inertia or fast frequency response is to make the grid more tolerant of larger and faster rates of change of frequency (RoCoF) (DGA Consulting, 2016). Additional, and faster, spinning reserve could also be used. Batteries, PHES and EVs could be put on under-frequency load shedding alert (AEMO, 2013).

Table 50 summarises the enabling technologies and shows which issues they address.

Table 50 – Enabling technologies for VRE

Enabling technologies:	**Storage**	**Smart grid technologies**	**Conventional power equipment**	**Dispatchable generation**	
Example technologies:	Batteries Pumped hydro	Advanced inverters; smart meters; telemetry & sensors; demand	Synchronous condensers; transmission & distribution; protection systems	Peaking gas and CCGT; CST with storage; fuel cells	**Other enablers:**

			and generation forecasting			
Character-istics of VRE / issues caused by VRE:	Variability	✓	✓	✓	✓	Geographical & technology diversity; overbuilding; demand response
	Low inertia / frequency control	✓	✓	✓	✓	Synthetic inertia from wind farms; making system more tolerant of larger and fasters frequency deviations
	Low fault current	✓	✓	✓	✓	
	Reverse power flows / voltage control	✓	✓	✓	×	
	Lack of observability / controllability	×	✓	×	×	

In a system with sufficient fault level, fault ride through does not require technological enablers as such; rather it depends on regulators setting appropriate requirements guiding wind and solar farm developers to design systems accordingly.

13.3 Required deployment and cost of enabling technologies

13.3.1 Storage

CSIRO modelling suggests that VRE share can reach around 40-50% before significant storage (or other sources of system flexibility such as demand management) is required to mitigate variability of renewables on timescales greater than 5 minutes (see Appendix B in the main report). At high VRE share, a total of around 45 GW and 2,000 GWh is found to be sufficient to balance supply and demand based on typical demand and weather profiles for a modelled year. Note that battery storage (and other fast response storage such as super capacitors) have other applications such as frequency regulation in low inertia systems. Required deployment for these purposes has not been modelled for this report, and would require further detailed investigation.

Assuming battery storage, with costs as described in the batteries appendix, the cumulative total cost of this storage in Pathway 2 by 2050 is around $32 billion, which is 3.7% of total cumulative system expenditure (comprising transmission and distribution, storage, generation, O&M and fuel) up to this time. Battery costs were used to estimate the cost of providing storage since cost and performance data are available, and scaling to the required level of deployment is known to be technically feasible. However off-river PHES is likely to provide a less expensive option, if it is able to reach scale.

13.3.2 Smart grid technologies

For required deployment and expected costs of smart grid technologies, refer to the smart grid technologies technical assessment.

13.3.3 Conventional power equipment

Reactive power control technologies

Synchronous condensers can be added to a grid to provide inertia and increase fault level. The quantity required depends on other equipment present (e.g. advanced inverters) and on whether there are markets for provision of frequency stabilisation ancillary services at sufficiently low timescales. Alternatively, generators such as hydro plant or open cycle gas turbines can potentially be modified at low cost to operate in synchronous condenser mode (TasNetworks, 2016).

Calculating the quantity and cost of synchronous condensers required to replace synchronous generation would require detailed system modelling. However, a rough estimate can be made for the purposes of comparing overall system cost of a 95-100% VRE grid with one largely powered by dispatchable low emissions generation.

The mainland NEM (i.e. excluding Tasmania which is connected by HVDC and hence doesn’t share inertia with the other states) currently operates with inertia ranging from 80,000-140,000 MW.s (AEMO, 2016). Assuming all generation is replaced with VRE and that synchronous condensers are used to provide the full maximum level of inertia of the current grid, with a cost of $50 million for a 1,000 MWs synchronous condenser[16], the total cost for synchronous condensers would be $7 billion. This provides a highly conservative estimate of the cost of synchronous condensers required, since the NEM routinely operates with less inertia than 140,000 MWs.

A slightly more detailed calculation can be made factoring in likely contingency sizes with VRE including potential fault ride through behaviour. Assuming that RoCoF should be kept below 3 Hz/s, an estimated 140,000 MW.s of inertia would be required in a 100% VRE NEM with contingencies up to 500 MW and additionally with 20-70% of VRE (depending on state) temporarily disconnecting during a fault. This is the same level of inertia and hence cost as in the simpler estimate.

These estimates are conservative since they assume no contribution to frequency stabilisation from the batteries that would presumably be present in the system at this share of VRE, and neglect the possibility of existing synchronous generators being converted to synchronous condensers on retirement. While $7 billion is not a small amount, it is less than 1% of the total cumulative expenditure that is required in the timeframe concerned in Pathway 2 ($854 billion), and is also small compared to the estimated additional cost of Pathway 3 compared to Pathway 2 ($185 billion).

[16] Cost estimate from 2016 NTNDP (AEMO, 2016)

The synchronous condensers added to provide inertia could also provide fault level, and for this would need to be located around the grid according to where they were needed to increase the system strength. The NTNDP estimates $5-10 million of synchronous condensers is needed to support 150 MW of wind from a system strength point of view (AEMO, 2016). Assuming the same deployment of synchronous condensers is required to support solar PV, for a 100% VRE scenario with peak demand of 30 GW comprised of wind and solar with an average capacity factor of 30% (requiring 100 GW of VRE capacity), approximately $3-7 billion of synchronous condenser spend would be required. This suggests that synchronous condensers deployed to provide system inertia would also be sufficient to provide fault level if appropriately located around the network.

Transmission and distribution

See the overall modelling approach and electricity modelling methodology and assumption appendix in the main report for a discussion of the network spend required in a scenario with high VRE share.

13.3.4 Dispatchable generation

Deployment and cost of dispatchable generation is discussed within each pathway and in the respective technology assessments.

14 Energy storage – batteries

While batteries are an important enabler of VRE, they also provide a number of other electricity network support services. The rate of adoption for behind-the-meter batteries is increasing and utility-scale batteries are likely to follow a similar trajectory once the share of VRE exceeds ˜40%. For utility-scale batteries in particular, implementation of new regulations that enable battery proponents to derive proper value for the energy stored is critical. There is also significant opportunities for Australia to participate in global battery supply chains, most notably in the provision of raw materials (e.g. lithium)

- Batteries are a readily available technology that provide a series of grid support services and are a critical enabler of VRE. They are modular and are therefore applicable to both BTM and utility scale operations. BTM batteries are likely to be widely deployed in conjunction with rooftop solar PV.
- There are several key battery technologies that are currently available in the market, each with varying characteristics: lithium ion, advanced lead-acid and flow batteries. Depending on the application, certain battery types may be more favourable than others.
- While significant roll-out of energy storage is not necessary (in terms of network energy security) until renewable generation exceeds ˜40% of total energy, other economic factors (e.g. managing electricity cost, increasing capacity factors) could lead to further adoption in the near term.
- High capital costs are currently preventing mass uptake. However, costs are expected to drop by ~30-40% by 2020 and further to 2030.
- Regulatory changes that ensure asset owners can capture the full value of energy stored is also critical to deployment, particularly for utility-scale batteries.
- Although Australia is likely to continue to import battery cells, there are significant opportunities to participate in the battery supply chain, most notably through mining and processing of raw materials. Manufacturing of battery systems, installation, operations and recycling present as other possible opportunities but could rely heavily on local industry growth.

14.1 Technology overview

Technology description

A battery is a form of electrochemical storage, wherein chemical changes allow energy to be released on demand. A battery comprises multiple electrochemical cells connected in series and/or in parallel. A cell consists of two electrodes—a cathode and anode. Both are immersed in an electrolyte that allows the movement of electrons or ions, thereby creating electrical current (Cavanagh, et al., 2015). Batteries may also contain a battery management system (BMS) which monitors and controls the system's primary functions.

Batteries are modular and therefore applicable to both BTM and utility scale operations. BTM batteries are likely to continue to be widely deployed in order to support the deployment of rooftop solar PV.

The choice of materials for each of the cathode, anode and electrolyte affects the properties of a battery. Such properties include (but are not limited to) battery life, energy efficiency, discharge and recharge times, optimum operating temperature and cost. Different compositions therefore make batteries more suitable for certain applications than others.

A battery system also includes the inverter which is responsible for converting DC power from batteries into AC. This is discussed further in Section 13.2.

Technology Impact

As shown in Table 51 and further described in Section 14.3 below, battery technology is largely proven. Further development across the industry is therefore largely focused on achieving incremental improvements that improve operating performance and reduce cost.

While significant roll-out of energy storage is not necessary (in terms of network energy security) until renewable generation exceeds ~40% of total energy, other economic factors (e.g. managing electricity cost, increasing capacity factors) could lead to further adoption in the near term.

There are a number of ways in which batteries can facilitate the integration of VRE into the grid. They include (Cavanagh, et al., 2015):

- Managing medium term variability (MV) (i.e. bulk energy storage/shifting) – For example, this allows solar generation output to be shifted to the evening in order to better align with energy demand. The battery system will discharge and recharge typically over a number of hours and so does not need high power levels or fast response.
- Managing short term variability (SV) – Solar and wind resources can experience significant changes in output over short periods of time (e.g. cloud cover can reduce the output of a solar PV system to zero in seconds). Batteries with fast response times can smooth renewable generation output.
- Power quality (PQ) – Fast response batteries can also help manage power quality issues such as fluctuations in voltage and frequency as well as harmonics and phase imbalance.

Other applications for batteries to assist the grid more broadly include network augmentation deferral (i.e. allowing for network upgrade deferral and assisting with meeting peak demands on the grid that may only last for a few hours per year).

Three key battery technologies have been identified as having significant market potential in relation to the applications described above. These are summarised in Table 51 below.

Table 51 – Summary of battery technologies and applications

BATTERY	DESCRIPTION	APPLICATIONS			ADVANTAGES	DISADVANTAGES
		MV	**SV**	**PQ**		
Lithium-ion	Operates through the transfer of lithium cations from a lithium-ion based cathode to a graphite anode	✓	✓	✓	• High energy storage, power delivery, cycle count and cell voltage • Widely available in multiple applications • Public familiarity	• Safety risk • Poor recycling • Use of heavy metals • Poor operation in extreme temperature weather events
Advanced lead-acid	Same chemistry as lead-acid but with carbon based		✓	✓	• Rapid response and longer cycle life • Lower cost	• Contains heavy metals (although good recycling

BATTERY	DESCRIPTION	APPLICATIONS			ADVANTAGES	DISADVANTAGES
		MV	**SV**	**PQ**		
	anode. Exhibits properties of a supercapacitor.					capabilities for lead exist) • Low energy density • Shorter life-cycle at higher temperatures
Flow batteries	Electrolyte solution in tanks are pumped through electrochemical cells to produce electricity. For example, for a zinc bromine flow battery, zinc is plated onto a negative plastic electrode and bromide is converted to bromine. The reverse occurs during discharge.	✓	✓		• Batteries can be fully discharged and have long cycle life. • Fast response times if flow rates are high (requires more O&M) • Easily scalable • Parts can be replaced individually • Tolerance to over-charge/discharge	• Complicated with multiple components, requiring regular maintenance • Limited electrolyte stability • Relatively high parasitic load

14.2 Technology status

Cost - current state and projections

The battery itself represents the largest cost component of the battery system (Hinkley, et al., 2015). With increased technology penetration and industry maturity, the average LCOEs of each of the batteries identified in Section 14.1 is forecast to decline significantly. This is represented below for both utility-scale and BTM batteries.

Table 52 – Utility-scale battery LCOE forecast ($AUD/MWh)

BATTERY	2015	2020	2030
Lithium ion	230-280	160-200	120-140
Advanced lead-acid battery	960-1180	720-880	480-590
Flow battery	590-720	390-480	180-210

Table 53 – BTM battery LCOE forecast ($AUD/MWh)

BATTERY	2015	2020	2030
Lithium Ion	340-410	280-340	230-280
Advanced lead-acid battery	1160-1410	940-1150	710-870
Flow battery	660-810	480-590	280-350

Technological and commercial readiness - current state

The technological and commercial readiness associated with each of the battery technologies is discussed in Table 54 below.

Table 54 – Technological and commercial readiness 2016

BATTERY	TRL	CRI UTILITY-SCALE	CRI BTM	COMMENTS
Lithium Ion	9	2	6	• Some key technological challenges still need to be resolved. Tesla and Panasonic starting to develop lithium batteries for the grid energy storage market. • Residential scale batteries have been deployed.
Advanced lead-acid battery	9	3	2	• Currently being used in electricity grid integration and given similarities in structure, can be manufactured in existing lead-acid battery factories. • Currently being tested in the residential market.
Zinc bromine flow battery	9	2	2	• A number of companies are currently developing zinc bromide flow batteries • Currently being tested in the residential market.

14.3 Barriers to development and potential enablers

As shown in Table 54, the listed batteries are technologically mature. Thus widespread adoption is more reliant on establishing the right commercial environment. While there is some overlap, a unique set of barriers and potential enablers apply to utility-scale and BTM batteries. These are reflected in

Table 55 and

Table 56 below.

Key barriers for utility-scale batteries relate to the high cost of the technology and a regulatory environment that prevents asset owners from capturing the full value of the energy stored. Cost reductions can be achieved by creating a competitive market, incentivising higher utilisation of raw materials and improving regulations governing installation and operation. Regulatory reform is also required to ensure that battery owners can participate in the electricity market and when doing so, are compensated for the supply of renewable energy.

Table 55 – Utility-scale battery barriers and potential enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• High cost of key raw materials	• Expand mining development; Implement appropriate recycling regulations to enhance resource efficiency	• Mining companies; Government	Ongoing
	• High cost of cell manufacturing	• Expected to decrease as global manufacturing capacity increases	• n/a	Ongoing
	• High margins on battery packs	• Support a competitive market in Australia	• Government, AER	Ongoing
	• Higher installation and operational costs due to regulatory hurdles	• Improve regulations governing installation and operation	• Government, AER	2017-2020
Revenue/market opportunity	• Lack of clarity in relation to optimal usage patterns and battery ownership (i.e. retailer, NSP or third party)	• Conduct further studies/modelling to determine best usage cases and ownership structures	• Industry bodies	Ongoing
	• Battery owners pay a premium (e.g. through LRET) for renewable energy to charge the battery. Lack of clarity as to whether they can recoup that payment when selling stored energy to the network	• Implement/amend policy to ensure that battery owners are properly compensated for supplying renewable energy	• AER, AEMC	2017-2020
Regulatory environment	• Current regulations limit asset owners' capacity to participate in the market	• Implement regulatory reform to ensure owners of utility-scale batteries can capture full value for system services provided	• Government, AEMC, AEMO	2017-2020
Technical performance	• Uncertainty on battery performance under real world operating conditions (e.g. depth of discharge, charging rate)	• Further testing and demonstration of batteries under real world operating conditions	• Research institutions, ARENA	2017-2020
Stakeholder acceptance	• Bias towards adding network capacity over deploying distributed energy resource solutions (i.e. batteries)	• Create a level playing field for investment in distributed energy resource solutions	• AER, AEMC, AEMO	2017-2020
Industry and supply chain skills	• Limited knowledge regarding installation and operation of utility scale batteries	• Encourage information sharing between generators, TNSPs and DNSPs	• ENA	2017-2020

The high cost of technology and failure to generate revenue is also preventing mass uptake of BTM batteries. While potential enablers for reducing costs are consistent with utility-scale batteries, implementing frameworks that support innovative battery ownership as well as improving access to battery performance data are key to ensuring that BTM battery owners can capture greater value.

Table 56 – BTM batter barriers and potential enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• Cost of technology	• As per utility-scale batteries	• As per utility-scale batteries	2017-2020
	• High cost of installation due to novel nature of technology	• Implement training for installers; increase installations with PV to take advantage of learning-by-doing	• Industry bodies	2017-2020
Revenue/market opportunity	• No revenue for owners from batteries, only taking advantage of TOU tariffs for charge/discharge cycles	• Implement policy/market frameworks that support innovative battery ownership and operational models (e.g. participation by 'aggregators')	• Government, AEMC, AEMO, industry	2017-2020
	• Lack of clarity on which battery use methods provide best economic opportunities	• Improve access to load-profile and battery performance data	• Broader industry	Ongoing
Regulatory environment	• No standards in place for residential battery installations	• Develop appropriate standards that allow industry growth and innovation without compromising safety etc	• Research institutions, Standards Australia (note this work is being undertaken)	2017-2020
Technical performance	• Limited capability of battery management systems	• Conduct research into algorithms for "smart" and optimal battery management systems	• Research Institutions, ARENA	2017-2020
	• Uncertainty on battery performance and safety under real world operating conditions	• As per utility-scale batteries •	• As per utility-scale batteries	2017-2020
Stakeholder acceptance	• Perception that batteries will improve and drop in cost is preventing immediate uptake	• Promote leasing models for batteries	• Electricity retailers, local industry	2017-2020
Industry and supply chain skills	• Limited knowledge regarding installation and operation	• Training for installers, increase installations as with PV to take advantage of learning-by-doing	• Industry bodies	Ongoing

14.4 Opportunities for Australian Industry

The most obvious opportunity for Australia to participate in the global battery supply chain is through mining and potentially processing of raw materials for different batteries. While likely to require significant investment, with currently held IP and available resources, there may be some scope to build a local battery design and manufacturing industry.

The establishment of a battery recycling industry should also be considered given the need for better utilisation of materials and the underlying opportunity to service both local and global markets.

A detailed assessment of the supply chain opportunities for batteries is set out in

Table 57 below.

Table 57 – Opportunities for Australian industry

	Natural resource extraction	Natural resource processing	Cell design and manufacture	Battery pack design and manufacture	Distribution, installation and operation	Recycling of base materials
Description	Mining of raw materials including lithium, magnesium, cobalt, nickel, lead, zinc and graphite	Processing of raw materials into form needed for electrodes/electrolytes	Assembly of electrodes and electrolytes into cells	Assembly of cells & battery management system into a battery pack	Marketing, distribution and installation, potentially with ongoing operations and maintenance	Used batteries are broken down into their base materials for reuse
Australia's comparative advantage	High + Large deposits of relevant materials + Large mining entities with strong presence in Australia + Significant mining RD&D	Medium + Pre-existing raw materials processing industry and capabilities + RD&D strength and IP (e.g. Sileach process – Lithium Australia) - Established global industry	Low + Strong IP in certain cell technologies + Ample space for large manufacturing facilities (e.g. Gigafactory) + Skilled workforce - High labour cost - Lack of local industry; global industry dominated by large corporations (e.g. Panasonic)	Medium +Strong IP e.g. BMS, Ultrabattery + Reputation for quality + Well-educated workforce + Local need for bespoke battery solutions - Small existing local industry; many global competitors exist	High + Must be undertaken locally + Strong IP in system integration + High penetration of rooftop solar	Medium + Good recycling practice in lead acid + Established recycling industry - High cost of labour in Australia compared to e.g., Asia - High transport cost to Australia - High cost environmental permitting
Market size (2030)	High Global battery market	High Global battery market	High Global battery market	High Global battery market	High Domestic battery market	High Global battery market
Opportunity for Australian industry	High	Medium	Low Large global market but dominated by industry giants	Medium Opportunity exists to develop batteries for domestic and global markets, using local market as test bed	High	Medium Large global market but likely with strong competition

	Natural resource extraction	Natural resource processing	Cell design and manufacture	Battery pack design and manufacture	Distribution, installation and operation	Recycling of base materials
Jobs opportunity	Medium	Medium	Low	Medium	High	Medium
Main location of opportunity	Regional/remote	Regional/remote	Urban/regional	Urban/regional	Urban/regional/remote	Urban/regional
Difficulty of capture/level of investment	Low	Medium Requires targeted support for minerals processing industry	High	High Currently small local industry	Low	Medium

15 Other energy storage

Currently, there are a number of utility-scale energy storage alternatives to batteries. Of these, 'off-river' pumped hydro is the most promising for Australia. While it faces the same regulatory barriers as batteries in relation to integration into the network, this is a proven off-the-shelf technology that may prove to be the most cost effective form of energy storage.

- Pumped hydro energy storage, compressed air energy storage and flywheels are three mature technological alternatives to batteries for utility-scale energy storage.
- Of those technologies, 'off-river' pumped hydro is most likely to be adopted in Australia.
- 'Off-river' pumped hydro is a mature off-the-shelf technology. As opposed to 'on-river' pumped hydro, it does not carry the same cost (e.g. flooding control systems), restriction on suitable sites or public opposition.
- The deployment of technological alternatives to utility-scale batteries will depend somewhat on comparative costs as well as flexibility and availability of resources. Initial estimates indicate PHES will be significantly cheaper than batteries.
- Further studies and demonstration projects are needed to confirm costs and potential energy storage capacity across Australia.
- While PHES won't be needed at scale until a high share of renewables is achieved, in time, it could provide new opportunities for Australian industry given that EPC and O&M must occur locally.

15.1 Technology overview

Technology description

Three potential energy storage technologies are considered here as alternatives to utility-scale batteries. These are:

1. Pumped Hydro (PHES)
2. Compressed air energy storage (CAES)
3. Flywheels

PHES

PHES systems operate using two water reservoirs at different elevations. When available, VRE may be used to pump water from the lower to the higher reservoir. Upon discharge, the energy is recovered by allowing the water to push turbines (with an attached generator) as it flows back to the lower reservoir. Energy storage and power capacity is proportionate to the head (height difference between the reservoirs).

Approximately 80% of the electricity used to pump the water is recovered through the turbine (Blakers, 2015). Typical discharge times can span from hours to days. PHES represents nearly 99% of installed energy storage capacity globally (Cavanagh, et al., 2015).

PHES may be 'on-river' or 'off-river'. The former are conventional hydroelectric systems located in naturally occurring water systems (e.g. valleys and lakes) (Blakers, 2015). The latter does not require existing rivers.

Rather, it involves the construction of two reservoirs at different heights (i.e. at the top and bottom of a hill).

CAES

CAES uses air as an energy storage medium. Electricity may be used to compress and heat the air which is stored in either above (CAES – a) or underground vessels (CAES – u). When needed, the compressed air is mixed with natural gas, expanded and combusted (Cavanagh, et al., 2015).

Flywheels

Flywheels are large rotating cylinders. The amount of energy stored is proportional to the rotational speed. More energy may be stored in the flywheel by increasing the rotational speed using electricity supplied by a transmission device (i.e. gearbox). If a load (i.e. a device that draws energy) is applied through the transmission device, the flywheel speed is decreased and energy is released accordingly. The capacity of the flywheel depends on its size and maximum speed. 'To increase efficiency, flywheel systems are operated in a vacuum environment to reduce drag' (Cavanagh, et al., 2015).

The applications, relative advantages and disadvantages of each of the energy storage technologies are represented in Table 58 below.

Note the key advantages of off-river over on-river PHES relate primarily to the number of available sites, proximity to transmission networks and reduced public resistance. Off-river PHES is also cheaper given that there is no need for expensive flood control measures.

Table 58 – Other energy storage technologies

ENERGY STORAGE	APPLICATIONS			ADVANTAGES	DISADVANTAGES
	MEDIUM TERM INTERMITTENCY	**SHORT TERM INTERMITTENCY**	**POWER QUALITY**		
On-river PHES	✓	✓	✓	• Mature technology • Long life • High energy storage capacity (>6 hours) • High ramp rate • High cycle stability • Can be set up to provide either synchronous or asynchronous generation	• Long time to build • Large footprint • Water usage • Requires specific geological topographic structures • Expensive flood control measures • Social licence/Community conflict
Off-river PHES	✓	✓	✓	• As per 'On-river' pumped-hydro but additional advantages include: • Reduced public resistance • Large number of potential sites • Can be located near transmission networks	• Water usage • Requires specific geological topographic structures

ENERGY STORAGE	APPLICATIONS			ADVANTAGES	DISADVANTAGES
	MEDIUM TERM INTERMITTENCY	**SHORT TERM INTERMITTENCY**	**POWER QUALITY**		
CAES	✓	✓	✓	• High energy storage capacity • No hazardous waste • Potential to utilise waste heat	• High cost • Low efficiency • Large footprint/underground energy storage • Safety risks with high pressure gas
Flywheels			✓	• Excellent cycle stability • Long life • Low maintenance requirements • High power density • Uses environmentally inert material	• High self-discharge due to air resistance • Poor energy density • Large standby losses • High cost • Complicated device

Technology impact

As shown in Section 15.2, while these energy storage technologies are mature, development in Australia may depend on the rate of adoption of batteries (i.e. if batteries become cost competitive and widely deployed, there is unlikely to be a need for investment in alternative forms of energy storage)

That said, PHES has already seen some level of activity in Australia. There are currently three projects in operation (Tumut 3, Wivenhoe and Shoalhaven) with a fourth, Kidston, currently undergoing construction. Further, ARENA have recently funded a study to determine the potential number of sites that could be suitable for deployment of off-river PHES in Australia.

Flywheels have been deployed in Australia to provide power quality solutions in niche applications. However, with increasing emphasis on battery storage, new developments have currently stalled (Cavanagh, et al., 2015).

There have been no demonstration projects of CAES to date in Australia (Cavanagh, et al., 2015).

15.2 Technology status

Cost - current state and projections

LCOEs for each of the energy storage technologies is set out in

Table 59 below.

Table 59 – Other energy storage technologies LCOEs ($/MWh)

ENERGY STORAGE	2016	2020	2030
PHES	95-280	95-280	95-280
CAES-a	250-310	250-310	250-310
CAES-u	920-1120	920-1120	920-1120
Flywheels	280-350	280-350	280-350

The TRL and CRI associated with each of the energy storage technologies discussed in Section 15.1 is outlined below.

Table 60 – Technological and commercial readiness 2016

ENERGY STORAGE	TRL	CRI	COMMENTS
PHES	9	6	This is a mature technology and the most widely deployed form of energy storage globally. There are 3 pumped hydro facilities in Australia with a total capacity of 1.34 GW **Invalid source specified.**
CAES	9	2	CAES has had limited deployment in Europe and the USA. It is a mature technology but it requires the presence of a salt cavern for the lower-cost underground storage. Above ground storage is expensive and is less mature (James & Hayward, 2012).
Flywheels	9	6	Flywheels are a mature technology that have been used for providing power quality both locally and overseas.

15.3 Barriers to development and potential enablers

On-river PHES, CAES and flywheels are expected to have minimal (if any) impact on energy storage solutions. This section therefore only considers the potential for deployment of off-river PHES.

As discussed in relation to utility-scale batteries, regulatory reform is required to ensure that PHES asset owners can participate in the market and are fully compensated for supplying renewable energy. Removing negative public perception associated with on-river PHES is also important in allowing for further industry development.

Table 61 – PHES barriers and potential enablers

Category	Barriers	Potential enablers	Responsibility	Timing
Costs	• Potential high costs associated with network infrastructure due to distance to PHES sites	• Conduct site analysis (i.e. consider proximity to network) and modelling of connection costs	• Government/ universities/research bodies	2017-2020
Revenue/market opportunity	• Asset owners pay a premium for renewable energy used to pump water. Lack of clarity as to whether they can recoup that payment when selling stored energy to the network	• Implement/amend policy to ensure that asset owners are properly compensated for supplying renewable energy	• AER, AEMC	2017-2020
Regulatory environment	• By limiting asset owners' capacity to participate in the market, current	• Implement regulatory reform to ensure owners of	• Government, AEMC, AEMO	2017-2020

Category	Barriers	Potential enablers	Responsibility	Timing
	regulations do not incentivise adoption of PHES	PHES can capture value for services provided		
Technical performance	• Evaporation of water	• Support R&D looking at minimising evaporation of water	• Government/ universities/research bodies	2017-2020
Stakeholder acceptance	• Negative public perception of 'on-river' pumped hydro	• Improve awareness of 'off-river' pumped hydro and relative benefits	• Government •	Ongoing
	• Uncertainty around number of suitable sites for pumped hydro	• Continue assessments regarding suitable PHES sites and cost	• Government/ universities/research bodies	Ongoing
	• Perception that batteries are the best form of energy storage	• Improve awareness of PHES and relative benefits	• Government	Ongoing
	• High water usage	• Use of sea-water and components designed to withstand corrosion	• Project developers •	Ongoing
Industry and supply chain skills	• n/a	• n/a	• n/a	n/a

15.4 Opportunities for Australian Industry

The opportunities for Australian industry along the PHES supply chain are represented in Table 62 below. PHES is an off-the-shelf technology and requires a low level of O&M. However there may still be scope to create new industry opportunities, particularly in relation to EPC.

Table 62 – PHES opportunities for Australian industry

	Component manufacturing	**EPC**	**O&M**
Description	Key components include: pumps, pipes, breakers, transformers, transmission	EPC requirements include site studies, land leasing, logistics and construction	Ongoing operations and maintenance of pumped hydro systems
Australia's comparative advantage	Low - Off-the-shelf technology - High cost of manufacturing relative to global industry - Established markets overseas with greater manufacturing capacity	High + Site studies, logistics , assembling of components and pumped hydro construction must occur locally	High + O&M of pumped hydro must occur locally
Market size (2030)	High > Global and domestic wind market	Medium	Low > Minimal O&M requirement
Opportunity for Australian industry	Low > Australia generally imports this type of technology	Medium	Medium

Jobs opportunity	Low	Medium	Low > Minimal O&M requirement
Main location of opportunity	Urban/regional	Regional/remote	Regional/remote
Difficulty of capture/level of investment	Medium	Low	Low

16 Smart grid technologies

16.1 Technology summary

Smart grid technologies will be key to achieving high VRE share and maximising value capture as DERs such as rooftop solar PV, behind the meter batteries and EVs reach high penetrations. Rolling out these smart grid technologies will rely on market and regulatory reform.

- Along with storage, conventional power equipment and dispatchable generation, smart grid technologies are one of the key sets of enabling technology for achieving high VRE share.
- High penetrations of DERs are likely to occur regardless of specific changes to regulations and market design, driven by consumer choices. As DERs reach high penetration, smart grid technologies will be key to minimising system cost and maximising the value provided by DERs.
- Smart grid technologies enable DERs to operate together in a way that is most beneficial for individual players and for the overall system, in particular by increasing system flexibility.
- The key smart grid technologies are smart appliances, advanced inverters, control platforms, market platforms, smart meters, telemetry and sensors, advanced protection systems, system data and models, demand forecasting, generation forecasting and secure communications protocols and architectures.
- While many of the individual technologies are reasonably advanced, there is still a need to bring them together into systems and deploy them in the market.
- The main barriers to developing and deploying smart grid technologies relate to the existing market structures and regulations, which have been developed in the context of large centralised generators and one-way flow of energy to users. Substantial market and regulatory reform will be required to unlock the potential offered by smart grid technologies.
- In addition to minimising system costs, there are significant commercial opportunities presented by these technologies, such as the creation of new value added services for consumers and the development of software for local and global markets.

Smart grid technologies can be applied in the context of microgrids, which are discussed in the RAPS, microgrids and SAPS technical assessment.

16.2 Technology overview

Technology description

This section describes the set of inter-related technologies that will need to be developed and deployed as the grid transitions from a model involving few, large generators with one way energy flow, to one involving millions of distributed energy resources (DERs) drawing from and feeding back into the grid.

The key capability this set of technologies needs to provide is to manage the DERs such that they operate in a way that optimises the benefits to the system and the individual players e.g. owners of DERs, energy consumers, networks and generators. In this report, this set of technologies is referred to as "smart grid technologies". An alternate term that is gaining traction is "DER orchestration technologies".

A limited form of DER management, known as demand response (DR) or load control, has been operating in Australia for some time. In DR, the operation of a load is controlled to better match demand with supply. For example, in some states, hot water systems, pool pumps, or air-conditioners are controlled by signals from the grid, and made to turn on when demand is low and electricity is cheap or to act as a 'solar sponge' to absorb excess PV generation in areas of high PV penetration.

The control systems required for demand response are relatively simple. Grid control becomes significantly more complex as supply becomes more variable with increasing renewables share, and as more DERs enter the equation, particularly those like rooftop solar PV, behind the meter storage and EVs that can export energy to the grid. The large number of devices involved and the short timescales at which control is required mean large quantities of data are involved. This control will likely involve a mix of markets as well as physical controls and optimisation algorithms.

The key smart grid technologies are shown in Table 63 – Smart grid technologiesTable 63. Consistent with the fact that smart grids involve big data and complex algorithms, many of the smart grid technologies are software-based, in contrast to the hardware technologies that have traditionally dominated the electricity industry.

Table 63 – Smart grid technologies

TECHNOLOGY	DESCRIPTION
Smart appliances	Appliances capable of altering their energy consumption or supply in response to signals from utilities and other third parties. This includes air conditioners, pool pumps, washing machines and other appliances. It also includes solar PV, batteries, and EVs—these technologies are described in detail in their respective sections.
Advanced inverters/ converters	Inverters and converters are the solid state power electronic devices that connect VRE and batteries to the grid. Converters are the general class of technologies that allow transfer of electrical energy between AC and DC circuits. Inverters are the subset of converters that convert DC power (which is produced by solar PV and batteries) into the AC power required by the grid. Modern converter/inverters can provide a number of functions to help enable high renewables share (Piekutowski, 2016): Providing synthetic inertia (fast response) Injecting fault current (may require oversizing of inverters to provide sufficient current) Providing reactive power, voltage and power factor control, phase balancing and active filtering via operation in STATCOM mode Communications to enable observability and controllability.
Control platforms	Systems/platforms to manage distribution networks and DERs using advanced analytics and optimisation algorithms. They provide visibility and control of multiple DERs and will likely include a mix of centralised and distributed optimisation, e.g.: Distribution Management System (DMS) for basic control, or a Distributed Energy Resources Management (DERM) platform, for advanced control and optimisation; used by a network operator Systems operated by aggregators e.g. for operating a 'virtual power stations' or VPS Home energy management systems. These platforms allow decision-making and optimisation of outcomes in the face of competing objectives. These competing objectives may relate to: An individual player e.g. a consumer may want to both reduce cost and minimise the proportion of energy they use from the grid Different players e.g. a network operator may wish to minimise thermal loading of their assets while a household may wish to maximise the energy they export to the grid.

