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Meeting the challenge of change

Delivering a competitive Australian power system

Part 2: The challenges, the scenarios

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Australia's abundant supply of coal has underpinned its power system. Competing countries have used a variety of energy resources, which sees many of them now equipped with resilient power systems to provide future electrical power. This paper considers the implication of possible scenarios for the Australian power system in 2035.

Executive summary

This paper is the second in a series entitled "Delivering a competitive Australian power system". In Part 1, Australia's current global position was analysed with respect to its resource-rich competitors.

In Part 2, the possible scenarios for delivering a competitive Australian power system in 2035 are investigated. Accordingly, this paper examines where the Australian power economy needs to be positioned to address the issues that global change presents. In Part 3, the possible routes to transition the industry to a target position will be examined.

As we look to 2035, the Australian stationary energy industry faces a confluence of environmental, economic and technological challenges. This paper submits that the major forces driving the industry are:

- Rising electricity prices driven by increasing fuel costs and distribution investment
- Emissions constraints
- Infrastructure renewal
- Public support for renewable generation
- Technology shift to renewable and distributed generation

In this paper scenario analysis anticipates the shifts possible by 2035 to meet the challenges facing the stationary energy industry. These scenarios are grouped into three categories. The first of these categories is the base scenario *Business-as-Usual (BAU)*, which builds on the implicit views of the future as forecast in the Australian Government's Draft Energy White Paper, *Strengthening the Foundations for Australia's Energy Future*. The second category is the Changing Technological Landscape category, which offers an incremental transition to deal with the forces driving the industry. The third category is the Non-Renewable Centralised Power category, which offers a reactive approach to dealing with greenhouse gas reductions. The scenarios outlined under each of these three categories highlight the complex uncertainties facing the industry and provide views that may deviate from dominant industry perceptions.

To facilitate the analysis this paper models the transition to a lower carbon emission future, rather than a total replacement of infrastructure. This means that coal-fired generation continues to play a role in power generation in 2035.

The key messages that emerge from the modelling are:

- The market does not deliver an Australian power system that will be able to meet an 80% emissions reduction in line with the country's overall 2050 emissions target, even with a high carbon price. (Although the current Government emissions projections don't seek an 80% emissions reduction from the energy sector, instead rely on other measures including the purchase of offshore emissions reductions to meet targets).
- There is no apparent price premium associated with any of the scenarios, even the scenarios with a high deployment of renewable generation.
- There are benefits for Australia to start investment in the technologies included in the Changing Technological Landscape scenarios immediately.
- There is a need to lay the foundations for a possible deployment of the technologies included in the Non-Renewable Centralised Power scenarios should substantial emissions reductions become an imperative.
- Despite the benefits associated with the Changing Technological Landscape scenarios, there are risks associated with the distribution network which must be sufficiently robust to respond to intermittency and stability challenges. An in-depth study into the effect of distributed generation (e.g. rooftop solar panels) on the distribution network is urgent and overdue.

Public support for renewable and distributed generation is strong. Global investment and improvements in technology are creating an expectation that a substantial roll-out of renewable and distributed generation is possible. The results of the analysis in this paper suggest that there is benefit to be gained from using consumer momentum while preparing for the potential of an investment in carbon capture and storage (CCS) and/or nuclear power. Concerted action as detailed above will be the only way Australia has any chance of meeting its 2050 emissions goals.

Modelling has been based on 2010 demand projections and subsequent projections show a fall-off in demand. Decreasing demand projections introduce uncertainty and thus delay in implementing investment decisions. This takes pressure off the need to enact policy hastily and instead allows consideration of policy that would meet long term strategic goals.

1. Introduction

Australia's plentiful supply of coal has defined the structure of its stationary energy power generation and consumption. Economies of scale derived from large coal-fired generation have enabled the supply of reliable, affordable electricity and encouraged investment in power intensive industries.

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This paper is part of a three-part series entitled "*Delivering a competitive Australian power system*". In Part 1, Australia's current global position was analysed with respect to its resource rich competitors. In Part 2, possible scenarios for the Australian power system to be competitive in 2035 are considered. Part 3 will examine the results of the scenario analysis, which will outline options towards a 2035 Target. In order to facilitate the comparative analysis, the Resilience Index as defined in Part 1 is used (with a few minor adjustments following a peer-reviewed publication process Molyneaux et al. (2012)), as a strategic, national (top down) barometer of power economy performance. This allows a systematic and rational appraisal of the relative efficiency, diversity and security of national power systems. As a recap of Part 1's findings, Figure 1 shows how Australia rates in 2009 relative to key global competitors in terms of the resilience of our power economy versus the cost of electricity to our industry. Australia's resilience is currently poor (only better than India and South Africa) and this is not compensated by low electricity costs.

In this paper, the Australian Power Resilience in 2035 is mapped as a metric for competitiveness.

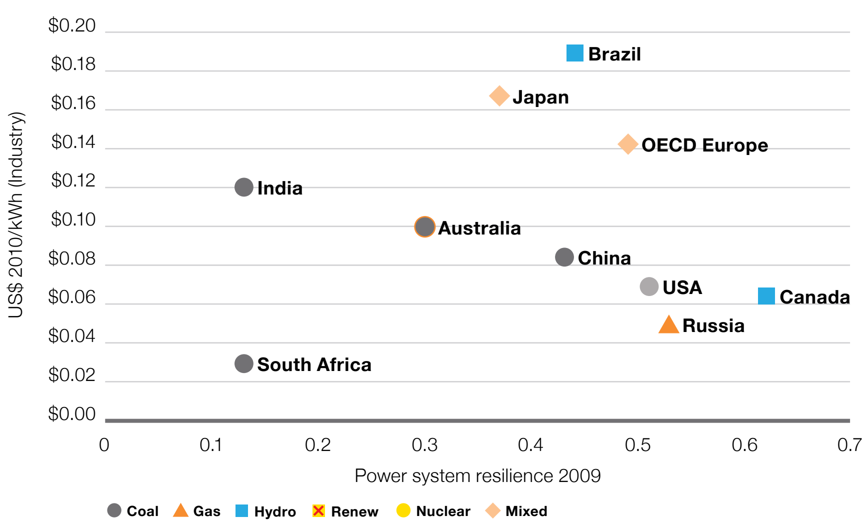
As Australians look to 2035, the abundant supply of unconventional gas could dominate the future structure of the nation's power generation. However, with the development of an export market for liquified natural gas (LNG), Australian gas-fired generators will be competing with large global consumers for the supply of gas at prices determined on the international market.

As proposed in the Australian Government's Draft Energy White Paper, switching from the burning of coal to the burning of gas will reduce the intensity of emissions from Australia's power generation. However, growth in energy consumption will negate the impact of reduced emissions intensity.

Costs associated with emissions from the burning of coal and gas will increase the cost of power generation as carbon constraints are applied globally in an attempt to reduce greenhouse gas concentrations in the atmosphere. However, this paper seeks to model a transition to a lower carbon emission future, rather than a total replacement of infrastructure. This means that coal-fired generation, where affordable, continues to play a role in Australia's power generation in 2035.

This paper conducts scenario analysis to anticipate the major shifts required to meet the challenges facing the electricity industry. It suggests that the confluence of environmental, economic and technological constraints facing the electricity industry do not allow for a single "right" projection that can be deduced from past behavior.

Figure 1. How Australia compares to its competitors in 2009



The future scenarios chosen for analysis in this paper are unlikely to occur as described. Rather they were chosen to show the complex uncertainties facing the industry, and provide views that may deviate from dominant industry perceptions. In particular, this paper highlights the characteristics specific to each scenario that would need to be in place, if such a scenario was to be feasible.

The uncertainties facing stakeholders are broken down in this study into pre-determined forces driving the industry. It is submitted that the forces driving the industry are:

- Rising electricity prices driven by
  - Increasing fuel prices as a result of growing global population striving for greater consumption and wealth
  - A requirement for distribution investment to address increasing peak demand, or distributed generation like photovoltaics (solar PV)
- Emissions constraints
- Infrastructure renewal
- Public support for renewables
- Technology shift to renewables and distributed generation

Forces driving the industry will be common to all scenarios. However each scenario will be subject to specific actions which are included in the modelling assumptions.

These scenarios are grouped into three distinct categories.

The first category is the dominant industry view category (Business-as-Usual). It builds on the implicit views of the future shared by most industry stakeholders as forecast in the Australian Government's Draft Energy White Paper.

The second category offers a measured, incremental transition to deal with the forces driving the industry (the Changing Technological Landscape response).

The third category offers the crisis response to climate change, where there has been a failure to pursue incremental transition, climate change becomes a critical global issue such that greenhouse gas reductions have to be achieved urgently and the industry has to react in haste to meet environmental pressures (the Non-Renewable Centralised Power response).

Table 1 provides a summary of the scenario analysis categories and some of the key findings.

This paper reveals that modelling of generator behaviour to recover costs and earn reasonable profit increases the wholesale cost of generation from approximately \$40/MWh in 2011 to \$154/MWh in 2035 with only a 9 percent decrease in annual CO_2 emissions in the *Business-as-Usual* scenario.

There is no evidence of a cost premium for shifting from the *Business-as-Usual* scenario to renewable, distributed generation and CCS. However, there is evidence of a cost premium for shifting away from coal. The Changing Technological Landscape scenarios require a shift of investment to transmission and distribution whilst the *Business-as-Usual*

Table 1 Options facing the Australian power industry

1. Dominant Industry View category (Business-as-Usual)	**2. Changing Technological Landscape category**	**3. Non-Renewable Centralised Power category**
• ***Business-as-Usual* scenario**	Action now for measured shift • ***Large-scale renewable* scenario** • ***Consumer action* scenario**	Action in 2025 to react to crisis • ***Nuclear power* scenario** • ***Carbon capture & storage (CCS)* scenario**
Wholesale cost range **\$154 (base)** **\$91-\$188 (sensitivities)**	Wholesale cost range **\$150 (base)** **\$105-\$215 (sensitivities)**	Wholesale cost range **\$142-\$169 (base)** **\$146-\$197 (sensitivities)**
Projected emissions **130-167 mtpaCO_2**	Projected emissions **101-145 mtpaCO_2**	Projected emissions **77-130 mtpaCO_2**
Infrastructure cost **\$61-65 bn**	Infrastructure cost **\$85-198 bn**	Infrastructure cost **\$104-123 bn**
Risks/Cost • Distribution investment for demand growth • Global LNG price volatility	**Risks/Cost** • Shift distribution investment to DG • Transmission investment	**Risks/Cost** • Distribution investment for demand growth • Public support • Over-investment in centralised generation

and Non-Renewable Centralised Power scenarios require continued investment in infrastructure to meet consumption levels reflective of historic growth trends. They also run the risk of the uncertainties associated with global energy price volatility.

Pursuing the *Consumer action* scenario under the Changing Technological Landscape category has the potential to reduce the wholesale cost of generation whilst reducing CO_2 emissions and increasing resilience.

The *Nuclear power* and *CCS* scenarios offer good emission reduction but depend on significant investment in large-scale centralised generation and ensure continued dependence on non-renewable fuels subject to global market forces.

In addition, this paper shows that the Changing Technological Landscape scenarios address more of the forces driving the power system than the *Business-as-Usual* and Non-Renewable Centralised Power scenarios. This will be discussed in more detail in each of the scenarios. An overview is available in Table 2.

The Changing Technological Landscape scenarios reduce reliance on fuels vulnerable to global market forces and carbon emissions and reflect public support for renewables and the global shift in investment to renewables and distributed generation (DG). The Non-Renewable Centralised Power scenarios offer a replacement for coal by gas or nuclear power and continue the provision of centralised power.

Australia has the opportunity to restructure its electricity system for an uncertain future. Public support for renewable and distributed generation is strong with one study indicating that 60 percent consider 'both the environment and economy are important but the environment should come first'. (Ashworth 2009, P1). This paper's analysis of the market allocating resources to technologies using a carbon price, even a high carbon price, indicates that the Australian Power Economy will be very far from its 2050 emissions target by 2035. So, the power system restructure will require significant investment in multiple technologies and significant policy intervention to reach emissions targets and public expectations.