TECHNOLOGY	DESCRIPTION
	Control platforms will become increasingly decentralised, with implications for data sharing and processing, privacy, communications protocols and cyber security (Ruud Kempener, 2015). Control platforms will also need to be able to cope with increasing volumes of data.
Market platforms	Includes: Digital market platform (DMP): Enables market control and monetisation of DERs by enabling both Peer-to-Grid (P2G) and peer-to-peer (P2P) transactions to take place, based on the instantaneous locational value calculated for each DER (achieved through advanced analytics and big data). Platforms to enable DERs to trade energy/services on the wholesale market.
Smart meters	Allows communication between the utility and consumers (or between different consumers' DERs).
Telemetry and sensors	Generate granular spatial and temporal information to provide visibility on the state of the grid and individual components, as well measuring user behaviour, e.g. through smart lighting and smart thermostats (Citi, 2016). Includes phasor measurement units (PMUs), which measure the electrical waves in the grid.
Advanced protection systems	Increasing VRE share will result in weaker systems, in which current protection systems, which rely on high fault level, may not be adequate. More advanced protection system suitable for weaker systems will require development.
System data, characterisation and models	Detailed computational models of the grid and the DERs (including locational value data) will be required by the optimisation algorithms of control platforms and market platforms in order to calculate optimal outcomes. System characterisation includes dynamic line ratings, which allow capacity limits for transmission and distribution lines to be adjusted depending on weather conditions.
Demand forecasting	Systems used by control platforms to provide information about likely demand in order to better plan system operation.
Generation forecasting	Systems used by control platforms to predict the output from solar PV and wind generators based on weather forecasting at different timescales, and to predict state of customers' batteries, to enable supply-demand balance to be maintained (e.g. through deployment of dispatchable generation or energy from batteries, or demand reduction).
Secure communications protocols and architectures	Given distributed system operation involves control of a large number of critical devices using communications messages, secure communications protocols and architectures are crucial for system safety, security and reliability and for user privacy.

Management of DERs can occur in two main ways (IEC, 2009):

- Dispatchable: DERs are controlled directly by the network/utility with either coarse control (i.e. an on/off signal) or by increasing/decreasing energy output or consumption in a continuous manner (e.g. lighting output may be adjusted by a few percent).
- Reactive: Information such as a price signal is provided to the user, who can choose how to respond. (The decision would typically be made automatically by a DER or the user's energy management system.)

Potential players involved are:

- Consumers/commercial users—end users or suppliers of electricity.
- Networks—these have historically been responsible for load control, and this may also apply for future DER control and management.

- Intermediaries/aggregators—other businesses that act as intermediaries between end users of energy and the broader system. For example, a retailer might offer a plan to customers whereby they agree for the retailer to control their DERs in return for lower electricity costs.

Applications

There are a number of key uses of smart grid technologies in the context of enabling increased renewables share:

- Load control / load shifting / demand-side balancing: Changing the demand from loads in response to system needs. This could involve:
  - Shifting demand to off-peak times (IEC, 2009). This will become particularly important as EV penetration increases, as EVs could add substantially to peak demand, if for instance a large proportion of the population plugs in their EVs after arriving home from work each evening.
  - Ramping loads in response to fast changes in renewables output (IEC, 2009).
  - Rapidly ramping down loads in response to contingencies such as the loss of a generator or transmissions line.
- Storage control: Ramping up output from distributed batteries in response to system needs, such as changes in renewables output or variations in grid frequency. This can include 'synthetic inertia', either as fast frequency response, in which power is rapidly injected into the grid in response to a contingency, or as continuous rapid frequency control.
- Managing voltage in distribution networks: Limiting the power being fed into the distribution network from solar PV or storage as required to keep distribution network voltages within acceptable limits
- Provision of limited back up supply in the case of controlled islanding of a portion of the grid.
- Providing fault current: Using batteries or rooftop solar PV systems to provide sufficient current to trip protection in the event of a fault
- Alternative system protection mechanisms if fault current is too low for this purpose

Several of these applications (load control, storage control and managing voltage) can be combined in a 'Virtual Power Station', in which the DERs of multiple customers are coordinated to provide a dispatchable power supply.

Potential impact and breakthroughs

The potential impact of smart grid technologies is to enable high penetrations of key abatement technologies (large-scale wind and solar PV, solar rooftop PV and EVs) at much lower system cost, while creating new opportunities to create value for consumers and other energy users. The goal can be captured with the term 'transactive energy': "A system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter. The benefit in optimising the distribution system in this way is estimated to be a 30% increase in electricity affordability (CSIRO, 2015)."

16.3 Technology status

Cost – current state and projections

Costs for individual smart grid technologies are expected to be relatively small compared to total network expenditure, since they are either:

- Much smaller than network system investment e.g. the cost of developing system models
- Included in the cost of renewables e.g. rooftop solar PV systems are typically sold with smart meters
- Only slightly more expensive compared to alternatives e.g. advanced inverters have small additional costs compared to conventional inverter (<5% increase) [2]
- Cheap to scale and typically bundled with other products e.g. weather forecasting bundled into home energy management services
- Value creating e.g. 'orchestration' of DERs is expected to enable avoiding $16b of network infrastructure investment by 2050 in the NEM (ENA, 2016).

In general, the cost of smart grid technologies is not expected to be the key barrier to uptake, and costs are expected to decline as these systems are further developed and become more widespread. As an indication, projected costs of advanced inverters are shown in Table 64.

Table 64 – Projected advanced inverter cost ($/kW) (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)

Year	2016	2020	2030
Cost	500-1400	400-1150	320-900

Technological and commercial readiness - current state

As shown in

Table 65, most smart grid technologies are fairly mature, although at early to medium stages of commercial readiness. While the individual technologies are reasonably mature, there remains significant work to be done in bringing them together in integrated systems.

Table 65 – Technological and commercial readiness 2016

TECHNOLOGY	TRL	CRI	COMMENTS
Smart appliances	Various, up to 9	2-4	Technologies exist but are not widespread, and are subject to continuous improvement and standardisation
Advanced inverters	6 to 9	3-6	Inverters are a mature technology, but certain features are only being piloted or used in demonstration projects e.g. synthetic inertia, virtual generator mode, fault current injection, fault ride through and power factor control.
Control platforms	6-9	1-4	Home energy management systems exist but are yet to reach wide penetration. DMS and DERM platforms still requiring significant development, and standardisation presents a significant challenge.
Market platforms	6-9	1-2	Startups for P2P trading starting to emerge
Smart meters	7-9	4 (in places)	Commercial models for rolling out smart meters beyond Victoria are still in development, smart meters are still improving. Smart meters currently rolled out in Victoria have insufficient response times to enable support provision of fast FCAS for frequency stabilisation
Telemetry and sensors	6-9	2	Technology transfer to distribution systems has started
System data and models	2-9	~1	Basic models exists. Detailed models including rich locational information on DERs yet to be developed
Advanced protection systems	6-9	1-3	Some advanced systems exist e.g. differential protection systems which use current measurements at two points in a network to determine whether there is a short circuit and do not rely on system strength. These systems may not be practical in all circumstances and more advanced protection systems will need to be developed and trialled.
Demand forecasting	7-9	6	Technologies and implementations are mature, improvements are required
Generation forecasting - solar	7-9	4	Several cloud position forecasting technologies are commercial available but uptake is still low
Generation forecasting - wind	6-9	6	Technologies and implementation are mature and very good in the key sub-one hour timescale; further granularity of forecasting possible
Secure communications protocols and architectures	5-9	3	Technologies exist but are not in wide use; development of core architectures still required

16.4 Target deployment

Australian electricity networks will need to undergo substantial transformation to transition to a system with high penetration of VRE and DERs. The required deployment of smart grid technologies to support this transition is show in

Table 66. The barriers and proposed solutions to achieving those milestones are explored further in Section 16.5.

Table 66 – Required deployment of smart grid technologies

Technology	Now (2017-2020)	2021-2025	2026-2030
Smart appliances	Following consumer adoption		
Advanced inverters	Commercial trials of advanced inverters	Deployment at scale to support high VRE share and high non-synchronous penetrations	
Control platforms	Commercial trial of home energy management systems; Develop and trial network control systems	Roll out	
Market platforms	Implementation of basic markets; Demonstration of integration of network control platforms with market platforms	Wide monetisation of DERs services via aggregation platforms	Development of digital Network Optimisation Market
Smart meters	Wide roll out		
Telemetry and sensors	Commercial trials	Roll out	
Advanced system protection	Develop and trial	Roll out	
System data and models	Develop and roll out		
Demand forecasting	Develop and roll out		
Generation forecasting - solar	Commercial trials and rollout		
Generation forecasting - wind	Already in place		
Secure communications protocols and architectures	Develop and agree standards		

16.5 Barriers to development and potential enablers

As shown in Section 16.3, the individual smart grid technologies are typically mature (high TRL). The key challenge is to deploy them commercially in integrated systems.

Table 67 shows the key barriers to deployment of smart grid technologies, as well as potential enablers and indicative timing of these enablers. The key barrier is the lack of incentives provided by the existing market structure and regulations, which were designed for the existing paradigm of centralised generation and one-way flow of energy. Regulatory and market reform will be required to overcome this barrier. Other key barriers are a lack of technical standards and a lack of system data. Regulatory and market reform will also be required to overcome these barriers.

Table 67 – Barriers and potential enablers (key barriers highlighted in grey)

Category	Barrier	Potential enablers	Responsibility	Timing
Cost	> n/a	> n/a	> n/a	> n/a
Revenue / market oppty	> Lack of market mechanism or price signal (except peak/off-peak tariffs) to make provision of grid services (e.g. demand response, sub 6-second FCAS, inertia) attractive to consumers and aggregators, and encourage uptake of DERs with suitable specifications	> Tariff reform, with prices reflective of system cost > Further rollout of smart meters > Introduce a market mechanism/platform enabling owners of DERs and/or aggregators to monetise services provided to the grid > Establish DER service valuation methods > Introduce markets for	> Tariff reform: AEMC/state governments/networks (underway currently) System security - review of inertia, RoCoF and other issues: AEMC > Retailers and other providers of	2017-2020

Category	Barrier	Potential enablers	Responsibility	Timing
		procurement of technical services e.g. inertia market and/or high frequency FCAS market > Non-market based procurement of technical services > Regulatory requirements e.g. technical standards	smart meters > AEMC / AEMO / network operators	
Regula-tory environ-ment	> Lack of technical standards e.g. for secure communications protocols and standards for inverters and other DERs to enable full provision of services to the grid	> Introduce/continue to update technical standards > Develop secure communications protocols and architectures	> Standards Australia (together with international standards bodies) > CSIRO/Data 61 > AEMC	2017-2020
	> Lack of clarity about who controls what	> Industry-wide process to design the future operating model for the grid, including distribution system operator and market platforms	> ENA/CSIRO (Electricity Network Transformation Roadmap), AER, others?	2017-2020
Technical perform-ance	> Current protection systems require upgrade to support high penetrations of VRE and DER	> Upgrade protection systems	> Networks	2017-2025
	> Technologies may require adaptation to local requirements	> Work with OEMs e.g. inverter manufacturers	> Networks, project developers	2017-2020
	> Slow turnover of legacy equipment	> n/a	> n/a	> n/a
Stake-holder accept-ance	> Insufficient prioritisation of understanding impact of transition to higher penetration of VRE and DERs and implications for transition to future grid	> Raise grid transformation to high priority	> All industry players	2017-2020
	> Customers unaware of effect of their energy usage patterns on system costs	> Tariff reform; educating customers and make data available (e.g. through smart meters, in-home displays) > Create 'set-and-forget' technologies	> Retailers, networks, AEMO > Technology providers	2017-2020
	> Reluctance of consumers to have utilities control their DERs	> Communicate benefits e.g. cost savings with negligible impact on lifestyle > Apply behavioural economics research to designing solutions	> Retailers, networks > Research groups e.g. CSIRO	2017-2020
	> Lack of awareness of capabilities of DER control technologies e.g. advanced inverters	> Educate regulators and networks in capabilities of technology, especially via pilot and demonstration projects	> Technology developers, project developers, ARENA	2017-2020

Category	Barrier	Potential enablers	Responsibility	Timing
Industry and supply chain skills and know-ledge	> Lack of granular energy use data to inform system design (e.g. tariff structures)	> Build a system to aggregate system data, including location and attributes of DERs, power flows, demand profiles > Resolve issues around access to data e.g. retailers providing data to 3rd parties > Research response of customers' energy use to price signals	> CSIRO - EUDM (in train) > Retailers, regulators	2017-2018
	> Limited understanding of required specifications and deployment of technical enablers of VRE	> Detailed system modelling at sub-5 minute timescales to understand required specifications and deployment of enablers of VRE > Further research to understand effect of high RoCoF in large grids	AEMO, networks	2017-2020
	>Inadequate granular understanding of system characteristics and performance e.g. acceptable operating regimes to avoid excessive thermal loading	> Conduct research to characterise system and develop dynamic ratings and updated standards (e.g. frequency standards) > Undertake detailed power system modelling to assess optimal solutions for generation mix and grid topology	> CSIRO/ universities, DNSPs, AEMO, AEMC	2017-2020
	> Lack of skills required for the future grid	> Upskill the workforce	> Industry bodies, government	Ongoing

16.6 Opportunities for Australian Industry

Australia is in a leading position in the deployment of smart grid technologies (PNNL, 2016). The factors that create this comparative advantage are:

- High penetration of distributed renewables
- Relatively few network/market players to coordinate
- Relatively weak network (less interconnections), necessitating novel solutions to enable higher penetration of DERs
- A strong research program in microgrids/remote area power networks and distributed energy integration, covering CSIRO and most Australian universities.

This comparative advantage, together with specific sources of comparative advantage along the smart grid value chain, create a number of opportunities for Australian industry (see Table 68). Key opportunities involve creation of software and services that use smart grid technologies to create value by reducing cost and creating additional benefits for energy users and other system participants.

Table 68 – Opportunities for Australian industry

Supply chain steps	1. Design and manufacture of DERs	2. Creation and marketing of services	3. Managing distributed network	4. Creation of software
Description	Design and manufacture of controllable DERs (e.g. appliances, inverters). Excludes EVs, batteries and PVs (covered elsewhere)	Creating convenient services for customers, including for accessing benefits of providing grid services and peer-to-peer transactions (virtual net metering)	Operating a platform to enable market participants to trade energy and services	Creation of software for control and market platforms, system modelling, demand and generation forecasting and cyber-security
Australia's comparative advantage	Medium + Highly educated population + Domestic market world-leading in penetration of DERs - High labour cost - Relatively small local industry and existing capabilities	Medium + Existing customer relationships of incumbents in domestic market + Domestic market world-leading in penetration of DERs	High + Domestic market world-leading in penetration of DERs + Relatively few players to coordinate + Would likely have to be a domestic entity due to strategic importance of this service	Medium + Domestic market world-leading in penetration of DERs + Relatively few players to coordinate + Strong skills in software development, cyber security, data science etc. - Many global competitors
Market size (2030)	Large - global market for appliances	Large - value add to domestic retail electricity market, potential export opportunities	Large - value add to domestic retail electricity market	Large - global electricity services market
Opportunities for Australian industry	Medium - some opportunity to build existing industry but difficult to compete with global players	High - Creating new services for domestic and potentially global markets	High - opportunity to share in unlocked value from domestic market, also to export solutions	High - develop software for domestic and global markets
Jobs opportunity	Medium	High	Low - low labour intensiveness	Medium - relatively low labour intensiveness
Main location of opportunity	Urban	Urban	Urban	Urban
Difficulty of capture/level of investment required	Medium	Medium (Although some services require market/regulatory reform)	High - market/regulatory reform required	Medium

17 VRE in remote area power systems (RAPS), microgrids and standalone power systems

17.1 Technology overview

Most of the VRE rolled out in Australia in the coming decades is expected to be connected to the major grids, the NEM and the SWIS. However, a significant proportion of Australia's electricity use is off-grid, and technological developments are expected to result in more and more energy users disconnecting from the grid. Integration of renewables in off-grid settings is therefore an important enabler of decarbonisation of the electricity sector. There are also strong drivers for uptake of renewables in off-grid settings, which can help accelerate rollout of VRE.

There are three main types of off-grid settings:

1. Remote area power systems (RAPS): Remote communities and industrial users (e.g. mines) located too far from grids to be economically connected.
2. Microgrids: Small grids that are connected to larger grids, but which can be operated independently, or 'islanded'.
3. Standalone power systems (SAPS): Individual users not connected to a grid. This may be due to remoteness, or a desire for energy independence.

Remote area power systems

Remote area power systems (RAPSs) are small, self-sufficient electricity grids serving the needs of isolated energy users such as mines, remote communities and off-shore islands. Their large distances from population centres means the cost of providing electricity via transmission or distribution lines from large grids like the NEM or SWIS is prohibitive. Consequently, they are served by local generation, typically diesel or gas. The high costs of these fuels, particularly factoring in transport, as well as price volatility and the risk of fuel supply interruptions, makes RAPS prime candidates for introducing renewable generation. Furthermore, RAPS represent 6% of Australia's electricity use (ARENA, Australia's Off-Grid Clean Energy Market, 2014) and so transitioning RAPS to renewables is important for decarbonisation of the electricity sector.

Australia is fairly exceptional as an advanced economy with a relatively high proportion of energy demand in remote locations (the so-called 'archipelago of energy users'). These factors create a comparative advantage for Australia in developing solutions for achieving high renewables share in RAPSs, and this comparative advantage has indeed translated into a globally leading position. Australia has a number of remote area power networks with high renewables share, such as the King Island RAPS, developed by Hydro Tasmania. This RAPS serves a population of 1,200 people, with 50-60% of annual energy generated from renewable sources, and has had periods of 100% renewable generation of up to 60 hours (Piekutowski, 2016).

A number of other projects are currently in development, including:

- Weipa Solar Farm, at Rio Tinto's remote bauxite mine in Weipa: 6.7 MW of solar PV, integrated into the existing 26 MW power station (ARENA, 2016).

- DeGrussa Copper Mine (Sandfire): 10.6 MW solar PV plus storage, integrating into the existing 19 MW diesel generator facility, reducing diesel consumption by 20% (ARENA, 2016).
- SETuP project: In development by the Power and Water Corporation in the Northern Territory, this project will introduce solar PV into the RAPSs of 30 indigenous communities, with initially 15% of electricity coming from renewables. One test site will have 80-90% share of renewables and will serve as a test bed for integration technologies for subsequent rollout to the other sites (ARENA, 2016).
- Flinders Island: building on lessons learned in renewables integration from the King Island RAPS, Hydro Tasmania is developing a system for Flinders Island. This system incorporates 0.9 MW of wind and 0.2 MW of solar generation and will be based on modularised components such as diesel uninterruptible power supplies (DUPSs), dynamic resistors and batteries, to be built in containers in Tasmania and shipped to the island. The IP being developed and the modularisation will allow similar systems to be easily rolled out elsewhere (ARENA, 2016).
- Developing RAPS with high renewables share represents an opportunity in itself (see Table 5) but also provides a good platform for testing enabling technologies. In certain respects, RAPS provide greater challenges for achieving high renewables share than large grids like the NEM, due to less redundancy, less averaging of supply and demand (due to lower geographic diversity and a smaller number of generators and energy users) and lower system inertia, and solving these challenges in the test beds provided by RAPS provides lessons applicable to larger grids.

RAPS with high share of renewables offer potential benefits for servicing fringe of grid communities. Many remote communities in Australia currently receive their electricity from the NEM or SWIS, at high system cost due to the large transmission distances involved and relatively small electricity demand. For such communities, when transmission upgrade or replacement is required, a lower cost solution may be to replace the grid connection with a RAPS with high renewables share. This may also improve energy security and reliability, by eliminating the distribution line, which is susceptible to disruption due to storms and bushfires.

As renewables are integrated into existing RAPS, the cost of these systems will decrease, making it more economically viable to disconnect fringe of grid communities from the grid. A potential path to transition is for fringe of grid communities to develop microgrids, where they operate largely autonomously, but retaining their grid connection. In time, it may then make sense and be acceptable to the community to disconnect from the grid entirely.

Microgrids

Similar to RAPS, microgrids are electricity networks that can be run independent from a larger grid like the NEM or SWIS, but that retain a connection with a larger grid, from which they can import and export electricity.

Potential benefits of microgrids include increased energy security, lower costs due to lower transmission losses, greater self-sufficiency and end-user control, such as the ability to source a greater percentage of electricity from renewable sources.

Microgrids that can automatically disconnect and reconnect and synchronise with the grid provide additional benefits to the grid by acting as an implementation of demand response. This has the potential to reduce system costs by reducing the reliability required of the centralised generation and transmission system.

Microgrids also enable the uptake of other smart grid technologies, helping reshape the electric grid from a one-way conduit for distributing power into a decentralised, intelligent network.

Standalone power systems

Standalone power systems are simpler versions of RAPS, for individual households or commercial users, without the need for a distribution network. As smaller, simpler systems without the complexity of a grid connection, they are prime candidates for achieving very high share of VRE. These systems can provide power for remote users where the cost of grid connection is prohibitive, or allow grid-connected users to defect from the grid. Energy storage can be used to help manage the variability and intermittency of VRE generation. It is generally most cost-effective to incorporate a DUPS as backup, otherwise the cost of storage may become very high. A key concept with standalone power systems is that with the incorporation of renewables, diesel generation can go from being the primary energy source to a backup.

Key technologies

The technologies involved in RAPS, microgrids and SAPS are largely the same, although microgrids need to be able to import and export energy to the grid in an optimised way, and RAPSs need greater redundancy due a lack of grid connection. Broadly, these systems need:

- Renewable generation, such as wind and/or solar PV. Wave/tidal energy is also a good option increasing supply diversity for small islands which lack space for wind turbines and solar arrays, and which may be subject to long periods of cloud and low wind.
- Energy storage, such as batteries, and/or diesel or gas backup generation.
- Additional enabling equipment to maintain power security and quality, such as flywheels (to provide inertia), batteries and super-capacitors (for fast injection of energy for frequency stabilisation) and resistive frequency control (to dump excess power), and inverters that can provide fault current and synthetic inertia.
- Control systems (see also the section on DER control technologies – key technologies/capabilities include weather forecasting and demand management).

17.2 Barriers to development and potential enablers

Key barriers to achieving greater share of renewables in RAPS, microgrids and SAPS are shown in Table 69. The main barriers are cost, a lack of standardised ‘plug-and-play’ solutions and a lack of experience in project developers and data from multiple projects demonstrating power supply reliability, resulting in a lack of confidence from potential users with stringent reliability requirements. The key enabler to overcome these barriers is further rollout of demonstration projects with a focus on modularised components, and subsequent sharing of data and learnings.

Table 69 - Barriers and potential enablers

Category	Barrier	Potential enablers	Responsibility
Cost	> Bespoke engineering and design increases project cost > Remoteness > Challenges associated with integration in a microgrid with a high level of redundancy	> Support more demonstration projects, focusing on modularising components > Set up centre of excellence to share learnings and foster connections > Develop standardised solutions	> ARENA/CEFC > Government > Industry
Revenue / market oppty	> Development of mature supply contracts that integrate solar and diesel into commercial arrangements is proving problematic for industrial off-grid users (miners) > Value of solar often discounted in the sector and inappropriate commercial structures can lead to excessive curtailment of renewable energy	> Industry to coalesce around established commercial and contracting arrangements to reduce commercial risk.	> Industry > ARENA/CEFC
Regulatory environment	> Regulatory barriers to disconnecting a community from the grid, or planning a new development that is not connected to the grid > Concern over system reliability in a very small grid—utilities often impose hard caps on the proportion of VRE that can be allowed into the grid, or demand that VRE is accompanied by large storage capacity.	> Regulatory reform to enable microgrids, and remote area power systems, while providing suitable consumer protections (e.g. ensuring clear responsibility for maintenance) > Demonstration of how these VRE limits and requirements can be eased while maintaining system reliability.	> AER for NEM and SWIS fringe of grid/local utility for areas already off-grid > ARENA
Technical performance	> Lack of projects to prove performance > Plant modelling not standardised	> Support more demonstration projects to prove performance of RAPS and microgrids with high VRE share	> ARENA/CEFC > Government
Stakeholder acceptance	> Resistance of some customers to being disconnected from the main grid	> Support more demonstration projects to show how RAPS provide security and reliability at low cost > Transition fringe of grid communities to microgrids and prove successful operation before disconnecting from grid entirely	> ARENA/CEFC > Government > Network operators
	> Prices don't currently reflect network cost (remote customers have higher cost to serve than urban customers but pay the same). If remote customer go offgrid, price becomes more transparent and they may be charged more as a result	> Continue cross-subsidisation of remote customers even if served by RAPS	> Network operators
Industry and supply chain skills and knowledge	> Lack of experience of project developers in setting up RAPS and microgrids and finding supply chain partners; lack of data	> Set up centre of excellence to share learnings and foster connections > Continue to support projects while streamlining processes and establishing standardised approaches	> ARENA

17.3 Opportunities for Australian Industry

The main opportunities presented by RAPS, microgrids and SAPS with high renewables share are shown in Table 70. The key domestic opportunity is reduced system electricity, resulting from reduced spend on network connections and diesel fuel. There is also a large opportunity from the capital works, with over $2 billion of estimated opportunity in remote area power systems alone (ARENA, Australia's Off-Grid Clean Energy Market, 2014). Additionally, a large potential export opportunity exists in developing RAPS and microgrids for the international market of remote communities that rely on diesel generation, or that lack access to electricity. Carnegie Wave Energy, an Australian wave energy technology developer, has recently bought EMC, a microgrid EPC company, recognising the potential of this market. The Australian Government Department of Foreign Affairs and Trade (DFAT) has identified a number of opportunities for Australia to help deploy renewables in RAPS in the Indo-Pacific region (Entura, 2016).

Table 70 - Opportunities for Australian industry

Supply chain steps	1. Building modularised components for RAPS, SAPS and microgrids	2. Deploying renewables in RAPS and SAPS	3. Building microgrids	4. Converting fringe of grid to microgrids and RAPS
Description	Build modular components e.g. containerised batteries, UPSs etc., and IP for rolling out in different settings with limited bespoke design	Deploy and operate remote area power systems with high VRE share in Australia and overseas	Build microgrids in greenfield developments e.g. new suburbs and convert existing grids to microgrids; may be via 'community energy' projects	Convert fringe of grid communities to microgrids and remote area power systems
Australia's comparative advantage	High + Many remote energy users + Current world-leading position in development of RAPSs and microgrids + Diverse climates across the country, applicable to many potential customers + Strong capabilities in systems integration			
Market size (2030)	Large - Remote Aus energy users & large opportunities for remote communities in Africa and Asia Pacific yet to electrify, although difficult to capture		Large - new community developments in Australia plus existing grid	Medium - relatively small total population living on fringe of grid
Opportun-ities for Australian industry	High - develop RAPS and microgrid solutions for Aus and oversea, including modular components and consulting services; save money in serving remote communities		Large	Medium - opportunities for developers and savings opportunities for network operators
Jobs opportunity	High	Medium	High	Medium
Main location of opportunity	Urban	Remote/rural	Urban/regional population centres	Remote/rural
Difficulty of capture/ level of	Low	Low (for Australia); High (for overseas)	Medium	Medium

Supply chain steps	1. Building modularised components for RAPS, SAPS and microgrids	2. Deploying renewables in RAPS and SAPS	3. Building microgrids	4. Converting fringe of grid to microgrids and RAPS
investment required				

18 Concentrated solar thermal (CST)

As an alternative to solar PV, CST provides a well understood means of harvesting solar energy and has applications in the generation of electricity, heat for industrial processing and solar fuels. CST's key differentiator is that as compared with VRE, energy storage is relatively cheap to incorporate, enabling it to provide dispatchable renewable energy, albeit at a higher cost (than VRE without energy storage). For the Australian electricity market, CST is therefore unlikely to be competitive until there is a significant need for large-scale energy storage (i.e. at a VRE share greater than ~40%). Significant cost reductions may also be achieved through further investment in R&D and a pipeline of projects prior to 2030. If deployed at scale, this will bring significant EPC and O&M opportunities, particularly in remote regions of Australia. A domestic industry would also increase scope for export of key technology components (e.g. heliostats and receivers) as well as IP.

- CST provides a technologically mature, alternative means of harvesting solar energy and has applications in the generation of electricity, heat for industrial processing (discussed in Section 2) and solar fuels.
- While CST is expected to remain high cost in 2030 ($80-$140/MWh), it has a number of advantages over VRE. It relies on a steam turbine which provides inertia to the grid and can also generate heat up to temperatures of 1200˚C. The key differentiator however is the option for cheap in-built energy storage which allows for dispatchable generation.
- For the Australian electricity market, CST is unlikely to be cost competitive until there is a need to invest in large-scale energy storage (i.e. when the share of VRE exceeds ~40%).
- A number of CST projects are required in Australia order to remove 'first-of-kind' risk and establish supply chains. However, currently CST is cheaper at scale (˜100MW) and securing projects is likely to be challenging given the currently oversupplied electricity market and scarcity of large capacity PPAs.
- Australia has world-leading capabilities in developing CST components that include heliostats, receivers and power blocks. Continued R&D investment and international collaboration is recommended to maintain this capability as well as improve system efficiencies and optimise plant designs. Key learnings may also be leveraged from the rollout of CST for industrial heating applications.
- CST brings a number of opportunities for Australian industry, particularly in relation to EPC and O&M for large-scale plants in remote areas. A domestic industry would also increase scope for local manufacture as well as further commercialisation and export of IP.

18.1 Technology overview

Technology description

CST relies on mirrors to concentrate sunlight or 'direct normal irradiation' (DNI) onto a receiver containing a 'heat transfer fluid' (HTF). Heat is transferred from the HTF to water to produce steam via a heat exchanger. The steam may be used as heat for industrial processes or for electricity generation via a turbine. Four primary CST technology designs exist currently, as shown in

Table 71 – CST technologies

Table 71 below:

Table 71 – CST technologies

TECHNOLOGY	DESCRIPTION
Power Tower	Heliostats are used to focus the sun's rays onto a receiver located at the top of a tower. The receiver contains the HTF which is typically a molten salt. This technology is able to operate at high temperatures greater than ~565˚C and is therefore more efficient than other CST designs. It is also suitable for broader applications in solar fuels (e.g. direct water splitting). Some of the challenges however include the high upfront capital cost, need for local design and heliostat tracking systems which result in a high parasitic load. Molten salt also freezes at 220°C and so auxiliary heating is required
Parabolic Trough	Single-axis parabolic trough shaped mirrors are arrayed in rows with the HTF (an oil) flowing in a tube along the focal point of the trough. While trough systems have a lower capital cost, they operate at lower efficiencies given that the HTF is limited to temperatures of ~390˚C.
Linear Fresnel	Multiple linearly organised mirrors are fixed on a dual-axis sun tracker to concentrate DNI onto a single elevated receiver. Water is used as the heat transfer fluid and thus steam is generated directly. While water provides a cheap and relatively safe HTF, it also means that the system operates at a lower temperature (˜<300°C) and therefore reduced efficiencies. However, new compact linear Fresnel reflector technology which are expected to achieve temperatures up to 500°C are currently under development.
Parabolic dish	Dual-axis tracking mirrors curved in a parabolic dish shape concentrate DNI onto a receiver that is fixed along the dish structure focal point. These systems are capable of reaching high temperatures (up to 700°C), however due to their design, can only be built on a kW scale.

CST plants may require some form of auxiliary energy to ensure reliability. This is usually in the form of gas-fired boilers which can couple with a steam turbine, as well as help mitigate thermal losses overnight or prevent freezing of the HTF (IEA, 2014).

Energy storage

One of the primary advantages of CST is the option for in-built energy storage that is relatively cheap to incorporate. Excess heat can be stored in insulated tanks and then released into the steam cycle (via the HTF), enabling the system to provide dispatchable energy. R&D is ongoing into advanced materials for energy storage technologies such as use of graphite or concrete, thermoclines, thermochemical energy storage (TEF) and phase change materials (CO2CRC, 2015).

By oversizing the solar field (i.e. number of heliostats) against the size of the turbine, typically anywhere from 3-14 hours of energy storage can be achieved (i.e. the plant can continue to run up to 14 hours at specified loads from the point at which there is no DNI).

Given that it relies on a steam turbine to provide electricity, CST has the added advantage (compared with solar PV) of providing inertia in order to help stabilise the grid (issues discussed further in Section 13.1). As mentioned above, it can also be coupled with other forms of heat generation (e.g. HELE, biomass)

Technology impact

As an alternative to solar PV, CST provides a well understood means of harvesting solar energy and has applications in the generation of electricity, heat for industrial processing and solar fuels.

Electricity

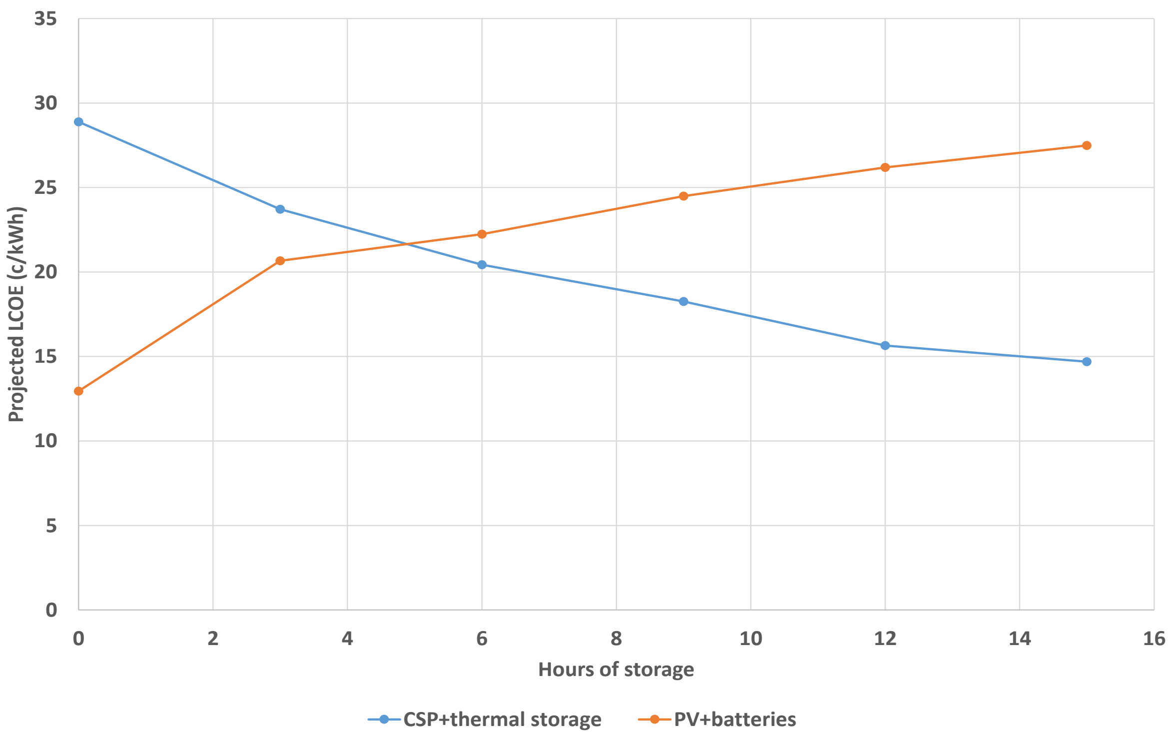
Deployment of CST is gaining considerable momentum internationally with 4.749 GW currently in operation and 1.187 GW under construction (IEA, 2016). For example, in September 2015, SolarReserve commissioned a 110 MW power tower plant in Crescent Dunes, Nevada. They are currently in discussions with the South Australian Government to deploy the same technology in Port Augusta. Importantly, China has also recently contracted 1.35 GW of CST capacity to be built.

In Australia, there has been relatively little activity, with two exceptions. Firstly, Sundrop Farms, whose core business is tomato cultivation are generating electricity via a 36$MW_{thermal}$ (1.5MW_e for electricity) CST plant in South Australia (although the primary purpose for CST is heat and desalination). Secondly, Vast Solar are also commissioning a modular 5 tower field totalling 6$MW_{thermal}$ to generate 1MW_e near Forbes in NSW. They are also proceeding with plans to develop a 30MW system using multiple modules.

CST may also be applied to pre-heating of feedwater in coal-fired power plants. This was the intention behind the CST installation at the Liddell and Kogan Creek facilities. However, for a variety of reasons, both CST plants are currently inactive.

CST provides one of few alternative dispatchable renewable sources of power and may prove to be a critical component of Australia's energy mix. This is particularly the case if there are technical limits on the share of VRE and social licence barriers relating to deployment of HELE, CCS and nuclear are not overcome. Further, as shown in the analysis represented in Figure 28 below, CST may prove to be considerably cheaper than deploying additional VRE with batteries where greater than five hours of energy storage is required.

Figure 28 - Cost comparisons of CST v solar PV with batteries



Solar fuels

Through the generation of high temperature heat (>750˚) (CSIRO, 2016), CST enables the production of fuels (i.e. hydrogen, syngas and with further processing, other liquid fuels) via a number of different reactions. For conventional carbonaceous based fuel production processes (e.g. SMR and coal gasification), CST provides renewable heat that would otherwise be generated by burning additional fossil fuels.

Heat produced via CST can also be used in the direct splitting of water to produce hydrogen or the combined splitting of CO_2 and water to produce syngas.

Solar fuels produced via SMR are the most mature of the technologies and, if adequately funded, could be available by 2030 (CSIRO, 2016)

Industrial processes

CST may also supplement heat that would otherwise be produced by burning coal or natural gas in industrial processes such as steel or cement manufacturing. This is discussed further in Section 2.

18.2 Technology status

Cost - current state and projections

The current and projected LCOEs for each of the CST technologies is set out in

Table 30 below. It is important to recognise that the cost of CST can differ significantly on a plant by plant basis due to factors such as system design and DNI availability. Also note that parabolic dish technology has not been included here given that it is yet to have been deployed commercially.

Table 72 - CST LCOE forecast ($AUD/MWh)

CST	2015	2020	2030
Power Tower	200-250	170-210	160-200
Parabolic troughs	290-350	190-230	170-200
Linear Fresnel	300-370	190-240	170-210

Technological and commercial readiness - current state

The TRL and CRI associated with each of the CST technologies discussed in section 18.1 is outlined in Table 73 below.

Table 73 – CST technological and commercial readiness

TECHNOLOGY	TRL	CRI	COMMENTS
Power Tower	8-9	2	Relatively new technology with close to 700MW of installed capacity globally. No dedicated electricity generation plants exist in Australia currently. Current research is looking at achieving higher efficiencies in smaller plants.
Parabolic troughs	9	4	Parabolic troughs are the most mature CST technology and represent 41% (3GW) of global capacity. Advanced parabolic troughs that use molten salt or direct steam are under development (TRL 4)
Linear Fresnel Reflector	6	1	LFR is in the early stages of development with approximately 200 MW installed globally.

Parabolic dish	8-9	1	Small-scale supported deployment for electricity overseas. Current prototypes at Australian National University primarily used for energy conversion processing.

18.3 Barriers to development and potential enablers

A pipeline of CST projects in Australia will be required to lower the capital cost due to the contingency risk and higher cost of financing typically associated with first-of-kind projects. However, securing investment in large-scale CST plants (~100MW) is likely to be challenging given the currently oversupplied electricity market and scarcity of PPAs. Government subsidies and incentives are therefore needed in order to underwrite the investment risk associated with early CST projects.

Note that Vast Solar is looking to overcome this issue from a technological perspective by developing more modularised CST designs.

A summary of the key barriers and enablers is shown in Table 74 below:

Table 74 - CST barriers and enablers

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	High capital cost of technology	> Incentivise new build CST plants for electricity generation in Australia. Overcoming 'first of a kind' risk will significantly lower the capital and financing cost. > Facilitate sharing of key learnings and deployment of local supply chains > Maintain international collaborations on CST development. R&D should be focused on increasing efficiencies via system design and higher temperatures and improving energy storage capacities	> Government > Industry	2021-2025
Revenue/market opportunity	CST projects typically need to be large (~100MW) to be cost effective. Australia currently has an oversupplied electricity market which could lead to challenges in securing PPAs and investment	> (As above) Incentivise/underwrite risk of new build CST > Support modularised CST technology options (e.g. Vast Solar)	> Government	2021-2025
Regulatory environment	Lack of policy certainty post-2020 to continue driving uptake.	> Establish certain policy framework post-2020 early enough to limit uncertainty and encourage investment	> Government	2017
Technical performance	Certain HTFs (e.g. molten salts) have high freezing points and therefore require an external heat source to maintain temperatures in the absence of sunlight	> Further R&D focusing on advanced energy storage materials > Exploration of bioenergy to provide heat	> Industry > Research organisations	Ongoing

Category	Barrier	Potential enablers	Responsibility	Timing
	Lack of experience in procuring large-scale CST plants	> Engage global EPCs with experience in rolling out CST to ensure that first of kind projects are completed efficiently and inspire confidence in technology. > Ensure components fit together if provided by different providers	> Government > Industry	2021-2025
	CST requires direct solar radiation and so is more heavily impacted by cloud cover (than solar PV)	> Ensure thorough DNI assessments have been conducted in prospective areas to determine best positioning of CST plants (e.g. desert) > Optimise energy storage capacity	> Industry > Research organisations	2021-2025
Stakeholder acceptance	Belief that CST is not needed due to increasing penetration of solar PV	> Increase industry awareness of benefits of dispatchability provided by CST (e.g. industry workshops)	> Government > Industry bodies	Ongoing
	Concern that CST plants have significant land and water requirements	> Conduct and communicate findings from detailed LCAs over prospective CST sites, considering all environmental impacts	> Government	2021-2025
Industry and supply chain skills	Lack of local supply chains with expertise in procurement of large-scale CST plants	> Encourage experienced EPC contractors from overseas to develop first CST plants in Australia but incentivise utilisation of local content and industries in order to develop local supply chains	> Government	2021-2025

18.4 Opportunities for Australian Industry

CST plants are typically large-scale and therefore bring significant EPC and O&M opportunities to Australian industry, particularly in remote areas. Due to the complexity of design and to encourage consumer confidence, it is important for the first few projects to be built by experienced overseas developers, albeit using as much local content as possible (e.g. concrete, labour). During that time however, there is also significant opportunity for Australia to develop local supply chains. This includes manufacture of component parts such as receivers and heliostats (refer to Heliostats SA case study) which may bring additional export opportunities.

As mentioned above, Australia currently retains a comparative advantage in terms of CST IP, design, performance testing and manufacturing of component parts. For instance, as shown in the example of Heliostat SA (refer to Appendix C of the main report) there is considerable scope to manufacture and export heliostats to countries such as China and India. Domestic procurement of CST and development of domestic supply chains may help Australia maintain its R&D capabilities by encouraging further commercialisation of IP via collaboration with local industry. A failure to do so increases the risk that this advantage will be eroded and export opportunities lost.

A summary of the supply chain opportunities is included in

Table 75 below.

Table 75 - Opportunities for Australian Industry Summary

	Technology manufacture	EPC	O&M	Production of solar fuels
Description	> Manufacture of key CST components (e.g. heliostats, receivers)	> Involves design, procurement and construction of CST plants	> Involves ongoing operation and maintenance of CST plants	> Production of solar fuels (e.g. syngas, hydrogen) using either carbonaceous feedstocks (e.g. coal gasification) or direct splitting
Australia's comparative advantage	Medium + Strong IP and established manufacturing for CST components (i.e. heliostats, receivers) + Other components such as foundations, towers are typically derived from local content - Other countries with more developed CST industries (e.g. Morocco, Sth Africa, Chile and US)	High + Design and procurement must be done locally + Strong IP in relation to CST design	High + O&M must be done locally + Skilled local labour workforce	High + Strong IP in relation to solar fuel production + Vast natural resources (e.g. coal, sunlight) + Established coal, oil & gas industry
Size of market	High - service of local market, potential export of heliostats, receivers and other IP	High - Service of local market	High - Service of local market	High > Potential local and export markets for hydrogen > Local syngas market and potential for export of synthetic fuels
Opportunity for Australian industry	High	High - labour intensive	High	High
Jobs opportunity	Medium	High	Medium	High
Main location of opportunity	Urban/regional	Regional/remote	Regional/remote	Urban/regional
Difficulty of capture/level of investment	Low > Manufacture of components already taking place in Australia. However, further development may be dependent on domestic procurement of CST plants	High > Early projects likely to require significant financial support.	High > Early projects likely to require significant financial support.	High > Technologies are less mature - requires significant R&D investment

19 High efficiency low emissions (HELE)

HELE technologies allow for use of fossil fuel energy generation at higher efficiencies and therefore lower emissions. In Australia, with the likely retirement of existing coal-fired generation and possible limitations on the share of VRE, there may be scope for deployment of new build HELE plants in order to meet electricity demand. According to CSIRO modelling however, in order to achieve abatement targets, all new build HELE will either need to be combined cycle gas and/or require CCS. The viability of HELE in Australia also depends on whether a social licence for new build coal and gas generation can be obtained. While Australia has R&D capability supporting certain HELE technologies (e.g. DICE, gasification), it is likely to continue to remain an importer of these energy generation systems. Uptake of these technologies globally will enable the continuation of Australia's fossil fuel export. Locally, there may also be opportunities associated with new plant EPC and O&M.

- HELE technologies allow for the continued use of fossil fuel feedstocks at higher efficiencies and significantly lower emissions. They also provide a high efficiency platform which significantly reduces the cost of staged CCS deployment. A number of technology options exist currently at varying levels of maturity.
- New build gas combined cycle is currently cost competitive (~$70/MWh) and relatively low emissions. Note however that use of coal seam gas is likely to carry significant social licence risk.
- In the event that the electricity network is unable to accommodate a share of VRE that is greater than ~40%, and is subject to an abatement target of approximately 95%, new build HELE with CCS could become cost competitive with other forms of generation.
- The competitiveness of new build gas-fired HELE (with CCS) over coal depends primarily on whether there is a high gas price (i.e.~$9-12/GJ). It is also unclear whether new build gas with CCS is likely, given limited interest from the industry to date.
- Reciprocating engines, namely DICE, provide additional flexibility in that they have high ramp rates, are modular and can accept a range of different feedstocks. While further RD&D is required, DICE and other modular dispatchable systems are recognised as potentially viable options for providing backup for VRE.
- While Australia retains strong IP (e.g. DICE, gasification), it is likely to remain an importer of relevant technologies.
- Uptake of HELE technologies internationally may also prolong Australian thermal coal export within a carbon constrained world. International collaboration supporting fuel matching (i.e. matching Australian coal to specific HELE technologies used overseas) will also be critical to continued export.
- Opportunities may also exist in the EPC and O&M associated with deployment of new plant.

19.1 Technology overview

Technology description

The primary HELE technology categories include:

1. Pulverised coal
2. Gasification (Integrated Gasification Combined Cycle)

3. Gas turbines
4. Reciprocating combustion engines

Ancillary technologies such as coal drying and CST may also be incorporated into generation plants in order to achieve further gains in efficiencies.

Pulverised coal

Coal is pulverised into a powder. This powder is then combusted and used to generate steam to power a turbine. As shown in Table 76, other than Oxyfuel, HELE pulverised coal technologies achieve greater efficiencies by operating at higher steam temperatures and pressures which also imposes a higher capital and operating cost (CO2CRC, 2015). However, given that the plant operates at higher efficiency, less fuel is required per MWh of energy produced. This enables significant reductions in operating costs as compared with incumbent generation.

Table 76 – Pulverised coal technologies (CO2CRC, 2015)

TECHNOLOGY	DESCRIPTION
Supercritical steam	Steam temperatures at 565/585˚C and > 24.8 MPa at efficiencies of approximately 38-41%[17]
Ultra-supercritical	Steam temperatures at 593/621˚C and > 24.8 MPa at efficiencies of approximately 41-42%[17].
Advanced ultra-supercritical	Steam temperatures of > 677˚C and > 34.5 MPa at efficiencies of > 42%. This is not yet feasible and likely to be very expensive.
Oxyfuel	Pulverised coal is fired using oxygen and recycled exhaust gas rather than air. The high concentration oxygen stream is produced in an air-separation unit. The fuel combustion produces a concentrated stream of CO_2 that allows for more efficient capture. However, the air separation unit has a high upfront capital cost and high auxiliary power usage (CO2CRC, 2015)

Gasification – Integrated gasification combined cycle (IGCC)

IGCC involves the reaction of a carbonaceous feedstock (e.g. coal) at high temperatures (> 700˚C) without combustion, in the presence of either air or oxygen to produce syngas. The syngas can then be combusted in a gas turbine system to produce electricity (CO2CRC, 2015). The process can be operated with integrated high pressure CO_2 capture.

Importantly, the range of products able to be produced from syngas via gasification can make project economics more favourable.

There are three types of gasifiers available as described in

[17] Note that efficiencies and temperatures for supercritical steam may have improved since the writing of the Australian Power Generation Technology Report in 2015

Table 77 below. Each differs significantly in terms of operating conditions and feedstock requirements.

Table 77- Gasification technologies

TECHNOLOGY	DESCRIPTION
Fixed bed	Fixed bed gasifiers convert large lumps of coal in a fixed bed reactor similar to a blast furnace. Air or oxygen is injected at the bottom of a permeable bed and syngas leave the reactor at the top. Ash or molten slag (depending on the technology variant) is discharged from the bottom of the reactor.
Fluidised bed	Granular coal is converted in an air blown (or oxygen enriched) fluidised bed reactor **Invalid source specified.**.
Entrained flow	Pulverised coal or a coal slurry and air or oxygen are fed into the reactor at high temperature and pressure. This forms an entrained flow of coal particles which rapidly gasify. The high temperature means that different types of fuel may be used. Further, given that the mineral matter is usually removed as a molten slag, there is very little ash and a low volume, high density slag is produced which can be easily used or disposed of **Invalid source specified.**.

Gas Turbines

A summary of the types of gas turbine technologies available is provided in Table 78.

Table 78 - Gas turbine technologies (CO2CRC, 2015)

TECHNOLOGY	DESCRIPTION
Frame gas turbines	Natural gas is combusted under pressure to produce hot gas that drives the turbine. These turbines are larger, but typically less flexible than aeroderivative turbines (i.e. bulkier with reduced ramp rates)
Aeroderivative (open cycle) gas turbines	Derived from jet engines and typically used as gas peakers. These are comparatively lightweight turbines that rely on a continuous mixture of air and fuel which is compressed in order to create a hot pressurised gas flow that expands in the turbine. The hot gas rotates the turbine blades and drives the compressor.

Gas turbines may be combined cycle (i.e. where heat is recovered in order to power a steam turbine) thus raising the overall efficiency of the system.

Combustion engines

In combustion engines, a combustible mixture (including fuel) is compressed in a cylinder of an engine using the piston for compression. This mixture is then ignited, which causes an expansion of gases and pushes the piston down. The continual up and down motion of the piston is converted to electrical energy via a crankshaft.

Table 79 – Reciprocating engine technologies (CO2CRC, 2015)

TECHNOLOGY	DESCRIPTION
Compression ignition (diesel) engine	Ignition occurs using a highly compressed air and fuel mixture.
Spark or pilot injection engine	The fuel mixture does not get hot enough when compressed and so requires a spark or other ignition source. Although less affected by increasing elevation and ambient temperature, it must operate at lower compression ratios to prevent uncontrolled auto-ignition and engine knock
Direct injection carbon engines	A specifically modified diesel engine that uses a micronized coal-water or biomass (i.e. BioDICE) slurry as the fuel. These engines are modular, are therefore easy to scale and operate at high efficiencies (>45%)

Ancillary technologies

Other technologies that assist in improving efficiencies of HELE plant include (but are not limited to):

- Coal drying – Typically involves using low grade waste heat from a power station to dry thermal coal (CO2CRC, 2015)
- CST – Can be applied to existing or new HELE generation in order to supplement heating requirements that would otherwise be obtained by burning additional coal or gas (refer to CST appendix).

Technology impact

HELE technologies operate at higher efficiencies than current fossil fuel based energy generation technologies. Consequently, they require less fuel per unit of electricity generated, which significantly reduces emissions. HELE technologies are at varying levels of maturity (as shown in Table 81 below).

In Australia, with the likely retirement of existing coal-fired generation, deployment of new build HELE is more likely to be required where the electricity network is unable to accommodate a share of VRE greater than ~40%. Under a stringent 2050 emissions target (~95%), after 2030, most new build HELE will likely require CCS. However, it is still expected to be cost competitive with other types of dispatchable generation (e.g. CST, nuclear). Note that a 100% emission reduction target in electricity generation may preclude HELE even with CCS. This is due to the fact that complete capture of upstream and downstream emissions from coal/gas is likely to be technologically and cost prohibitive.

Gas turbines (i.e. gas combined cycle and gas peakers) are technologically mature, relatively low cost ~$65-80/MWh) and have a relatively low emissions profile compared to coal (i.e. 373 kg CO_2/MWh versus 740 kg CO_2/MWh). Further, it is more suited to deployment alongside VRE given its greater flexibility, higher ramp rates and consequent ability to load follow VRE.

Reciprocating engines, namely DICE, provide additional flexibility in that they have high ramp rates, are modular and can accept a range of different feedstocks (Nicol, 2014). While further RD&D is required, DICE and other modular dispatchable systems are recognised as potentially viable options for providing backup for VRE. BioDICE (i.e. biomass fuelled DICE) in particular also offers the potential to provide near zero net greenhouse gas emissions and be cost competitive with other forms of renewable generation (e.g. solar and wind).

The competitiveness of new build gas-fired generation (with CCS) over coal depends primarily on whether there is a high gas price (i.e.~$9-12/GJ). It is also unclear whether new build gas with CCS is likely, given limited interest from the industry to date.

19.2 Technology status

Cost - current state and projections

Projected LCOEs and emissions intensities for potential new build HELE generation in Australia are set out in Table 80 below. Note the emissions intensity for existing sub-critical coal-fired power in Australia is approximately 1,100 – 1200 kg CO_2e/MWh)[18].

Table 80- Key HELE technologies LCOEs ($AUD/MWh)

	2015	2020	2030	EMISSIONS INTENSITY (KG CO_2E/MWH)[19]
Supercritical pulverised black coal	70-85	70-85	65-80	792
Ultra-supercritical black coal	70-85	70-85	65-80	740
Black coal IGCC	100-130	100-130	90-110	792
Combined cycle gas turbine	65-80	65-80	65-80	373
DICE (coal)[20]	60-75	60-75	60-75	670
BioDICE	70-85	70-85	70-85	n/a

Technological and commercial readiness - current state

The technological and commercial readiness of each of the relevant HELE technologies is considered in Table 81.

[18] Derived from http://www.cleanenergyregulator.gov.au/DocumentAssets/Pages/2014-15-Greenhouse-and-energy-information-for-designated-generation-facilities.aspx
[19] Refer to (CO2CRC, 2015)
[20] DICE running as baseload (80% capacity factor) using a brown coal slurry

Table 81 – Technological and commercial readiness 2016

WIND TURBINE	TRL	CRI	COMMENTS
Supercritical coal	9	6	Supercritical plants are a mature technology.
Ultra-supercritical	8	5-6	Technological readiness has improved with the recent development of new materials (alloys) that can tolerate higher temperatures (˜600˚C).
Black coal IGCC	8-9	3-4	Numerous coal-based gasification units exist at chemical plants around the world. Several decades of experience has made the basic combined cycle plant a mature generating technology (CO2CRC, 2015). For electricity, at present there are only fourteen IGCC plants operating worldwide with a capacity size ranging from 40 MW to 582 MW **Invalid source specified.**
Combined cycle gas turbine	9	6	Combined cycle gas turbines are a mature technology
DICE	8	2	At pre-commercial stages – demonstration projects required (Nicol, 2014)

19.3 Barriers to development and potential enablers

Deployment of new build HELE relies heavily on whether a social licence to continued use of gas and coal can be obtained. One possible exception to this may be new build gas turbines for reasons outlined above. Widespread communication of the impact of HELE in lowering emissions (as compared with incumbent generation) could be somewhat effective. However, overcoming these barriers also relies heavily on the availability of CCS.

Further, it may also be difficult to secure investment for 'bulky' generation given the difficulty associated with predicting long term demand profiles. Rigorous modelling and securing PPAs where possible will be critical to mitigating this risk.

For gas-fired generation, another key concern is the long term availability and price of gas of domestic gas. This is most likely to depend on the future of the gas export market as well as current moratoriums on unconventional gas reserves in Australian states such as Victoria and NSW.

Table 82 - HELE barriers and potential enablers

Category	**Barrier**	**Potential enablers**	**Responsibility**	**Timing**
Costs	Cost of certain HELE technologies (e.g. IGCC, ultra-supercritical coal)	> Continue international R&D collaborations > Pursue bilateral agreements with countries heavily reliant on fossil fuel generation (e.g. China)	> Industry > Research organisations	Ongoing
	Availability and consequent price of gas	> Conduct detailed research on the impact of drilling in unconventional gas reserves (e.g. coal-seam gas) and consider removal of moratoriums	> Government > Research organisations	Ongoing
Revenue/market opportunity	Difficult for new fossil fuel assets to attract investment due to social licence	> Refer to stakeholder acceptance below	> Government > Industry	Ongoing

Category	Barrier	Potential enablers	Responsibility	Timing
	HELE generation may be bulky and inflexible. It is therefore difficult to secure investment given that it is unclear what energy demand will be at the time of deployment	> Continue to develop flexible types of HELE generation (e.g. DICE) > Conduct rigorous modelling to understand demand profiles and secure PPAs where possible	> Industry > Research organisations	Ongoing
Regulatory environment	n/a	n/a	n/a	n/a
Technical performance	HELE technologies are still emissions intensive as compared with renewable alternatives	Develop and deploy with CCS in order to significantly reduce the emissions profile	> Government > Industry	2025-2030
Stakeholder acceptance	Public opposition to continued reliance on fossil fuel generation (i.e. social licence barriers)	> Communicate high efficiencies and lower emissions readily achieved by HELE technologies > Develop CCS and engage stakeholders to demonstrate the impact in lowering emissions > Communicate role of gas combined cycle as a low emissions energy transition option	> Government > Industry	Ongoing
	Environmental concerns over other by-products from generation (smog, NOx, SOx, particulates)	> Communicate impact of HELE technologies in reducing other harmful by-products from fossil fuel generation	> Government > Industry	Ongoing
Industry and supply chain skills	n/a	n/a	n/a	n/a

19.4 Opportunities for Australian Industry

Australia has a well-established coal and oil & gas industry as well as vast coal and gas reserves. New build HELE with CCS would therefore enable the continuation of the current industry, creating further EPC and O&M opportunities associated with new plant. Australia is also a world leader in development of technologies such as DICE and so additional opportunities may be gained through the export of IP to countries still heavily reliant on fossil fuel generation (e.g. China).

While uptake of HELE technologies globally may not lead to expansion of Australia’s coal and gas export, it does play an important role in pro-longing current industry while there is scope to do so within a tightening global carbon budget. Fuel specifications for advanced gasification and oxyfuel technologies are significantly different than those for conventional combustion technologies.

Australian partnerships with international technology developers will therefore be important in supporting the export coal industry to ensure the most efficient outcomes from fuel-technology matching and in maximising the value of Australian resources. That said, with recent International Energy Agency (IEA) (IEA, 2016) reports suggesting that imports of thermal coal are expected to decline in China and India in order to limit warming to 2˚C, it is important for Australia to take a conservative approach to the future of export.

Table 83 - Opportunities for Australian Industry Summary

	Technology manufacture	**Extraction of raw materials**	**EPC**	**O&M**
Description	Manufacture of HELE technology and relevant BoP	Involves continued coal mining as well as extraction and processing of natural gas	Involves design and procurement of HELE plant	Involves operation and maintenance of DICE generators
Australia's comparative advantage	Low + Strong IP in design of technologies (DICE, gasification) - Established manufacturing industries for HELE technologies overseas - High cost of manufactring locally	High + Abundant natural fossil fuel resources + Established coal mining and oil & gas processing industries	High + Established fossil fuel industry with strong engineering capabilities + EPC must be done locally	High + Established fossil fuel industry with strong engineering capabilities + O&M must be done locally
Size of market	High - Small local market and share of global market	Medium- Local market for new build (prolonging of current export markets)	Medium - Local market for new build	Medium - Local market for new build
Opportunity for Australian industry	Low - Potential to export IP to share of global market	Medium > Pro-longing of export market (as opposed to exapansion) within tightening global carbon budget	Medium	Medium
Jobs opportunity	Low	Medium	Medium	Medium
Main location of opportunity	Urban/regional	Regional/remote	Regional/remote	Regional/remote
Difficulty of capture/level of investment	Medium	Medium > May require ongoing stakeholder consultation and possible removal of moratorium on coal seam gas. International collaboration for fuel matching also critical	Medium	Medium

20 Carbon capture and storage (CCS)

Globally, CCS provides a critical means of decarbonisation across a number of different industries. For the Australian electricity sector, continued use of most coal or gas-fired generation is likely to require CCS in order to meet 2050 emissions targets. This may be achieved by deployment with new build HELE or via retrofit of existing generation. Both could be cost-competitive with other generation technologies after 2025 if the right policy drivers are in place. CCS is also likely to (continue to) be applied to gas processing and is critical to the development of low emissions coal-based hydrogen production for export. While the need for CCS in Australia is not immediate (i.e. pre-2030), a considerable amount of work is required to maintain momentum for deployment and ensure that the technology is available when required. Australia's deep technical expertise and established oil & gas industry leave it well placed to capitalise on CCS development, both in servicing local (or nearby) markets and exporting IP overseas.

- Globally, CCS is a critical enabler of continued fossil fuel use in a carbon constrained world. However, implementation of CCS imposes additional costs on existing operations (e.g. overall LCOEs of ~$95-160/MWh for likely electricity generation in 2030).
- In order for the electricity sector to decarbonise in line with likely 2050 abatement targets, with the possible exception of gas turbines (e.g. gas combined cycle and gas peakers), any continued fossil fuel power generation will require CCS. CCS may be deployed with new build HELE or via retrofit of capture systems on existing generation. Both could be cost-competitive with other generation technologies after 2025 if the right economic drivers are in place.
- CCS can also be applied to biomass-fired electricity generation (i.e. BECCS). However this is likely to be expensive (i.e. $210-260/MWh in 2030) and so would require a policy regime that encourages/mandates negative emissions to be achieved.
- Aside from electricity generation, CCS may be deployed for other applications:
  - Natural gas processing (for LNG) (refer to Section 9)
  - Hydrogen production via gasification of coal (refer to Section 23)
- Although a number of industrial processing facilities in Australia (e.g. ammonia plants) already undertake some form of CO_2 capture, as with gas processing, the application of full scale CCS imposes a cost on operations and will be challenging given the trade-exposed nature of these industries. A global carbon price or pre-existing CO_2 transport and storage network established for the electricity sector could serve to mitigate these costs.
- A considerable amount of work is required to maintain momentum for CCS and ensure that the technology is widely available when required. This includes:
  - Implementing appropriate policy measures
  - Ensuring that storage sites are well characterised
  - Progressing R&D focused on improving the efficiency and lowering the cost of CO_2 capture as part of a global program
  - Conducting widespread stakeholder engagement to communicate the risk and benefits of CCS
- Australia has a well-established oil & gas industry with deep technical expertise and would be well placed to capitalise on deployment of CCS. This would provide new opportunities for Australia in servicing local or nearby markets and exporting IP overseas (e.g. capture technologies).

20.1 Technology overview

Technology description

In CCS, CO_2 emitted from different facilities may be captured and then transported for the purpose of geological storage. Alternatively, the CO_2 may be 'utilised' in relation to certain processes.

Each of the supply chain steps is described in further detail below.

Capture

CO_2 capture technologies may be applied to fossil fuel power generation, gas processing and other emissions intensive industrial processes (e.g. cement, chemicals). The capture rate (i.e. percentage of CO_2 captured from a particular process) is generally based on the available technology, concentration of CO_2 in the exhaust gas, as well as overall project economics (i.e. CO_2 capture may be cost prohibitive above a specified percentage).

Capture technologies relating to electricity generation are discussed further in Table 84.

Table 84 – CO_2 capture technologies for electricity generation (IEA, 2013)

TECHNOLOGY	DESCRIPTION
Post-combustion capture (PCC)	Contaminants (e.g. SOx, NOx) are first removed from the exhaust of a combustion process via flue gas desulphurisation (FGD) and selective catalytic reduction (SCR). CO_2 may be separated from the stream via one of the techniques discussed in Table 85. It is then dried and compressed for transport and storage. 90% CO_2 removal is typical for this capture process.
Pre-combustion capture	Syngas is produced from coal gasification or SMR. The syngas then undergoes a 'water gas shift reaction' which leads to an increase the proportion of CO_2. This CO_2 is then removed using one of the separation techniques discussed in Table 85, leaving a combustible fuel (e.g. hydrogen). CO_2 is easier to remove via pre-combustion capture than via post-combustion capture due to its higher concentration. This process therefore requires less extensive CO_2 separation equipment which reduces the cost (CO2CRC, 2015). Optimised capture rates can range between 65% to close to 100%
Oxyfuel combustion	This process is similar to PCC, however oxygen (rather than air) is used in the combustion process to yield a high concentration of CO_2 which makes capture easier and less costly (CO2CRC, 2015). However, it requires initial separation of oxygen from air which increases cost and is more energy intensive. 100% of the CO_2 may be captured as a result of this process.

Key CO_2 separation technologies for post and pre-combustion capture are set out in

Table 85.

Table 85 – CO_2 separation technologies (Leung, 2014)

TECHNOLOGY	DESCRIPTION
Absorption	The most common method for CO_2 separation involves passing the treated gas through a column where it is typically absorbed by an amine solvent (via a thermally reversible reaction). The mixture is then passed through a stripper column where heat is used to regenerate the amine, allowing CO_2 to be released at the top (CO2CRC, 2015). Amines may be subject to degradation, resulting in solvent loss, equipment corrosion and generation of dangerous compounds. Other solvents are therefore currently being considered.
Adsorption (solid sorbent)	This method relies on a solid sorbent that can bind the CO_2 on its surface. CO_2 can be recovered by changing the pressure/temperature in the system which allows for desorption to occur. These sorbents typically have high regeneration abilities, large surface areas and are selective in terms of which compounds may be adsorbed.
Chemical looping combustion	This is suitable for pre-combustion capture. The fuel is combusted indirectly using a metal oxide as an oxygen carrier. During combustion, the metal oxide is reduced to the metal (only) while the fuel is oxidised to produce CO_2 and water. The CO_2 is then separated via condensation of the water and the metal re-oxidised for future use **Invalid source specified.**.
Membrane separation	Membranes that only allow CO_2 to permeate through can be applied to an exhaust gas. These membranes are made primarily of composite polymers and have been traditionally used to separate gases such as oxygen, nitrogen and CO_2 from natural gas
Hydrate-based separation	Exhaust gas is exposed to water at the optimal pressure for hydrate formation allowing the CO_2 to become trapped inside hydrates (i.e. ice-like water structures which contain cavities where small gases can be trapped). This allows for separation from other gases.
Cryogenic distillation	This process relies on very low temperatures but high pressures to solidify CO_2 and thus separate it from other gases.

Transport

CO_2 is typically transported via pipeline. Pipeline infrastructure has a high upfront capital cost. However this is amortised over the lifetime of a CCS project and therefore makes up a small proportion of the overall cost. Ships or trucks may also be used to transport CO_2 where commercially favourable.

Storage

CO_2 may be injected into both onshore and offshore stable rock formations. These formations consist of porous rocks that are permeable (i.e. CO_2 can spread through) and a seal or cap at the top that enables permanent storage. Examples of suitable formations include:

- Deep saline aquifer - naturally occurring reservoirs that have trapped saline water greater than 1km below the earth's surface
- Depleted oil and gas fields

There is an ongoing risk that stored CO_2 could leak from reservoirs, particularly in the event of a natural disaster (i.e. earthquake). Detailed assessments of the risk of leakage, response strategies as well as considerable measurement, monitoring and verification (MMV) is required in order to gain comfort over the storage capability of different sites. As additional confidence in the storage reservoir is achieved post injection (i.e. once the CO_2 is demonstrated to be behaving as expected) MMV requirements are continually lessened.

Utilisation

Captured CO_2 may be utilised for a variety of applications (e.g. chemical solvents). EOR however, is most suited to large-scale carbon capture given the quantities of CO_2 required (i.e. greater than 60 Mt CO_2 per year globally (IEA, 2013)). As with storage, ongoing monitoring is required to assess the effectiveness of EOR in achieving long term CO_2 storage. Further, it is unlikely to be applicable in Australia given the already small and declining nature of domestic oil production.

ECBM may be more relevant in an Australian context. While at a lower TRL, this technology follows a similar concept to EOR wherein methane in coal seams can be displaced by injected CO_2 and subsequently recovered and used.

Other less mature uses are set out in Table 86 below. While these technologies may be valuable in improving a business case for CO_2 capture at a particular facility, it is questionable as to whether they will contribute to material emissions abatement. One possible exception to this may be via mineral carbonation which provides the option for solid CO_2 storage once the designated market (e.g. cement, bricks) has been saturated. In Australia, this technology is being developed by Mineral Carbonation International (MCI) who are aiming to utilise 20 Mt CO_2 per annum in Australia, targeting a price of \$50/tCO_2.

Table 86 - Emerging CO_2 utilisation technologies

TECHNOLOGY	DESCRIPTION
Mineral carbonation and CO_2 concreting	Various minerals (calcium or magnesium silicates) may be reacted with CO_2 to form inert carbonates (Centre for low carbon futures, 2011). Solid CO_2 formed as a result of these processes may be sold or stored in old quarries.
Algae cultivation	Cultivation of microalgae using CO_2 from flue gases in open ponds or photo-bioreactors. This algae could then be used for accelerated biofuels production at low cost for use in transport.
Fuel production	CO_2 may be combined with water at high temperature to form syngas (which may then be further refined into other fuels). This requires an energy input and so in order to reduce emissions, it may use plant waste heat or be coupled with renewable energy (e.g. CST)
Plastics	Production of plastics using a combination of CO_2 and agricultural waste **Invalid source specified.**

Technology impact

Globally, CCS provides a critical means of decarbonisation across a number of different sectors.[21] However, implementation imposes an additional cost on existing operations (e.g. overall LCOEs of ~\$95-160/MWh[22] for likely electricity generation in 2030 as per Section 20.2). Therefore, even if utilisation (e.g. ECBM) is available, appropriate policy incentives/mandates are still likely to be required in order to facilitate

[21] The report is primarily concerned with the application of CCS in electricity generation, direct combustion and fugitive emissions. Emissions derived from industrial processes such as cement and steel manufacture may be able to technically incorporate CCS, however detailed analysis is outside the scope of the report.
[22] LCOEs are derived from CSIRO modelling undertaken for the project and are based on costs from (CO2CRC, 2015). Note that based on stakeholder interviews conducted as part of the project, overall storage costs may be higher depending on the reservoir properties, transport distance and regulations imposed

deployment. Even in the absence of uniform local and global policy, considerable work is being undertaken in order to improve the technology and overall cost.