The industry and governments face two basic choices: to start now on a course of action that will lead to abatement, reduced pressure on electricity prices and offer increased technology choices by 2025; or alternatively to wait until technology options like CCS and nuclear become viable, and then implement the technologies in relative haste to meet climate change requirements.

The results of the analysis in this paper would suggest that there is benefit in starting now to facilitate consumer action and the deployment of renewable forms of generation.

Concomitantly, action to prepare for the potential of an investment in CCS and/or nuclear power should substantial emissions reductions become an imperative should be taken. Concerted action along these lines will be the only way Australia has any chance of meeting its 2050 emissions goals.

Table 2 Responses to forces driving the power system

Forces driving the power system	**Ability to address forces driving the system**				
Category	**1. Dominant Industry View**	**2. Changing Technological Landscape**		**3. Non-Renewable Centralised Power**	
Scenario	***Business-as-Usual***	***Large-scale renewable***	***Consumer action***	***Nuclear power***	***Carbon capture & storage***
Rising prices					
Fuel	✗	✓	✓	✗	✗
Distribution	✗	✗	✗	✗	✗
Carbon constraints	✗	✓	✓	✓	✓
Infrastructure renewal	✓	✗	✓	✗	✗
Public support for renewables	✗	✓	✓	✗	✗
Technology shift to renewables and DG	✗	✓	✓	✗	✗

Box 1
Why scenario analysis?

When there is a fundamental shift in the system, the basic rules of operation are no longer applicable. Lessons learnt from experience and history can become an impediment. Experimentation becomes the new operational imperative so that changes can be accommodated and new ways of doing business can be found.

Developments in the Middle East that resulted in an energy crisis in the 1970s and 1980s provide an example of a fundamental shift in the system. Prior to the Middle East crisis, Shell had turned to scenario analysis as a planning technique to forecast future projections for demand and supply. Armed with the foresight gained from developing a number of scenarios that were contrary to dominant oil industry views, Shell was able to recognize the implications of the unfolding geopolitical situation in the Middle East and restructure its refining investment. Being prepared helped Shell avoid over-investment and the financial consequences that beset the rest of the industry which had failed to foresee the potential for a fundamental shift (van der Heijden 2005, Wack 1985).

The computer industry in the late 1980s and early 1990s experienced a similar fundamental shift. IBM's inaction when faced with a shift away from mainframe computing to personal computing offers a classic example of a failure to see the early signals of a technological change, in a company that traded in technological change. Their reliance on a probabilistic approach to planning supported a tacit assumption that computing infrastructure would continue to be demanded in the traditional form. Some individuals within IBM recognized the signals, but they couldn't make themselves heard above the conventional view. Executive management's limits in perception led IBM into serious financial problems and nearly resulted in its demise.

Hindsight is good at identifying the early signals, but at the time there are not consistent signals. Stakeholders have to think and plan into the future whilst considering the implications of current developments within the industry. As evidence builds to support one or other scenario, appropriate action needs to be taken to meet the change and avoid substantial disruption.

Australia's stationary energy industry faces fundamental shifts as a result of the multitude of forces driving the industry. Stakeholders need to understand how their industry view measures against potential industry responses to drivers outside their control. Scenario analysis helps to identify trends and possibilities, encourages experimentation with new policies and operations, and questions perceptions which fail to react positively to dramatic market shifts.

2. The possible scenarios in 2035

Investment in the power system today will determine what the Australian power economy looks like in 2035. For this reason, this paper takes a scenario approach to projecting the Australian power economy in 2035.

The scenarios assume that each major technology option facing Australia today is pursued single-mindedly to deliver the power economy of 2035. This allows this study to compare the benefits and costs of each option. It is assumed that each scenario will unfold within the same electricity demand and economic environment with medium growth reflecting the long-term trend.

The scene is initially set with the scenario that seeks best to represent the principles as set out in the Australian Government's Draft Energy White Paper of 2012, the *Business-as-Usual* scenario. The expectation is for deployment of gas-fired generation in response to demand, carbon pricing signals, the development of Australia's unconventional gas resources and the retirement of aged coal-fired generation. As currently set out in policy, the Renewable Energy Target will expire in 2020, but the generation to meet that target will have been implemented predominantly via wind power, since it is currently the most affordable renewable energy technology available. Although difficult to predict, wind energy will always be deployed due to the merit order effect; that is with extremely low marginal costs, energy generated by wind will be dispatched in preference to fossil fuel power. With reduced appetite for feed-in-tariffs, referred to in the Australian Government's Draft Energy White Paper as expensive and contributing to electricity price increases, growth in energy from photovoltaic panels is not considered to be a part of this scenario.

In response to widespread public support for renewable energy, Australia would roll out a *Large-scale renewable* scenario to meet its carbon dioxide emission targets. With geothermal and high-quality solar resources in remote locations, large base-load renewable deployment requires investment in transmission infrastructure to transport the power to load centers. Large-scale concentrated solar power (CSP) with storage is deployed to meet electricity demand until 2025, and a combination of CSP with storage and geothermal power is deployed after 2025 to meet demand.

In response to a centralised system that offers the prospect of no respite from rising prices, consumers will pursue distributed generation in the *Consumer action* scenario. This represents a fundamental shift in the power system, away from large-scale centralised power generation towards rooftop photovoltaic, micro gas turbines, landfill gas, wind and co-and tri-generation. Importantly, none of the technologies deployed require significant research or development to become commercially-viable.

With the International Energy Agency (IEA) predicting that carbon capture and storage (CCS) is a key technology option for meeting global carbon dioxide goals, the *CCS* scenario assumes that with concern about the impact of climate change and a lack of action to address emissions from stationary energy, the CCS technological barriers are overcome and deployment of coal and gas with CCS will occur after 2025. In all other respects, the scenario is the same as the *Business-as-Usual* scenario.

The IEA predicts that nuclear generated power is a further key technology option for meeting global carbon dioxide goals. The *Nuclear power* scenario assumes that there is wide-spread implementation of nuclear power globally. In such a global nuclear renaissance, Australia gains bipartisan support to change its current policy to be able to deploy nuclear power to meet its electricity demand and its carbon dioxide goals, with deployment starting after 2025. In all other respects, the scenario is the same as the *Business-as-Usual* scenario.

In all scenarios, modelling has been conducted to simulate the National Electricity Market (NEM) only as the NEM represents more than 80 percent of the Australian power system. The power systems in Western Australia and the Northern Territory have not been included because power generation and supply is relatively small, geographically dispersed and not connected to the NEM. Modelling of NEM generation required in 2035 has been carried out using PLEXOS (refer to annexure 3), an electricity market simulation package. It uses deterministic linear programming techniques, and transmission and generating plant data, to economically optimise the power system over a variety of time scales and determine the least cost dispatch of generating resources to meet a given demand (Energy Exemplar 2012). PLEXOS simulates generator behavior, such that generators participate in the market only if they can cover costs and make a profit. Wholesale cost projections therefore represent generator behavior and cost recovery, rather than just the latter. It is important to recognize that this project represents a study of Australian power generation, it does not attempt to assess the network security or stability limitations from a power systems engineering perspective.

2.1. Business-as-Usual (BAU) scenario

As detailed in the Australian Government's Draft Energy White Paper, Australia is engaged in significant development of its coal seam gas resource for export to lucrative global markets. With its lower emissions intensity, gas is seen by the International Energy Agency and the Australian Department of Resources, Energy and Tourism as the transition fuel to reduce carbon dioxide emissions from power generation.

The specific assumptions that underpin this scenario are:

- Long-term historic trend in consumption growth
- No consumer reaction to rising prices
- Gas prices reflect global energy trends
- Climate change is not an issue, so little requirement for abatement
- No recognition of technology shift towards renewable and distributed generation

Using the Australian Energy Market Operator (AEMO) projections to 2035 for gas price, generation cost and demand, and Treasury mid-point projections for carbon price, the model predicts that generators in the National Electricity Market (NEM) will invest $61 billion to deploy 26GW of combined cycle gas turbines (CCGT), 2GW of open cycle gas turbines (OCGT) and 12GW of wind power to meet demand in 2035, as shown in Table 3.

Table 3 Comparing KPIs for AEMO, BREE and *Business-as-Usual* scenario

	2000	2010	2035 (AEMO)	2035 (BREE)	2035 Business-as-Usual
mtpaCO_2 from electricity	161	183	183	n/a	167
Emission intensity	0.87	0.85	0.53	n/a	0.52
% of 2050 target achieved			-17%		-5%
Generation (TWh)	185	215	346	297	324
Annual growth		1.5%	1.9%	1.3%	1.7%
Wholesale cost ($/MWh)	$60	$47	$98	n/a	$154
Coal generation	87%	80%	36%	42%	42%
Gas generation	4%	11%	45%	30%	41%
Renew generation	9%	9%	19%	28%	17%
Generation investment (bn)			$65	n/a	$61
Gas price ($2011)	$3.51	$5.19	$8.32	$12.06	$8.32
Carbon price ($2011)	$0	$0	$72	$72	$73

If Australia is to reduce its emissions to 80 percent below 2000 levels by 2050, emissions from power generation would need to reduce to 32 mtpaCO_2 in 2050. Investment in generation in the *BAU* scenario will reduce the emissions from power generation in 2010 of 183 million tons of carbon dioxide equivalent per annum (mtpaCO_2) to 167 mtpaCO_2 in 2035. This would require a further reduction of 135 mtpaCO_2 to reach the 80 percent target in only 15 years.

Box 2 provides some discussion on coal seam gas extraction.

There are a number of uncertainties inherent in the *BAU* scenario, which tests the sensitivity of the system to significant shifts in gas price, Renewable Energy Target and carbon price. An analysis of the sensitivity of this scenario to these uncertainties follows:

Box 2

The benefits and challenges of coal seam gas extraction

Gas has traditionally been a more scarce and expensive fuel than coal. However the widespread development of unconventional gas resources from shale and coal seams has increased reserves considerably and potentially makes gas more affordable. In the USA widespread shale gas development has seen gas prices reduce from over US$8 per GJ to less than US$3 per GJ in just four years. The development of Australian coal seam gas (CSG) in recent years and the future potential in domestic shale gas resources could represent a similar opportunity. Much of the Australian CSG production currently under development, however, will be liquefied and exported to Asia. This is predicted to increase domestic gas prices for use in gas-fired generation.

Benefits

- A plentiful supply of gas will encourage a shift to more energy-efficient gas-fired power generation both in Australia and in Asia
- Widespread development of unconventional gas globally could assure abundant low cost gas for Australia's electricity sector
- Shifting to gas-fired power reduces the intensity of carbon emissions from generation both in Australia and in Asia
- $50 billion investment in Queensland and New South Wales to develop extraction and liquefaction facilities delivers economic growth and employment
- Revenue from the export of up to 50 million tons per annum of LNG for several decades

Challenges

- The widespread development of CSG in Queensland and NSW is contentious with concerns about:
  - Competing agricultural land use
  - Potential environmental consequences associated with hydraulic fracturing
  - Produced water and brine management
  - Impacts on subterranean aquifers and consequently the quality and security of water supplies
  - Industry regulatory processes not keeping pace with development
- Uncertainty concerning leakage of fugitive emissions from CSG wells has implications for the life cycle GHG emissions intensity of CSG-LNG-Electricity in SE Asia
- Uncertainty around gas production quantities relative to the requirements for export LNG may adversely impact on security and price of gas supplies for domestic power generation

2.1.1. Examining the impact of alternative assumptions: Lower gas prices

Global production of LNG is forecast to grow from 14500PJ in 2011 to 25000PJ in 2018 and 55000PJ in 2035. Australia is projected to contribute 44 percent of the increased global productive capacity in 2018. In the event that demand increases at a slower rate than supply, vigorous competition between suppliers will place downward pressure on LNG prices. Recently, the price of gas in the USA has showed the effect of aggressive production growth coupled with anaemic consumption. Box 3 provides some detail.

The modeling undertaken suggests that with current plans for global LNG production, surplus capacity may become a reality, such that the price of LNG at the regional hub, Moomba, could settle at $4.89/GJ in 2035. It is therefore important to assess the impact of a lower global price for LNG on the Australian power system. Sensitivity analysis on the *Business-as-Usual* scenario to assess the impact of a low gas price was undertaken with the major differences presented in Table 4.