Currently there are 15 large scale CCS projects in operation globally, capturing 28.7 Mt of CO_2 annually with another 23 under construction or in development. Only 3 of the 15 operating projects are using dedicated CO_2 storage with the remainder applying EOR.

In Australia, to date there have been a number of projects that have been either mandated under existing policy or deployed to demonstrate the applicability of CCS in Australia. The most significant has been the Gorgon project at Barrow Island. In this instance, as a condition of development of offshore gas reserves for LNG production, the Gorgon Joint Venture[23] was required by the Western Australian Government to sequester otherwise vented CO_2 in deep saline aquifers. Injection of CO_2 is expected to start in 2017.

Other extensive research into various CCS technologies has also been ongoing. Notable Australian projects include:

- Otway – A pilot scale deep geological storage demonstration project in Victoria
- CarbonNet – A project jointly funded by Commonwealth and Victorian Governments assessing feasibility and commercial viability of commercial scale CCS in the Latrobe Valley/Gippsland Basin. The project has made significant progress in validating the potential for storage sites in the offshore Gippsland basin and would be able to provide a CCS service to projects such as the HESC (case study).
- Surat Basin - CTSCo, a wholly owned non-for-profit subsidiary of Glencore is leading a project to demonstrate the technical viability of CCS in the Surat Basin, Queensland.
- Callide Oxyfuel Project - was the world's first industrial scale demonstration of oxyfuel combustion and carbon capture technology, in Biloela Queensland.
- South West Hub – Western Australian and industry partnership assessing the viability of the Lesueur Sandstone formation as an onshore CO_2 storage reservoir.

As discussed below, CCS may enable significant CO_2 reductions in the electricity, gas processing and manufacturing sectors.

Electricity

As per CSIRO modelling (Appendix C of the main report), there is unlikely to be a need for CCS until after 2030. With the possible exception of gas combined cycle (as discussed in Section 19), in order for the electricity sector to meet potential 2050 abatement targets, post 2030, any continued coal or gas-fired power generation is likely to require CCS. CCS may be deployed with new build HELE or via retrofit PCC on existing generation. Both could be cost-competitive after 2025 if the right policy drivers are in place (as per CSIRO modelling).

While not included in the modelling presented in this report, it is acknowledged that retrofit PCC may provide a more cost effective option than new-build HELE with CCS (as discussed in Section 20.2 below). Australia should continue to participate in international efforts and leverage learnings from retrofit projects

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[23] Includes Chevron, ExxonMobil. Shell, Osaka Gas, Tokyo Gas and JERA

overseas such as Boundary Dam (Canada) and Petra Nova (USA) in order to help lower costs and optimise pathways to deployment.

CCS can also be applied to biomass-fired electricity generation (i.e BECCS). However this is likely to be expensive (i.e. $210-260/MWh in 2030) and so would require a policy regime that encourages/mandates negative emissions to be achieved. Assuming all of Australia's estimated ~1000 PJ/year[24] of potential biomass was used for BECCS, this could provide around a third of Australia's current electricity demand and create ~84 MtCO2e[25] of negative emissions. However this is likely to be expensive ($210-260/MWh in 2030).

Gas

CCS may (continue to) be deployed in:

- Natural gas processing (for LNG) – Discussed further in Section 9
- Hydrogen production – CCS will be a key enabler of low emissions exportable hydrogen if produced at scale via gasification of coal (refer to Section 23).

Industrial processing

While outside the scope of this report, CCS also has applications in industrial processing (i.e. not direct combustion). Although a number of industrial processing facilities in Australia (e.g. ammonia plants) already undertake some form of CO_2 capture, as with gas processing, the application of full scale CCS imposes a cost on operations and may be challenging given the trade-exposed nature of these industries. A global carbon price or pre-existing CO_2 transport and storage network established for the electricity sector could serve to mitigate these costs.

20.2 Technology status

Cost - current state and projections

The cost projections for key HELE technologies with CCS are set out in

[24] Refer to SKM study in (ClimateWorks Australia, 2014)

[25] Calculation based on emissions factor of 84.24 KgCO2/GJ for IGCC plant using lignocellulosic biomass (Farine, 2012)

Table 87 below.[26]

[26] Refer to LCOE methodology for further details

Table 87- CCS with key HELE technologies LCOE ($AUD/MWh)

TECHNOLOGY	2015	2020	2030
Pulverised black coal	150-180	150-180	130-160
Pulverised brown coal	160-200	160-200	140-180
Black coal IGCC	170-200	150-190	130-160
Gas combined cycle	110-130	110-130	100-130
Oxyfuel black coal combustion	150-180	140-180	130-160
Retrofit PCC coal generation	100-150	100-150	95-130
Biomass gasification with CCS	270-330	240-290	210-260

For retrofit PCC of coal fired-generation, LCOEs are estimated to be in the order of $100-150/MWh. This assumes there will be significant cost reductions based on learning from plants being retrofitted overseas (e.g. Boundary Dam, Petra Nova and the ROAD project). This also assumes the availability of novel solvents which are lower cost and more efficient and that additional pollution control measures such as flue gas desulpherisation (to remove NOx) and selective catalytic reduction (to remove SOx) may not be required.

Note that the LCOEs for PCC retrofit depend heavily on the age, condition and location of the asset. For example, NSW generators such as Liddell power station, which are nearing retirement would be less favourable given the upgrades required and proximity of prospective geological storage sites. Conversely, younger generators such as Loy Yang A & B (Victoria) as well as Kogan Creek (Queensland) may prove viable given their lifetime and possible storage options in the Gippsland and Surat Basins respectively.

Technological and commercial readiness – current state

All technology elements of the CCS supply chain are well understood and could be deployed at scale. For electricity generation, CO_2 capture represents 70-80% of overall CCS expenditure (Leung, 2014) and so considerable research efforts are currently being targeted towards improving efficiencies and reducing the cost of capture. Improvements in CO_2 separation technologies are therefore critical. These are discussed further in

Table 88 below.

In Australia, existing and future generation facilities do not, or are unlikely to contain FGD due to the low sulphur content of local coal. Separation technologies that are not contaminated by trace amounts of sulphur, or simultaneously remove SO_2 and CO_2, will also be important in reducing capture costs.

Other developments will stem from the need to broaden the portfolio of storage reserves as well as improve MMV technologies deployed at commercial scale.

Further emissions reductions can be achieved through the deployment of hybrid systems such as CST, geothermal and biomass which can provide low (or zero) emissions energy in order to supplement plant heating requirements.

Table 88 - TRL and CRI for relevant CO_2 capture technologies

CCS	TRL	CRI	COMMENTS
Absorption	9	3-4	Boundary Dam, in operation since 2014, using Shell-Cansolv technology; Petra Nova, which is in start- up phase, is using Mitsubishi Heavy Industries technology. Aqueous ammonia has been shown to be a promising solvent for combined capture of SOx, NOx and CO_2
Adsorption (solid sorbent)	6	1	Trials currently underway at US National Carbon Capture Centre in Wilsonville, USA
Chemical looping combustion	4-6	1	A prototype plant was developed by Alstom in Germany in 2014 **Invalid source specified.**
Membrane separation	6	1	Various trials with membrane systems underway in the US
Hydrate-based separation	1-2	1	This is at the experimental stage **Invalid source specified.**
Cryogenic distillation	1-3	1	Brigham-Young University has been mostly active in this field **Invalid source specified.**

As emerging CO_2 utilisation technologies continue to develop, there may be scope to create further commercial solutions for capture of CO_2. Their current technological and commercial readiness is assessed in Table 89.

Table 89 - TRL and CRI for emerging utilisation technologies

CCS	TRL	CRI	COMMENTS
ECBM	1-3	1	This is at an early stage of development. Requires more research to understand the impact on different types of coal **Invalid source specified.**.
Mineral carbonation and CO_2 concreting	8-9	2	This is at the demonstration phase and may be economically feasible now under the right conditions MCI are about to commission a 2nd stage reactor.
Algae cultivation	8-9	2	There are several demonstration projects where CO_2 flue gas is being injected into algae ponds. The algae is used for nutraceuticals, food dyes and supplements **Invalid source specified.**.
Fuel production	5-7	1	Ongoing research as well as a small pilot plant which has produced methanol from CO_2 and H_2. NewCO2Fuels is an ASX listed Australian company that has been quite active in this field, developing modular reactors that can be retrofitted to various generation facilities.
Plastics	1-2	1	This is at the early laboratory research stages **Invalid source specified.**

20.3 Barriers to development and potential enablers

While unlikely to be deployed commercially for electricity generation until after 2025, there are a number of key measures that should be implemented to ensure that Australia maintains momentum and is 'CCS ready' when and if required. These include:

- Implementing appropriate policy (discussed further in Table 90)
- Ensuring that prospective storage sites are well characterised
- Progressing R&D focused on improving the efficiency and lowering the cost of CO_2 capture as part of a global program
- Conduct widespread stakeholder engagement to communicate the risk and benefits of CCS

There is also an ongoing perception that CCS promotes continued use of coal and is unsafe due to CO_2 leakage from reservoirs, particularly onshore. Widespread consultation with stakeholders regarding the safety of geological storage and continual community has been found to be critical in overcoming these social licence barriers (Ashworth, et al., 2013).

Note that the University of Queensland were recently commissioned by the Low Emissions Fossil Fuel working group to develop a roadmap for CCS in Australia. This roadmap has been used to help inform the barriers and potential enablers discussed in Table 90 below.

Table 90 - CCS barriers and potential enablers

Category	**Barrier**	**Potential enablers**	**Responsibility**	**Timing**
Costs	High cost of infrastructure/technology	> Explore opportunities for joint development of infrastructure (e.g. sharing of pipelines, drill rigs) > Conduct modelling in order to optimise networks, matching future capture points to storage/utilisation with potential to scale up existing networks > As part of global programs, support R&D and demonstration projects that focus on lowering cost of CO_2 capture (i.e. combined capture of SO_2 and CO_2)	> Industry > Research organisations > Government	2017-2020
	High cost and high risk associated with storage appraisal	> Continue to update 'precompetitive' geoscientific data (i.e. 'storage atlas') to stimulate exploration > Continue to develop policies to foster a competitive environment for geological storage (e.g. permitting, non-prohibitive costs associated with proving storage capacity) > Continue R&D into various means of alternative storage (e.g. burying solid CO_2 produced via mineral carbonation and other potential rock formations)	> Government > Academia > Industry bodies	2017-2020
Revenue/market opportunity	No economic drives in place or incentives driving uptake	> Government should provide a long term commitment in order to stimulate industry > Implement a stable policy regime for decarbonisation that creates a financial incentive for CCS and drives investment. > Conduct a review of appropriate financial instruments and commercial structures and models to optimise revenue and attract investment. > Determine most appropriate role for Government	> Government > Industry bodies	2021-2025
	Unknown economic conditions under which a full scale CCS project would operate (e.g. financial instruments commercial structures)	> Conduct a review of appropriate financial instruments and commercial structures and models to optimise revenue and attract investment.	> Government > Industry bodies	2017-2020

Category	Barrier	Potential enablers	Responsibility	Timing
		> Determine most appropriate role for Government		
Regulatory environment	Lack of a uniform favourable regulatory framework	> Continue to develop a regulatory framework that is aligned to global standards and encourages efficient, cost effective deployment of CCS without compromising safety and reliability.	> Government	2017-2020
Technical performance	> Uncertainty over the ability of geological sites to store CO_2 due to geological variability across sites	> As per storage appraisal costs	> Industry > Research organisations	Ongoing
Stakeholder acceptance	Lack of understanding and acceptance of the technology by the public due to associations with coal/gas and concern over safety (particularly for onshore)	> Reinforce that CCS is an important part of a national/regional climate change mitigation strategy > Effectively communicate safety risks and mitigation measures in place	> Government	Ongoing
	Limited awareness of CO_2 utilisation opportunities and associated benefits and belief that storage is the only solution	> Encourage organisations such as the GCCSI and CO2CRC to promote and pursue CCU opportunities > Ensure clean energy funding schemes explicitly include CCU as well as CCS	> Government	Ongoing
Industry and supply chain skills	Limited experience in integrating discrete components into end-to-end CCS network for electricity generation	> Develop standardised training for system operators consistent with global standards > Ensure that the knowledge gained from existing and future demonstration projects are reflected in emerging technical standards	> Government > Industry bodies > Project developers	Ongoing

20.4 Opportunities for Australian Industry

Australia has a well-established oil & gas industry with deep technical expertise and would be well placed to capitalise on deployment of CCS. This would provide a range of new opportunities for Australia that may include:

- Appraisal of storage reservoirs using existing companies and infrastructure
- EPC and O&M for CO_2 capture, pipeline and storage/utilisation
- Export of solutions or EPC and O&M for storage sites up to South East Asia
- Export of IP (e.g. capture technologies)

Australia also retains strong IP in utilisation technologies (e.g. ECBM, mineral carbonation) which could enable the development of new CO_2 storage markets.

Table 91 - Opportunities for Australian Industry Summary

	Capture	Transport	Geological storage	Utilisation
Description	> Involves the capture of CO_2 from flue gas or syngas, removal of impurities such as SOx and NOx and compression for transport > CO_2 may be captured in offshore/onshore gas processing, fossil fuel power generation, coal/gas to other products (e.g. hydrogen) and industrial processing	> Once captured, CO_2 is typically transported via pipeline. Ship and truck may also be used where commercially favourable	> Transported CO_2 is injected into underground rock formations using onshore/offshore wells	> Involves the use of CO_2 for other commercial purposes (e.g. Fuel production, mineral carbonation). The resulting products may be sold were possible or stored
Australia's comparative advantage	High + Established fossil fuel industry with expertise in gas processing + Established industrial processing industry for emissions intensive products (e.g. cement, steel) + Fossil fuel operations in close proximity to reservoirs characterised as potential storage options (e.g. La trobe valley) + Strong IP relating to CO_2 capture (e.g. regeneration of liquid absorbents) - High cost of manufacturing for relevant technologies	High + Established fossil fuel industry + Significant experience in gas transport + EPC and O&M must be done locally	High + Numerous identified potential storage sites with high theoretical capacity - Storage sites not distributed evenly across Australia + Broad range of established companies that carry out modelling, surveys and sample analysis + Developing CCS industry (e.g. Gorgon project, Surat Basin (CTSco))	High + Strong IP in relation to certain types of utilisation (mineral carbonation, ECBM) + Available natural resources (e.g. quarried minerals for carbonation) - Relatively small and declining oil industry so less need for EOR
Size of market	High > Service of local market and part of global market	High > Service of local market	High > Service of local and nearby markets (e.g. gas fields that extend up to South East Asia)	High > Service of local market and part of global market
Opportunity for Australian industry	High > Opportunity to export IP > Relevant technology likely to be manufactured overseas but EPC and O&M must occur locally	High > Opportunity to procure new pipeline infrastructure in Australia	High > Opportunity to support regional solutions > New opportunities for companies that support O&G industry	High > Service of local market > Export of IP and services
Jobs opportunity	Medium	High	High	High
Main location of opportunity	Urban/regional	Urban/regional/remote	Remote	Urban/regional
Difficulty of capture/level of investment	High	High	High	High

21 Geothermal

Geothermal will require a technology breakthrough to have a chance of being competitive with other generation technologies. Australia should continue to support low cost R&D aimed at decreasing the risk associated with drilling, but avoid large investments until this risk is brought down. This section largely relies on the International Geothermal Expert Group (IGEG) report (ARENA, 2014)**. This is the most recent and comprehensive assessment of geothermal in Australia.**

- Australia's potential geothermal resources have been classified into two broad groups that form a continuum – enhanced geothermal systems (EGS) and hot sedimentary aquifers (HSA) (Huddlestone-Holmes & Russell, 2012). So far none of these resources have been successfully developed.
- Australia also has shallow direct use resources that are ~100°C. These occur in several basins in Australia: Otway Basin and Great Artesian Basin for example. These resources consist of large quantities of warm water at accessible depths. However, unlike EGS and HSA, these resources are not sufficient to contribute to MW scale generation.
- EGS could potentially provide a large, low carbon, dispatchable power source. It has been estimated that more than 360 GW could be installed in the NEM (Huddlestone-Holmes & Russell, 2012). However, the majority of these resources are located away from electricity networks.
- Direct shallow resources have been used to generate electricity for many years in Birdsville, QLD. Winton, QLD is considering building a small geothermal power station also based on this resource (ABC, 2015). These are fringe of grid locations in outback QLD.
- Geothermal is unlikely to be competitive against VRE i.e. wind and solar PV. The optimistic best case LCOE of geothermal in 2030 is around $100/MWh (ARENA, 2014); the cost for geothermal for a remote resource such as the Cooper Basin is even higher; grid connection would add an additional $23/MWh for a 300 MW plant or $77/MWh for a 50 MW plant. While geothermal is likely to remain more expensive than VRE, geothermal is dispatchable, which means cost should be compared against VRE plus storage once VRE share is high enough that it can only be deployed with storage.
- Dispatchable technologies such as geothermal will have a greater role to play if VRE share is limited due to challenges in transforming the grid. Geothermal could be cheaper than nuclear and coal + CCUS, and may be competitive with gas combined cycle + CCUS and CST with storage.
- EGS in Australia has low technological and commercial readiness; to achieve commercial maturity, major breakthroughs are required to improve the success rate of drilling, and to increase flow rates from reservoirs. Overseas efforts such as the research program by the US DOE may help with this but Australian resources are sufficiently different that local research would also be needed (ARENA, 2014).
- Investment and research in Australia peaked in 2010 and has since dropped off, hampered in particular by high drilling costs, driven by competition with the oil and gas sector; the sector faced funding challenges in 2014 and many players have exited; ARENA is only funding smaller research projects which are focussed on understanding where to drill and how to reliably extract the heat from the wells.
- Due to the absence of large companies interested in investing long term in geothermal, it would require public investment to lower the risk of geothermal energy such that it is cost competitive with other electricity generation technologies by 2030.
- Due to the uncertainty of this investment being successful, large public funding of geothermal is not recommended. However, low cost research aimed at improving the success rate of drilling makes sense as part of an overall portfolio of research for the country.

- Absent a significant breakthrough, the most promising applications for geothermal energy are in electricity generation in remote, off-grid locations for community power and for direct heat use for gas processing where there is already proven heat reserves.
- The economics of geothermal energy could potentially be improved by extracting lithium from geothermal wells.

22 Nuclear

Nuclear energy is a well understood and widely deployed form of low emissions energy generation. Industry growth has recovered in many countries following a downturn in response to the Fukushima accident in 2011. In Australia, a considerable amount of effort would be required to support deployment of nuclear energy, particularly due to social licence barriers, investment risk and lack of a full-scale local industry. In the absence of local deployment, there may still be significant opportunities for Australia to participate along the supply chain. This may be achieved through the expansion of uranium mining, but most notably via the establishment of infrastructure supporting receipt and storage of used fuel and/or radioactive waste from overseas.

- Nuclear energy provides another avenue for achieving low emissions dispatchable energy. Globally, it is well established, meeting 11% of total electricity demand (IEA, 2015).
- Japan's Fukushima Daiichi accident in March 2011, in which an earthquake and tsunami resulted in meltdowns at the nuclear plant, caused a temporary decline in global deployment of nuclear energy. The industry appears to have recovered with 60 projects currently under construction globally.
- While the technology is well understood, further development of nuclear reactors (e.g. 'Generation IV') is ongoing, with the overall objective being to improve safety, efficiency as well as reduce water requirements, radioactive waste and proliferation risks.
- A key development will be in the adoption of SMRs which have capacities of less than 300MW and allow for more flexible integration within existing energy networks.
- Adoption of nuclear power in Australia poses a significant challenge. This is primarily due to the fact that the technology is currently prohibited in Australia and is subject to significant community opposition. Further, it would take an estimated 14 years before a nuclear plant could be operational due to the time required to establish an appropriate regulatory framework as well as procure, construct and commission the first reactor.
- For mature (large-scale) generation, the long lead time to deployment also makes the task of securing investment more difficult, particularly in light of uncertainty of over future electricity demand and the inflexible nature of current large-scale thermal generation.
- Aside from electricity generation, there is significant potential for Australia to further expand its participation in the global nuclear supply chain (e.g. by expanding uranium mining operations or through the manufacture and supply of reactor and auxiliary nuclear-grade components).
- Although subject to significant public opposition, greater long-term opportunities may however be realised through the establishment of infrastructure supporting receipt, storage and disposal of radioactive waste from overseas. If successful, this could increase the scope for deployment of local nuclear generation.

22.1 Technology overview

Technology description

Nuclear energy may be generated via two types of reactions:

1. Fission – The nucleus of an atom is split into two smaller atomic particles and neutrons, resulting in the release of energy. The energy released is derived primarily from the kinetic energy in the fission products. Free neutrons then cause a chain reaction by colliding with other nuclei.
2. Fusion – Two or more nuclei are combined to form heavier nuclei, resulting in the release of energy. In order to be self-sustaining, the energy released from the fusion reaction must be greater than the heat input to maintain the fusion process.

Currently, commercial nuclear power plants rely on nuclear fission which generates heat to power a turbine. As discussed below, fusion plants are under development but still far from commercialisation.

Output from a fission reactor is controlled by a moderator (typically coolant flow) and control rods. Thermal reactors use a moderator (for example water or graphite) to slow the neutrons down and improve the efficiency of the fission process. Control rods absorb neutrons and control the rate of fission by governing the number of neutrons available (CO2CRC, 2015).

Nuclear power plants can generate large amounts of radioactive waste which must be managed appropriately. The waste typically has a long half-life (i.e. it can remain radioactive for thousands of years) and could have a harmful impact on plants and animals via radiation exposure if not managed in accordance with current international standards.

The different types of nuclear fission reactors are set out in Table 92 below.

Table 92 – Nuclear fission technologies

TECHNOLOGY	DESCRIPTION
Pressurised water reactors (PWR)	This is the most common type of reactor. (Light) water is used as both the moderator and coolant and flows through two circuits. In the primary circuit, water is passed through the core of the reactor under high temperatures (˜325˚C) and pressures (˜150 atm) to prevent boiling. In the secondary circuit, the water flows at lower pressures and consequently boils to produce steam to drive a turbine (CO2CRC, 2015).
Boiling water reactors (BWR)	Also a light water reactor, the BWR consists of a single circuit in which the water is passed through the core at lower pressures (75 atm). Generated steam passes through a 'steam separator' at the top of the reactor. This is a simpler design than PWR. However, the steam passing through the turbine is radioactive (although with a very short half-life) and so the pipelines must be made so they are radiation resistant. Protective equipment is also required during maintenance. These factors can offset the lower capital cost of the single circuit design (CO2CRC, 2015).
Pressurised heavy water reactors (PHWR)	This is a two circuit reactor where fuels such as natural uranium oxide may be used with heavy water (D_2O) as a moderator and coolant (at 290˚C). The reactor can be refuelled progressively without shutting it down by isolating pressure tubes that transfer the fuel through the reactor (CO2CRC, 2015).
Fast neutron reactors	Fission reactions are sustained by "fast" neutrons, which are of higher energy than the thermal neutrons that sustain fission in light water reactors. No moderator is required. Fast neutron reactors are able to use a broader range of fuels (e.g. the more abundant U-238 isotope which makes up 99% of natural uranium) and have a higher fuel efficiency than conventional thermal neutron reactors. These reactors can also burn actinides, which are components of radioactive waste that have a long half-life (CO2CRC, 2015). However, there are proliferation concerns associated with fast reactors, in that they can be engineered to produce more plutonium than they consume. Fast reactors remain a largely experimental technology.
SMRs	SMRs have capacities of up to 300MW (CO2CRC, 2015). SMRs currently under development are being designed to be manufactured in a controlled factory setting which can reduce costs and increase safety. Some designs will also be capable of being deployed underground, have fewer cooling requirements and will be easier to decommission given that they can be removed from site (CO2CRC, 2015). The first types to be deployed are likely to be based on PWR technology, although there are also Generation IV-type designs under development. The loss of economies of scale has to be offset by series production

TECHNOLOGY	DESCRIPTION
	(so that revenues from the first SMRs on a site can pay for installation of subsequent modules), factory build and innovative design.
Generation IV Technology	New Generation IV technology is being developed with the goals of sustainability, safety and reliability, effective fuel utilisation, competitive economics and proliferation resistance (GEA, 2012). The six technologies being developed are sodium cooled fast reactors, supercritical water cooled reactors, lead cooled fast reactors, very-high-temperature reactors, molten salt reactors and gas cooled fast reactors (GEA, 2012).

Technology impact

Nuclear energy provides another avenue for achieving low emissions dispatchable energy. Globally, it is well established, meeting 11% of total electricity demand (IEA, 2015). Japan's Fukushima Daiichi accident in March 2011, in which an earthquake and tsunami resulted in meltdowns at the nuclear plant, caused a temporary decline in global deployment of nuclear energy. The industry appears to have recovered with 60 reactors currently under construction globally[27].

While the technology is well understood, further development of nuclear reactors (e.g. 'Generation IV') is ongoing with the overall objective being to improve safety (e.g. via designs that require zero intervention in the case of loss of external power) and efficiency as well as reduce water requirements, radioactive waste and proliferation risk. A key development however will be in the adoption of SMRs. This group of technologies, which have capacities of up to 300MW (as opposed to large-scale plants of > 1 GW), have the potential to significantly disrupt the nuclear industry. This is due to the fact that they can be more easily integrated into existing electricity networks (e.g. they can 'load follow' VRE, modular design), have a lower capital cost, superior safety characteristics and require less water (GEA , 2012).

Nuclear fusion represents a longer term opportunity for disruption. These reactors could offer unlimited, low cost electricity without the production of radioactive waste. To date however, while controlled fusion reactions have occurred at a number of demonstration facilities (e.g. the 'Stellarator' in Germany), the amount of energy produced has been less than the energy input, and the technology is not likely to be commercialised for decades. The 'ITER' international fusion project, based in France, is aiming to demonstrate the net production of nuclear fusion by 2030 with the goal of producing 500 MW thermal power (MW_t) from an input of 50 MW_t. Australia recently became the first non-member country to sign a technical collaboration agreement with ITER.

There is currently no nuclear powered electricity generation in Australia. Given social licence requirements, the need to develop the required regulatory framework and the lead time associated with technology selection, procurement, construction and commissioning, it is expected to take at least 14 years before the first reactor could be realised (Nuclear Fuel Cycle Royal Commission, Government of South Australia, 2016). It is therefore unlikely to be available until after 2031. By this stage however, SMRs may have been adopted overseas and could potentially be more readily deployed in Australia.

[27] Refer to http://www.world-nuclear.org/information-library/facts-and-figures/world-nuclear-power-reactors-and-uranium-requireme.aspx

22.2 Technology status

Cost - current state and projections

The current and projected LCOE for large-scale nuclear is included below. It is anticipated however that SMRs could be cheaper once they are commercially available.

Table 93 - Nuclear LCOE forecast ($AUD/MWh)

	2015	2020	2030
Large-scale Nuclear	160-190	160-190	140-170

Technological and commercial readiness - current state

The technological and commercial readiness of key nuclear technologies is set out in Table 94 below.

Table 94 –technological and commercial readiness 2016

TECHNOLOGY	TRL	CRI	COMMENTS
Pressurised water reactors	9	6	Mature and commonly used nuclear reactor overseas
Boiling water reactors	9	6	Mature and commonly used nuclear reactor overseas
Pressurised heavy water reactors	9	6	Mature and commonly used nuclear reactor (e.g. CANDU6 in Canada)
Fast neutron reactors	2-8	1	This is an area of active research to produce the next generation of nuclear plant design. There have been several demonstration plants. The Russian BN-600 fast reactor has been in commercial operation producing 600 MWe since 1980, and the new BN-800 fast reactor commenced operations in 2016.
SMRs	6-8	2	There are no true small modular reactors in operation. With financial support from the US DOE, NuScale recently lodged a design certification application to the US Nuclear Regulatory Commission for its SMR design and is likely to be the first modern SMR to be constructed.
Fusion reactor	1-3	1	This is an area of active research by several global organisations (e.g. ITER).

22.3 Barriers to development and potential enablers

Adoption of nuclear generation in Australia poses a significant challenge. This is primarily due to the fact that there is currently a small local industry and generation is prohibited under Commonwealth legislation. To date, there has also been no long term commitment on behalf of the Government.

This, combined with the need to develop a regulatory structure capable of dealing with the deployment and operation of nuclear power, means that a significant amount of work would be required in order to ensure that nuclear energy is available when and if needed. This, and the long lead times involved, also makes the task of securing investment more difficult.

Thus for Australia to have the option of nuclear generation, a clear and direct policy would need to be implemented. There is an additional requirement for an overall deployment strategy and widespread stakeholder consultation and engagement that facilitates fact based discussions on the risks and benefits associated with nuclear power.

Given that there is likely to be less of a requirement for 'bulky' inflexible electricity generation after 2030, Australia should continue to participate in Generation IV and fusion technology development, and to monitor global developments in SMR technology as recommended by the Nuclear Fuel Cycle Royal Commission (NFCRC).

Table 95 - Nuclear barriers and enablers

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	High capital cost of nuclear generation	> Continue to follow global developments in SMRs and cost projects of all nuclear generation > Remove prohibition on CEFC funding of nuclear technologies and related projects	> ANSTO	2021-2025
Revenue/market opportunity	Difficulty of securing investment given 'bulky' nature of mature generation and electricity demand uncertainty	> As per costs > Implement stable policy incentivising in low emissions energy generation that explicitly includes nuclear energy > Conduct rigorous modelling to understand demand profiles and secure PPAs where possible	> Government	2021-2025
Regulatory environment	Nuclear generation in is currently prohibited under commonwealth legislation	Remove legislative prohibitions on nuclear generation in Australia, establish nationally consistent regulatory arrangements and implement stable long-term strategies for development	> Government	2021-2025
Technical performance	Vulnerability of nuclear reactors and potentially catastrophic consequences in the event of natural or man-made disasters	> Deploy modern reactors with passive safety systems, monitor development of Gen IV reactors, work to International Atomic Energy Agency (IAEA) siting standards > Conduct detailed site risk assessments	> Government > Industry	2025-2030
Stakeholder acceptance	Concern over safety associated with nuclear plants and waste management	> Undertake widespread stakeholder consultation including providing fact-based information on risks and benefits of nuclear power > Integrate lessons learnt from experienced operators concerning how to improve safety > Continue to develop strategies and policies for managing radioactive waste and follow global developments in waste recycling	> Government > ANSTO	Ongoing
Industry and supply chain skills	No local industry	> Develop requisite training, education and regulation as part of a nuclear programme	> Government	2021-2025

22.4 Opportunities for Australian Industry

Aside from local deployment of nuclear generation, there are various opportunities for Australia to further expand its participation in the global supply chain of this technology. In the first instance, this may be achieved by expanding uranium mining operations.

Another potentially more significant opportunity exists in relation to the management of used fuel and radioactive waste from overseas. The value of the opportunity has been estimated as being able to generate a profit of $100 billion over a 120-year project life (Nuclear Fuel Cycle Royal Commission, Government of South Australia, 2016). Australia's vast geologically stable land and robust social and political environment make it a suitable location for long term storage and monitoring.

Additionally, Australia's strong capability in research and development of nuclear materials could be lead to further export opportunities. Australia has recently increased its participation in the research and development of Generation IV reactors, through membership of the Generation IV International Forum, and fusion technologies, with the signing of the first ever ITER technical cooperation agreement with a non-member country. More broadly, ANSTO is the custodian of nuclear capabilities and expertise in Australia, and is mandated to undertake research and monitor international developments in the peaceful applications of nuclear technology, including for energy.

A summary of the supply chain opportunities is included in

Table 96 below.

Table 96 - Opportunities for Australian Industry Summary

	Technology manufacture and distribution	Raw materials extraction	EPC	O&M	Management, storage and disposal of radioactive waste
Description	Manufacture of nuclear plant components (e.g. reactors, rods)	> Mining of radioactive ores (e.g. uranium) and enrichment into fissile material	Involves design and procurement and construction of nuclear plant	Involves operation and maintenance of nuclear plant	Radioactive waste is contained and stored. It also requires ongoing monitoring to ensure no leakage
Australia's comparative advantage	Low - More established global industry + Local manufacture of specialised componenets (e.g. Teralba and ANSTO)	High + Established mining industry + World's largest economic uranium reserves	Medium + EPC must be done locally - No existing nuclear industry	Medium + O&M must be done locally - No existing nuclear industry	High + Vast geologically stable land suitable for storage + Stable government and robust regulations + Strong waste management IP (e.g. Synroc technology)
Market size (2030)	Medium > Share of global market, possible local market	High > Share of global market and potentially local market	Medium - Local market for new build	Medium - Local market for new build	High > Share of global market and potentially local market
Opportunity for Australian industry	Low	High	Medium	Medium	High
Jobs opportunity	Low	High	Medium	Medium	High
Main location of opportunity	Urban/regional	Remote	Regional/remote	Regional/remote	Remote
Difficulty of capture/level of investment	High	Medium > Depends on world uranium pricing and demand	High	High	High Requires social licence and implementation of appropriate regulatory framework

23 Hydrogen

Hydrogen provides a flexible means of storing and transporting renewable (and fossil fuel derived) energy. Deployment of hydrogen systems and infrastructure is gaining considerable momentum globally, particularly in countries such as South Korea and Japan. Australia's vast primary energy resources (e.g. solar, coal), existing export capabilities and relationships leave it well placed to develop a hydrogen export industry. Low or zero emissions hydrogen can be produced at scale using either dedicated renewables with electrolysis and/or gasification of coal with CCS. Development of a hydrogen export industry may also increase the scope for its use in Australia, with likely applications in fuel substitution for road transport and energy storage. Government incentives are required to help stimulate this industry. If successful, this could create significant supply chain opportunities, particularly in regional and remote areas of Australia.