Considerably lower gas prices will facilitate a shift away from coal-fired generation to gas-fired generation of around 84TWh, reducing carbon dioxide emissions by 35mtpaCO_2 and reducing total fossil fuel used by 202PJ. The reduced cost of gas results in a decrease in average wholesale cost from $154 to $91 per MWh.

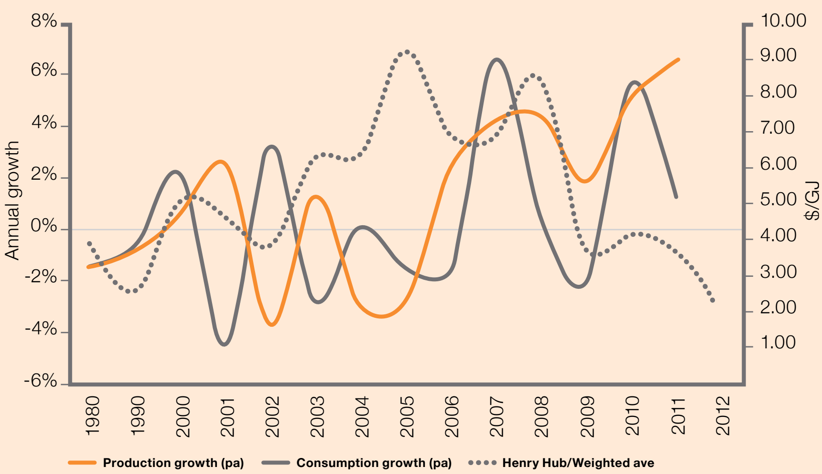
Emissions of 132 mtpaCO_2 in 2035 still leaves a substantial challenge to reach 32 mtpaCO_2 per annum by 2050, especially considering that the 28 GW of new gas-fired generation (the capacity of coal-fired generation today) is likely to be less than 15 years old.

Box 3

The impact of unconventional gas on the US gas market

In 2005 gas prices soared in the US after years of decline in production. With the advent of hydraulic fracturing and horizontal drilling for extraction of shale gas after 2005, the downward production trend was reversed. A fall in consumption after the financial crisis of 2008, and growth in production of gas, has resulted in a surplus of gas and price falling below $2/GJ in 2012. Figure 2 shows the growth in extraction and the recent slump in consumption and price at the Henry Hub (the pricing point for natural gas futures contracts in the US).

Figure 2 US gas production, consumption and price



2.1.2. Examining the impact of alternative assumptions: Higher gas prices

With significant growth projected for developing nations, forecasts of much higher gas prices abound. For this reason, this paper the impact of a gas price of $12/GJ in 2035 was examined with the major differences presented in Table 5.

A high gas price reduces the shift of generation from coal to gas, but has little impact on wholesale price and leaves a substantial challenge to reach 32 mtpaCO_2 by 2050.

2.1.3. Examining the impact of alternative assumptions: Extending the Renewable Energy Target to 2035

The Renewable Energy Target (RET) requirement for 20 percent of electricity to be sourced from renewable sources ceases after 2020. Our modelling indicates that no further investment in renewable energy generation will be made after 2020. Keeping the 20 percent Renewable Energy

Target in place until 2035 has been considered with a comparison to the *Business-as-Usual* scenario presented in Table 6.

As the table above shows maintaining the RET target of 20 percent to 2035, marginally decreases investment in gas in favour of wind power but reduces weighted average wholesale costs. There is also a very small decrease in emissions.

2.1.4. Examining the impact of alternative assumptions: High carbon price

In the event of global agreement on containing GHG concentrations in the atmosphere to 450 ppm, The Commonwealth Treasury forecasts that the carbon price will reach \$159/ tCO_2 by 2035. Another sensitivity analysis undertaken on the *Business-as-Usual* scenario was to increase the carbon price to the above level with the results being presented in Table 7.

The table above shows generation shifts from coal to gas, reducing emissions and fuel usage. However, average wholesale cost increases by 22 percent. Whilst emissions reduce to 130 $mtpaCO_2$, reaching a target of 32 $mtpaCO_2$ in 2050 will remain a substantial challenge.

Table 4 Impact of lower gas prices on *Business-as-Usual* scenario

	Business-as-Usual (gas price = \$8/GJ)	Business-as-Usual (gas price = \$4/GJ)
Emissions ($mtpaCO_2$)	167	132
Emissions intensity (tCO_2/MWh)	0.52	0.41
% of 2050 target achieved	-5%	23%
Fuel usage (PJ)	2372	2170
toe/MWh	175	161
Generation from coal	42%	15%
Generation from gas	41%	68%
Wholesale cost (\$/MWh)	\$154	\$91

Table 5 Impact of higher gas prices on *Business-as-Usual* scenario

	Business-as-Usual (gas price = \$8/GJ)	Business-as-Usual (gas price = \$12/GJ)
Emissions ($mtpaCO_2$)	167	171
Emissions intensity (tCO_2/MWh)	0.52	0.53
% of 2050 target achieved	-5%	-8%
Fuel usage (PJ)	2372	2388
toe/MWh	175	176
Generation from coal	42%	44%
Generation from gas	41%	39%
Wholesale cost (\$/MWh)	\$154	\$153

Table 6 Impact of retaining RET on *Business-as-Usual* scenario

	Business-as-Usual (RET expired)	Business-as-Usual (RET 20%)
Emissions ($mtpaCO_2$)	167	165
Emissions intensity (tCO_2/MWh)	0.52	0.51
% of 2050 target achieved	-5%	-4%
Fuel usage (PJ)	2372	2322
toe/MWh	175	170
Generation from coal	42%	43%
Generation from gas	41%	38%
Generation from renewables	17%	19%
Investment (\$bn)	\$61	\$65
Wholesale cost (\$/MWh)	\$154	\$146

Table 7 Impact of high carbon price on *Business-as-Usual* scenario

	Business-as-Usual (\$74/tCO_2e)	Business-as-Usual (\$159/tCO_2e)
Emissions ($mtpaCO_2$)	167	130
Emissions intensity (tCO_2/MWh)	0.52	0.40
% of 2050 target achieved	-5%	24%
Fuel usage (PJ)	2372	2174
toe/MWh	175	161
Generation from coal	42%	16%
Generation from gas	41%	67%
Wholesale cost (\$/MWh)	\$154	\$188

2.1.5. *Business-as-Usual* scenario conclusions

With gas prices projected to increase globally, $62 billion of investment in gas generation to transform Australia's power system shows little evidence of carbon abatement. This is because the growth in electricity generated will negate the benefit of the lower-emissions intensity of gas.

Greater abatement will only be achieved if the international gas price decreases or if high carbon prices are introduced.

Table 8 presents the results of all sensitivity analyses conducted on the *Business-as-Usual* scenario.

This scenario represents the dominant industry view of how the Australian power industry will be structured in 2035 with fuel price, renewable energy target and carbon price sensitivities.

The key principles that underpin this scenario are that there is no perceived need for additional action on climate change, electricity market forces will dictate generation technologies, and energy use will increase based on historic trends and usage patterns. Gas prices will increase based on the internationalization of domestic gas prices. Renewable energy will only be deployed to 20 percent of generation in 2020 because of unfavourable levelised cost projections. Consumers will be indifferent to the deployment of gas-fired generation in preference to photovoltaic, wind and concentrated solar thermal power.

The sensitivity analysis shows that:

- high carbon prices shift generation from coal to gas, decreasing emissions by 22 percent but resulting in higher wholesale costs of 22 percent and a fuel cost bill of $4 billion over the base scenario
- extending the renewable energy target to 20 percent of generation to 2035 increases investment by $4 billion but decreases average wholesale cost by 5 percent
- low gas prices improve all metrics including a 21 percent improvement in abatement, a 41 percent decrease in wholesale costs and a $2.2 billion reduction in the fuel bill. However, it should not be forgotten that the majority of the fleet will be relatively new, making abatement post 2035 very difficult to achieve without a substantial turn-over of the new gas-fired generation fleet

Table 8 Business-as-Usual in 2035 sensitivity analysis

	2035 Business-as-Usual	2035 RET	2035 $4 gas price	2035 $12 gas price	2035 High Carbon Price
mtpaCO_2 from electricity	167	165	132	171	130
Emission intensity	0.52	0.51	0.41	0.53	0.40
% of 2050 target achieved	-5%	-4%	23%	-8%	24%
Generation (TWh)	324	325	322	324	321
Annual growth	1.7%	1.7%	1.6%	1.7%	1.6%
Wholesale cost ($/MWh)	$154	$146	$91	$153	$188
Coal generation	42%	43%	15%	44%	16%
Gas generation	41%	38%	68%	39%	67%
Renew generation	17%	19%	17%	17%	17%
Generation investment (bn)	$61	$65	$62	$61	$62
Fuel used (PJ)	2372	2322	2170	2388	2174
Fuel cost ($mill)	$9,421	$8,754	$7,204	$12,172	$13,407
Gas price ($2011)	$8.32	$8.32	$4.89	$12	$8.32
Carbon price ($2011)	$74	$74	$74	$74	$159

- high gas prices result mainly in $2.7 billion additional fuel cost with no evidence of impact on weighted average wholesale cost

The table below provides a synopsis of the assumptions included in the scenario.

In conclusion, the analysis of the *Business-as-Usual* scenario addresses the forces that are facing the Australian power industry.

- A shift to gas-fired generation, and the development of the LNG market on the Eastern coast, implies fuel cost increases from shifting from (cheaper) coal to (more expensive) gas generation. Accordingly, it fails to deal with the potential for sharply increasing wholesale electricity costs
- Continued support for growth in peak and average demand will require continued investment to bolster distribution assets for increasing demand and a few extreme demand events, currently responsible for nearly $3 billion annual investment by the distribution companies. Due to this it fails to deal with the potential for sharply increasing residential electricity prices
- Whilst gas-fired generation is more efficient than coal-fired generation, continued growth in energy demand significantly reduces the potential to reduce emissions overall, such that it fails to reduce carbon emissions significantly
- The relatively low capital cost of gas-fired generation provides a capital efficient means of renewing the generator fleet
- Since gas is not a renewable source of energy and there is some community concern over unconventional gas extraction, the *Business-as-Usual* scenario does not represent a public preference for renewable forms of energy
- With Europe, Japan and China rolling out technology that enables a shift to distributed and renewable generation, the *Business-as-Usual* scenario fails to address the technology trends that are gathering momentum globally.

Table 9 Assumptions for *Business-as-Usual* scenario

Forces underpinning scenario	Long-term historic trend consumption growth
	No consumer reaction to rising prices
	Gas prices reflect global energy trends
	Climate change not an issue
	No recognition of technology shift to renewables and distributed generation
Capital costs	CCGT $1100/kW
	OCGT $1100/kW
	Wind $2558/kW
Network topology	Existing
Generation locations	Located close to transmission infrastructure
Modelling assumptions	Wind intermittent to 30% capacity factor
Fuel price (Moomba)	Gas $8.32/GJ
	Low gas price $4.89/GJ
	High gas price $12/GJ

2.2. Large scale renewable scenario

In the first of the Changing Technological Landscape scenarios, the impact of developing geothermal and Concentrated Solar Thermal (CST) generation (with storage) hubs in remote locations is examined, with investment in transmission infrastructure to transport the power to load centres. Whilst large scale solar thermal generation technology is already deployed, it is assumed that the geothermal resource currently being developed will be technically proven and deployable after 2025.

The specific assumptions that underpin this scenario are:

- Widespread public support for renewables
- No consumer reaction to rising prices
- Gas prices reflect global energy trends
- Perceived requirement for abatement
- Policy to encourage investment in solar thermal and geothermal generation and transmission from remote locations to load centres

Using the Australian Energy Market Operator (AEMO) projections to 2035 for gas price, generation cost and demand, and the Commonwealth Treasury projections for carbon price, this study's model predicts that large-scale renewable power plants will be too expensive to be deployed in the National Electricity Market (NEM).

The model used is designed to determine the least cost dispatch of generation resources to meet demand. In order to facilitate deployment of renewable technologies the model discourages investment in these technologies:

- Combined cycle gas turbines (CCGT)
- Coal and gas fitted with CCS technologies
- Nuclear power

Without the deployment of CCGT, CCS and Nuclear power, the model predicts that 20GW of Concentrated Solar Thermal (CST) with storage, 4GW of Geothermal, 18GW of Wind Power and 2GW of OCGT will provide sufficient supply to meet increased demand. Carbon emissions are reduced to 133mtpaCO_2 by 2035 at a cost of $210 billion for generation and transmission requirements. The modelling excludes analysis of any impact on the distribution network.

What is surprising about the modelling is that it does not predict a very high average wholesale cost by comparison to the *Business-as-Usual* scenario.

Table 10 Comparing KPIs for *Business-as-Usual* and *Large-scale renewable* scenarios

	2010	2035 AEMO	2035 Business-as-Usual	2035 Renewables
mtpaCO_2 from electricity	183	183	167	133
Emission intensity	0.85	0.53	0.52	0.39
% of 2050 target achieved		-17%	-5%	22%
Generation (TWh)	215	346	324	337
Annual growth	1.5%	1.9%	1.7%	1.8%
Wholesale cost ($/MWh)	$47	$98	$154	$150
Coal generation	80%	36%	42%	42%
Gas generation	11%	45%	41%	11%
Renew generation	9%	19%	17%	47%
Generation investment ($bn)		$65	$61	$197
Transmission investment ($bn)				$13 (AEMO)
Gas price ($2011)	$5.19	$8.32	$8.32	$8.32
Carbon price ($2011)	$0	$72	$74	$74

This is as a result of the dispatch of 55TWh of wind at zero marginal cost and a levelised cost of around $70/MWh. CST (with storage) and geothermal power provide schedulable and base-load power generally dispatched at pool prices.

Box 4 provides a historical perspective of the impact of wind generation on South Australian average wholesale price.

The other major uncertainty inherent in this scenario is the impact of a high carbon price on the deployment of large-scale renewable energy. The sensitivity of the scenario to a high carbon price is tested in the following section.

2.2.1. Examining the impact of alternative assumptions: High carbon price

In the event of global agreement on containing GHG concentrations in the atmosphere to 450 ppm, the Commonwealth Treasury forecasts that the carbon price will reach $159/t$CO_2$ by 2035. The sensitivity analysis conducted was to assess the impact of increasing the carbon price to $159/t$CO_2$.

High carbon prices significantly drive up the cost of coal-fired generation. With coal-fired generation providing base-load power, this increases the average cost of generation considerably. A shift to gas-fired generation could have a small mitigating influence on average cost but deployment of CCGT was disabled in the model to understand the impact of large-scale renewable generation.

Box 4

Impact of wind on South Australian price

Figure 3 shows South Australian weighted average wholesale cost compared to the average of New South Wales, Queensland and Victoria. Until 2007, South Australian prices were similar to the averaged group. Subsequent to 2007, South Australian prices have been significantly higher than the group. Wholesale prices for wind are lower than thermal prices. With increased dispatch of wind generation, the average spot prices in South Australia have come back into line with the reference group.

Figure 3 Average spot prices in South Australia

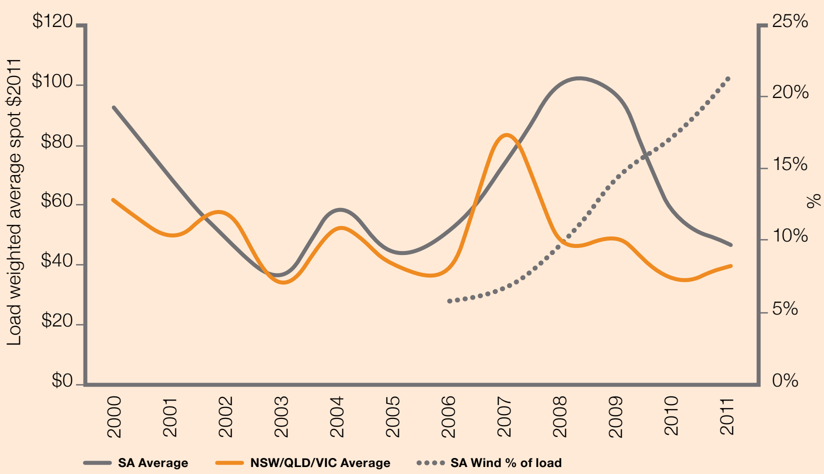


Table 11 Impact of high carbon prices on *Large-scale renewable* scenario

	Renewables ($74/t$CO_2$e)	Renewables ($159/t$CO_2$e)
Emissions (mtpaCO_2)	133	130
Emissions intensity (tCO_2/MWh)	0.39	0.39
% of 2050 target achieved	22%	24%
Fuel usage (PJ)	1740	1740
toe/MWh	123	123
Generation from coal	42%	42%
Generation from gas	11%	11%
Generation from renewables	47%	47%
Generation investment ($bn)	$197	$197
Transmission invest ($bn)	$13	$13
Wholesale cost ($/MWh)	$150	$215

2.2.2. *Large-scale renewable* scenario conclusions

The *Large-scale renewable* scenario presents a picture of large-scale (greater than 100MW) renewable generation at an individual site replacing large-scale fossil-fuel generation. Capital investment of $210 billion is required to reduce emissions by 50 $mtCO_2$ per annum. Whilst an investment requirement of this magnitude would tend to indicate that this scenario is too expensive to consider positively, the wholesale cost projections provide an insight into the benefits of generation from sources with minimal marginal costs.

Table 12 presents the results of the sensitivity analysis conducted on the *Large-scale renewable* scenario compared to the *BAU* scenario.

Our model predicts that with nearly 50 percent of generation from renewable sources, the average wholesale cost of generation is slightly less than the *Business-as-Usual* scenario.

This scenario represents a renewable energy alternative to the dominant industry view of how the Australian power industry could be structured in 2035. The key principles that underpin this scenario are that there is a perceived need for action on climate change, some form of intervention will be required to deploy renewable technologies, and energy use will increase based on historic trends and usage patterns. Because of a shift away from fossil fuels, wholesale prices will not be vulnerable to global energy trends. Consumers will be indifferent to the deployment of large-scale renewable generation in preference to photovoltaic power and energy efficiency measures.

The sensitivity analysis shows that:

- high carbon prices make no appreciable difference to emissions but do result in 43 percent higher wholesale costs over the base scenario.

The table below provides a synopsis of the assumptions.

Table 12 *Large-scale renewable* in 2035 sensitivity analysis

	2035 Business-as-Usual	2035 Renewables	2035 High Carbon Price
$mtpaCO_2$ from electricity	167	133	130
Emission intensity	0.52	0.39	0.39
% of 2050 target achieved	-5%	22%	24%
Generation (TWh)	324	337	337
Annual growth	1.7%	1.8%	1.8%
Wholesale cost ($/MWh)	$154	$143	$198
Coal generation	42%	42%	42%
Gas generation	41%	11%	11%
Renew generation	17%	47%	47%
Generation investment ($bn)	$61	$197	$197
Transmission investment ($bn)		$13	$13
Fuel used (PJ)	2372	1740	1740
Fuel cost ($mill)	$9,421	$4,094	$4,094
Gas price ($2011)	$8	$8	$8
Carbon price ($2011)	$74	$74	$159

In conclusion, the *Large-scale renewable* scenario addresses the forces that are facing the Australian power industry.

- A shift to renewable generation implies fuel cost reductions and therefore it deals effectively with reducing vulnerability to sharply increasing global energy prices
- Continued support for growth in peak and average demand will require investment to bolster distribution assets for a few extreme demand events, currently responsible for nearly $3 billion annual investment by the distribution companies. For this reason, it fails to deal with the potential for sharply increasing residential electricity prices
- Shifting to renewable sources of energy significantly reduces emissions, such that it successfully addresses the climate change imperative but still leaves a large challenge to meet 2050 targets
- The high capital cost of renewable generation provides an inherent barrier to renewing the generation fleet
- A significant shift to renewable generation successfully meets public expectations for renewable forms of energy
- With Germany and China rolling out technology that enables a shift to renewable and distributed generation, the *Large-scale renewable* scenario only partially addresses the technology trends that are gathering momentum globally

Table 13 Assumptions for *Large-scale renewable* scenario

Forces underpinning scenario	Widespread public support for renewables
	No consumer reaction to rising prices
	Gas prices reflect global energy trends
	Policy to encourage investment in solar thermal and geothermal generation and transmission from remote locations to load centres
Capital costs	Geothermal $6200/kW
	Concentrated solar thermal with 6 hrs storage $6200/kW
	Wind $2558/kw
Network topology	Existing plus AEMO's Innamincka options 4 and 6 chosen to reach the significant nodes in the network. HVDC connections from Innamincka to Adelaide, Melbourne and Sydney; and Innamincka to Western Downs and Sydney. A second path to Sydney establishes an element of spare capacity and robustness. Investing in a connection from South Australia to Queensland has not been included here.
Generation locations	CST and WIND located in all states
	Geothermal located in Innamincka
Modelling assumptions	CCGT disabled
	Nuclear disabled
	CCS disabled
	CST with storage is schedulable with capacity factor of 42%
	Wind intermittent to 30% capacity factor

2.3. Consumer action scenario

In the absence of investment in large centralised generation and transmission infrastructure, this Changing Technological Landscape scenario assumes that distributed generation (DG) will be pursued. This requires a shift towards rooftop photovoltaic, micro gas turbines, landfill gas, wind, and co- and tri-generation. None of the technologies deployed require significant research and are deployable today.

The specific assumptions that underpin this scenario are:

- Widespread public support for renewables
- Consumer reaction to rising prices by pursuing domestic generation
- Gas prices which reflect global energy trends
- Perceived requirement for abatement
- Policy to encourage investment in distributed generation

This scenario introduces complexity into the model in that large scale rooftop PV generation is intermittent and not able to be scheduled. For this reason it is always dispatched, but not subject to price-related demand considerations. As the model is designed to determine the least cost dispatch of generation resources to meet demand, modelling facilitates the deployment of distributed generation technologies and discourages investment in the following technologies:

- Coal and gas generation fitted with CCS
- Nuclear power
- Supercritical pulverized combustion coal

CSIRO projections to 2035 are used for quantity and costs of distributed generation deployment, including 8GW of PV, 10GW of biogas and 1GW of biomass in addition to 12GW of CCGT and 4GW of OCGT to meet demand in 2035. AEMO has projected a likely scenario of 12GW of deployment of PV by 2031 so our inclusion of 8GW of PV could be considered to be conservative. On all other matters the assumptions remain the same as for the other scenarios.

Under these circumstances the model predicts that emissions can be reduced to 144mtpaCO_2 and the average wholesale cost would be $150/MWh. Coal and gas generation would be less than the *Business-as-Usual* scenario and generation from renewable would increase to 38 percent.

The modelling focuses on generation dispatch rather than on distribution. Accordingly, it does not take into account any requirement for network ancillary services, such as storage or generator dispatch, to manage increased load intermittency from high levels of solar penetration. It is recognized that generation, especially intermittent generation, cannot be considered in isolation from the network. For this reason, the sensitivity analysis considers the impact of storage, which would act to transform intermittent generation into schedulable generation and reduce potential for network instability through provision of an ancillary service.

Table 14 Comparing KPIs for *Business-as-Usual* and *Consumer action* scenarios

	2010	2035 AEMO	2035 Business-as-Usual	2035 Consumer action
mtpaCO_2 from electricity	183	183	167	144
Emission intensity	0.85	0.53	0.52	0.43
% of 2050 target achieved		-17%	-5%	13%
Generation (TWh)	215	346	324	335
Annual growth	1.5%	1.9%	1.7%	1.8%
Average wholesale cost	$47	$98	$154	$150
Coal generation	80%	36%	42%	42%
Gas generation	11%	45%	41%	20%
Renew generation	9%	19%	17%	38%
Generation investment ($bn)		$65	$61	$85
Gas price ($2011)	$5.19	$8.32	$8.32	$8.32
Carbon price ($2011)	$0	$72	$74	$74

With AEMO predicting a decrease in its latest demand forecasts, the modelling also tests the sensitivity of the scenario to lower demand.