- As a flexible energy carrier, hydrogen may be used to provide low emissions heat, electricity and transport fuel.
- Globally, deployment of hydrogen is gaining considerable momentum, particularly in countries such as Japan and South Korea, which do not have the same vast renewable resources (e.g. solar, wind) and available land, are likely to rely on imported hydrogen in order to help transition to a low carbon economy.
- Hydrogen has the potential to become a key export opportunity for Australia. Low or zero emissions hydrogen is most likely to be produced at large-scale using:
    - Electrolysis using dedicated renewables - higher cost (~$8-10/kg in 2030) but zero emissions
    - Coal gasification with CCS - lower cost (~$2-3/kg in 2030) but higher emissions intensity than electrolysis (7-15 kg CO_2e/kg H_2)
- Development of a hydrogen export industry may increase scope for domestic use across the energy sector. One of the primary local applications is likely to be transport:
    - For passenger vehicles, by 2025, FCVs (˜$29,000) could be cost competitive with EVs ($˜25,000). FCVs may however be preferred for long distance travel in the absence of widespread EV recharging infrastructure.
    - Heavy vehicles typically operate at close to maximum weight capacity. FCVs may therefore be more suitable due to the superior energy density (MJ/kg) of hydrogen over batteries.
- Hydrogen may also be used as an alternative for long term, large-scale energy storage and electricity generation in certain applications (e.g. RAPS on mining sites). It also provides an alternative means of utilising otherwise curtailed VRE.
- Burning of hydrogen or hydrogen derived products (e.g. ammonia, enriched methane) may have some application in domestic and/or industrial heat generation.
- While Australia is likely to continue to import hydrogen-based technologies (e.g. electrolysers, fuel cells and FCVs), there may be opportunities for further development and export of niche technologies along the supply chain (e.g. ammonia cracking). Key opportunities are therefore

more likely to be associated with EPC and O&M for large-scale production plant, as well as local infrastructure such as refuelling stations and RAPS.

23.1 Technology overview

Technology description

Hydrogen based technologies fall under three primary categories:

1. Production
2. Storage and transport
3. Consumption (to produce heat/electricity)

Hydrogen production

Low emissions hydrogen can be produced via a number of processes:

- Thermochemical: Uses a fossil fuel or biomass feedstock and water to produce hydrogen via coal gasification or steam methane reforming (SMR). This process requires use of biomass, CCS and/or CST (as discussed in Section 18) in order to lower the emissions profile.
- Electrochemical: Uses an electric current to split water molecules into hydrogen (H_2) and oxygen (O_2). This process is zero emissions if powered by renewable energy.
- Emerging: Involves splitting of water molecules using direct sunlight or biological mechanisms (e.g. bacteria, microalgae).

Further detail on each of the specific technologies is provided in Table 97 below.

Table 97 - Hydrogen production technologies

TECHNOLOGY	DESCRIPTION
Thermochemical	
Steam methane reforming (SMR)	Methane and water are converted to H_2 and CO/CO2 using a catalyst at high temperatures (~750°C). The ratio of CO_2 to CO can be increased by reacting the syngas further with water, allowing for easier removal of hydrogen (Hinkley, et al., 2013). This is a low cost, commonly used method of production.
Coal gasification	Dried and pulverised coal is reacted with oxygen and steam in a gasifier at high temperature to produce syngas (Gray & Tomlinson, 2002). This is a well understood, commercially mature technology which is widely used around the world to produce hydrogen, ammonia, explosives and fertilisers
Biomass gasification	As per coal gasification but uses biomass as a feedstock. Often reformed at lower temperatures and pressures due to cost and feedstock availability
Biomass-derived liquid reforming	Liquids produced from biomass such as ethanol or bio-oil can be converted to syngas and then hydrogen in a process similar to SMR (Manzolini & Tosti, 2008).
Methane cracking	A column of liquid metal (tin) is used to split methane into hydrogen and carbon. The reaction requires high temperatures (800°C-1200°C) (Ottewell, 2015)
Electrochemical	

TECHNOLOGY	DESCRIPTION
Alkaline electrolysis (AE)	Electrochemical cell that uses a potassium hydroxide electrolyte to form H_2 at the negative electrode and O_2 at the positive electrode (Hinkley, et al., 2015). This is a low cost form of electrolysis but is unsuitable for direct coupling with intermittent renewables. It also produces hydrogen at low pressures (< 30 bar).
Proton exchange membrane (PEM)	Uses a proton exchange membrane and noble metal catalysts to separate H_2 and O_2 (Hinkley, et al., 2015). While it has a higher capital cost, PEM is more efficient than AE and has a higher ramp rate which makes it more suitable for direct coupling with VRE.
Solid oxide electrolyser cells (SOEC)	Uses a ceramic metal (solid oxide) and electrolyte (zirconia dioxide) to produce hydrogen. There is potential for high efficiency, however a high operating temperature (700-1000˚C) is also required.
Chlor-alkali	Hydrogen is a by-product from the chlor-alkali production process, which uses electrolysis to produce chemicals such as chlorine (Cox, 2011).
Emerging	
Photoelectrochemical	Hydrogen is formed by splitting water using direct sunlight and a specialised semiconductor in a water soluble electrolyte (Shi, et al., 2015).
Microbial biomass conversion	Organic matter is fermented using specific microorganisms (Ozansoy & Heard, 2011).
Photobiological	Uses microorganisms and sunlight to convert water and other organic matter into hydrogen gas (National Renewable Energy Laboratory, 2016).

Storage & Transport

Hydrogen may be transported via truck, ship or pipeline. However, given that it has a very low energy per unit volume (i.e. volumetric density), a number of techniques are being developed in order to improve the economics of both storage and transport (as shown in Table 98).

Table 98 - Hydrogen storage technologies

TECHNOLOGY	DESCRIPTION
Compression	
Pressurised tanks	Hydrogen is compressed in a tank in order to increase pressures to between 200 and 700 bar. While compression costs are high, these tanks are scalable, easy to transport and suitable for long term storage (SBC Energy Institute, 2014).
Underground storage	Hydrogen is compressed to pressures of 200-300 bar and typically stored in salt caverns. While more suitable for large-scale hydrogen storage (SBC Energy Institute, 2014), this is unlikely to be applicable in Australia given that there are no salt caverns. Saline aquifers have been suggested as a possible alternative (P.O. Carden, 1979)
Liquefaction	
Cryogenic tanks	Hydrogen is cooled to temperatures of -120˚C (150K) and liquefied, making it a suitable option for shipping. Cooling however requires significant energy use.
Cryo-compressed	This is an intermediary solution between pressurised and cryogenic (350 bar and temperatures between 180-300K (or -26.85°C to -93.15°C)) (US DOE Hydrogen Program, 2008).
Material based	
Metal hydrides	Hydrogen covalently bonds with metal complexes. They have the ability to carry significant quantities of hydrogen safely and at a high density (SBC Energy Institute, 2014). Suitable for long term storage but requires energy to re-release the hydrogen.

TECHNOLOGY	DESCRIPTION
Chemical hydrogen (ammonia)	Hydrogen can be converted to ammonia (via Haber Bosch) or other chemical compounds (e.g. complex amines, methanol). This process is suitable for long term storage but requires energy to re-release hydrogen (e.g. cracking) (CSIRO, 2016). Ammonia already has a well-established production, storage and distribution infrastructure
Liquid organic	Hydrogen can also be stored as methylcyclohexane (C_7H_{14}) and then converted to toluene (C_7H_8) which involves releasing 3 hydrogen (H_2) molecules. This is currently being explored as a method of hydrogen transport and storage by Chiyoda Corporation in Japan (Hinkley, et al., 2013).
Adsorbent	A material with a high surface area (e.g. in the form of a powder) adsorbs hydrogen on cooling. Heat is then used to release the hydrogen. This material would typically be placed in a tank to be used for hydrogen transport (Siegel & Hardy, 2015).

Consumption (to produce heat/electricity)

Hydrogen can be consumed to provide both heat and electricity and therefore has a number of applications across the energy sector:

- Electricity/energy storage: Hydrogen may be stored for extended periods and then used as input into fuel cells (FC) to produce electricity. Within an FC, hydrogen and water are combined to produce an electrical current and water (i.e. the reverse of electrolysis). Direct combustion hydrogen (or ammonia) turbines are also being developed as an alternative to fuel cells.
- Transport: Hydrogen may be used to power fuel cell electric vehicles (FCVs). With a more favourable energy density (MJ/kg) than batteries it is more suitable for use in heavy vehicles (as compared with EVs).
- Heat: Burning of hydrogen or related products (e.g. hydrogen-enriched methane, ammonia) to provide heat. Fuel cells can be used for both combined heat and power applications. They are more efficient when used in this way (possibly 80% compared to 50%) given that the waste heat is captured and used.

Enabling technologies for conversion of hydrogen into electricity/heat are outlined in Table 99 below.

Table 99 - Hydrogen electricity production and transport technologies

TECHNOLOGY	DESCRIPTION
Electricity - FCs	
Polymer Electrolyte Membrane (PEM) FC	Also known as a proton exchange membrane FC. Hydrogen is catalytically split into protons which permeate through the membrane from the anode to the cathode to create an electrical current. This is a relatively low cost FC, is highly efficient and suitable for smaller applications such as FCVs (Salvi & Subramanian, 2015).
Alkaline Fuel Cell (AFC)	Uses a potassium hydroxide electrolyte and is suitable for small scale (<100 kW) applications. It has a low cost, low temperature and short start up time. However, it is also sensitive to traces of CO_2 (SBC Energy Institute, 2014)
Solid Oxide Fuel Cell (SOFC)	Fuel cell that uses a solid oxide or ceramic electrolyte but requires high operating temperatures (>500°C). It is suitable for both industrial and residential applications and can run using fuels other than hydrogen (i.e. syngas, ammonia). However, it has a long start time and therefore needs to be run continuously (Dodds, et al., 2015).
Molten Carbonate FC	Use a molten carbonate electrolyte and runs at high temperatures. It does not require hydrogen (i.e.it can run off natural gas and CO_2). It is suitable for industrial and grid scale

TECHNOLOGY	DESCRIPTION
	applications (i.e. tens of MW) (Dodds, et al., 2015). It is also relatively low cost but has a short lifespan and low power density.
Phosphoric acid fuel cell	Uses a liquid phosphoric acid electrolyte and has typically been applied in commercial, combined-heat power systems. It requires a temperature of between 150-200°C to operate, has a long start time and relies on expensive catalysts (Dodds, et al., 2015).
Electricity - Direct combustion	
Hydrogen gas turbines	Likely to be used in IGCC power plants. These are turbines that can run off hydrogen or a hydrogen-rich syngas mixture. There are technical challenges associated with the high combustion temperature of hydrogen (Kraftwerk Forschung, 2016).
Ammonia turbines	Involves the combustion of ammonia, a methane mixture or ammonia mixed with hydrogen. NOx emissions from the combustion of ammonia need to be removed which creates additional costs (Valera-Medina, et al., 2015).
Transport	
FCVs	FCVs are a form of electric vehicle where the motor is driven by a fuel cell, typically in combination with a battery. A tank storing compressed hydrogen [~700 bar] is situated on board.
Production of other fuels (e.g. methanol)	Hydrogen can be used to produce methanol which can be blended with conventional fuels. With further processing, methanol can also be converted into dimethyl ether (DME) and used as a replacement for diesel.

Technology impact

Hydrogen provides a flexible means of storing and transporting energy. Globally, deployment of hydrogen-based technologies is gaining considerable momentum. This is particularly true for countries such as South Korea and Japan that do not have vast primary renewable energy resources (e.g. solar, wind) or available land, and are set to rely heavily on imported hydrogen in order to transition to a low carbon economy.

For example, in the aftermath of the Fukushima nuclear disaster, Japan specifically endorsed the use of imported hydrogen as a component of the Basic Energy Plan and is aiming to showcase a range of hydrogen technologies at the forthcoming 2020 Tokyo Olympics (KPMG, 2014).

Thus as discussed further in Section 23.4 hydrogen has the potential to become a key export opportunity for Australia. Low or zero emissions hydrogen can be produced at large-scale using electrolysis, coal gasification and potentially SMR (depending on the availability of gas) with CCS. There are a number of projects/feasibility studies underway.

Hydrogen is expected to have some domestic applications, particularly in heavy vehicle road transport and long term energy storage (as discussed below). However, scope for local use of hydrogen may be increased through the development of infrastructure and technologies required to support an export industry.

Electricity/energy storage

Hydrogen may be stored for long periods, in large quantities and then fed through a fuel cell (or combusted) in order to generate electricity. Energy storage can be scaled cheaply (i.e. it requires more or larger tanks, which are relatively low cost). This makes it a complementary technology to batteries, particularly in distributed applications where long discharge times are required or for mitigating long-term variability in grids with a significant proportion of VRE. It also provides a useful means of storing otherwise curtailed wind and solar energy.

Transport

There is scope for FCVs to penetrate both the light and heavy vehicle market. For the latter, the superior energy density (i.e. higher energy to weight ratio) of hydrogen over electricity stored in batteries make hydrogen more favourable in trucks and buses due to the fact that these vehicles typically operate at close to maximum weight.

For light vehicles, EVs are a more mature technology, have more established markets and a lower capital and operating cost. However, the key market differentiator for FCVs is that they have superior energy capacity and therefore enable longer distance travel without the need for recharge. This advantage may be somewhat eroded as commercial EV recharging infrastructure is deployed and charging times as well as battery capacities continue to improve.

Fuel cells are also highly suitable in material handling equipment, such as forklift trucks in warehouses. Fuel cell forklifts trucks can operate for more than 12 hours without performance degradation and can be charged in a couple of minutes (as compared to batteries which could take hours). Fuel cell forklift trucks can also operate in a wide range of temperatures.

Note also that In September 2016, German engineering company Alstom unveiled its first hydrogen fuel cell powered train. It expects that the first trial run will occur in December 2017.

Heat

Hydrogen may be blended with natural gas, transformed into synthetic methane, or combusted directly. All three options enable the substitution of natural gas with a low emissions combustible fuel. It may therefore have some application in industrial and/or domestic heat generation. For instance, in Leeds (United Kingdom), the 'H21 Project' has been established to assess the feasibility of replacing natural gas with hydrogen within the overall gas network. The hydrogen is intended to be produced via SMR and CCS and used in the same pipes, power cookers and boilers in the same way as natural gas (Leeds City Gate, 2016).

Industrial processing

Hydrogen has a number of applications outside of electricity/heat generation. For instance, it is commonly used in a number of industrial processes (e.g. hydrocracking in petroleum, steel refining, ammonia production). In these sectors, hydrogen is typically produced via SMR, which is an emissions intensive process in the absence of CCS. A developed export and local market may also enable low emissions hydrogen to be readily available and then integrated into these processes.

23.2 Technology status

Cost - current state and projections

Table 100 compares the forecast 2030 cost of hydrogen produced by the different methods discussed in

Table 71. The associated LCOEs are also captured. This assessment does not include hydrogen transport and storage costs. Note that electrolysis from otherwise curtailed renewables is more expensive than dedicated renewables due to a lower utilisation factor.

Table 100 – Cost of hydrogen production ($/kg H_2)

HYDROGEN PRODUCTION	2030 ($/KG H_2)	2030 LCOE ($/MWH)[28]
SMR with CCS	2-3	210-250
Coal gasification with CCS	2-3	190-240
Biomass Gasification	3-4	220-270
PEM electrolysis from Grid	4-5	290-360
PEM electrolysis from dedicated renewables	8-10	550-680
PEM electrolysis from otherwise curtailed renewables[29]	18-21	1090-1330

Figure 29 below compares the cost and emissions intensity associated with each of the hydrogen production technologies. Electrolysis remains the most expensive hydrogen production technology but can be a zero emissions process. The cost of coal gasification with CCS is relatively cheap, but still has a notable emissions profile which becomes material (i.e. millions of tCO2 annually) when producing hydrogen at scale.

Figure 29 - Cost and emissions intensity of hydrogen production technologies

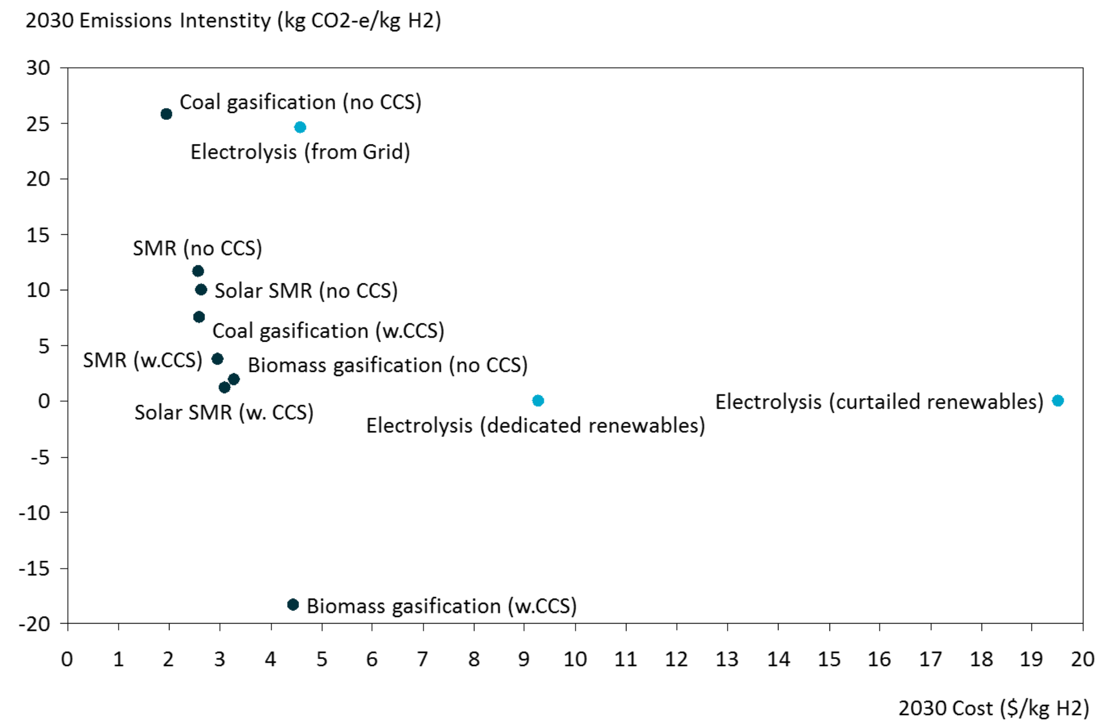


Table 101 shows the expected capital and operating cost of 'mass market' passenger FCVs.

[28] LCOEs assume electricity generation via a 1 MW PEM fuel cell which is used for 4 hours per day
[29] Note that electrolysis from otherwise curtailed renewables is more expensive than dedicated renewables due to a lower utilisation factor.

Table 101 - Capital and operating costs for FCVs

HYDROGEN PRODUCTION	2020	2030
Capital cost of FCVs	56,000	29,000
LCOT for FCVs using coal gasification with CCS ($/km)		0.65-0.80
LCOT for FCVs using grid electrolysis ($/km)		0.70-0.85
LCOT for FCVs using dedicated renewables ($/km)		0.70-0.90

Technological and commercial readiness - current state

The TRL and CRI associated with the key hydrogen-based technologies is shown in Table 102 below.

Table 102 – Hydrogen production technological and commercial readiness 2016

TECHNOLOGY	TRL	CRI	COMMENTS
Production			
SMR	9	6	Mature technology. Research ongoing into process improvements e.g. membrane separation systems to further improve efficiency
Coal gasification	8-9	4-6	Mature technology. Hydrogen is typically produced as an intermediate and then used to manufacture fertilizers, explosives, plastics, chemicals etc.
Biomass Gasification	6-7	1-2	Technology is similar but not as mature as coal gasification (requires different feedstock preparation and has different impurities). Biomass plants would need to be large-scale in order to be economical.
PEM electrolysis	8-9	3-4	Commercially available but high cost. Currently only used for niche applications. Further R&D is required to bring down costs
Photoelectrochemical	1-2	1	In early stages of research
Microbial biomass conversion	1-2	1	In early stages of research
Photobiological	1-2	1	In early stages of research
Methane cracking	3-4	1	A prototype has been built and demonstrated for continuous operation (Ottewell, 2015)
Consumption			
Polymer Electrolyte Membrane (PEM) FC	9	3-4	Mature technology. Currently used in FCVs
Alkaline Fuel Cell (AFC)	9	3-4	Oldest fuel cell technology but is only used in niche applications
Solid Oxide Fuel Cell (SOFC)	9	3-4	Mature technology but high cost
Hydrogen gas turbines	3-4	1	Turbines that combust pure hydrogen are still at research stage. Turbines that combust hydrogen rich gases or syngas are more mature.
Ammonia turbines	6-8	1	Ammonia combustion has been demonstrated in a small-scale turbine in Japan
FCVs	9	3-4	Commercially available but high cost. Research is ongoing into reducing the cost, improving the performance of the fuel cells and building refuelling infrastructure

23.3 Barriers to development and enablers

As shown in Table 101, key hydrogen production technologies are well understood but high cost. While likely to take place in countries with more established hydrogen industries (e.g. US, Japan), cost reductions can be achieved in Australia by increased investment in R&D as well as greater economies of scale. Beforehand, government incentives (e.g. grants) are likely to be required in order to assist the development of an export industry as well as encourage local uptake of FCVs and supporting infrastructure. This is particularly critical for the heavy vehicle transport industry given smaller operating margins.

It is also important to develop domestic regulations that align with global standards, communicate global technological progress and encourage upskilling within the O&G industries.

A summary of the key barriers and potential enablers is provided in Table 103.

Table 103 - Key barriers and potential enablers

Category	Barrier	Potential enablers	Responsibility	Timing
Costs	High cost of production and technologies (export)	> Implement incentives to encourage deployment of large-scale hydrogen production facilities (for both electrolysis and coal gasification with CCS) > Strategically deploy hydrogen production plants so they are in close proximity to existing infrastructure (e.g. ammonia plants) or required resources (e.g. coal reserves) > Progress R&D in relation to niche elements of the hydrogen supply chain (e.g. catalytic cracking of ammonia) as well as lowering the cost of storage	> Government > Research organisations > Industry	2017-2020
	High cost of production and technologies (domestic transport)	> Develop targets for roll out of FCVs for heavy vehicles and implement technology neutral incentives to encourage uptake > Incentivise retrofit of existing refuelling stations or bus/truck depots with hydrogen production and storage technologies	> Government > Industry	2021-2025
Revenue/market opportunity	Investment risk (export)	> Ensure that long-term feedstock and offtake agreements are in place prior to deployment of local infrastructure > Ensure that deployment of hydrogen infrastructure is well coordinated amongst different stakeholders (e.g. gas producers, transport operators, CCS proponents)	> Government > Industry	2021-2025
Regulatory environment	Lack of standards (local and global) regulating overall use of hydrogen across the energy sector	Align with international codes as they are developed to ensure necessary standards are in place (e.g. storage, transport and distribution pressures)	> Government	Ongoing
Technical performance	Concerns over storage capabilities, particularly for long distance transport	> Progress demonstration in relation to different transport options (e.g. upgrading boats for liquefaction) and continue to explore different carrier options (e.g. ammonia)	> Industry > Research organisations	2017-2021
Stakeholder acceptance	Safety concerns over operation of hydrogen	> Increase public awareness of results from safety testing (e.g. for FCVs, passenger safety in collisions and refuelling)	> Government > Industry groups	Ongoing
	Pre-conceived opinions around complexity and technical challenges associated with hydrogen	> Widely communicate findings from demonstration projects as well as global progress	> Government	Ongoing
	High carbon footprint if renewables are not utilised	> Continue to support the deployment and integration of electrolysers with renewables > Progress development of CCS (Refer to Section 20)	> Government > Industry groups	Ongoing

Category	Barrier	Potential enablers	Responsibility	Timing
Industry and supply chain skills	Currently small local supply chains with limited experience in large-scale hydrogen operation	> Encourage transition and upskilling from conventional O&G sector > Implement training, accreditation and standards > Leverage developments from overseas, particularly Japan and Korea	> Government > Industry groups	Ongoing

23.4 Opportunities for Australian Industry

As explained above, large-scale hydrogen export is a key opportunity for Australian industry. This will also provide significant domestic opportunities in the procurement and operation of hydrogen production facilities as well as supporting infrastructure (e.g. shipping, CCS).

Australia is likely to remain an importer of relevant technologies (e.g. electrolysers and fuel cells and FCVs). However, there is also scope to build on currently held IP through further R&D in niche applications along the supply chain (e.g. ammonia cracking) as well as gasification and solar fuels. There may also be opportunities associated with use of hydrogen storage for electricity in RAPS and in the development of further infrastructure supporting local use (e.g. refuelling stations).

Table 104 - Opportunities for Australian Industry Summary

	Technology manufacture and distribution	Hydrogen production	Storage and transport infrastructure
Description	> Manufacture of hydrogen-related technologies including coal gasification plants, electrolysers, FCs and FCVs	> Hydrogen production can be achieved through a variety of methods including gasification of coal, SMR and electrolysis.	> For storage, hydrogen must be compressed, liquefied or turned into other products (e.g. ammonia) > It can then be transported by a number of means to point of use (e.g. pipeline, ship, truck) > Also includes build out of local refuelling stations
Australia's comparative advantage	Low + Strong IP in relation to coal gasification and SMR + Strong IP in niche applications (ammonia cracking, solar fuels) + Marketing and distribution of technologies must be done locally - No existing local coal gasification industry - Established global manufacturers with technological lead (e.g. for FCs and FCVs)	High + Significant coal, gas and biomass resources + Developing CCS industry + Established coal and gas extraction industries + Significant solar and wind resource with growing RE industry	High + Strong engineering capabilities and well established gas industry - well placed to build local infrastructure (e.g. storage and transport facilities) + Design and procurement of potential infrastructure must be done locally
Market size (2030)	Medium > Local market and share of global market	High > Export to share of global market (primarily Asia) > Service of local market (e.g.	High - Service of local and export market

	Technology manufacture and distribution	Hydrogen production	Storage and transport infrastructure
		Hydrogen for FCVs in heavy vehicle transport)	
Opportunity for Australian industry	Low > Possible manufacture and export of niche technologies across the supply chain (e.g. cracking) with some export of IP	High > Hydrogen export > Significant EPC and O&M opportunities for large-scale production plant	High Significant EPC and O&M opportunities supporting infrastructure for export and domestic use
Jobs opportunity	Low	High	High
Main location of opportunity	Urban/regional	Regional/remote	Urban/regional
Difficulty of capture/level of investment	Medium	High	High

Appendix A Electricity cost

Figure 30 below shows projections of an average annual energy bill in a grid-connected household in each of the modelled pathways, as well as a 'No abatement' scenario for comparison. The differences in energy bills results from the major differences in how abatement is achieved in each pathway. (Highlighting the effect of the different choices made in each pathway is the purpose for using pathways in this report). The key differences between pathways that effect household energy bills are:

- Rate of improvement in energy productivity
- Relative levels of abatement achieved by each of the energy subsectors (electricity, direct combustion, transport, fugitive emissions)
- Types of new electricity generation

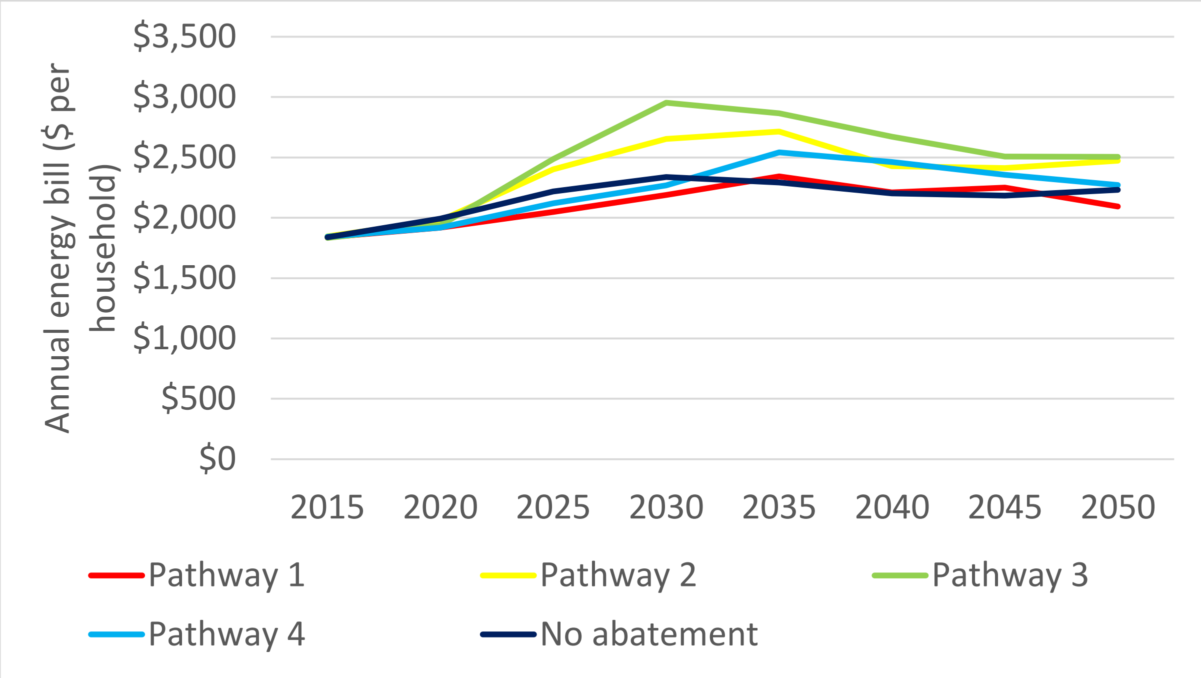
A further discussion on the comparability of the cost projections between pathways is given below in Section A.1.1.

Equation 1 shows a simplified calculation of how this bill was derived. It can be seen that changes in the unit retail electricity or gas prices must be considered alongside changes in total household demand so as to understand the actual effect on a household bill.

Equation 1 – Household energy cost calculation

$$\begin{aligned} &\mathit{Household\ energy\ bill} \\ &\quad = \mathit{electricity\ unit\ price}\ \times \mathit{electricity\ consumption}\ + \mathit{gas\ unit\ price} \\ &\quad \times \mathit{gas\ consumption} + \mathit{incremental\ capital\ costs\ of\ equipment} \end{aligned}$$

Figure 30 – Comparison of annual energy bill (electricity + gas) across pathways ($ per household) including capital costs for high efficiency equipment in Pathways 1 and 4.



This section focuses on the electricity component of the household bill and presents detail of the electricity price components as they apply to the different pathways. The components discussed include wholesale, network and retail prices, energy demand as well as component costs and total expenditure.

A.1.1 Comparability of cost projections between pathways

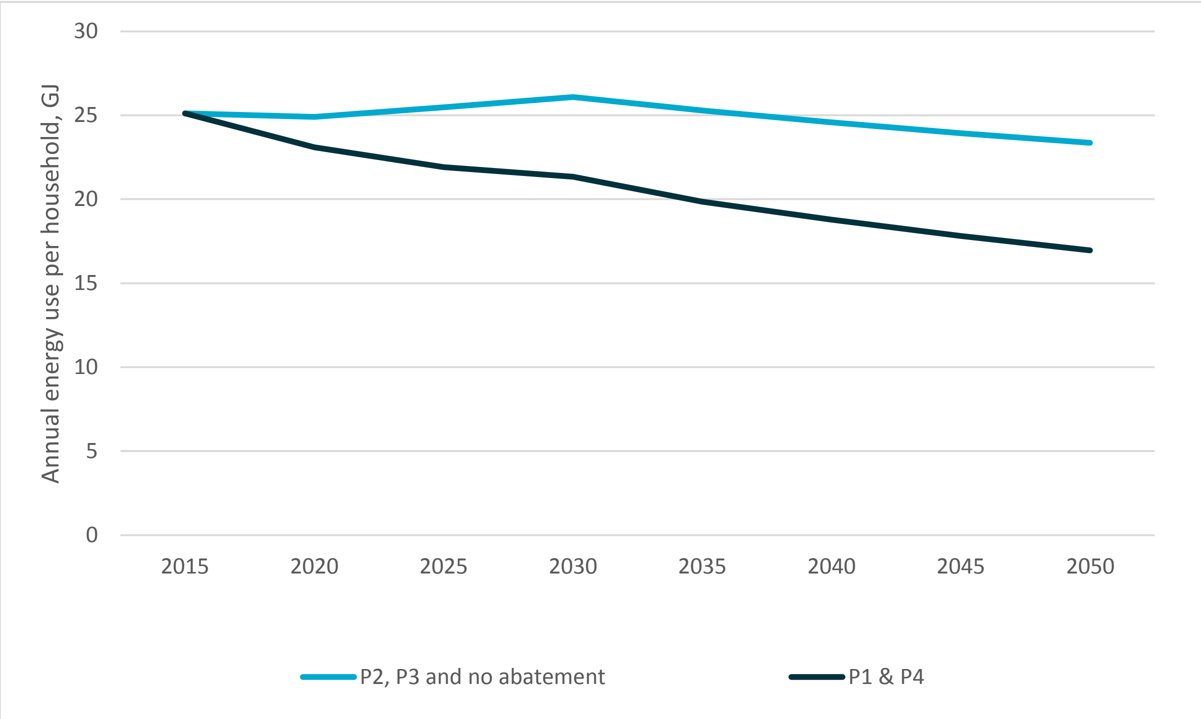
The economic modelling framework applied to assess the electricity and transport sectors means that a number of costs projections are available for these sectors, unlike other sectors. It is worth noting certain points regarding comparability between pathways regarding these cost projections:

- There are different levels of emissions abatement in the electricity sector in 2030 between pathways. This is an important feature of the pathways – pathways in which more abatement is achieved in other sectors can reduce the abatement required from the electricity sector, and hence costs in this sector.
- Pathway 1 has lower 2050 electricity sector abatement (75%) than the other pathways (95%), as discussed in Section 2.2 of the main report. However, since total abatement in 2050 in Pathway 1 is similar to or greater than in Pathways 2 and 3 (see Section 3.14 of the main report), it still provides a useful basis for comparison.
- Not all costs have been included. While costs of demand side technologies have been factored into the overall bill shown in Figure 7 in the main report, these costs have not been included in the electricity price or total expenditure (Retail price
- Figure 35 and Figure 32). Other costs that have not been quantified include:
    - Costs of regulatory regimes, or transaction costs required to assess and choose new equipment, which may be required to achieve energy productivity improvements in Pathway 1.

- Costs of managing power system security under high variable renewable generation in Pathway 2. These costs are expected to be relatively small compared with total spend however, as discussed in Section A.1.4.
- RD&D costs of technologies, e.g. the costs of characterising CCS storage resources in Pathway 3. These costs would not be expected to add significantly to the costs faced by consumers however.
- Costs of any incentives or subsidies. Note that these could reduce the costs to energy users, while acting as a cost to taxpayers.