As with the other scenarios, the sensitivity of the scenario to a high carbon price is tested.

The sensitivity analysis of the *Consumer action* scenario follows.

2.3.1. Examining the impact of alternative assumptions: Photovoltaic with storage

Panasonic Corporation, Kyocera Corporation and Hanwha SolarOne have announced photovoltaic/lithium-ion storage packages will be available in Europe, US and Japan this year. With AEMO forecasting that 12GW of photovoltaics could be deployed in the NEM by 2031, this study tests the impact of a large take-up of storage on peak demand, and thus energy needs, for 2035.

Modelling predicts that having 5.5GW of solar PV with storage reduces the average wholesale cost from $150 to $105/MWh with a $4billion increase in capital expenditure. The decrease in average wholesale cost is the result of a greater capacity to meet the residential peak from storage. Whilst this results in a decrease in average cost, it will have implications for the distribution network, the extent of which our model cannot predict.

Box 5

What about electric vehicles?

Electric vehicles (EV) have the potential to increase dramatically the consumption of power should demand for EVs increase. Widespread adoption of EVs, without measures to control charging, could significantly affect maximum demand leading to increased high price periods, investment in peaking generation and network expenditure.

Demand for EVs will be dependent on a number of factors, such as the global price of oil and gas, the domestic price of electricity, and the outlook for economic growth. Forecasting global energy prices and economic growth was outside the scope of this paper, and the scenarios have, in the main, relied on demand forecasts which currently exclude a substantial roll-out of EVs.

EVs could impact on demand but with electricity prices rising fast, consumers may be wary of investing in electric transportation unless oil prices also rise dramatically. Rapidly rising energy prices will affect global growth which in turn will limit the roll-out of EVs.

Table 15 Impact of storage on *Consumer action* scenario

	Consumer action (0 storage)	Consumer action (5GW storage)
Emissions (mtpaCO_2)	144	145
Emissions intensity (tCO_2/MWh)	0.43	0.44
% of 2050 target achieved	13%	12%
Fuel usage (PJ)	2565	2516
Non-renewable toe/MWh	134	143
Generation from coal	42%	43%
Generation from gas	20%	22%
Generation from renewables	38%	35%
Generation investment ($bn)	$85	$89
Wholesale cost ($/MWh)	$150	$105

Box 6
Demand Side Management vs. Distributed Generation

Australia's increasing population and investment in household electrical equipment and appliances are driving substantial investment in network expenditure to meet escalating peak demand. There are a range of options available to address peak load management issues, all requiring flexibility in the operation of consumers' end-use equipment to allow supply from the grid to be interrupted or reduced when required. Such flexibility may be enhanced through pricing and incentives that encourage consumers to shift their load to lower-demand periods. The roll-out of smart-grids and smart appliances will empower consumers to manage their household energy use and expenditure. At present, there are few strong incentives for network businesses to implement Demand Side Management (DSM) in favour of traditional network solutions (Ernst and Young 2011). Assumptions with respect to DSM have not been included in this paper's modeling. It is assumed that AEMO demand projections include an appropriate level of DSM.

Consultants engaged by the AEMC estimate that there is approximately 2.9GW of dispatchable distributed generation (DG) in the NEM at present although there is little evidence that small to medium consumers are engaged in these activities. This resource is thought to be under-developed in the NEM compared to Western Australia and California (Futura Consulting 2011).

In the modeling of distributed generation (DG) in this study it is hypothesized that increasing power costs will encourage a shift away from centralised power provision toward private or community generation. It is suggested that this is feasible because of similar shifts from centralised to distributed systems in Information Technology and Telecommunications over the last three decades. Whilst this is an intriguing concept, it raises a number of discussion points:

Technical

1. Electrical transmission and distribution circuits have traditionally been designed and operated based on the principle of large centralised generation, in which electricity flows in one direction from the generator to the consumer via the intermediate use of transmission and distribution substations. These substations are designed to provide power to consumers based on the forecasted load demand, reduce voltage levels for distribution, and to ensure adequate power quality and reliability.
2. As increasing amounts of customer-generated power, usually solar PV, are installed at consumers' homes and businesses, generation may exceed the total load from consumers at different times of the day and flow backward towards the distribution substation. This power back flow will result in the corresponding voltage levels to rise within the distribution network.
3. Currently, voltage levels on the distribution network are controlled by adjusting transformer taps or by voltage regulators installed on the lines. Voltage regulator and transformer tap adjustments have discrete steps for adjustment, and can electromechanically change tap settings within tens of seconds. Solar PV power generation is variable by nature, and the power change is in the order of milliseconds. If weather conditions are variable, the resulting power changes from PV generation produce voltage fluctuations on the distribution network in the same order of time. In the case of large amounts of PV generation, rapid voltage fluctuations can force transformer tap regulation and line voltage regulators to continually change tap levels and hunt for the best voltage level. Persistent tap changing of voltage regulators to manage constant voltage fluctuations can reduce the useful life of this equipment and can contribute to instability of the distribution network.
4. Australian distributors are inclined to limit the installation of PV because of concerns about potential network problems from intermittent generation but there are valuable insights to be gained from the European experience, which has managed massive integration of PV (25GW in Germany, 12GW in Italy and 5GW in Spain) over a relatively short period of time.
5. Germany has been able to integrate PV by network upgrading near the DG interconnection; using fault and overload protection systems designed to accommodate back-flow; requiring small PV systems to have technical equipment for remote control; installing telemetry that provides grid operators with PV real-time data; and improved weather forecasting to predict sudden changes in generation (California Energy Commission 2011). CSIRO finds that thorough analysis of the network is required to assess the capability and requirement to deal with high penetration of intermittent solar power (CSIRO 2012).

6. Several corporations have announced intentions to market PV/lithium-ion storage packages to small consumers in Europe, Japan and North America by the end of 2012. The availability of affordable storage for home and commercial use could change the load profile of the NEM by 2035.

Institutional

7. A shift from centralised to distributed (independent) generation transfers the capital cost from generators who provide a service to consumers to consumers themselves.
8. High levels of energy independence like PV generation with storage, therefore present a challenge to institutions reliant on supplying electricity to consumers.

2.3.2. Examining the impact of alternative assumptions: High carbon price

In the event of global agreement on containing GHG concentrations in the atmosphere to 450 ppm, the Department of Treasury forecasts that the carbon price will reach \$159/tCO_2 by 2035. We have conducted sensitivity analysis to assess the impact of increasing the carbon price to \$159/tCO_2.

Table 16 shows the impact of a high carbon price on the *Consumer action* scenario. The high carbon price encourages an additional deployment of 8GW of gas-fired generation which reduces volatility in the market and brings wholesale prices down. Emissions reduce by 38mtpaCO_2 at an investment cost of an additional \$8 billion. There is a shift to generation from biogas with the prospect of a high carbon price.

Box 7 examines the historical precedence for, and consequences of, substantial shifts in technology.

2.3.3. Examining the impact of alternative assumptions: low growth in demand

The IEA suggests that reduced demand will be responsible for the largest contribution to emissions reductions in future carbon constrained scenarios. With wholesale and residential prices projected to rise sharply due to the rising cost of gas for generation and substantial investment in the distribution network to meet increasing peak demand, it is possible that electricity usage in Australia will become more sensitive to price than it has been historically. AEMO too, in its latest energy forecasts, has projected a 16 percent reduction from 2011 forecasts. For this reason, this study tests the impact of consumer action to reduce consumption of electricity.

Table 17 shows the impact of reduced demand on the power system. Reduced consumption improves every measure of performance although it does not take into account the impact on the distribution network.

Most specifically there is a reduction in weighted average wholesale cost from \$145 to \$105/MWh, reduced emissions and fuel use. Reducing demand will also benefit distribution networks by requiring less investment in demand growth, although as stated previously, investment in network ancillary services will be required for DG. Encouraging energy efficiency and reduced consumption appears to be one of the most effective measures available to address price escalation.

Table 16 Impact of high carbon prices on *Consumer action* scenario

	Consumer action (\$74/tCO_2)	Consumer action (\$159/tCO_2)
Emissions (mtpaCO_2)	144	106
Emissions intensity (tCO_2/MWh)	0.43	0.32
% of 2050 target achieved	13%	43%
Fuel usage (PJ)	2565	3817
Non-renewable toe/MWh	134	122
Generation from coal	42%	21%
Generation from gas	20%	37%
Generation from renewables	38%	42%
Generation investment (\$bn)	\$85	\$94
Wholesale cost (\$/MWh)	\$150	\$135

Table 17 Impact of low demand on *Consumer action* scenario

	Consumer action (2011 forecast)	Consumer action (2012 forecast)
Emissions (mtpaCO_2)	144	106
Emissions intensity (tCO_2/MWh)	0.43	0.38
% of 2050 target achieved	13%	43%
Fuel usage (PJ)	2565	1912
Non-renewable toe/MWh	134	133
Generation from coal	41%	37%
Generation from gas	20%	21%
Generation from renewables	38%	42%
Generation investment (\$bn)	\$85	\$97
Wholesale cost (\$/MWh)	\$150	\$105

Box 7
Groundswell movements cause change

Information technology industry

International Business Machines (IBM) was formed in 1922. Its early success with government contracts, and the leadership of Thomas Watson Sr. and Jr. for more than six decades, propelled it through the depression and World Wars. A commitment to product innovation, which resulted in Nobel prizes, accolades and lucrative patents, also established IBM's dominance in the industry through the provision of a platform that is operating system compatibility across computers with different processors, disks, screens and printers. Platforms enabled customers to upgrade and adjust their IT infrastructure to meet changing needs. This flexibility came at a cost and many corporations found themselves locked into an extended relationship with IBM because of the costs sunk in IT.

Until the arrival of the personal computer (PC) in the 1980s, corporate departmental IT users had been reliant on centralised IT departments to interpret their needs and provide services. Often departmental requests were slow to be delivered, if at all. Purchasing a PC or small network of PCs became affordable and departmental managers started requiring autonomy from centralised computing services to develop IT services that were more suited to their needs. IBM was unprepared to meet this shift to decentralization. Its customers were equally ill-equipped to respond to departments demanding autonomy from centralised IT services. Sales of mainframes evaporated and IBM faced an uncertain future.

A new CEO refocused the company on customer requirements, shifting its resources to provide services to connect decentralised users rather than provide central computing (Gerstner 2002). IBM survived as a result of its recognition of the need to meet a radical shift in technology taken up by a majority seeking change.

City of Sydney Decentralised Energy Master Plan

The City of Sydney is committed to becoming a green, global and connected city. As part of the process they seek to become an environmental leader in green industry driving economic growth. One of the Key Performance Indicators of a Sustainable Sydney 2030 is to reduce Greenhouse Gas emissions by 70 percent below 2006 levels, by 2030. The path to reach their emissions target includes energy efficiency, transport options like cycling and walking, utilizing waste as energy, renewable energy and a decentralised energy network powered by tri-generation.

The key sustainability component of the plan is a network of Green Transformers, principally housing tri-generation, to supply the city with electricity, heating and cooling. The Green Transformers will be sited to deliver electricity to the high voltage network and waste heat to a pipe network to supply district heat. This introduces a shift to community or district scale power provision away from reliance on the provision of power from centralised sources.

There are many grandiose city plans that have failed to materialize, but the City of Sydney's energy plan provides an insight into how communities might represent public support for renewable forms of energy and decarbonising the economy in the *Consumer action* scenario. Whilst the Decentralised Energy Plan mentions that it still intends to be connected to the grid, the distribution network will have to be enhanced to accommodate district scale generation. Also the provision of heat for heating and cooling needs may reduce the quantity of electricity delivered through the grid. This will reduce revenue streams for network companies unless they become involved in the provision of decentralised energy.

When there is a groundswell of support for change, institutional structures have to adapt to meet that change.

2.3.4. *Consumer action* scenario conclusions

For an investment of $85 billion the *Consumer action* scenario delivers 23 mtpaCO_2 more of annual abatement than the *Business-as-Usual* scenario. However, reaching a target of 32 mtpaCO_2 in 2050 will remain a substantial challenge. There are few technology-related risks since the technologies are commercially available already. Our finding that distributed generation (DG) delivers reasonable emissions reduction with favourable impacts on wholesale cost is supported by CSIRO's 2009 report entitled "Intelligent Grid: A value proposition for distributed energy in Australia". The report states:

"The modelling indicates that the role out of DG will have a significant impact on the average spot price of electricity throughout the NEM. The drop in average spot prices for each of the DG scenarios indicates that investment in new technology stimulated by the CPRS will lower the delivered energy cost across the NEM." (CSIRO 2009, P28)

The risks associated with the *Consumer action* scenario are more to do with the distribution network which will have to be sufficiently robust to be able to respond to intermittency and stability challenges. If DG is to be embraced as a provider of energy to the market then distribution companies will have to invest in the distribution network. These costs could, however, be off-set against reduced requirements for rising demand if consumers can be encouraged to shift their energy usage away from peak demand times. Without an in-depth study into the effect of DG on the distribution network it is hard to quantify how much investment is required to meet intermittency and stability challenges. It is proposed that a study of this nature is imperative and overdue.

This scenario represents a renewable energy and technology alternative to the dominant industry view of how the Australian power industry will be structured in 2035. The key principles that underpin this scenario are that there is strong perceived need from the public for action on climate change, some form of intervention to deploy distributed technologies and growth in energy use will slow due to increasing power prices. Because of a shift away from fossil fuels, wholesale power prices will be less vulnerable to global energy trends. Consumers will have a strong preference for photovoltaic power and energy efficiency measures to insure them against rising electricity prices.

Table 18 Consumer Action in 2035 sensitivity analysis

	2035 Business-as-Usual	2035 Consumer action	2035 PV with storage	2035 High carbon price	2035 Low demand
mtpaCO_2 from electricity	167	144	145	106	106
Emission intensity	0.52	0.43	0.44	0.32	0.38
% of 2050 target achieved	-5%	13%	12%	43%	43%
Generation (TWh)	324	335	327	325	275
Annual growth	1.7%	1.8%	1.7%	1.7%	1.0%
Wholesale cost ($/MWh)	$154	$150	$105	$136	$105
Coal generation	42%	41%	43%	21%	37%
Gas generation	41%	20%	22%	37%	21%
Renew generation	17%	38%	35%	42%	42%
Generation investment (bn)	$61	$85	$89	$94	$97
Fuel used (PJ)	2372	2565	2516	3817	1912
Fuel cost ($mill)	$9,421	$10,372	$9,999	$27,381	$9,035
Gas price ($2011)	$8	$8	$8	$8	$8
Carbon price ($2011)	$74	$74	$74	$159	$74

The sensitivity analysis above shows that:

- high carbon prices will decrease emissions by 38 mtpaCO_2 with no increase on wholesale cost over the base scenario
- storage reduces wholesale cost by 30 percent by reducing the impact of the residential peak, making it only 15 percent more expensive than the *Business-as-Usual* $4 gas price sensitivity
- low demand decreases emissions by 38mtpaCO_2 and the weighted average wholesale cost by 30 percent.

The table below provides a summary of the assumptions

In this scenario, this study has modeled the DG technologies as participating in a centrally managed market and has not facilitated deployment with incentives like feed in tariffs, and included in the capital cost what should in many instances be private consumer investment. This is to ensure that the costs in this scenario are comparable to the costs in the other scenarios.

However, this is contrary to how industry investment decisions are made because without rebates, PV is a capital cost for consumers, not industry. For now consumers have taken up the opportunity of generating power from PV in response to rebates offered by states and governments and attractive feed-in tariffs that reduce consumer electricity costs. In the event that storage becomes commercially attractive, consumers may seek to gain certainty with respect to power costs as well as independence from centralised power providers. This will reduce demand and flatten the load curve of centralised power, particularly during summer.

In most circumstances, reducing demand and flattening the load curve should be considered to be a positive outcome and yet there are concerns that private PV generators will 'free ride' on other electricity consumers. This view is based on the understanding that PV owners will reduce their consumption of centralised electricity and consequently not pick up their share of the costs related to investment in the network. But this fails to consider that substantial investment is currently justified to manage increased demand, especially peak demand on a few hot days a year. Installing PV, which will directly address those few hot days a year, is a positive measure that will reduce the requirement for investment. Justifying investment in the network to meet peak demand and then labeling measures to reduce peak demand as 'free riding' does not make sense.

PV is not a panacea to the provision of electricity, but there needs to be fair representation of the benefits of PV as well as the challenges. The challenges are not incidental and revolve around how to manage traditional generation that has been designed to function most efficiently when generating power at constant, high capacity, under circumstances that require variable generation; and a network that requires a constant flow of power to keep the lights on, under circumstances where power is coming from highly volatile sources. It is preferable to refer to this as a management and engineering challenge rather than accusing PV owners of seeking an unfair advantage.

Table 19 Summary of assumptions for the sensitivity analysis

Forces underpinning scenario	Widespread public support for renewable and distributed generation
	Consumer reaction to rising prices
	Gas prices which reflect global energy trends
	Climate change not an issue
	Policy to encourage investment in distribution
Capital costs	For all DG technologies, see appendix 1
	Wind $2558/kW
	PV with storage (battery, possibly li-ion) $2100/kW
Network topology	Existing
Generation locations	Distributed across the states
Modelling assumptions	Technologies with CCS are disabled
	Nuclear is disabled
	SCPf coal is disabled
	Wind intermittent to 30% capacity factor
	PV is available only during sunlight hours
	PV with storage is schedulable with capacity factor of 13%

In many respects, distributed generation, both centrally managed and privately used, offers the opportunity to spread the costs of generation investment across a wider base of private consumers and commercial generators thereby reducing the risks associated with having to pick winners from amongst a complicated array of expensive technology options.

With a large deployment of DG, the energy market could be extended to incorporate small, private generators. Currently, institutional structures do not provide a suitable market response to the provision of energy from small, private generators, which reduces competition.

In conclusion, the analysis of how the *Consumer action* scenario addresses the forces that are facing the Australian power industry indicates:

- A shift to distributed generation implies fuel cost reductions and therefore it deals effectively with reducing vulnerability to sharply increasing global energy prices
- Generating power locally will reduce pressures on the distribution network from rising peak demand thus reducing the potential for sharply increasing residential electricity prices, although investment will need to be directed to bolstering the network and providing fast response back-up generation to cope with intermittent generation
- Shifting to renewable sources of energy significantly reduces emissions, such that it successfully addresses the climate change imperative although reaching a target of 32 mtpaCO_2 in 2050 will remain a substantial challenge
- The reasonable capital cost of distributed, renewable generation provides an affordable alternative to renewing the generator fleet
- A significant shift to renewable generation successfully meets public expectations for renewable forms of energy
- With Germany, Japan and China rolling out technology that enables a shift to distributed and renewable generation (and the understanding that network investment is a prerequisite for this changing landscape), the *Consumer action* scenario addresses the technology trends that are gathering momentum globally

2.4. Renewable plus consumer action scenario

CSIRO's Energy Transformed Flagship has conducted studies into public perceptions towards climate change and low-emission technologies. In general public perceptions tend to be strongly positive toward renewable technologies. Two of the key messages from participants in one of the studies were "how to empower local action" and "Don't wait – what can we do now?" (Peta Ashworth 2009, P2). With this level of public support for renewable forms of energy and consumer action on efficiency and distributed generation, we consider a scenario where the industry endeavours to meet public expectations with respect to transitioning the power system to meet climate change challenges from renewable forms of energy. This is, in effect, merging the *Large-scale renewable* scenario with the *Consumer action* scenario to create a single Changing Technological Landscape scenario.

The specific assumptions that underpin this scenario are:

- Widespread public support for renewable and distributed generation
- Consumer reaction to rising prices by pursuing domestic generation
- Gas prices which reflect global energy trends
- Strong requirement for abatement
- Policy to encourage investment in large-scale renewables and distributed generation, and transmission from remote locations to load centres

This scenario introduces complexity into the model in that both large-scale renewable and large scale rooftop PV generation need to be accommodated. For this reason the assumptions for *Large-scale renewable* and *Consumer action* have been combined. As the model is designed to determine the least cost dispatch of generation resources to meet demand, we facilitate the deployment of renewable and DG technologies by discouraging investment in the following technologies:

- Coal and gas fitted with CCS
- Nuclear power
- Supercritical pulverized combustion coal
- CCGT

Modelling predicts that 12GW of wind, 11GW of rooftop PV (no storage), 10GW of CST (with storage), 7GW of biogas, 5GW of distributed gas generation, 3GW of geothermal, 2GW of CCGT and OCGT at a total cost of $160 billion will be deployed to meet demand in 2035. As a result, generation from renewable sources will increase to 54 percent of the total, carbon emissions will decrease to 101 $mtCO_2$ and the average wholesale cost will be $126/MWh. This excludes any network costs that might eventuate from investment in remote renewable locations and a high density of rooftop PV systems.

The weighted average wholesale cost was analysed because it was unexpectedly low, indicating that some legacy coal and CCGT generators, whilst still dispatching energy, are operating at very low capacity, close to their minimum requirement. As a result in some instances gross margin for legacy coal and CCGT generation is marginal. This is a consequence of failing to retire coal-fired power stations and using them to balance intermittent load. It is unlikely that generators would willingly operate in an environment of such low margins, so a consequence of high renewable and intermittent generation may be the requirement for capacity payments to key generators to ensure load stability.

Having examined in depth the sensitivities of both the *Large-scale renewable* and the *Consumer action* scenarios, this study does not pursue sensitivity analysis on this combined scenario.

2.4.1. *Renewable plus consumer action* scenario conclusions

For an investment of $160 billion (plus network costs) this scenario delivers 66 mtpaCO_2 more of annual abatement than the *Business-as-Usual* scenario. The technology risk is with geothermal, although there is little reliance on geothermal, as only 3GW is deployed.

The risks associated with this scenario are more to do with the distribution network, which will have to be sufficiently robust to be able to respond to intermittency and stability challenges, and the transmission infrastructure, which will have to be upgraded to shift power over long distances from remote locations. These costs could however be off-set against reduced requirements for rising demand if consumers can be encouraged to shift their energy usage away from peak demand times.

This scenario represents a renewable energy and technology alternative to the dominant industry view of how the Australian power industry will be structured in 2035. The key principles that underpin this scenario are that there is a strong perceived need from the public for action on climate change, some form of intervention to deploy renewable and distributed technologies and investment in transmission infrastructure, and growth in energy use will slow due to increasing power prices. Because of a shift away from fossil fuels, wholesale prices will be less vulnerable to global energy trends. Consumers will have a strong preference for renewable, photovoltaic power and energy efficiency measures to insure them against rising electricity prices.

Table 20 Comparing KPIs for *Business-as-Usual* and *Renewable plus consumer action* scenarios

	2010	2035 AEMO	2035 Business-as-Usual	2035 REN_DG
mtpaCO_2 from electricity	183	183	167	101
Emission intensity	0.85	0.53	0.52	0.31
% of 2050 target achieved		-17%	-5%	46%
Generation (TWh)	215	346	324	327
Annual growth	1.5%	1.9%	1.7%	1.7%
Wholesale cost ($/MWh)	$47	$98	$154	$126
Coal generation	80%	36%	42%	31%
Gas generation	11%	45%	41%	15%
Renew generation	9%	19%	17%	54%
Generation investment ($bn)		$65	$61	$160
Gas price ($2011)	$5.19	$8.32	$8.32	$8.32
Carbon price ($2011)	$0	$72	$74	$74

In conclusion, the analyses shows how the *Renewable plus consumer action* scenario addresses the forces that are facing the Australian power industry.