A.1.2 Demand

Figure 31 – Average household electricity demand



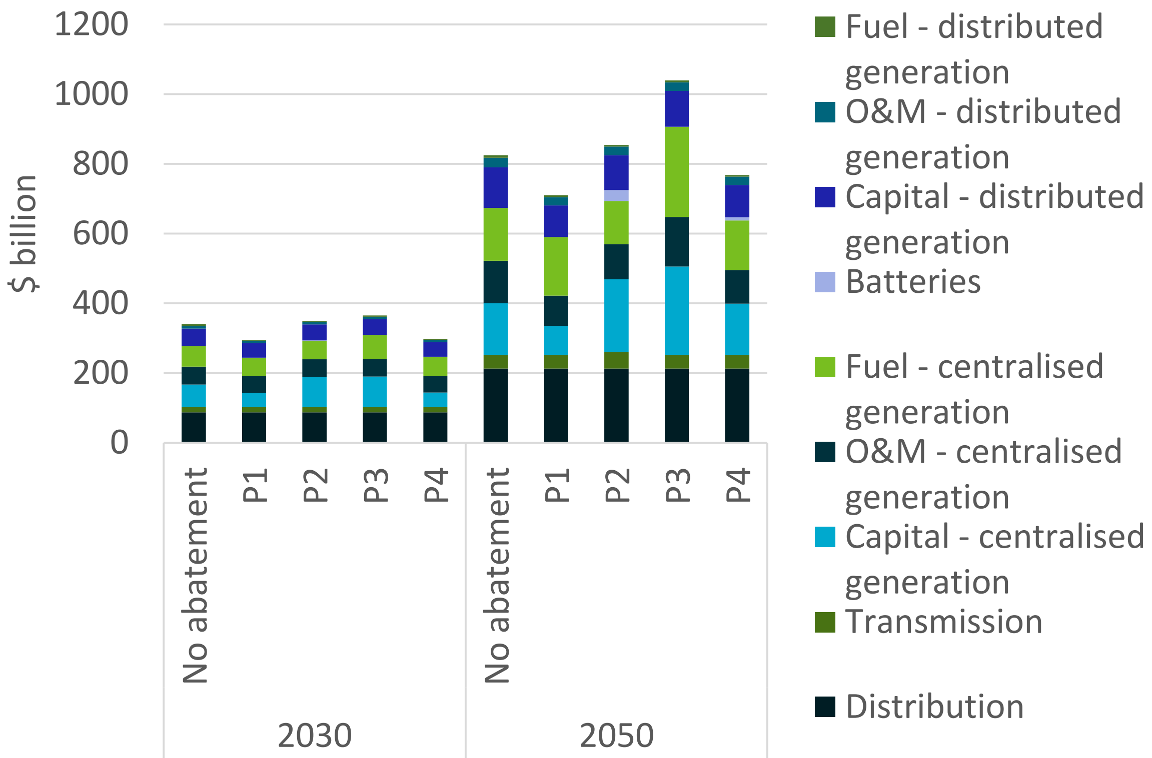
The average household electricity consumption over the modelled period is shown in Figure 31. In P2, P3 and the no abatement scenario, energy consumption per household in 2050 is expected to be less than current levels owing to the continuation of the observed historical trend towards lower energy use per household. This is a result of continually improving appliance efficiency driven by Minimum Energy Performance Standards (MEPS), increased desirability of efficient appliances and lighting (e.g. LED LCD TVs and LED lights) as well as new buildings replacing old premises, which were sometimes built to no minimum standards.

Demand in P1 and P4 is lower still, owing to continually improving minimum standards that improve the building 'envelope', replacement of appliances and equipment with higher efficiency or electric alternatives at end of life as well as better building management.

A.1.3 Electricity price components

Total expenditure

Figure 32 – Comparison of cumulative total electricity supply chain expenditure between pathways



Cumulative electricity supply chain total expenditure from 2016 including generation and network capital, operations and maintenance (O&M) and fuel costs in each pathway is shown in Figure 32.

Key points to note are:

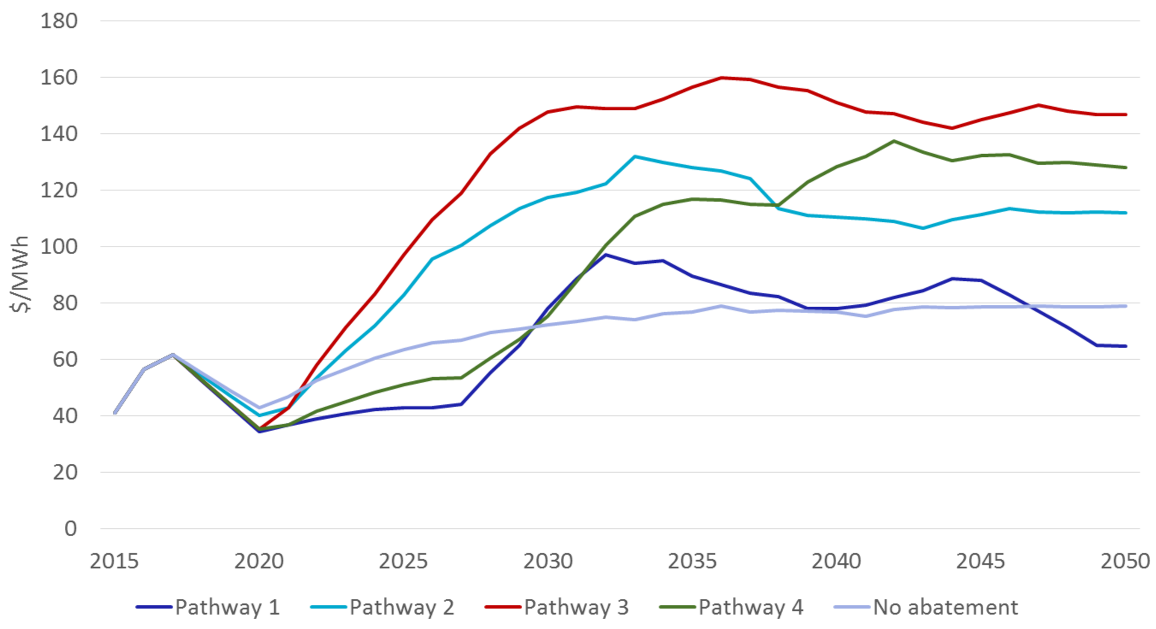
- Expenditure on electricity supply is lowest in Pathways 1 and 4, due to the reduced demand in these pathways. Notably, electricity supply chain spend is lower in Pathways 1 and 4 than in the no abatement scenario, with less generation requiring deployment and savings in O&M and fuel.
- Pathways 2 and 3, which have slower improvements in energy productivity, have similar costs as each other on a 2030 timeframe, reflecting the comparable energy demand and generation profiles of these pathways up to this time. On the 2050 timeframe, Pathway 2 requires ~$175 billion less cumulative spend than Pathway 3, due to its use of lower cost technologies. Note that these costs do not include the full integration costs of renewables, but that these costs are expected to be significantly less than $175 billion (for further details, see the discussion in Section A.1.4).
- Significant levels of storage are expected to be required in Pathway 2 from the mid-2020s, resulting in modest contributions to system cost (~5% of cumulative total expenditure in 2030 and ~6.5% in 2050). Furthermore, spend was calculated based on expected battery costs; savings may be possible if off-river PHES proves cheaper than batteries and is able to be widely deployed.
- Additional transmission expenditure is expected in scenarios with high VRE share (AEMO, 2013) (Graham, 2013). A similar amount of transmission expenditure is expected for all pathways up to 2030 and an additional $9 billion of cumulative transmission expenditure is expected in Pathway 2

by 2050 compared to the other pathways, to enable more large-scale VRE to be connected in weaker, remote areas of the network. Similar levels of distribution expenditure are expected among pathways. Further discussion on transmission and distribution required to support a high share of VRE is presented in the electricity modelling methodology (Section B.3).

- Distribution expenditure (note this excludes batteries and other integration costs for VRE) is the same in each pathway since this is driven by peak demand, which is assumed to be the same in each pathway. It is possible that peak demand could be lower in Pathways 1 and 4 (along with lower total demand) but to be conservative this has not been assumed.
- No new interconnectors were assumed in the modelling, with the modelling achieving energy balancing through other means e.g. dispatchable power and batteries. This is a conservative approach – it is possible that spend could be less with interconnectors, but it is a substantial modelling task to determine whether this is the case.
- Transmission and distribution spend is essentially replacement, since peak demand does not grow significantly.
- Expenditure for Pathway 2 is shown for the centralised (base) case. Spend is 11% higher in the decentralised case, which has a higher share of rooftop solar PV and lower share of large-scale generation compared to the centralised case (rooftop solar PV costs more per kW than large-scale solar PV). Spend for Pathway 3 is shown for the base case. See Figure 44 of for a comparison of expenditure in the sensitivity cases.

Wholesale price

Figure 33 – Comparison of electricity wholesale price between pathways



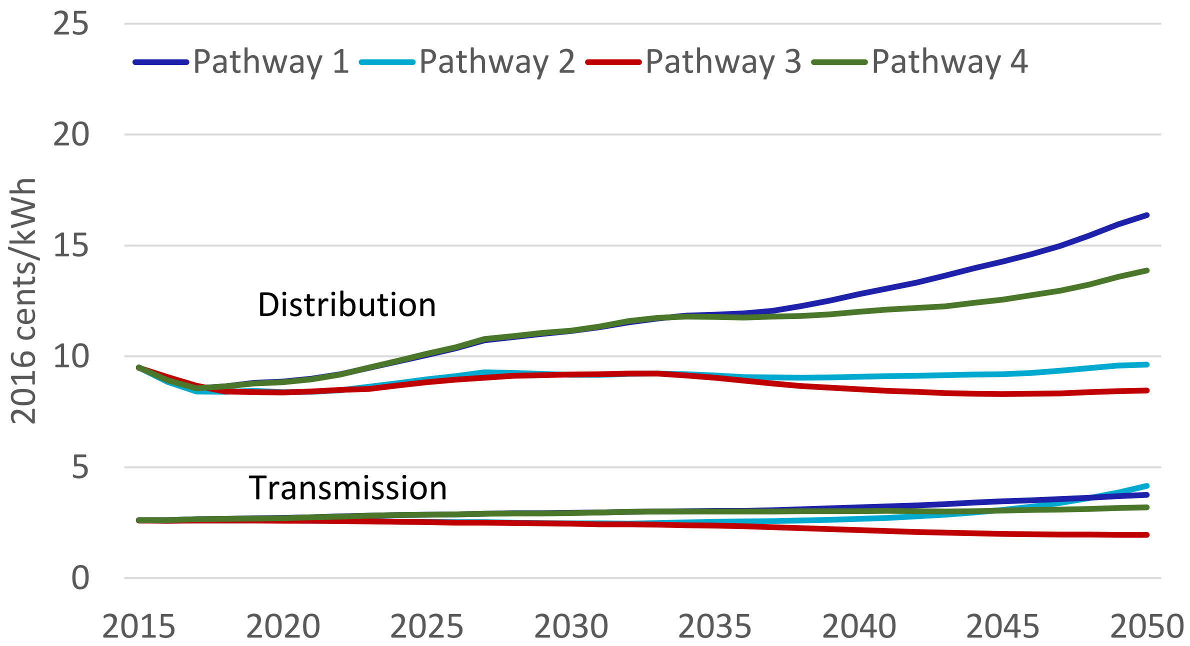
The wholesale component of the retail electricity price for pathways modelled is shown in Figure 33. Key points to note:

- While there are relatively large relative differences in wholesale prices between pathways, the relative differences in retail prices are much smaller (see Retail price
- Figure 35 below), given that wholesale prices is a relatively small component of the retail price.

- In all pathways, prices eventually rise above the no abatement price due to the need to replace existing generation earlier than would be the case if there was no constraint on emissions, and to the higher costs of some low emission technologies. Note that an increase in wholesale price is required to incentivise investment in new generation assets.
- Prices rise in Pathways 2 and 3 sooner than in Pathways 1 and 4, driven by the higher total demand in these pathways, which means existing higher emission coal generation needs to be replaced sooner to remain within the specified abatement trajectory.
- Prices rise in Pathway 1 less than in Pathway 4 due to the lower abatement requirement for the electricity sector in this pathway; additionally, greater expenditure on new generation is required in Pathway 4 to support higher consumption due to hydrogen production.

Network component

Figure 34 – Comparison of electricity transmission and distribution prices between pathways



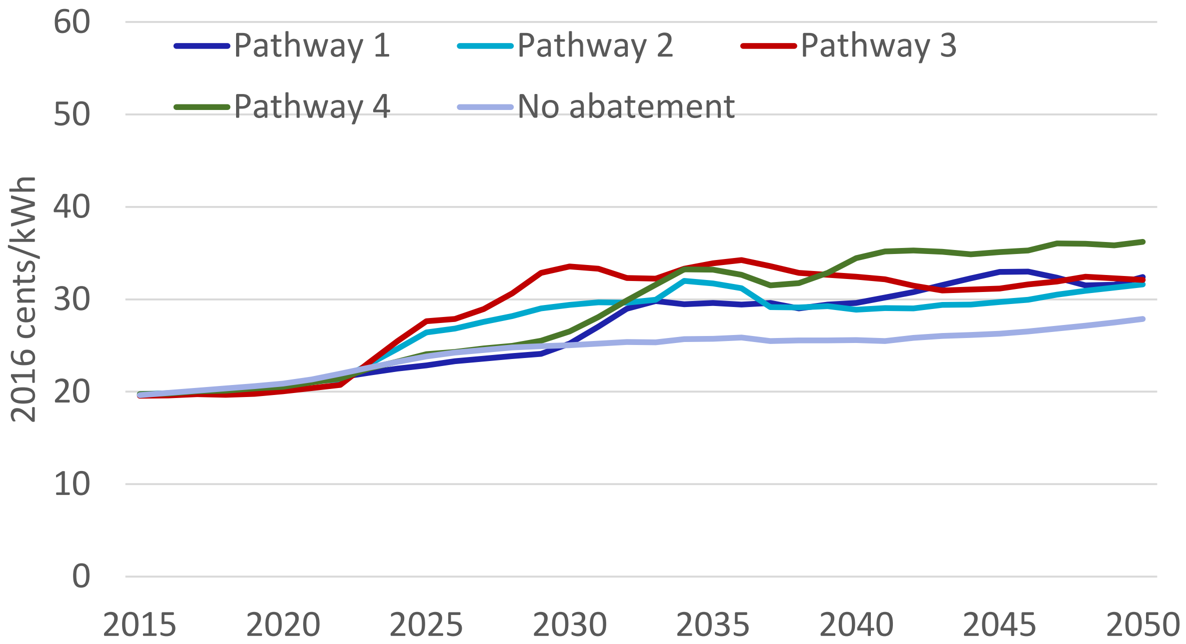
The network components of the retail electricity price for each pathway modelled are shown in Figure 34.

- While the lower consumption of Pathways 1 and 4 compared with Pathways 2 and 3 means less new generation is required, they are assumed to have similar network expenditure[30]. Since this network expenditure must be recovered over less consumption, Pathways 1 and 4 have higher unit network costs than Pathways 2 and 3.
- This effect is offset for transmission in Pathway 2, due to the additional $9 billion in cumulative transmission cost by 2050 in this pathway.

[30] Network expenditure is driven by peak demand, which is assumed to be the same across pathways (see Section B.3.2 for further discussion).

Retail price

Figure 35 – Comparison of electricity retail price between pathways



Expected retail prices for each pathway and for the no abatement scenario are shown in Retail price

Figure 35. Given that the retail price comprises the wholesale price and network components described above (as well as a retail margin, which is assumed to be the same across pathways), the differences between pathways are explained in the commentary provided above. Additionally, key points to notes are:

- Prices to 2030 remain similar in Pathways 1 and 4 to the no abatement scenario.
- In all pathways, prices eventually rise above the no abatement price driven by increases in the wholesale price.
- While retail electricity prices rise in all cases, these changes are partially offset by customer energy efficiency improvements and diversification of supply through installation of rooftop solar and other distributed energy resources. These reduce the volume of grid supplied electricity consumed and may provide opportunities to sell surplus electricity and/or demand reduction services back to the grid. As a result, the rate of change in average customer bills will be less than the rate of change in retail electricity prices and there may be significant diversity in customer bill outcomes depending on access to distributed energy resources.

A.1.4 Other integration costs

Additional integration costs not included in the retail price calculation may be required to support the high share of VRE in Pathway 2. Initial estimates suggest that the net impact of these costs will be small compared with total system expenditure (or possibly even negative), but more work is recommended to examine this in further detail.

Smart grid technologies

As discussed in 13.2.2, the total cost of smart grid technologies is likely to be relatively small compared to system spend. These costs have not been calculated as part of this assessment. Furthermore, these technologies are expected to reduce system spend by avoiding network investment – the Electricity Network Transformation Roadmap estimates a $16 billion saving is possible by 2050 (Energy Networks Australia and CSIRO, 2016).

Frequency stabilisation and fault level

Synchronous condensers could be added to the grid as VRE share increases in order to provide inertia for frequency stabilisation and to increase fault level. The degree to which this would be needed depends on other equipment present (e.g. batteries and advanced inverters) and whether there are markets for sufficiently fast frequency control ancillary services (FCAS). As a preliminary conservative estimate, a ~$7 billion investment is expected to be sufficient to provide all the inertia required for frequency stabilisation and fault level required by a 100% VRE system using synchronous condensers (see 13.2 for further details). This cost is only 0.8% of total cumulative system expenditure (including transmission and distribution, storage, generation, O&M and fuel) from 2016 to 2050 in Pathway 2. This cost could be further reduced if inertia were provided by other sources already present in the system for other purposes (e.g. modern wind farms can provide inertia, and battery storage with advanced inverters can provide fast frequency response) or if existing synchronous generators were to be converted to synchronous condensers when retired (this would also provide ongoing economic benefit to assets owners and retain jobs). Further modelling would be required to examine system performance at sub-5 minute timescales to determine the optimal way to achieve system stability in a system with high VRE share, thereby refining the cost estimate.

Appendix B Methodology

B.1 Overall methodology

B.1.1 Technology identification and classification

The technologies considered as part of the roadmap exist across the energy sector (i.e. electricity, transport, direct combustion and fugitives). Given the broad scope of the report, a desktop review (discussed below) was undertaken in order to identify the key technologies and understand their potential impact on short and long term abatement targets.

Desktop review

The desktop review included two primary activities:

1. Review of relevant materials – This included a review and synthesis of relevant local and international publications. Key sources include (CO2CRC, 2015) and (ClimateWorks Australia, 2014). For a complete list, refer to the references in this and the main report.
2. Stakeholder engagement – This involved engaging with industry experts across the energy sector to understand the role of each of the technologies as well as current trends influencing development. A full list of stakeholders consulted is provided in Appendix E of the main report.

Technology classification and pathway development

In order to construct the pathways, the key technologies identified were then categorised in terms of their role (under the four pillars of decarbonisation described by ClimateWorks) and deployment readiness in an Australian context. This is described further in Section 2 of the report.

B.1.2 Technology impact on short and long term abatement targets

Each of the identified technologies were then assessed individually to further understand their abatement potential, current technological and commercial readiness, barriers to development and potential enablers. Note that each of the assessments were undertaken with input from the relevant CSIRO researchers as well as external experts and industry leaders (see Appendix E of the main report).

Abatement potential

The abatement potential for each of the technologies is reflected in the pathway modelling. As described later in this section, this illustrates an optimised share of the technologies under a range of different scenarios.

LCA emissions

It is important to note that as part of this report, these technologies have not been assessed in terms of lifecycle emissions. This has been examined for electricity generation technologies by the National Renewable Energy Laboratory (NREL). The findings for some of the key low emissions technologies are set out in Figure 36 below.

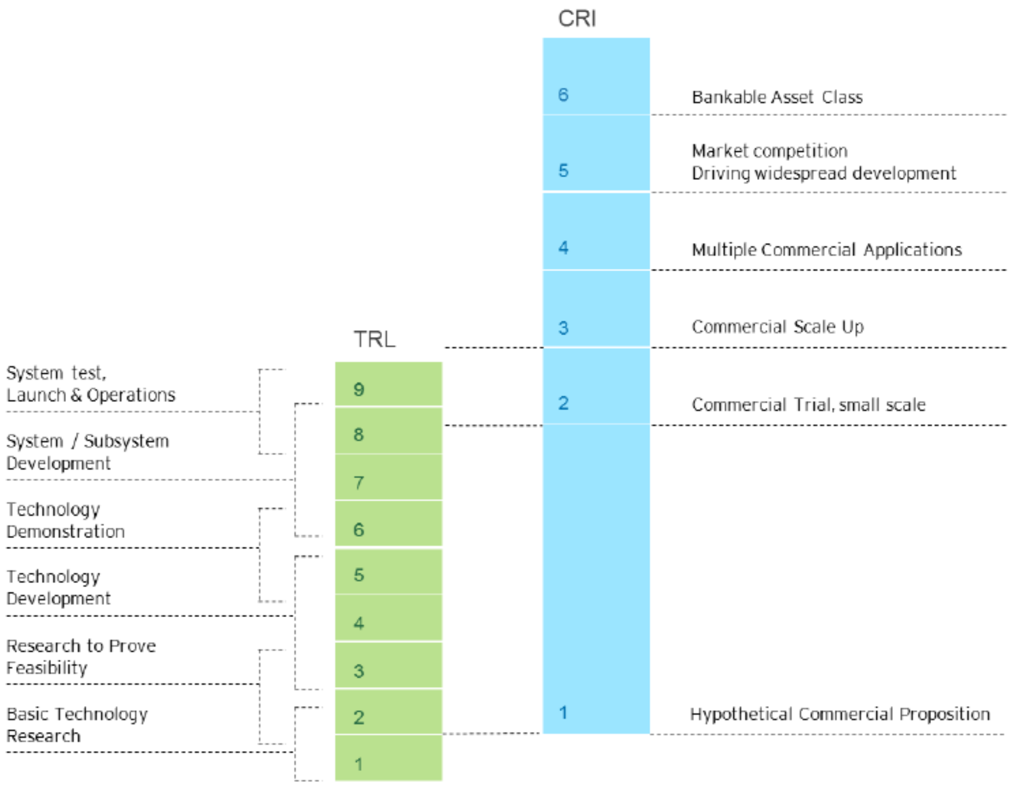
Figure 36 – Lifecycle GHG emissions (g CO_2e/KWh) [31]

Technological and commercial readiness

Each technology (or group of technologies) was assessed according to the Technological Readiness Level (TRL) framework first developed by NASA in 1974 and the Commercial Readiness Index (CRI) framework developed by ARENA in 2013 (ARENA, 2014). These frameworks are used by ARENA when considering the technical and commercial readiness of renewable energy technologies. They are summarised in Figure 37 below.

[31] Data sourced from National Renewable Energy Laboratory, ‘Life cycle assessment harmonization results and findings’, NREL.gov, last modified 21 July 2014, www.nrel.gov/analysis/sustain_lca_results.html.

Figure 37 – Technological and commercial readiness index
(source: ARENA Commercial Readiness index for renewable energy sectors)



Barriers to deployment

Barriers to (further) deployment of each of the technologies have been categorised as follows (following the classifications used when measuring CRI):

- Cost – High upfront capital cost and/or operating cost
- Revenue/market opportunities – Lack of sufficiently large and low risk revenue opportunity for a particular technology. Market or regulatory frameworks may also not allow technologies to derive (full) remuneration for the value they provide
- Regulatory environment – Regulations impeding uptake of technologies e.g. current regulations that make deployment cost prohibitive, lack of appropriate operating standards
- Technical performance – Many of the generation technologies expected to deliver abatement in a 2030 timeframe are not technologically mature. Others, although mature, have technical challenges associated with integration and operation at scale
- Stakeholder acceptance – Certain low emissions technologies face opposition from some segments of the community or from industry stakeholders
- Industry and supply chain skills – Deployment of certain technologies may be impeded by the absence of a local industry and lack of required skills.

Enablers

Policy

In keeping with the scope of this project and CSIRO's role, no specific policy enablers have been recommended. However, areas where changes to policy and regulations could increase the uptake of low emissions technologies have been identified.

Stakeholder engagement

Stakeholder engagement is needed to help create awareness of the benefits and risks of certain low emissions technologies and to encourage adoption. This can be achieved via industry consultation and by making information and training readily available.

Skills and business models

The private sector has a key role to play in increasing uptake of low emissions technologies through the development of new business models. Industry upskilling will also be important in supporting the rollout of low emissions technologies.

RDD&D funding

While RDD&D funding is key to supporting Australia's abatement challenge, it is also important in helping other countries decarbonise and capturing potential export opportunities.

Figure 38 describes these RDD&D objectives, and outlines the conditions in which funding is required to satisfy them. In the absence of these conditions, Australia could simply act as a 'technology taker' (i.e. deploy technologies that have been developed elsewhere).

Based on these objectives and conditions, categories have been defined to help prioritise funding.

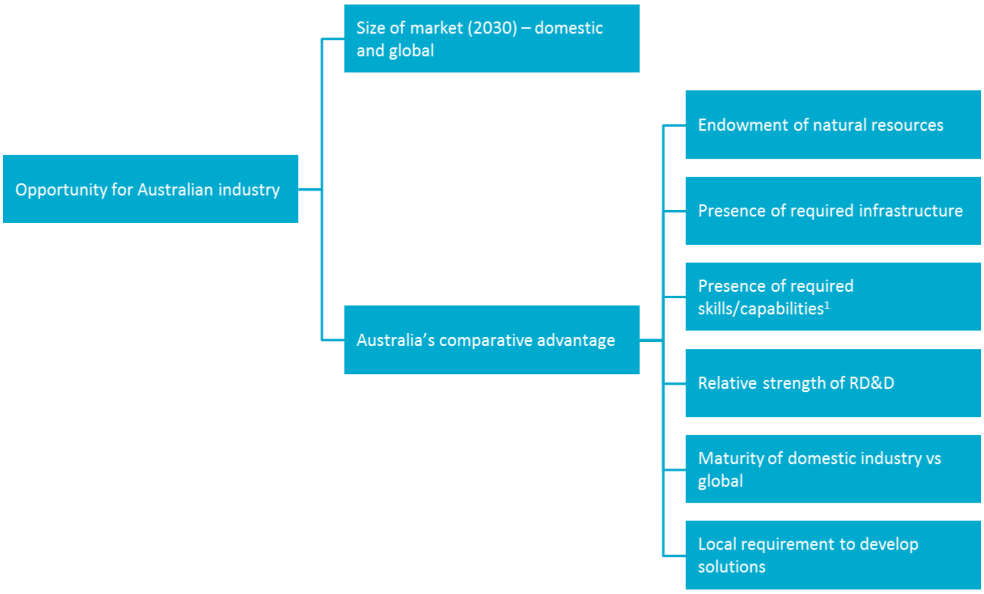
Figure 38 – Funding categories

Overall objectives	When funding in Australia is required to achieve objectives	Funding categories	Comments
Increased uptake of low emissions technologies in Australia (and capture local commercial opportunities)	• To drive down the cost of technologies in Australia • To develop / adapt technology for local conditions • To overcome local barriers e.g. financing	Key for Australian abatement	Critical for abatement across pathways
		For optionality	Maintains optionality in achieving abatement
		Targeted bets	High risk / high reward opportunities
Global abatement and capture of export opportunities	• To contribute to global technology development • To capitalise on global market opportunities	Primarily commercial / global	Less impact for Australia but unlocks global abatement / commercial opportunities

B.1.3 Opportunities for Australian industry

The following framework was used to assess the opportunities for Australian industry across each of the technology supply chains.

Figure 39 – Framework for assessing opportunities for Australian industry



Based on this framework, a high level estimate was made of the value of each opportunity (high, medium or low, according to the criteria in Figure 40). Detailed modelling of the opportunities was outside the scope of the project, given the large breadth of technologies analysed. Instead, the analysis of opportunities is intended to identify areas of opportunity for further investigation. The 'difficulty in capturing/level of RD&D investment required' refers to the overall investment needed to capture opportunities, both financial and non-financial, to ensure that the technology is commercially viable in Australia. Again, high level estimates were made for this metric.

Figure 40 – Framework for assessing opportunities

	OPPORTUNITY FOR AUSTRALIAN INDUSTRY	DIFFICULTY IN CAPTURING/LEVEL OF RDD&D INVESTMENT REQUIRED
High	>$1b in potential annual revenues	• Requires developing new capabilities or regulations, or coordinating multiple stakeholders • Multiyear, programmatic RDD&D investment required with high risk • Typically greater than >$500m total RDD&D investment required
Medium	$100m-$1b in annual revenues	• Some development of new capabilities or regulations and stakeholder coordination may be required • Investments required over a period of <3 years, with low-moderate risk • Typically $50-$500m total RDD&D investment required
Low	<$100m in annual revenues	• Required capabilities and regulations largely exist; little stakeholder coordination required • Investments of 1-2 years provide high chance of acceptable returns • Typically <$50m total RDD&D investment required

B.1.4 Workshops

A series of industry workshops were held to test findings from each of the technology assessments as well as the project as a whole. These were:

1. Mature intermittent renewables (25 August 2016, Sydney)
2. Resource sector technologies (26 October 2016, Melbourne)
3. Transport sector technologies (27 October 2016, Melbourne)
4. Manufacturing sector technologies (24 November 2016, Webinar)
5. Coal based technologies (25 November 2016, Webinar)
6. Oil & gas technologies (25 November 2016, Webinar)

A cross-agency workshop with government stakeholders was also held to seek input on the overall project structure and refine findings from the 'mature intermittent renewables' workshop on 26 August 2016 in Canberra.

A full list of all stakeholders consulted can be found in Appendix E of the main report.

B.1.5 Relationship to other work

Given the wide scope of the Low Emission Technology Roadmap, this report draws on a number of existing and parallel studies. A particular relationship that should be highlighted is that the LETR drew on parts of the same CSIRO modelling framework that was applied in the CSIRO and Energy Networks Australia Electricity Network Transformation Roadmap (ENTR) – in particular the electricity generation, electricity network, storage and transport sector models which are discussed later in this appendix. The ENTR delivered its consultation report in December 2016 (Energy Networks Australia and CSIRO, 2016) focussing on actions over the next decade to improve customer outcomes in the electricity sector. Besides sharing some modelling approaches, the ENTR also provided input into the approaches identified in LETR for addressing barriers to integration of distributed energy resources such as rooftop solar, battery storage and electric vehicles. The pathway considered in the ENTR is similar to the electricity sector in Pathway 2, although the ENTR assumed 100% decarbonisation.

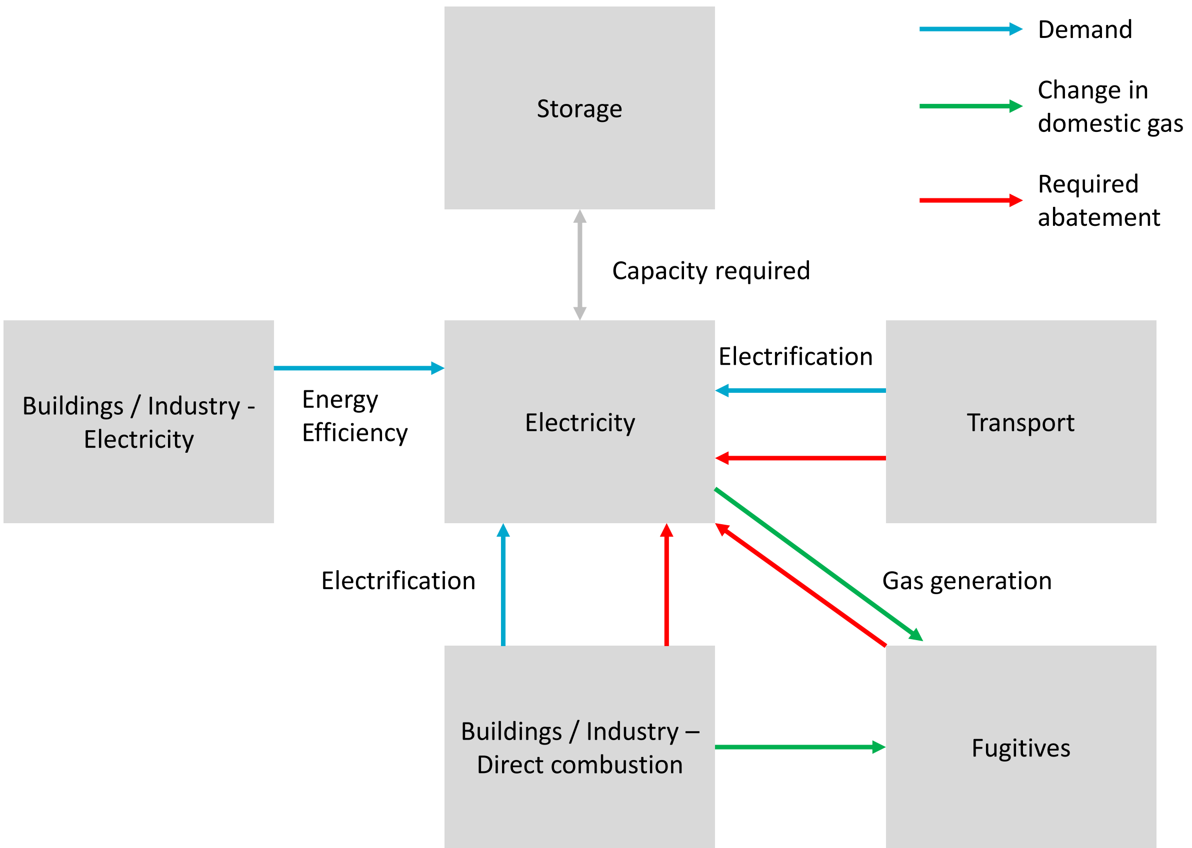
The transport sector modelling draws from recent analysis commissioned by the Department of the Environment and Energy (DoEE) to provide annual projections of emissions and fuel consumption for the transport sector to 2035, to inform *Australia's Emissions Projections 2016* (Reedman & Graham, 2016). This work provided updated assumptions on ICE vehicle efficiency improvements, projected vehicle costs, ranges of EV uptake, and demand growth (ABMARC, 2016), and oil price projections. The baseline scenario from (Reedman & Graham, 2016) was used as the "no abatement scenario" for benchmarking the LETR scenarios.

Buildings energy use and emissions were sourced from recent modelling undertaken for the Australian Sustainable Built Environment Council in 2016 (Australian Sustainable Built Environment Council, 2016). For industrial sectors, information regarding energy and emissions by end use or process as well as rates of energy efficiency were adapted from research undertaken by ClimateWorks Australia (ClimateWorks Australia, 2013).

B.2 Overall modelling approach

The Low Emission Technology Roadmap uses several models (Figure 41) as part of its pathway assessment process to deliver outputs such as projected emissions, expenditure and activity levels. An important aspect of the modelling framework is that it applies a mixture of two alternative approaches to develop its outputs. On the one hand, there are many cases where hard assumptions are applied in order to explore a particular emission reduction pathway. However, in other cases the model is used to determine least cost choices. Hard constraints were generally applied in sectors such as fugitives, buildings and industry because there are fewer choices available to be optimised by market actors. However, in electricity and transport, models were applied that optimise investment choices (based on minimising costs) within a given range of options available for that pathway.