- A shift to renewable and distributed generation implies fuel cost reductions and therefore it deals effectively with reducing vulnerability to sharply increasing global energy prices
- Generating decentralised power with potential for storage will reduce pressures on the distribution network from rising peak demand thus reducing the potential for sharply increasing residential electricity prices, although investment will need to be directed to bolstering the network for intermittent generation and for transmission infrastructure to shift power from remote locations
- Shifting to renewable sources of energy significantly reduces emissions, such that it successfully addresses the climate change imperative. However, reaching a target of 32 mtpaCO_2 in 2050 will remain a substantial challenge
- The capital cost of this scenario provides a barrier to renewing the generator fleet
- A significant shift to renewable generation successfully meets public expectations for renewable forms of energy
- With Germany, Japan and China rolling out technology that enables a shift to distributed and renewable generation, the *Consumer action* scenario addresses the technology trends that are gathering momentum globally

2.5. Carbon capture and storage scenario

The IEA warns that without carbon capture and storage (CCS) there is little chance to reduce GHG emissions from power generation to IEA meet climate change mitigation targets. For this reason, in this Non-Renewable Centralised Power scenarios the hypothesis that global investment will be made to explore and appraise large scale geo-storage resources so that power plant integration with CCS will be commercially available by 2025.

The specific assumptions that underpin this scenario are:

- Long-term historic trend in consumption growth
- No consumer reaction to rising prices
- Gas prices reflect global energy trends
- Perceived requirement for abatement as a result of fear of climate change
- Sustained global investment in research and deployment of CCS
- Investment in exploration and appraisal of Australian CO_2 storage resources

Using Australian Energy Market Operator (AEMO) projections to 2035 for gas price, generation cost and demand, and the Commonwealth Treasury projections for carbon price, our model predicts that new coal and gas generators fitted with CCS will be too expensive to be deployed in the National Electricity Market (NEM) in 2035.

The model is designed to determine the least cost dispatch of generation resources to meet demand. In order to facilitate deployment of CCS-enabled technologies, investment is discouraged in the following technologies:

- Combined cycle gas turbines (CCGT)
- Nuclear power

Without deployment of CCGT, our model predicts that generators in the National Electricity Market (NEM) will invest $104 billion to deploy 28GW of CCGT with CCS, 3GW of open cycle gas turbines (OCGT) and 12GW of wind power to meet demand in 2035, as shown in Table 21. The model includes no deployment of new-build coal-fired generation with CCS because of high capital costs.

This investment in generation will reduce the emissions from power generation in 2010 of 183 mtpaCO_2 to 129 mtpaCO_2 in 2035.

This leaves Australia with a large challenge to reach a greenhouse gas emission target of 32 mtpaCO_2 by 2050. Box 8 provides some discussion on CCS.

2.5.1. Examining the impact of alternative assumptions: Retrofit of CCS to existing coal-fired power plants

There are currently five power stations assessed to be viable for CCS retrofit, namely Stanwell, Tarong, Tarong North, Loy Yang B and Kogan Creek. Whilst Plexos is not designed to accommodate upgrades of this nature, the assumptions were adjusted to accommodate retrofit requirements such that the above mentioned power plants will be able to dispatch with reduced CO_2 emissions.

Table 21 Comparing KPIs for *Business-as-Usual* and *CCS* scenarios

	2010	2035 AEMO	2035 Business-as-Usual	2035 CCS
mtpaCO_2 from electricity	183	183	167	129
Emission intensity	0.85	0.53	0.52	0.37
% of 2050 target achieved		-17%	-5%	25%
Generation (TWh)	215	346	324	351
Annual growth	1.5%	1.9%	1.7%	2.0%
Wholesale cost ($/MWh)	$47	$98	$154	$142
Coal generation	80%	36%	42%	40%
Gas generation	11%	45%	41%	45%
Renew generation	9%	19%	17%	15%
Generation investment (bn)		$65	$61	$104
Gas price ($2011)	$5.19	$8.32	$8.32	$8.32
Carbon price ($2011)	$0	$72	$74	$74

Box 8
The potential of carbon capture and storage

Carbon capture and storage (CCS) is a technology that can be applied to fossil fuel fired power generation and other industries, such as steel, cement and petrochemical production. CO_2 is separated from the combustion flue gas (or syngas in the case of coal gasification with pre-combustion capture), compressed and then piped and injected under supercritical conditions into geological formations, typically at least 800 metres below the surface.

CCS has been identified as one of the important CO_2 abatement technologies to reduce the emissions intensity of coal and gas fired power generation.

Practically, with current technologies, it is anticipated that CCS can reduce the CO_2 emissions intensity of fossil fuel fired power plants by between 80 percent and 90 percent.

Benefits

- CCS can potentially be applied to much of Australia's existing and future fossil fuelled generation fleet.
- CCS can also be used to reduce CO_2 emissions from natural gas production and hydrocarbon processing.
- Most of the technologies needed for CCS are already applied extensively in a number of industries.
- Australia has several sedimentary basins in reasonable proximity to power generation related CO_2 sources that are potentially suitable for geological storage of CO_2.

Challenges

- There are no large-scale CCS demonstrations currently operating in power generation anywhere in the world today.
- The current estimates for capital and operating costs associated with the integration of fossil fuel fired power generation with carbon capture are high and contain significant uncertainty.
- One of the disadvantages of CCS is the large auxiliary power load consumed by the CO_2 capture, compression and transportation, which is typically 25 percent of the generation capacity with CCS.
- The lead time and cost to explore, appraise and develop CO_2 storage resources to enable an investment decision on a CCS project is significant.
- CCS does not currently attract tariff or other mechanisms of electricity price support, which are likely to be necessary to encourage investment in early-mover demonstration projects.
- The long lead-times to plan, build and operate CCS projects at commercial scale and the preferential treatment given to renewable technologies through the Renewable Energy Target (RET) and the Clean Energy Finance Corporation, which excludes CCS, gives rise to potential investment impediments.

Being able to retrofit coal-fired power stations reduces the shift to gas-fired generation, reducing emissions by 25 percent at an increased capital cost of $13 billion but with no observable impact on the average wholesale cost of generation. Fuel usage increases with the expected high auxiliary usage of plants fitted with CCS.

2.5.2. Examining the impact of alternative assumptions: High carbon price

In the event of global agreement on containing GHG concentrations in the atmosphere to 450 ppm, the Commonwealth Treasury forecasts that the carbon price will reach $159/t$CO_2$ by 2035. Sensitivity analysis to assess the impact of increasing the carbon price to $159/t$CO_2$ was conducted.

A high carbon price will shift generation away from coal to combined cycle gas turbines fitted with CCS providing the largest emissions reduction of any scenario or sensitivity studied. As gas-fired generation is more efficient than coal-fired generation, fuel use decreases.

2.5.3. *CCS* scenario conclusions

The table below presents the results of the sensitivity analysis conducted on the *CCS* scenario.

At a cost of around $104 billion CCS could deliver reasonable carbon abatement for the Australian power system if the technology becomes viable.

Deeper emissions can be achieved if coal-fired plants can be retrofitted with CCS technology and if a high carbon price eventuates. To keep its options open, Australia should invest in exploration and appraisal of CO_2 storage resources, such that if or when the technology and economic challenges are overcome, retrofitting of coal-fired plants and combined cycle gas turbines with CCS can be deployed without undue delay.

This scenario represents a variation to the dominant industry view taking carbon abatement into account of how the Australian power industry could be structured in 2035. The key principles that underpin this scenario are that there is strong perceived need from the public for action on climate change, there will be some form of intervention to deploy carbon capture and storage technology, energy generation will increase to allow for the energy needs of the technology and demand will increase based on historic trends and usage patterns. Gas prices will increase based on the internationalization of domestic gas prices. Renewable energy will only be deployed to 20 percent of generation in 2020 because of its high levelised cost projections. Consumers will be indifferent to the deployment of gas-fired generation with or without CCS in preference to photovoltaic, wind and concentrated solar thermal power.

The sensitivity analysis shows that:

- high carbon prices will decrease emissions by 52 mtpaCO_2 to 77 mtpaCO_2, making it the strongest carbon abatement case studied with only a 3 percent increase in average wholesale cost over the base scenario
- being able to retrofit CCS to existing coal-fired power stations reduces emissions by 25% to 97 mtpaCO_2 with no impact on average wholesale cost over the base scenario.

The table below provides a summary of the assumptions included in the scenario.

Table 22 Impact of existing plant retrofit on *CCS* scenario

	CCS (New build)	CCS (Retrofit)
Emissions (mtpaCO_2)	129	97
Emissions intensity (tCO_2/MWh)	0.37	0.27
% of 2050 target achieved	25%	49%
Fuel usage (PJ)	2374	2391
toe/MWh	161	158
Generation from coal	40%	42%
Generation from gas	45%	43%
Generation from renewables	15%	15%
Generation investment ($bn)	$104	$117
Wholesale cost ($/MWh)	$142	$141

Table 23 Impact of high carbon price on *CCS* scenario

	CCS ($74/t$CO_2$)	CCS ($159/t$CO_2$)
Emissions (mtpaCO_2)	129	77
Emissions intensity (tCO_2/MWh)	0.37	0.21
% of 2050 target achieved	25%	65%
Fuel usage (PJ)	2374	2239
toe/MWh	161	147
Generation from coal	40%	18%
Generation from gas	45%	67%
Generation from renewables	15%	15%
Generation investment ($bn)	$104	$123
Wholesale cost ($/MWh)	$142	$146

Table 24 CCS in 2035 sensitivity analysis

	2035 Business-as-Usual	2035 CCS	2035 Retrofit	2035 High Carbon Price
mtpaCO_2 from electricity	167	129	97	77
Emission intensity	0.52	0.37	0.27	0.21
% of 2050 target achieved	-5%	25%	49%	65%
Generation (TWh)	324	351	360	365
Annual growth	1.7%	2.0%	2.1%	2.1%
Wholesale cost ($/MWh)	$154	$142	$141	$146
Coal generation	42%	40%	42%	18%
Gas generation	41%	45%	43%	67%
Renew generation	17%	15%	15%	15%
Generation investment (bn)	$61	$104	$117	$123
Fuel used (PJ)	2372	2374	2391	2239
Fuel cost ($mill)	$9,421	$9,129	$8,965	$12,907
Gas price ($2011)	$8	$8	$8	$8
Carbon price ($2011)	$74	$74	$74	$159

Table 25 Assumptions for *CCS* scenario

Forces underpinning scenario	Long-term historic trend consumption growth
	No reaction to rising prices
	Gas prices reflect global energy trends
	Fear associated with climate change
	Global investment in research and development of CCS technology
	Australian investment in exploration and appraisal of CO2 storage resources
Capital costs	SCPf Black coal with CCS $4900/kW
	SCPf Brown coal with CCS $7100/kW
	Retrofit Black coal with CCS $2244/kW
	Retrofit Brown coal with CCS $3945/kW
	CCGT with CCS $2500/kW
	Wind $2558/kW
Network topology	Existing
Generation locations	Located close to transmission infrastructure
Modelling assumptions	CCGT disabled
	Nuclear disabled
	Wind intermittent to 30% capacity factor
	Carbon Capture 90%

In conclusion, the analyses of how the *CCS* scenario addresses the forces that are facing the Australian power industry are:

- A shift to gas-fired generation and the heavy energy requirements of CCS implies fuel cost increases from shifting from (cheaper) coal to (more expensive) gas generation such that it fails to deal with the potential for sharply increasing wholesale electricity prices
- Continued support for growth in peak and average demand will require continued investment in bolstering distribution capital for a few extreme demand events such that it fails to deal with the potential for sharply increasing residential electricity prices
- With successful long-term sequestration of CO_2 it is effective in reducing carbon emissions significantly
- The capital cost of gas-fired generation with CCS provides a barrier to renewing the generator fleet
- Since neither gas nor coal are renewable sources of energy and there is some community concern over unconventional gas extraction, the *CCS* scenario does not represent a public preference for renewable forms of energy
- With global focus on photovoltaic and wind investment, the *CCS* scenario fails to address the technology trends that are gathering momentum globally

2.6. Nuclear power scenario

In the *Nuclear power* scenario, a Non-Renewable Centralised Power scenario, it is assumed that global acceptance of nuclear power as an emissions reducing technology facilitates bipartisan support for policy change to deploy nuclear technology in Australia. The IEA warns that without nuclear deployment there is little chance to reduce GHG emissions from power generation to meet climate change mitigation targets. For this reason, the hypothesis is that global acceptance will facilitate the deployment of nuclear after 2025.