Figure 41 – Modelling framework



Another important aspect of the modelling framework is that the components have various interdependencies which must be resolved through an iterative approach. The first of three crucial dependencies is the level of required abatement. Given the LETR assumes that the energy sector must reach the goal of 26-28 % abatement by 2030, the proportion of emissions reduced in one sector impacts how much emission reduction must be achieved in other sectors. To resolve this problem, the electricity sector was chosen to act as the balancing sector. This is a natural role for electricity because it is responsible for the most emissions, has much greater abatement potential and has more moderate cost technological options available than any other sector. Thus the target for the electricity sector was set as the residual required for the energy sector as a whole to reach the target after all reasonable actions were taken in the remainder of the energy sector. 'All reasonable actions' is of course a matter of judgement which was why the LETR reviewed the literature and undertook a variety of stakeholder engagement workshops in order to test those assumed actions.

A second source of interdependency is that as electricity decarbonises, substituting fossil fuels such as coal or gas for electricity in various end uses becomes a stronger sources of abatement and increases the level of electricity demand. It was therefore necessary to perform several runs of the electricity model and other sector models to determine the emission intensity of electricity generation, the reasonable uptake of electricity as a substitute for direct use of fossil fuels in various end uses and the subsequent addition in electricity demand that must be met. Building/industry and transport electrification were two key sources of electricity demand, offset by energy efficiency improvements in buildings/industry.

The third interdependency is between the choices about uses of natural gas and fugitive emissions. Natural gas is a source of abatement where it substitutes for coal in electricity generation or in direct use. However, greater use of natural gas can be responsible for increases in fugitive emissions as there is a strong relationship between the quantity of gas consumption and fugitive emissions. To resolve this requires some iteration between the fugitive emissions model and the electricity and industry/direct combustion sector.

One more aspect of the modelling framework was to design a specific component to determine how storage could be used to assist the electricity sector deploy variable renewable energy technologies. The chosen approach to this topic is outlined in Section B.4.

All modelling is subject to uncertainty. The results presented in this report are based on numerous assumptions regarding rates of technological development and uptake. While these assumptions are based on extensive literature review and stakeholder consultation, they are inherently subject to uncertainty. As such, the modelling results should be interpreted as possible outcomes to guide decision making in the face of uncertainty, rather than as predictions.

B.3 Electricity modelling methodology

B.3.1 Modelling approach

Generation model options

Economic models of the electricity generation sector generally fall into two categories: half hourly/hourly dispatch models or intertemporal investment models. Dispatch models minimise the cost of meeting demand each half hour or hour (depending on required resolution) given the state of each generation plant in the previous interval and the current bids and transmission constraints. In many ways they work the same way the actual National Electricity Market dispatch algorithm operates in order to control the electricity system in real time. They are very time consuming models to run since the dispatch outcome for each time interval must be solved sequentially for the entire projection period of interest. However, their high temporal resolution means that they can give much greater confidence in the likely financial returns to each generation plant and greater confidence that a given set of generation plant will deliver the required standard of reliability (in terms of unserved energy).

Intertemporal investment models focus on solving the problem of what types of electricity plant should be built each year to meet demand over the entire projection period. They use an approximation of the annual load curve to represent demand in load blocks and solve each annual time period simultaneously with the others. Such models are said to be forward looking in that, like a real life investor, they anticipate changes in policy and gaps in supply. Intertemporal investment models produce results much faster but are not able to determine the profitability of each plant and the amount of unserved energy.

Both models, assuming they use the same technology and fuel cost assumptions, tend to produce similar electricity price projections in the long run since in theory, prices should converge towards long run marginal costs, otherwise eventually no new plant would be deployed. However, the electricity industry typically uses dispatch models for their greater accuracy, whilst running intertemporal investment models as a secondary information source to feed in information to the dispatch model about what new plant are coming online each year.

Generation modelling framework

Given the options available the LETR project chose to use an intertemporal investment model as the primary electricity modelling tool. The large number of scenarios and sensitivity cases that needed to be modelled over a 35 year projection period meant that a dispatch modelling approach would not be practical. The intertemporal investment model used is CSIRO's Energy Sector Model (ESM), previous results of which can be found in (Graham P. B., 2013)and (Graham P. , Brinsmead, Reedman, Hayward, & Ferraro, 2015). An interactive web version of the model is also available at http://efuture.csiro.au/.

Given the pathways explored in the LETR include scenarios with very high variable renewable electricity generation, we designed a sector model to support ESM and provide some confidence that electricity demand is being met reliably. There have been a number of studies that have addressed the topic of how to support variable renewable energy. For example (AEMO, 100 Percent renewables study - modelling outcomes, 2013) uses a combination of non-variable renewables, demand management and storage. However, CSIRO's recent analysis of storage in (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015) indicated that the falling costs of battery storage meant that it would likely play a significant role in any high variable renewable scenario. Consequently a 'storage' model was designed for the purposes of determining for any given level of variable renewable electricity generation share of energy supplied, and any other existing resources such coal, gas and hydro plant, what quantity of energy storage capacity was required to ensure demand was met for every hour of the day.

The storage model was deployed to check required storage levels in each state for high variable renewable scenarios and selected five yearly intervals. The next step after running the storage model was to interpolate between the five yearly intervals and apply the additional costs of storage onto ESM as a hard constraint. This ensured that the costs of energy balancing under high variable renewables were adequately represented in ESM. This involved some iteration between ESM and the storage model as indicated in Figure 41.

Where scenarios do not include high variable renewable shares, ESM operates in the ordinary way without the iteration process described above to ensure there is adequate capacity to meet peak demand and carry out energy balancing. This requires that there is sufficient dispatchable generation technology to meet demand at all times of the day when variable renewable output is near or at zero.

Network modelling framework

Australian electricity distribution and transmission systems are natural monopolies. They operate under a system of regulated rate of return for delivery of reliable transmission and connection services. Network prices are adjusted over time according to changes in the regulated asset base, the cost of financing and the utilisation of the network. The regulated asset base can increase over time if additions through augmentation and replacement (due to growth in peak demand) exceed depreciation. Capacity utilisation can fall if peak demand grows faster than energy consumption. For example, a strong rate of growth in rooftop solar installations puts networks at risk of lower capacity utilisation. To maintain their regulated return on investment, unless there are other offsetting factors, networks must increase prices, potentially encouraging faster rooftop solar installation and thereby creating a perverse price cycle. CSIRO employs a simple network asset stock, depreciation and investment model to capture these impacts on both the distribution and transmission sector, calculating total investment and average unit prices required. The modelling framework has been previously described in (Graham P. B., 2013).

Limitations in transmission modelling

Relative to the distribution sector, transmission augmentation is much larger and location specific in terms of estimating costs. Ideally a spatially detailed transmission model should be deployed for more accurate cost estimation. Due to the existing complexity of the modelling task and large number of scenarios explored, the modelling did not include any original analysis of specific transmission augmentation projects both from the perspective of state interconnectors and internal state strengthening. We maintain state interconnectors at their current capacity such that states must draw any additional energy balancing capacity requirements from within their own state.

While our modelling was not able to address this issue, the potential contribution of state interconnectors should be explored as an equally important means of supporting energy balancing. (AEMO, 2016) found that under their analysis a number of state interconnector expansions may have a positive net benefit with the caveat that these potential projects will still need to undergo a more detailed regulatory investment test before strong conclusions can be drawn.

In regard to internal state strengthening, previous analyses of scenarios with very high renewable shares have indicated a need for additional expenditure in the transmission system to access renewable resources and assist with energy balancing ((AEMO, 100 Percent renewables study - modelling outcomes, 2013); (Graham P. B., 2013)). To address this issue, where a scenario includes high variable renewable penetration the modelling adds an additional transmission cost consistent with these previous estimates.

B.3.2 Scenario assumptions and data sources

While ESM is designed to choose a least cost set of generation technologies to meet electricity demand, additional assumptions are also imposed in order to explore the LETR pathways, which represent specific technology combinations within a theme. These are set out in Table 105 and discussed further below.

Common pathway assumptions

Abatement signalling

A common assumption across the pathways is that the electricity sector faces an emission limit which we impose as a constraint within the intertemporal cost minimisation problem. This should not be interpreted as indicating any specific policy preference but is merely the most direct approach that could be applied to ensure the electricity sector delivers the abatement required. As discussed in the introduction to the appendix, the abatement amount for 2030 was determined as the amount necessary for the electricity sector to meet the 2030 target after taking into account the abatement delivered by non-electricity parts of the energy sector as discussed above. Each pathway has its own 2030 electricity sector target which is discussed in the main report.

For 2050, the level of abatement was set on the basis of what would be reasonable given the pathway and the cost of abatement. If costs of abatement are too high then one might reasonably expect abatement opportunities would be pursued elsewhere. For Pathway 1, the reliance on energy productivity rather than new low emission electricity generation technologies means that it was not cost effective to achieve more than a 75% reduction in emissions by 2050. For Pathways 2 to 4, we examined a number of different levels of abatement between 75 and 95% and found that it was feasible to achieve up to 95% abatement without significantly higher costs than a 75% level. Therefore this was chosen as the 2050 goal for those pathways.

Retirement

Each model has its own approach to retiring electricity generation plant. This is because there is some uncertainty about how this will happen in Australia. Some models have a bias towards longer life reflecting the fact that some plant have a strong inherent ability to extend their life by replacing parts and also may wish to avoid for as long as possible the time in which site rehabilitation costs will need to be met. A bias toward shorter lives would reflect a negative view on the plant owner's ability to finance life extensions in a decarbonising policy environment and social pressure on plant owners not to extend and even to close earlier. Australia has seen several announcements in recent years from companies in regard to closing plant early for economic reasons or wishing to signal to the public that they have a plan to transition out of high emission activities.

In ESM we strike a balance between these extremes by implementing any announced closures, allowing economic closures before end of life where appropriate for the scenario and otherwise closing plants according to their design life of typically 30-50 years. The most recent closure announcement included in the modelling was for the Hazelwood plant in Victoria in 2017.

Rooftop solar adoption

Rooftop solar adoption increased considerably in the last 5 years and is a significant source of uncertainty in future demand. While we explore higher rooftop adoption in one of the sensitivity cases discussed below, for all other pathways we assume rooftop solar adoption will increase according to the AEMO's 2016 National Electricity Forecasting Report (NEFR) (Australian Energy Market Operator (AEMO), 2016). However, given that the NEFR only projects rooftop solar installation until 2036 we extrapolate the trend rate of installation in the NEFR out to 2050.

Specific pathway assumptions

Energy efficiency and demand

The total level of electricity consumption is different under each pathway due to the different themes they explore. Each of the scenarios uses the (Australian Energy Market Operator (AEMO), 2016) NEFR electricity consumption as a starting point (and extrapolating where necessary out to 2050) but then modifies NEFR further to better represent the pathway. In Pathway 1, the NEFR energy efficiency assumption is replaced with a new, stronger projection for energy efficiency projection. Additional electricity demand from transport, building and industry electrification is also added. Pathway 4 is the same as Pathway 1 but with additional electricity consumption from hydrogen electrolysis for transport.

In Pathway 2, the NEFR energy efficiency assumption remains and only transport, building and industry electrification is added. Pathway 3 is the same as Pathway 2 but with additional electricity consumption from hydrogen electrolysis for transport. These assumptions mean that Pathway 1 has the lowest electricity consumption followed by Pathway 4, then Pathway 2 and Pathway 3 has the highest consumption.

No impact on demand due to changes in electricity price have been assumed. Given each pathway assumes some level of energy productivity improvement, any improvement due to price sensitivity could be interpreted as being one contributing factor to the levels of productivity improvement assumed (along with policy measures etc).

While there are significant differences in consumption across the pathways, peak demand is assumed to be the same across the scenarios, matching to the projections in (Australian Energy Market Operator (AEMO), 2016). The justification for this simplified approach is that while the scenarios include significant energy efficiency which could reduce peak demand they also include substantial adoption of electric and fuel cell vehicles that could contribute to peak demand growth. For a more moderate scenario of adoption of electric vehicles than explored here, (Graham & Brinsmead, Efficient capacity utilisation: transport and building services electrification, 2016) find that the impact of electric vehicles on peak demand growth can be significant but varies substantially depending on the state of future pricing and incentives for demand management. (Energeia, 2016) find that some price reform, if poorly targeted or incomplete, may not have the desired impact on peak demand. Given uncertainty around the pace and impact of pricing and incentive reform for demand management, and to be relatively conservative around the task of meeting peak demand in each scenario, we assume that AEMO's projection of peak demand is a reasonable middle ground.

Table 105 – Electricity assumptions
(base cases shown – sensitivity cases described below)

KEY DRIVER	P1: ENERGY PRODUCTIVITY PLUS		P2: VARIABLE RENEWABLE ENERGY (VRE)		P3: DISPATCHABLE POWER		P4: UNCONSTRAINED	
	2030	2050	2030	2050	2030	2050	2030	2050
Abatement signalling	Starting from 2020. Target for 2030 based on meeting 27% abatement in the energy sector as a whole, considering possible abatement in non-electricity sectors. Targeting 75% (P1) or 95% abatement (P2-4) in 2050.							
Retirement	Existing generation retires at nominated asset life (e.g. 50 years) or for economic reasons							
Energy efficiency and demand	Same as P2 but replace NEFR energy efficiency with stronger energy efficiency case		NEFR 2016 + EVs + building & industry electricity demand	Extrapol-ation + EVs + building & industry electricity demand	Same as P2 but add hydrogen electrolysis for transport		Same as P1 but add hydrogen electrolysis for transport	
Rooftop solar	2030 NEFR 2016; 2050 Extrapolation							
Allowed new build generation	Wind and PV: 45% cap Biomass Gas without CCS		Wind and PV: no cap Wave Biomass Gas without CCS		Same as P1, plus: Solar thermal HELE CCS Nuclear Enhanced geothermal		All allowed Wind and PV: no cap	

Allowed new build generation

While all technologies can compete in Pathway 4, Pathways 1 to 3 explore alternative futures where technologies may not be available or required within certain circumstances. To implement these pathways we impose constraints such that some technologies may not be built. In Pathway 1, wind and large-scale solar generation is limited to 45% of generation (consistent with the finding that storage or some other means of flexibility is required above VRE shares of 40-50%) and only existing demonstrated technologies such as biomass and natural gas technologies (excluding carbon capture and storage) may be built in order to meet the emission limit.

In Pathway 2, we expand the allowable technology set to include wave power and lift the cap on the amount of variable renewable electricity generation technologies. Consequently, under this scenario we allow battery storage to be deployed to assist in balancing energy demand. Battery storage is used because of good quality data being available on this technology, however other storage technologies such as small scale pumped hydro may be relevant.

In Pathway 3, we cap wind and large-scale solar generation again at 45% of generation, however we allow for a wide variety of dispatchable low emission electricity generation technologies including solar thermal, high efficiency low emissions coal, carbon capture and storage, nuclear, and geothermal.

B.3.3 Sensitivity case assumptions

Pathway 2 sensitivity: Decentralised

A sensitivity case on Pathway 2 is imposed in order to determine the impact of higher deployment of customer owned solar on rooftops rather than large-scale grid supplied solar. In this case we remove the constraint in ESM requiring rooftop solar adoption to equal the NEFR projection and allow ESM to determine the optimal amount of rooftop solar based on the relative cost of those systems versus grid supplied electricity. We constrain what ESM is able to deploy by assuming that residential and commercial adoption can be no higher than 70% and 30% respectively based on (Graham P. , Brinsmead, Reedman, Hayward, & Ferraro, 2015). We also assume that by 2030, 5% of rooftop solar owners elect to leave the grid altogether increasing to 10% by 2050.

Pathway 3 sensitivity: High gas price

A sensitivity case on Pathway 3 explores the outcome if gas was higher cost. This sensitivity case was identified when observing the high adoption of gas with CCS under Pathway 3. Given uncertainty in the gas price due to social license issues in accessing some gas fields and the likely scenario that other countries will also be looking to use natural gas as part of their own emission reduction pathways, it is important to understand how the target might be achieved if gas were higher cost. The costs assumed are shown in Table 106.

Gas price forecasts are generally available from two sources: AEMO's National Gas Forecasting Report and the US Energy Information Administration which each year presents its own forecasts along with a summary of other global forecasts of oil prices. Oil price forecasts are important because internationally traded gas is typically sold via a formula based on the oil price and therefore cannot move too far from oil price trends in the long run. Since the opening up of the east coast Australia gas consumption market to international demand via the Queensland LNG export terminals, the outlook for gas has been rising to be more consistent with international prices. However at the same time oil prices fell sharply in 2014 and have only slightly recovered creating a dampening effect on prices. Given the high degree of uncertainty, CSIRO developed its own forecast that averages over time these sometimes divergent projections.

Table 106 – Gas price forecast ($ per GJ)

GAS PRICE	2015	2030	2050
Base case	6.6	9.4	13.2

High gas price	6.6	12.7	21.7

Pathway 3 sensitivity: High gas price, no CCS, nuclear or HELE coal

Building on the previous sensitivity, the sensitivity explores how the abatement target could be met under a high gas price and if CCS, nuclear and high efficiency coal technologies are not available to be deployed. This scenario could occur due to technical or social licence barriers.

Pathway 3 sensitivity: High gas price, no CCS, nuclear, HELE coal or geothermal

The final sensitivity builds on the previous two and considers how the emission constraints in Pathway 3 can be met under a high gas price and if CCS, nuclear, HELE coal and geothermal technologies are not available to be deployed. Again, this sensitivity case examines the possible impact of technical and social barriers not being overcome.

B.3.4 Key data sources

They key data sources used in the electricity modelling are as follows:

- Electricity generation technology performance and costs: *Australian Power Generation Technology (APGT) 2015.* This source was used since it is the most recent, comprehensive source of electricity generation technology costs. It should be noted that costs of low emissions technologies evolve rapidly. It was outside the scope of this roadmap however to update all of the cost assumptions from APGT. Recent changes in technology costs are not expected to change the key insights of this report however.
- Electricity demand, energy efficiency and rooftop solar adoption: *National Electricity Forecasting Report* (Australian Energy Market Operator (AEMO), 2016)
- High rooftop solar sensitivity: *Future Grid Forum – 2015 Refresh: Technical report* (Graham P. , Brinsmead, Reedman, Hayward, & Ferraro, 2015)
- Battery storage performance and costs: *Future Energy Storage Trends: An Assessment of the Economic Viability, Potential Uptake and Impacts of Electrical Energy Storage on the NEM 2015-2035* (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
- Network asset base, existing capacity and performance: *Regulatory Information Notices responses*[32]

B.4 Energy storage modelling methodology

Pathway 2 allows a high share of variable renewable generation to be deployed on the basis that it achieves energy balancing through deployment of storage as well as any existing dispatchable generation such as gas, coal and hydro power, noting that available gas and coal capacity decline over time due to retirements and fewer new plant in response to a tightening GHG emissions limit.

[32] Refer to https://www.aer.gov.au/taxonomy/term/1495

Half-hourly storage modelling was undertaken in order to verify the ability of variable generation with storage to supply the required demand, and to inform ESM of the required amount of storage costs to take into account in its projections of Pathway 2. Load and supply by technology were modelled at half-hourly time intervals for selected sample years, and the optimisation of battery deployment and operation over the entire year calculated using a linear program.

Battery storage was chosen as the representative storage technology. It was chosen on the basis that cost and performance data was the most mature and readily accessible. However, other options such as pumped hydro energy storage could be considered.

Note that storage was only assumed to play a role in half-hourly energy balancing. No frequency stabilisation or other potential uses was assumed.

In each of the NEM states, only a single time series representing the availability of each variable generation source (non-tracking solar for domestic rooftop PV, tracking solar for large-scale PV, and wind) was permitted. A pessimistic case of renewable resources availability was synthesised by considering the worst single week of resource availability in each state and for each renewable resource type, over nine years' worth of weather data, and imposing those weekly trajectories not only simultaneously, but also repeatedly (periodically) for three consecutive weeks within a single modelled year. Furthermore, there was no allowance for electricity trade among states. All these assumptions are restrictive, making the results of the analysis conservative. Allowing several alternative time series from different regions within each state or across states through an interconnector would provide additional supply diversity, increasing the likelihood of being able to meet the demand trajectory. Being less pessimistic about the worst possible resource availability (including coincidence of worst case availability across resource types) would also reduce the degree of difficulty.

Arriving at an optimised outcome was an iterative approach. ESM initially provided a starting estimate of the amount of allowable generation capacity from rooftop solar, large-scale solar PV and wind. For the half-hourly storage modelling, the allowable generation capacities for each generation technology in each state were constrained to lie between 100% and 140% of the projected recommendations from ESM, excluding hydroelectric generation which was tightly constrained at exactly the recommended capacity.

The storage model also includes constraints to ensure that the overall share of renewable electricity generation projected by ESM is consistent at the national level but with some flexibility within and among states since ESM is working with less detailed state data. Achieving targets for renewable energy supply was encouraged rather than mandated by the inclusion of soft constraints (constraints which impose a penalty rather than a strict minimum limit on renewable share) on the objective function. These were imposed on a state by state basis for each year except 2050, where the renewable target is the most stringent.

Battery capacity (both energy and power) was modelled non-conservatively as a lumped parameter in each state, that is, without imposing transmission capacity constraints between generation and storage or storage and load, that might otherwise become binding in a storage system that is spatially distributed. Battery energy capacity was treated as the unknown variable, associated with a component cost per MWh. It was assumed that each unit of battery energy capacity was capable of delivering or storing energy at a rate up to that consistent with 3.5 hours charge or discharge time. Losses of 5% during each of storage charge and storage discharge were assumed, and no net discharge of the battery over the full year was permitted. In order to discourage rapidly alternating between charging and discharging the battery in consecutive periods, a small cost penalty was added that is proportional to the rate of change of charging and discharging.

No corresponding ramp rate constraints or costs were imposed on dispatchable plant, including baseload plant, though baseload plant was subject to a minimum supply constraint (optimistic approach). This was motivated primarily by model size (number of variables) consideration. This relaxed assumption implies that dispatchable plant might be required to undergo rapid changes in output in order to compensate for highly variable supply from renewable generation. While this is a reasonable assumption to make of peaking plant, such as peaking gas plant, a more rigorous analysis would apply additional constraints to account for ramp rate limitations in other dispatchable plant, particularly for thermal plant that might be damaged by mechanical stresses due to temperature changes caused by rapid changes in power output.

Model formulation

The linear program optimises the deployment and operation of storage and generation technology to support the target share of variable renewable generation and any other dispatchable generation remaining in the system. It does this by solving for half-hourly generation by technology and battery operations, all by state, for the selected sample years, to meet required half-hourly demand, minimising annualised equivalent costs, including a penalty for failing to meet a minimum renewable annual energy supply percentage soft constraint, a penalty to discourage rapid changes in battery charging or discharge rates, and a penalty for failing to limit non-synchronous penetration.

That is, for each year and state, over half hour time periods t and generation technologies k, minimise

$$\sum V_k \tilde{S}_{kt} + \sum K_k \tilde{G}_k + K_B \tilde{B} + \sum r_t |\tilde{R}_t| + \sum K_k \tilde{P}_{Gk} + V_R \tilde{T}_N + V_D \tilde{T}_D$$

where $V_{k,} \tilde{S}_{kt}, K_k, \tilde{G}_k, K_{B,} \tilde{B}$ are respectively variable cost per GWh by technology, supply in GWh by technology by time period, annualised fixed/capital costs per GW by technology, generation capacity in GW by technology, annualised fixed/capital costs per GWh for storage, storage capacity in GW. Further $r_t, \tilde{R}_t, K_k, \tilde{P}_{Gk}, V_R, \tilde{T}_R, V_D, \tilde{T}_D$ represent respectively a penalty cost to discourage battery cycling per GW change in charge or discharge rate each time period, the change in storage charge or discharge rates, a penalty cost per GW of generation capacity exceeding the recommended soft limit by technology, the generation capacity exceeding the soft limit, a penalty cost per GWh of energy generation failing to meet the renewable soft target, and the quantity by which the renewable target is missed, a penalty cost per GW of dispatchable generation failing to reach the non-synchronous penetration soft target, and the quantity by which the non-synchronous penetration target is missed.

This is subject to:

Demand balance:

$$D_t < \sum \tilde{S}_{kt} + \eta \tilde{d}_t - \tilde{c}_t$$

where $D_t, \eta, \tilde{d}_t, \tilde{c}_{t_t}$ are respectively total demand by time period, storage discharge efficiency factor, the supply made available by storage and the storage charge rate.

Supply constraint:

$$\tilde{S}_{kt} < Q_{kt} \tilde{G}_k$$

where Q_{kt} is the generation profile over all time periods for (renewable or dispatchable) generation in GWh production per GW of installed capacity

Battery storage charge:

$$\tilde{E}_{t+1} < \tilde{E}_t - \tilde{d}_t + \eta \tilde{c}_t$$

Storage capacity limits:

$$\tilde{E}_t < B$$

$$\tilde{d}_t < {}^{B}/_{H_d}$$

$$\tilde{c}_t < {}^{B}/_{H_c}$$

where H_d and H_c are nominally rated storage discharge and charge times.

Minimum baseload production constraint:

$$\tilde{S}_{bt} > m_b \tilde{G}_b$$

which requires a minimum supply $\tilde{S}_{bt}$ for baseload plant, including coal and gas combined cycle, where m_b is minimum production ratio production per GW of installed capacity $\tilde{G}_b$.

Penalty components:

$$\tilde{R}_t > \left|\tilde{d}_t - \tilde{d}_{t-1}\right|$$

$$\tilde{R}_t > |\tilde{c}_t - \tilde{c}_{t-1}|$$

$$G_k < \tilde{G}_k < (1+\kappa)\, G_k + \tilde{P}_{Gk}$$

where G_k, κ is generation capacity recommended by ESM and overbuild allowance factor, and

$$\sum \tilde{S}_{Nkt} < (1-\lambda) \sum D_t + \tilde{T}_N$$

where $\tilde{S}_{Nkt}, \lambda$ are the non-renewable energy supply by time period and technology, and the soft target renewable generation, and

$$\tilde{S}_{Dt} + \tilde{T}_D > (1-\mu) D_t$$

where $\tilde{S}_{Dt}, \mu$ are the dispatchable energy supply by time period, and the soft target nonsynchronous penetration.

Parameter Values

The cost function to be minimised includes annualised equivalent capital costs for generation technology and battery storage, annual operations costs including maintenance, fuel costs and a carbon emissions price, plus an additional cost penalty for rapid changes in the net rates of charging or discharging battery energy storage, in order to discourage short battery charging cycles.

Capital costs per MW for generation capacity and per MWh for battery storage capacity were based on those in (CO2CRC, 2015) and (Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015) respectively (with no benefits from the sale of Small-scale (renewable) Technology Certificates (STCs) assumed), with installation costs for batteries approximated as being identical to materials costs.

For fuel price assumptions see (Graham P. , Brinsmead, Reedman, Hayward, & Ferraro, 2015, p. 46). Oil price projections are derived from US (EIA, 2016) scenarios. The five-yearly projections to 2040 are interpolated and after 2040 they are extrapolated using the average growth rate between 2020 and 2040. Gas price projections are derived from the oil price projections, using the ratio between oil and gas prices from the (International Energy Agency, 2015) in their Current Policies scenario at ten-yearly intervals to 2040. The ten-yearly projections to 2040 are interpolated and after 2040 the projections are extrapolated using half the average growth rate between 2030 and 2040.

The penalty for exceeding the renewables target was set at, for the state by state constraints before 2050 and the national constraint at 2050, respectively, two times and five times the operating costs for a gas peaking plant. The penalty for changing the rate of battery charging was set at the same rate per MWh/h as the operating cost of batteries per MWh, a nominal rate of $100/MWh and $100/(MWh/h).

Renewable resource availability was taken from (AEMO, 100 Percent renewables study - modelling outcomes, 2013), using the sole representative time series for each state for rooftop solar and a single representative region in each state for wind and large-scale solar PV. Open cycle gas, coal, combined cycle gas, biomass thermal, and hydro, were assumed to be dispatchable at will with no constraints on minimum generation, or rate of change of generation between consecutive half-hour periods.

The hard constraint minimum supply for base-load plant such as coal or combined cycle gas was set at 40% of maximum supply, and the soft target non-synchronous penetration was set as a linear function of time, starting at 42.5% in 2015 and increasing to 95% in 2050. As stated above, no penalties or hard constraints were applied to rapid changes in generation output to represent output ramp rate limitations.

Demand extrapolation

Half-hourly demand in each state (NEM only) was based on 2010 data accessed from AEMO because it is consistent with the year from which the renewable generation profiles are taken. To extend the 2010 load profile to be consistent with the scale and changes in load profile of future time slices of interest (e.g. 2020, 2025, 2030, etc), the 2010 load data was extrapolated to match future projections of annual energy demand and summer and winter maximum demand provided by AEMO's 2016 National Electricity Forecasting Report. No additional changes to the load profile to represent, for example, charging profiles specific to electric vehicles, were made. This is a reasonable assumption given that plausible average electric vehicle charging profiles are qualitatively similar to that of a residential household (Graham & Brinsmead, 2016)The extrapolation requires nonlinear rescaling, which in this case was quadratic, using a least-squares optimisation criterion to minimise the weighted sum of squared errors in the maximum summer demand, maximum winter demand, annual energy, and minimum demand, with assumptions of no growth in minimum demand. (See also (Graham P. , Brinsmead, Reedman, Hayward, & Ferraro, 2015) for a brief description of extrapolation method). That is for each time period t, by year

$$D_t = a(d_t)^2 + bd_t + c$$

where a, b, c are scaling parameters to be found, D_t is rescaled demand and d_t is the demand in the representative year. The scaling parameters are chosen to minimise

$$\alpha\left(A - \sum D_t\right)^2 + \beta(S_M - \max_{St} D_t)^2 + \gamma(W_M - \max_{Wt} D_t)^2 + \delta(N - \min_t D_t)^2$$

where A, S_M, W_M, N are annual targets for respectively: total energy demand, maximum summer demand over summer periods S_t, maximum winter demand over winter periods W_t, and minimum annual demand over all periods; and $\alpha, \beta, \gamma, \delta$ are cost function weights. In this case we selected $\beta = \gamma = \delta = 17520\ \alpha$.

B.5 Direct combustion modelling methodology

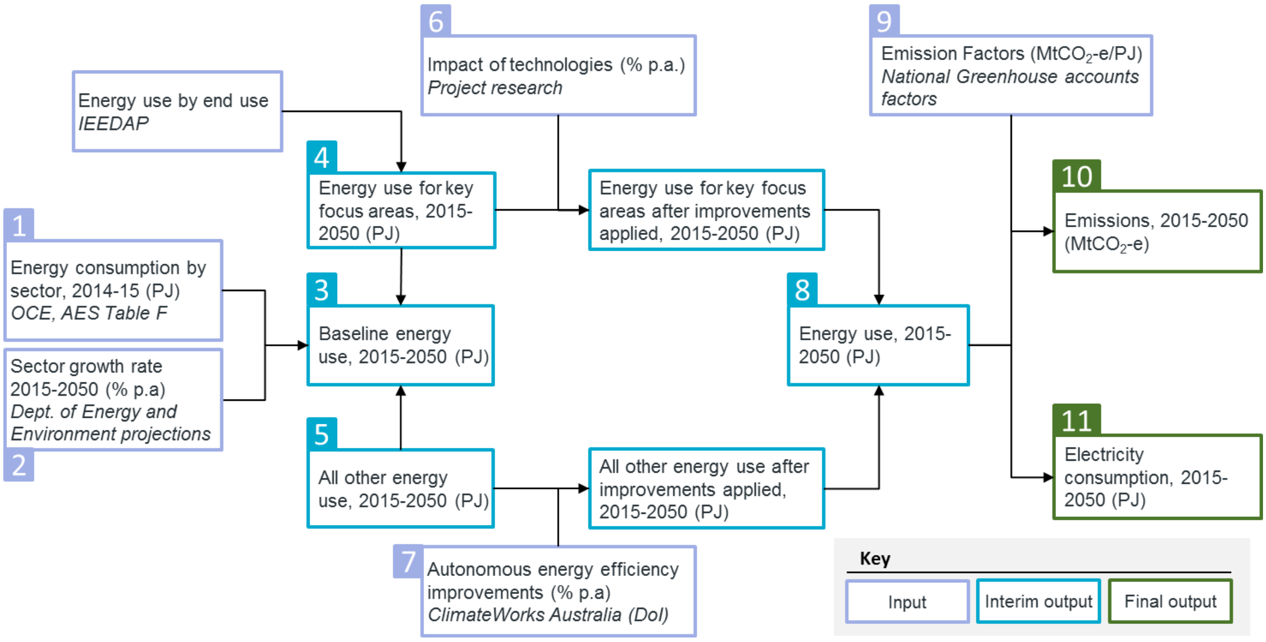
The direct combustion model is used to calculate the abatement from energy efficiency, electrification and any other technologies for direct combustion in sectors as described by (Australian Government Department of the Environment and Energy, 2016). This covers energy, mining, manufacturing, buildings, primary industries and military.

Buildings energy use and emissions were not modelled from scratch, but rather sourced from recent modelling undertaken for the Australian Sustainable Built Environment Council in 2016 (Australian Sustainable Built Environment Council, 2016).

B.5.1 Structure

The structure of the model is depicted in Figure 42 below. At the highest level, this model is focused around energy consumption, hence changes in energy and fuel types could be directly modelled. Emissions is calculated (using emissions factors) as an output.

Figure 42 – Structure of direct combustion model



The calculation steps and information sources are described below. Numbers in bold square brackets refer to the numbers in Figure 42.

- Energy consumption by ANZSIC sector was obtained from Australian Energy Statistics for 2014-15 (Office of the Chief Economist, 2015) **[1].**
- This energy consumption was assumed to grow at a rate consistent with the industry activity assumed in the Direct Combustion emissions projections 2015–16 (Australian Government Department of the Environment and Energy, 2016) out to 2035, then extrapolated out to 2050 using the 2030-35 growth rates **[2].**
    - The sectoral definitions were matched according to the National Inventory Report 2014 (Revised) Volume 1 (Department of the Environment and Energy, 2016).
- From the energy consumption and growth data, a baseline level of energy consumption was developed **[3].** This baseline serves to demonstrate what the energy use would be by sector, if each sector grew in size but remained at the current level of energy intensity. Efficiency improvements are then applied to this baseline.
- The baseline energy consumption was separated into two categories: 'Energy use for key focus areas', and 'All other energy use'.

    - Energy use for key focus areas was extracted from the overall baseline at the level of end use (e.g. Heating – furnaces/kilns) and by fuel type **[4].** For each focus area, energy use was aggregated across multiple sectors (i.e. energy use from comminution in iron ore and coal mining were combined into one category). The split of energy use in a given sector by focus area was informed using data from the Industrial Energy Efficiency Data Analysis Project (IEEDAP) (ClimateWorks Australia, 2013).
      The rationale for choosing particular focus areas is provided in the Pathway 1 of the main report and detailed in each relevant technology sections above.
    - 'All other energy use' **[5]** considers the energy use that was not extracted at an end use and fuel type level. It remained at sector and fuel type level.
- The assumptions applied to each category were informed by two main sources:
    - The impact of individual technologies, as determined by project research, was applied to energy use for key focus areas **[6].** For example, implementation of drained wetted cathodes in aluminium smelting was assumed to reduce emissions by 20% in 2050. The technologies and the impact that was assumed is presented below in Section B.5.2.
    - An autonomous rate of energy efficiency was applied to capture improvements in other end uses not discussed in detail, such as dryers and ovens **[7]**.This was adapted from research undertaken by ClimateWorks Australia at a sector and fuel type level. This energy efficiency rate also takes into consideration improvements that are not necessarily technological in nature, such as fixing leaks in a compressed air system or optimising the way in which equipment is ramped up or shut down.
- The total energy consumption was then aggregated back together **[8]**.
- Using the national greenhouse accounts factors **[9]** for each fuel type, the resulting emissions were calculated **[10]**.
- Changes in electricity consumption as a result of the modelling was extracted and used as an input to the electricity modelling **[11]**.

B.5.2 Technology impact assumptions

Two levels of ambition were modelled:

1. 'High', as applied in Pathway 1 and 4
2. 'BAU', as applied in Pathway 2 and 3

The electrification opportunities are assumed to start being implemented when the emissions intensity of the electricity grid drops below a point such that energy use from a given appliance creates less emissions than if it was burning a given fuel directly. This date differs between high and BAU scenarios, as the electricity grid decarbonises faster in Pathways 2 and 3.

Table 107 – Assumed energy consumption reductions (per unit of activity) from technologies

PILLAR	TECHNOLOGY **(SECTOR(S), FUEL)**	ENERGY CONSUMPTION REDUCTION – HIGH	ENERGY CONSUMPTION REDUCTION – BAU
Energy efficiency	High pressure grinding rolls and stirred mills (metal ore mining, electricity)	40% by 2050, starting from 2017	20% by 2050, starting from 2017

PILLAR	TECHNOLOGY **(SECTOR(S), FUEL)**	ENERGY CONSUMPTION REDUCTION – HIGH	ENERGY CONSUMPTION REDUCTION – BAU
	High efficiency boilers (all industry, gas)	10% by 2037, starting from 2017	5% by 2037, starting from 2017
	Drained wetted cathodes (aluminium smelting, electricity)	20% by 2050, starting from 2030	10% by 2050, starting from 2030
	Larger haul trucks (Coal & metal ore mining, oil)	52% by 2050, starting from 2017	26% by 2050, starting from 2017
	Liquefaction compressor turbine efficiency (LNG, gas)	1% p.a.	0.5% p.a.
Electrification	Electric boilers (All industry, gas)	5% net reduction in energy consumption. 26% gas reduction by 2050, starting from 2044. Assumed that electric boilers require 20% less energy.	4% net reduction in energy consumption. 20% gas reduction by 2050, starting from 2040. Assumed that electric boilers require 20% less energy.
	Electric conveyors (Metal ore mining, oil)	10% net reduction in energy consumption 13% oil reduction by 2050, starting from 2017. Assumed that electric conveyors require 80% less energy.	8% net reduction in energy consumption 10% oil reduction by 2050, starting from 2017. Assumed that electric conveyors require 80% less energy.
	Heat pumps (Non-metallic mineral product manufacturing; primary metal and metal product manufacturing; fabricated metal product manufacturing, gas)	43% net reduction in energy consumption 58% gas reduction by 2050, starting from 2020. Assumed that electric appliances require 74% less energy.	27% net reduction in energy consumption 37% gas reduction by 2050, starting from 2020. Assumed that electric appliances require 74% less energy.
	Electric Induction melting (Primary metal and metal product manufacturing, gas)		
	Electrolytic reduction (Non-metallic mineral product manufacturing; primary metal and metal product manufacturing; fabricated metal product manufacturing, gas)		
	Plasma melting (Non-metallic mineral product manufacturing; primary metal and metal product manufacturing; fabricated metal product manufacturing, gas)		
Fuel switching	Coal phase out	100% reduction in coal consumption by 2050, starting from 2017 all coal is switched to gas.	

Autonomous energy efficiency improvement is assumed to be 1.5% p.a. on average across all sectors in the High level, and 1.0% p.a. in the BAU level.

B.5.3 Contribution of renewable heat

The amount of abatement that renewable heating sources and fuels could deliver was considered additional to the technologies modelled above. This drew on recent and Australia-specific analysis for a report conducted by IT Power for ARENA (IT Power, 2015). The full abatement potential of renewable heat was calculated from the total mass market opportunity determined in the aforementioned report. This abatement potential and assumptions are shown in

Table 108.

Table 108 – Emissions abatement opportunity from renewable heat sources by heat range and technology Adapted from (IT Power, 2015)

Heat range	<150°	150–250°	250-800°	800-1300°	>1300°	Unit
Total mass market opportunity	16.6	111.0	31.3	60.2	192.6	PJ
Emissions	0.85	5.70	1.61	3.09	9.89	$MtCO_2e$
Example relevant technologies	Mass market solar, small biomass boiler, heat pumps, geothermal	Evacuated tube bespoke solar, concentrating solar, biomass boiler	Biomass boiler, concentrating solar parabolic troughs and fresnel	Concentrating solar – heliostats and parabolic troughs, biomass gasification and combustion	Concentrating solar – heliostats and tower, biomass gasification	
Assumption	Can be implemented by 2030	Can be implemented by 2030	Can be implemented by 2050	Can be implemented by 2050	Can be implemented by 2050	

This abatement potential was scaled in order to take into account the change in gas consumption determined from the direct combustion modelling and also realistic limitations on the rate at which these new technologies can be deployed.

In Pathways 1 and 4, ambitious energy efficiency and electrification leaves less gas that could be switched to renewable sources, resulting in an estimated 8 Mt of emissions abatement in 2050. Where less energy efficiency and electrification occurs in Pathways 2 and 3, twice as much abatement (16 Mt) is estimated. The opportunity for abatement to 2030 is more limited (up to 4 Mt). This is due to renewable heat technology being assumed to only replace equipment at end of life.

B.5.4 Electrification emissions assessment

In order to achieve an emissions reduction, electric appliances must not result in greater emissions (from electricity generation) than the fossil fuel that they replace. Three factors were considered in the assessment of electrification:

- The fuel source of the existing equipment. Different fuels have different emissions intensity, with coal being the most intensive and gas being the least. Oil (diesel) sits between the two
- Emissions intensity of the electricity grid (supplied from electricity modelling and different for each pathway)
- Relative efficiency of the electric appliance compared to the fossil fuel equivalent

The two tables below show the year in which switching to an electric appliance results in a net emissions benefit for two example scenarios: one where the electric technology is marginally more efficient than the fossil fuel counterpart (Table 109) and one where the electric technology is much more efficient (

Table 110). An example of the former is an electric boiler that consumes only 80% as much, whereas the latter may be a heat pump that is able to use merely 25% as much (a Coefficient of Performance, CoP, of 4).

Table 109 – Year in which switching to an electric appliance results in a net emissions benefit. For appliance with CoP= 1.25

CoP = 1.25	Pathway

Existing fuel source	1	2	3	4
Coal	2039	2034	2035	2036
Oil	2041	2037	2038	2039
Gas	2044	2040	2041	2041

Table 110 – Year in which switching to an electric appliance results in a net emissions benefit. For appliance with CoP= 4

CoP = 4	Pathway			
Existing fuel source	1	2	3	4
Coal	2015	2015	2015	2015
Oil	2016	2016	2016	2016
Gas	2017	2016	2016	2016

These tables demonstate that, for lower efficiency appliances, electrification only delivers an emissions benefit when the grid is sufficiently decarbonised and this does not occur until the 2040s. However, installation of higher efficiency appliances already offers emissions benefits.

Analysis was undertaken for each electrification technology described above in Table 107 to determine the year in which it can be installed to deliver a net emissions benefit.

B.6 Transport modelling methodology

The transport sector modelling is conducted using a combination of least cost economic modelling, subject to biophysical constraints, and applying a number of assumptions based on OEM engagement, surveys and expert judgment found in the literature. The economic partial equilibrium model applied is called the Energy Sector Model (ESM) and represents the Australian energy sector. The ESM was developed by CSIRO and ABARE in 2006. Since that time CSIRO has continued to develop and apply ESM in a large number of government and industry projection modelling projects.

The road sector is particularly amenable to partial equilibrium modelling of vehicle, fuel and engine choices. There is sufficient data for the whole cost of road transport to be estimated and modelled as a consumer choice optimisation problem. Data on vehicles, fuel and insurance are transparently provided by various suppliers. Government provides the excise framework and also the essential road infrastructure in response to demand but this additional cost is socialised through the tax system and so does not need to be bundled with an individual’s selection of vehicle and fuel type.

On the other hand the marine, aviation and rail sectors include more application dependent vehicles, less transparent cost components and a greater degree of privatisation in the planning and supply of infrastructure such as ports, rail lines and airports. Decisions about the underlying infrastructure may need to be bundled together with the vehicle purchase decision. Consequently, modelling a generalised whole cost of transport in these non-road sectors cannot be approached with the same degree of confidence unless conducted at a finer spatial scale or on a more project specific basis than is practical for national emissions modelling. Consequently, an integrated bottom-up and top-down modelling approach was used.

B.6.1 Road transport sector modelling

The road transport sector is modelled using ESM. ESM is a partial equilibrium ('bottom-up') model, implemented as a linear program optimisation. The model has a robust economic decision making framework that incorporates the cost of alternative fuels and vehicles, as well as detailed characterisation of fuel and vehicle technical performance, including fuel efficiencies and emission factors by transport mode, vehicle type, engine type and age. ESM determines the least cost mix of fuels, vehicles and other inputs to meet a given transport services demand, subject to policy or other constraints such as the rate of stock turnover. Key output variables include fuel consumption and GHG emissions, vehicle uptake and an estimated cost of road transport services (factoring in amortised vehicle costs, fuel costs, maintenance costs, insurance and registration costs in each market segment (passenger or heavy vehicles) based on the demand in each year).

B.6.2 Non-road transport methodology

Modelling the non-road transport sector modes required an integrated bottom-up and top-down modelling approach.

Non-road transport is characterised by strong infrastructure constraints (port access, airports, rail lines) and long lived vehicle fleets (minimum 20 year life of assets the norm compared to over 90 % of road vehicles retired by this age). Ideally, any modelling of non-road transport sectors would take into account these specific features. However, given the diversity of Australia's states and the unpredictability of infrastructure investment, CSIRO applies an alternative top-down approach.

The top-down approach assumes that demand is driven by population and industry activity that is a function of the general level of economic activity and that infrastructure needs will keep pace to meet that demand. A major advantage of this approach is that it is very amenable to modifying demand projections in response to measures such as major tax reform or industry restructuring that impacts the economy in general.

Projections of non-road transport activity in passenger or tonne kilometres is directly imposed. Fuel demand is projected by applying a fuel energy efficiency (MJ/km) improvement rate to the projected growth in non-road transport activity demand (km). The projected change in fuel efficiency represents a collection of multiple drivers for each mode. For example, in rail it reflects fleet upgrades, infrastructure and operational efficiency improvements. In marine transport it could include higher quality fuel, streamlining port logistics and tailoring shipping routes to expected weather and currents. In air transport it could include air traffic management and operation, aircraft light weighting and airframe aerodynamics.

B.6.3 Scenario assumptions and data sources

While ESM is designed to choose a least cost set of vehicle and fuel technologies to meet demand, additional assumptions are also imposed in order to explore the LETR pathways which represent specific technology combinations within a theme. These are set out in Table 111 and discussed further below.

Table 111 – Transport assumptions

KEY DRIVER	P1: ENERGY PRODUCTIVITY PLUS	P2: VARIABLE RENEWABLE ENERGY	P3: DISPATCHABLE POWER	P4: UNCONSTRAINED

	2030	2050	2030	2050	2030	2050	2030	2050
Demand	ABMARC/BITRE low case		BITRE high demand case (DoEE baseline)				ABMARC/BITRE low case	
Vehicle efficiency	Faster than BAU improvement		BAU improvement				Faster than BAU improvement	
Biofuels	Low initially, reflecting risks. Uptake from 2020 in aviation, consistent with industry plans.							
LNG/CNG	5% new articulated truck sales	10% new articulated truck sales	5% new articulated truck sales	10% new articulated truck sales	5% new articulated truck sales	5% new articulated truck sales	5% new articulated truck sales	5% new articulated truck sales
Vehicle electrif-ication	50% new light vehicle sales	80% new light vehicle sales	50% new light vehicle sales	80% new light vehicle sales	40% new light vehicle sales	65% new light vehicle sales	40% new light vehicle sales	65% new light vehicle sales
Hydrogen vehicles	None	None	None	None	10% new light and heavy vehicle sales	20% light and 30% heavy vehicle sales	10% new light and heavy vehicle sales	20% light and 30% heavy vehicle sales
					Hydrogen produced by electrolysis from the grid			
Aviation efficiency	1.5% p.a. efficiency improvements		1% p.a. efficiency improvements				1.5% p.a. efficiency improvements	

The demand projection for Pathways 1 and 4 was sourced from ABMARC and constitutes a low demand case when compared to the projection used in Pathways 2 and 3 that was sourced from the Bureau of Infrastructure, Transport and Regional Economics (BITRE). Both series provide annual projections to the year 2035 and were extrapolated to form projections to 2050. For Pathways 1 and 4, road transport activity is projected to increase to around 337 billion vehicle kilometres travelled (vkt) compared to around 460 billion vkt in Pathways 2 and 3.

For non-road transport in Pathways 1 and 4, rail freight is expected to be the fastest growing sector, increasing to around 663 billion tonne kilometres (tkm) by 2050, compared to 758 billion tkm in Pathways 2 and 3. Aviation demand also experiences strong growth increasing to 190 billion passenger kilometres (pkm) by 2050 in Pathways 1 and 4, compared to 193 billion pkm in Pathways 2 and 3. Rail passenger kilometre demand increases to 36 billion pkm by 2050 in Pathways 1 and 4, compared to 37 billion pkm in Pathways 2 and 3. Shipping tonne kilometre demand increases to 148 billion tkm by 2050 in Pathways 1 and 4, compared to 175 billion tkm in Pathways 2 and 3.

For efficiency improvements of new internal combustion engine vehicles in Pathways 2 and 3, a business as usual improvement rate was assumed for light and heavy vehicles. For light vehicles, this equates to an average annual rate of improvement of 1.6% per annum from 2015 onwards. For heavy vehicles, the same efficiency improvement rate was assumed from 2020 onwards. For Pathways 1 and 4 the assumed efficiency rate was increased to 2.1% per annum. Potential rates of improvement were developed in consultation with industry and are limited by factors such as uncertainty in real world performance of lower emission internal combustion vehicles.

Initially the uptake of biofuel is limited to existing mandates in NSW and Queensland. However, based on recent developments, biofuel uptake increases in aviation from 2020 onwards based on industry procurement plans. From around 2030, additional uptake of biofuels in aviation is dependent on the relative economics of bio-derived jet fuel compared to crude-derived jet fuel (largely influenced by the assumed oil price).

The rate of uptake of alternative drive trains (hybrid, electric and fuel cell vehicles) in the future is uncertain. To explore the potential impact of alternative drive train vehicles on transport sector emissions, each pathway assumed an uptake rate of a given percentage of new vehicle sales for two snapshot years: 2030 and 2050. The assumed uptake rates based on stakeholder engagement are shown in Table 111. Of the three options explored (electric vehicles (EVs), articulated vehicles fuelled by liquefied natural gas (LNG) and hydrogen fuel cell vehicles), EVs are expected to have the greatest impact, particularly in the light vehicle segments (passenger and light commercial vehicles) across all pathways, reflecting the rapid reduction in battery costs expected over the next decade. This means that the price of EVs is expected to decline significantly, reaching parity with ICE vehicles in 2025 (ABMARC, 2016) (Reedman & Graham, 2016) (International Energy Agency, 2016). As the vehicle cost is the largest component of an EV (maintenance and fuel costs are lower compared to an ICE vehicle), uptake of EVs is expected to accelerate around this time with the LETR pathways assuming emission reduction opportunities from EVs are captured as quickly as possible. Similarly, articulated vehicles fuelled by LNG/CNG feature in all pathways but with lower uptake (5-10% of new vehicles). Uptake of gas-powered vehicles is expected to be limited due to factors such as upstream emissions, gas availability, price volatility, and due to the fact that there is relatively low industry interest in gas, with manufacturers typically not offering gas-powered vehicles (although retrofit options exist), with greater interest in lower emissions diesel and a move to EVs in buses. Hydrogen fuel cell vehicles are explored in Pathways 3 and 4 with a corresponding reduction in EV uptake.

The key data sources used in the transport modelling are as follows:

- Vehicle stock and average vehicle kilometres travelled: ABS 2015, *Survey of Motor Vehicle Use, Australia, 12 months ended 31 October 2014*, Catalogue No. 9208.0 (ABS, 2015)
- Vehicle costs: ABMARC, NRMA, (Graham, Rai, & Pond, The outlook for gas in the transport fuel market, 2014), (EIA, 2016)
- Oil price projections: The oil price projection are an amalgam of the Office of the Chief Economist's latest Resources and Energy Quarterly (Office of the Chief Economist, 2016) and EIA's *Annual Energy Outlook 2016* released in May 2016 (EIA, 2016). The oil price projection uses the Resources and Energy Quarterly (REQ) data until 2022 and then assumes the growth rate of the EIA's low oil price scenario out to 2035, then extrapolated to 2050.
- Gas price projections: *ACIL Allen*
- Fuel excise rates: *Australian Taxation Office*
- Biofuel mandates: NSW - *Biofuel (Ethanol Content) Act 2007*, historical take-up of ethanol and biodiesel is from the *Office of Fair Trading*. QLD - The *Liquid Fuel Supply (Ethanol and Other Biofuels Mandate) Amendment Act 2015*
- Emissions factors: (Department of the Environment, 2015)
- Base year (2015) fuel consumption: (Office of the Chief Economist, 2016)

B.7 Fugitive emissions modelling approach

To calculate potential abatement in fugitive emissions, levels of abatement were applied to the official fugitive emissions BAU projections made by the Department of the Environment and Energy (DoEE). The DoEE projections extend to 2035; these numbers were extrapolated to 2050 in order to calculate total energy sector emissions for each pathway in that year. A detailed description of the assumptions on abatement for each segment of fugitive emissions is given in Section 9.

For fugitive emissions driven by domestic gas consumption (e.g. leaks from the gas distribution network), the BAU projections were scaled by each pathway's gas use compared with BAU.

B.8 LCOE methodology and results

The levelised cost of energy (LCOE) is a simple metric that represents the cost of producing a quantity of energy without profit or other financial considerations. It is a useful measure for comparing the economics of energy generation technologies, because it considers all technologies on the same basis. However, LCOEs are limited in that they cannot be used to represent the price of electricity as they do not consider the value of the electricity provided or include a margin, taxes etc. For renewable technologies in particular, the LCOE can vary depending on location however it is not possible to capture this in this study, instead a generic location in Australia has been assumed. LCOEs also typically do not capture integration costs, such as batteries or technologies required to stabilise grid frequency. They also assume a given asset life, and don't consider any costs incurred after this point (i.e. when the asset is fully depreciated but may continue to run and incur operating costs).

In this study, the LCOE of electricity generation technologies has the units \$/MWh, the LCOE of fuel conversion technologies has the units \$/GJ and the LCOE of hydrogen generation technologies has the units \$/kg.

The formula used is:

$$LCOE = IDC \times \frac{r \times (1+r)^L}{(1+r)^L - 1} \times \frac{K}{8760 \times Capfac} + \frac{O\&M_{FIX}}{8760 \times Capfac} + \frac{F \times 3.6}{Eff} + O\&M_{VAR} + T\&S$$

where r is the discount rate (6.42%), L is the lifetime (25 years for most technologies), K is the capital cost in \$/MW, *Capfac* is the plant capacity factor (as a ratio), $O\&M_{FIX}$ is the fixed operations and maintenance (O&M) cost in \$/MW/year, F is the fuel cost in \$/GJ, *Eff* is the fuel conversion efficiency (as a ratio), $O\&M_{VAR}$ is the variable O&M cost in \$/MWh and *T&S* is the cost of transporting and storing CO_2 (\$15/MWh), if applicable.

IDC is interest during construction which is paid over the construction period. It is given by:

$$IDC = \sum_{i=1}^{P} \frac{1}{P} \times (1+r)^{(i-1)}$$

where P is the construction period in years. This formula assumes the same annual payments during the construction period, which may not be the case in reality but the key cost reference for this work, the Australian Power Generation Technology report (CO2CRC, 2015), did not provide any information on how the IDC payments would be split over the construction period.

Table 112 lists the low and high LCOE values for each electricity generation technology along with the reference where the assumptions used to calculate LCOE can be found.

The capacity factor for fossil fuel based technologies was assumed to be 0.85 as per (CO2CRC, 2015). In the future, with increasing penetration of VRE, this capacity factor could be expected to decrease, since fossil fuel generators are likely to be acting as dispatchable generation to support VRE, rather than as baseload generation. This would increase the LCOE of fossil fuel based technologies. The capacity factor of variable renewable technologies and CST was based on the availability of the resource. The capacity factor of biomass-based technologies (including bio-DICE) was assumed to be 0.8, with the exception of biogas which was assumed to be lower at 0.2.

Additional financing costs due to the risks perceived by investors related to fossil fuel generation technologies have also not been included in the LCOE calculations.

Full asset lifetimes have also been assumed; LCOEs would be higher if technologies were to be retired early, for instance due to emissions constraints or due to unfavourable economics compared to zero-short run marginal cost renewable technologies.

Table 112 – LCOE ranges and references for electricity generation technologies

TECHNOLOGY	2015 LCOE ($/MWH)	2020 LCOE ($/MWH)	2030 LCOE ($/MWH)	REFERENCE
Biomass co-firing with coal	30-40	30-40	30-40	(CO2CRC, 2015) (Office of Environment and Heritage, 2014)
DICE brown coal slurry	60-75	60-75	55-65	(BREE, 2013) CSIRO Estimate
Gas combined cycle	65-80	65-80	65-80	(CO2CRC, 2015)
Bio-DICE	70-85	70-85	70-85	CSIRO Estimate
Supercritical pulverised black coal	70-85	70-85	65-80	(CO2CRC, 2015)
Ultrasupercritical pulverised black coal	70-85	70-85	65-80	(CO2CRC, 2015)
Wind	80-100	75-90	70-85	(CO2CRC, 2015)
Large-scale PV	100-120	75-95	55-70	(CO2CRC, 2015)
Black coal IGCC	100-130	100-130	90-110	(CO2CRC, 2015)
Biomass direct combustion	110-140	110-140	110-140	(BREE, 2013)
Gas with CCS	110-130	110-130	100-130	(CO2CRC, 2015)
Rooftop PV	120-150	100-120	70-85	(CO2CRC, 2015)
Black coal CCS retrofit	100-150	100-150	95-130	(CO2CRC, 2015) (Peter Cook Centre for CCS Research, 2016)
Biogas combustion	130-160	130-160	130-160	(CO2CRC, 2015) (Braun, Weiland, & Wellinger)

TECHNOLOGY	2015 LCOE ($/MWH)	2020 LCOE ($/MWH)	2030 LCOE ($/MWH)	REFERENCE
Offshore wind	150-180	130-160	130-150	(BREE, 2013) (CO2CRC, 2015)
Black coal with CCS	150-180	150-180	130-160	(CO2CRC, 2015)
Oxyfuel black coal with CCS	150-180	140-180	130-160	(CO2CRC, 2015)
Nuclear	160-190	160-190	140-170	(CO2CRC, 2015)
Brown coal with CCS	160-200	160-200	140-180	(CO2CRC, 2015)
Black coal IGCC with CCS	170-200	150-190	130-160	(CO2CRC, 2015)
Geothermal	180-220	180-220	180-210	(BREE, 2013), (ARENA, 2014)
CST tower	200-250	170-210	160-200	(CO2CRC, 2015)
Biomass gasification	200-250	190-230	180-220	(CO2CRC, 2015) (BREE, 2013)
Biomass gasification with CCS	270-330	240-290	210-260	(BREE, 2013) (CO2CRC, 2015)
CST trough	290-350	190-230	170-200	(BREE, 2013)
CST LFR	300-370	190-240	170-210	(BREE, 2013)

In Pathway 2, by the year 2050, there is approximately 90% share of VRE (namely wind and solar PV). This high share results in additional integration costs associated with storage and network upgrades. The LCOE of wind and solar PV will also increase, as the effective capacity factor of these technologies reduces due to curtailing generation. The capacity factor for wind reduces to 83% of its uncurtailed value (that is, from 39%) and the capacity factor for solar reduces to 62% of its uncurtailed value (that is, from 26% for large-scale solar). Despite the resulting drops in capacity factor, some degree of excess renewable capacity that must be occasionally curtailed is lower in cost than the alternative of building additional, rarely required, energy storage. The total LCOE of wind and solar PV including these integration costs, in the year 2050, is 100-130 $/MWh and 110-140 $/MWh respectively. This compares with 2050 LCOEs without any integration costs and no reduction in capacity factor of 65-80 $/MWh for wind and 40-45 $/MWh for solar PV, which means that the integration costs add 35-50 $/MWh and 70-95 $/MWh to the LCOE of wind and PV respectively at high penetrations of these technologies.

Table 113 lists low and high LCOE values for energy storage technologies in $/MWh. The assumed capacity factor of all of these technologies is 10% and this value was taken from the modelling results. The exception are fuel cells which have a 17% capacity factor (4 hours per day usage, to cover typical evening usage). It was assumed that batteries would only be discharged to their depth of discharge. Cost for fuel cells are only shown for 2030 as it was assumed that hydrogen would only be available from 2030 onwards in the modelling for Pathway 4. A ratio of energy capacity to power of 2 MWh per MW is assumed for batteries. Pumped hydro power assumed to be 500 MW. CAES-u power assumed to be 540 MW.

Table 113 – LCOE ranges and references for energy storage technologies
Li = Lithium; CAES-a = above ground Compressed Air Energy Storage; Zn-Br = Zinc-Bromine; CAES-u = underground Compressed Air Energy Storage; ALA = Advanced Lead Acid; SMR = Steam Methane Reforming; CCS = Carbon Capture and Storage

TECHNOLOGY	2015 LCOE ($/MWH)	2020 LCOE ($/MWH)	2030 LCOE ($/MWH)	REFERENCE
Pumped hydro	95-280	95-280	95-280	(ROAM Consulting, 2012)
Utility scale Li-ion batteries	120-140	80-100	60-70	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
CAES-a	150-190	150-190	150-190	(James & Hayward, 2012)
Residential scale Li-ion batteries	170-210	140-170	120-140	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
Utility scale Zn-Br batteries	300-360	200-170	120-140	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
Residential scale Zn-Br batteries	330-400	140-170	120-140	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
CAES-u	490-600	490-600	490-600	(James & Hayward, 2012)
Utility scale ALA batteries	480-590	360-590	240-290	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
Residential scale ALA batteries	580-710	470-570	360-440	(Brinsmead, Graham, Hayward, Ratnam, & Reedman, 2015)
Fuel cell using H_2 from coal gasification with CCS	-	-	190-240	CSIRO Estimate (Wei & McKone, 2013)
Fuel cell using H_2 from SMR with CCS	-	-	210-250	CSIRO Estimate (Wei & McKone, 2013)
Fuel cell using H_2 from biomass gasification	-	-	220-270	CSIRO Estimate (Wei & McKone, 2013)
Fuel cell using H_2 from grid electrolysis	-	-	290-360	CSIRO Estimate (Wei & McKone, 2013)
Fuel cell using H_2 from dedicated renewables electrolysis	-	-	550-680	CSIRO Estimate (Wei & McKone, 2013)
Fuel cell using H_2 from curtailed renewables electrolysis	-	-	580-700	CSIRO Estimate (Wei & McKone, 2013)

The lifetime of batteries was based on which value it reached first of either the cycle life (hours) or the technical lifetime (in years). For Li-ion and ALA batteries, the technical lifetime of 10 years was reached first. For Zn-Br batteries the cycle life converted to years, 8.56, was reached first.

The fuel cell electricity costs are relatively high compared to the other energy storage technologies. There is a great deal of uncertainty around fuel cell costs, given also that the cost varies with the application and size of the unit and whether it is used for providing heat as well as power. Because of this, the fuel cell data assumptions are provided in Table 114. We assumed an electricity only system.

Table 114 – Data assumptions behind fuel cell LCOE calculation (CSIRO Estimate) (Wei & McKone, 2013)

ASSUMPTION	VALUE AND UNIT
Size of system	1 MW
Capital cost	512 $/kW
Operational life	20 years
Stack replacement cost	80% of upfront capital cost
Stack life	10,000 hours
Round trip efficiency	46.5%
Fuel consumption	0.054 kgH_2/kWh

Table 115 lists the low and high LCOE values for fuel conversion technologies in $/GJ. Different technologies can produce different fuels and the LCOE is based on the energy content of the fuel produced.

Table 115 – LCOE ranges and references for fuel conversion technologies

TECHNOLOGY	2015 LCOE ($/GJ)	2020 LCOE ($/GJ)	2030 LCOE ($/GJ)	REFERENCE
Lignocellulosic biomass fast pyrolysis to produce drop-in fuels	35-40	30-40	30-35	(Hayward, et al., 2015)
Lignocellulosic biomass hydrothermal liquefaction to produce drop-in fuels	35-45	35-40	30-40	(Hayward, et al., 2015)
Waste oil esterification to produce biodiesel	35-45	35-40	30-40	(US Energy Information Administration, 2013) (Graham, et al., 2011)
Lignocellulosic biomass gasification and FT to produce drop-in fuels	45-55	40-50	40-45	(BREE, 2014)
Starch and sugar fermentation to produce ethanol	70-85	65-80	70-85	(US Energy Information Administration, 2013) (Graham, et al., 2011)

Table 116 lists the low and high LCOE values in the year 2030 for hydrogen production technologies in $/kg H_2 produced. Only 2030 values were calculated as it was assumed in the modelling that hydrogen is used from 2030 onwards. The electrolysis-based technologies only differ in their LCOE because of the different types of electricity generation and the capacity factor of those technologies. The capacity factor of the electrolyser using grid electricity is 80%, while using dedicated renewables (e.g. PV) it is 21% and for curtailed renewables it is 10%.These values were calculated using results from the modelling. The capital cost of the PV farm is included in the LCOE for the dedicated renewables case. It has been assumed that the price of electricity from curtailed renewables is 0. The price of electricity in the grid electricity case is 0.06 $/kWh, which was taken from the P4 scenario modelling results for the year 2030.

Table 116 – LCOE ranges and references for hydrogen production technologies

TECHNOLOGY	2030 LCOE ($/KG$H_2$)	REFERENCE
Coal gasification (no CCS)	1.8-2.2	(Rutkowski, 2008)
Steam methane reforming (SMR) (no CCS)	2.3-2.9	(Rutkowski, 2008)
Coal gasification (with CCS)	2.4-2.9	(Rutkowski, 2008)
Solar SMR (no CCS)	2.4-2.9	(Hinkley, Hayward, McNaughton, Edwards, & Lovegrove, Concentrating solar fuels roadmap: final report, 2015)
SMR (with CCS)	2.7-3.3	(Rutkowski, 2008)
Solar SMR (with CCS)	2.8-3.5	(Hinkley, Hayward, McNaughton, Edwards, & Lovegrove, Concentrating solar fuels roadmap: final report, 2015)
Biomass gasification (no CCS)	3.0-3.7	(Mann, 2015)
Biomass gasification (with CCS)	4.1-5.0	(Mann, 2015)
Grid electricity electrolysis	4.3-5.2	(Hinkley, et al., Cost assessment of hydrogen production from PV and electrolysis, 2015)
Dedicated renewables electrolysis	9.1-11	(Hinkley, et al., Cost assessment of hydrogen production from PV and electrolysis, 2015)
Curtailed renewables electrolysis	9.5-12	(Hinkley, et al., Cost assessment of hydrogen production from PV and electrolysis, 2015)

The levelised cost of transport (LCOT) in medium passenger vehicles has also been calculated for electric vehicles (EVs), fuel cell vehicles (FCV) and internal combustion engine vehicles (ICE) using petrol as shown in Table 117. FCV only have a 2030 value as it was assumed that hydrogen would be available from that year onwards in P4. It was assumed that EVs would be charged using grid electricity and FCVs fuelled using hydrogen produced from various technologies.

The formula for LCOT is similar to that of LCOE, except there are different cost components:

$$LCOT = \frac{r \times (1+r)^L}{(1+r)^L - 1} \times \frac{K}{vkm/year} + \frac{Insurance + Rego}{vkm/year} + F \times Con + C_{run}$$

where *K* is the upfront vehicle cost ($), *vkm* are the vehicle kilometres travelled, *Rego* ($/year) is the registration cost, *F* is the fuel cost ($/L for ICE, $/kWh for EV and $/kg H_2 for FCEV), *Con* is the fuel consumption per unit of fuel and C_{run} is the annual running cost ($/vkm).

Table 117 – LCOT range and reference for vehicle technologies.

TECHNOLOGY	2015 LCOT ($/VKM)	2020 LCOT ($/VKM)	2030 LCOT ($/VKM)	REFERENCE
ICE using petrol	0.70-0.85	0.65-0.80	0.65-0.80	CSIRO Estimate
EV using grid electricity	1.7-2.0	0.75-0.90	0.60-0.70	CSIRO Estimate
FCV using H_2 from coal gasification with CCS	-	-	0.65-0.80	CSIRO Estimate
FCV using H_2 from grid electrolysis	-	-	0.70-0.85	CSIRO Estimate
FCV using H_2 from dedicated renewables	-	-	0.70-0.90	CSIRO Estimate

All vehicle cost and fuel consumption assumptions were the same as those used in P2 for EVs and P4 modelling for FCV and are shown in

Table 118. The payback period of all vehicles was assumed to be 5 years.

Table 118 – Vehicle data assumptions

ASSUMPTION	2015	2020	2030
ICE vehicle cost ($K)	25	25	25
EV cost ($K)	90	35	25
FCEV cost ($K)	-	-	29
Registration ($/year)	270	270	270
Insurance ($/year)	1275	1275	1275
Running cost ($/vkm)	0.05	0.05	0.05
Distance travelled (1000vkm/year)	13	13	13
Petrol price ($/L)	1.27	1.21	1.27
Petrol consumption (L/vkm)	0.10	0.08	0.05
Electricity price ($/kWh)	0.041	0.036	0.112
Electricity consumption (kWh/vkm)	0.253	0.247	0.234
Hydrogen consumption (kWh/vkm)	-	-	0.35

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