The specific assumptions that underpin this scenario are:

- Long-term historic trend in consumption growth
- No consumer reaction to rising prices
- Perceived requirement for abatement as a result of fear of climate change
- Global investment in deployment of nuclear power
- Australian nuclear skills and expertise available

Using Australian Energy Market Operator (AEMO) projections to 2035 for gas price, generation cost and demand, Electric Power Research Institute (EPRI) and the Energy Information Administration (EIA) sources for nuclear capital, decommissioning and waste storage costs, and the Commonwealth Treasury projections for carbon price, the model predicts that nuclear power will be too expensive to be deployed in the National Electricity Market (NEM).

The model is designed to determine the least cost dispatch of generation resources to meet demand. In order to facilitate deployment of nuclear technologies, assumptions to favour deployment of nuclear were changed accordingly:

- economic life for nuclear power plants has to be increased to 50 years
- very large units have to be deployed to reduce the impact of high fixed operating costs
- the installation of 5 GW of nuclear power in New South Wales and Queensland, and 1 GW in Victoria and South Australia is predicated on base-load generation to meet load growth
- Combined cycle gas turbines (CCGT) have to be disabled from deployment

With 12 GW of nuclear power installed emissions from power generation decrease 35 percent from 2010. This decrease results from a reduction in coal generation and considerably less new generation from gas turbines. This still leaves a challenging emissions reduction target to reach 80 percent reduction by 2050. In line with the increased cost of nuclear power over gas power, the average wholesale price of electricity increases by 11 percent over the *Business-as-Usual* scenario.

With the 50 year economic life required to make nuclear power affordable and with possibly high insurance costs, it is suggested here that there is no alternative to public ownership or substantial public subsidization of nuclear power generation. A requirement for public ownership or public underwriting of very large nuclear generators will force substantial change on a deregulated, competitive market and discourage private investment.

Table 26 Comparing KPIs for *Business-as-Usual* and *Nuclear power* scenarios

	2010	2035 AEMO	2035 Business-as-Usual	2035 Nuclear
mtpaCO_2 from electricity	183	183	167	119
Emission intensity	0.85	0.53	0.52	0.37
% of 2050 target achieved		-17%	-5%	32%
Generation (TWh)	215	346	324	330
Annual growth	1.5%	1.9%	1.7%	1.7%
Wholesale cost ($/MWh)	$47	$98	$154	$170
Coal generation	80%	36%	42%	38%
Gas generation	11%	45%	41%	12%
Renew generation	9%	19%	17%	16%
Nuclear generation				34%
Generation investment (bn)		$65	$61	$115
Gas price ($2011)	$5.19	$8.32	$8.32	$8.32
Carbon price ($2011)	$0	$72	$74	$74

Box 9
The benefits and challenges of nuclear power

Nuclear energy for power was first deployed in the 1950s. More than 430 commercial nuclear power reactors operate in 31 countries, with approx 372 GW of capacity. In 2009, they provided 2,697 TWh of electricity, which is approximately 13.4 percent of the world's electricity as continuous, reliable base-load power. There are also 240 research reactors operating in 56 countries and a further 180 nuclear reactors power some 150 ships and submarines.

There are currently 63 nuclear reactors with a potential capacity of 58.5 GW, under construction in 14 countries. By far the largest investors in new nuclear power are China with 27 GW and Russia with 8GW although India (5GW), Korea (4GW) and Taiwan (3GW) are also making sizeable commitments to nuclear power.

Benefits

- Generation of nuclear power causes virtually no greenhouse gas emissions
- Fuel use in nuclear power is a small proportion of the levelised cost of generation
- Substantial amounts of schedulable energy can be generated
- Plants have a long operating life of between 50 to 80 years
- Reactors have a small land footprint in an increasingly populated world
- France's experience in the 1980s, building 42 reactors sequentially using the same design, provided a framework for reducing the potential for increasing cost of construction
- Australia has approximately 25 percent of the world's reasonably assured or inferred uranium deposits

Challenges

- Deregulated energy markets weigh against nuclear investment because of nuclear power's higher capital and operational costs
- Whilst nuclear accidents have been few, and the causes varied, the consequences of accidents are severe
- Estimates of uranium availability are that current reserves will be sufficient until the end of the 21st century and thereafter high prices will trigger new discoveries
- Nuclear proliferation could lead to illicit nuclear activity by rogue individuals/nations presenting a global risk
- Waste from nuclear generation is radioactive for many thousands of years and safe repositories for the spent fuel can be divisive community issues
- Decommissioning of reactors is costly and is a liability for many decades into the future

2.6.1. Examining the impact of alternative assumptions: Uranium price rises

The International Energy Agency forecasts that the world will not be able to reach its goal of limiting warming to 2 degrees Celsius without the deployment of both nuclear and CCS. It forecasts that if the world is to meet its goal of limiting greenhouse gases in the atmosphere to 450ppm, 865GW of nuclear and carbon capture for 617GW of coal/gas fired generation will need to be installed globally by 2035. This will require 1664mtoe of reactor-related uranium annually, which equates to consuming approximately 43 percent of Reasonably Assured and Inferred Resources recoverable at less than US$130/kgU by 2035.

However, in the event that CCS fails to become technically viable, this study speculates that the requirement for zero carbon energy from CCS-enabled generation will transfer to nuclear power. This will mean that globally approximately 1,414GW of nuclear power will need to be installed by 2035 and consumption of reactor-related uranium will increase to 2719mtoe per annum. This will consume 56 percent of Reasonably Assured and Inferred Resources recoverable at less than US$130/kgU by 2035 and will exceed the forecast planned and prospective production capacity.

The follow-on question is whether at this level of annual nuclear generation there will be sufficient reserves to feed the global fleet for their estimated lifetime. The International Atomic Energy Agency (IAEA) considers this question in their recent "Red Book" (IAEA 2012) and concludes that there will be insufficient uranium from identified resources but that resulting higher prices from significant reactor deployment would stimulate exploration and mine development. For these reasons the sensitivity analysis conducted was to consider the impact of uranium prices increasing to $1.80/GJ in 2035.

The model forecasts a small shift of generation from nuclear to coal and gas generation as a result of the higher nuclear fuel costs and a 16 percent rise in average wholesale cost.

2.6.2. Examining the impact of alternative assumptions: High carbon price

In the event of global agreement on containing GHG concentrations in the atmosphere to 450 ppm, the Commonwealth Treasury forecasts that the carbon price will reach $159/ tCO_2 by 2035. Sensitivity analysis has been undertaken to assess the impact of increasing the carbon price to $159/tCO_2$.

High carbon prices shift generation from coal to gas and nuclear. As gas fired generation is more efficient and less carbon intensive than coal, emissions and fuel usage decrease.

Table 27 Impact of high uranium prices on *Nuclear power* scenario

	Nuclear ($0.85/GJ)	Nuclear ($1.80/GJ)
Emissions (mtpaCO_2)	119	121
Emissions intensity (tCO_2/MWh)	0.36	0.37
% of 2050 target achieved	32%	31%
Fuel usage (PJ)	2558	2554
toe/MWh	185	185
Generation from coal	38%	38%
Generation from gas	12%	12%
Generation from renewables	34%	33%
Investment ($bn)	$115	$115
Wholesale cost ($/MWh)	$169	$197

Table 28 Impact of high carbon prices on *Nuclear power* scenario

	Nuclear ($74/$tCO_2$e)	Nuclear ($159/$tCO_2$e)
Emissions (mtpaCO_2)	119	95
Emissions intensity (tCO_2/MWh)	0.37	0.29
% of 2050 target achieved	32%	51%
Fuel usage (PJ)	2558	2467
toe/MWh	185	180
Generation from coal	38%	20%
Generation from gas	12%	28%
Generation from renewables	34%	35%
Investment ($bn)	$115	$116
Wholesale cost ($/MWh)	$169	$164

2.6.3. *Nuclear power* scenario conclusions

Nuclear power offers an opportunity to decrease emissions from power generation whilst still maintaining a centralised power structure. Introducing nuclear power into Australia is likely to entail state ownership, or subsidization, of large reactors and require a capital investment of $115 billion in reactors and institutional arrangements for decommissioning and radio-active waste storage.

There is little nuclear expertise in Australia and in the event of a global shift toward nuclear power, expertise will be scarce. In order to keep open the option for nuclear power, Australia needs to invest in skills and knowledge development now and establish programs for experience to be gained in the industry around the world.

Before introducing nuclear power into the Australian electricity market, several potential problems need to be addressed, namely:

- Regulatory reform to enable the deployment of nuclear power in Australia as well as allow mining of uranium in many States
- The impact of large state-owned, or subsidized, generators on a competitive market in terms of
  - Market price volatility from smaller generators
  - The incentive for investment by non-government agents
- The identification of potential long-term storage facilities for radio-active spent fuel
- The identification of potential sites for location of nuclear reactors in NSW, QLD, VIC and SA
- Institutional structures sufficiently robust to be charged with the responsibility for developing storage facilities, funding storage facilities and decommissioning of reactor sites many decades into the future

This scenario represents another variation to the dominant industry view of how the Australian power industry could be structured in 2035. The key principles that underpin this scenario are that there is strong perceived need for action on climate change, there will be substantial intervention worldwide to deploy nuclear power, and demand will increase based on historic trends and usage patterns. Gas prices will most likely not increase based on the global fuel switch to uranium. Renewable energy will only be deployed to 20 percent of generation in 2020 because of concerns over intermittency. Consumers will be indifferent to the deployment of nuclear in preference to photovoltaic, wind and concentrated solar thermal power.

The sensitivity analysis shows that:

- high carbon prices will decrease emissions by a further 25 $mtCO_2$ per annum without any increase in average wholesale price over the base scenario
- high uranium prices will increase prices but will not have a substantial impact on the power system

The table below provides a summary of the assumptions included in the scenario

Table 29 Nuclear in 2035 sensitivity analysis

	2035 Business-as-Usual	2035 Nuclear	2035 High uranium price	2035 High carbon price
$mtpaCO_2$ from electricity	167	119	121	95
Emission intensity	0.52	0.37	0.37	0.29
% of 2050 target achieved	-5%	32%	31%	51%
Generation (TWh)	324	329	329	328
Annual growth	1.7%	1.7%	1.7%	1.7%
Wholesale cost ($/MWh)	$154	$169	$197	$164
Coal generation	42%	38%	38%	20%
Gas generation	41%	12%	12%	28%
Renewable generation				
Nuclear generation	17%	34%	33%	35%
Generation investment (bn)	$61	$115	$115	$116
Fuel used (PJ)	2372	2558	2554	2467
Fuel cost ($mill)	$9,421	$4,571	$5,539	$7,939
Gas price ($2011)	$8	$8	$8	$8
Uranium price		$0.85	$1.80	$0.85
Carbon price ($2011)	$74	$74	$74	$159

Table 30 Assumptions for *Nuclear power* scenario

Forces underpinning scenario	Long-term historic trend consumption growth
	No consumer reaction to rising prices
	Perceived need for abatement as a result of fear of climate change
	Global investment in nuclear deployment
	Australian investment in developing nuclear skills and expertise
Capital costs	Nuclear 5500$/kW
	Wind $2558/kW
Network topology	Existing
Generation locations	Located close to transmission infrastructure in NSW, QLD, VIC, and SA
Modelling assumptions	CCGT disabled
	Wind intermittent to 30% capacity factor
	Nuclear economic life 50 years
	Nuclear minimum unit size is 1GW
Fuel costs	Uranium $0.85/GJ
	Uranium high price $1.80/GJ

In conclusion, analyses on how the *Nuclear power* scenario addresses the forces facing the Australian power industry indicates:

- A shift to nuclear implies fuel substitution from coal to uranium with continued reliance on a non-renewable source. In a global shift to nuclear power, uranium prices could rise in response to greater demand. As uranium is a small proportion of the cost of generation, the nuclear scenario partially deals with the potential for increasing wholesale electricity prices because the increased operating costs to account for storage and decommissioning limit the benefit of reduced fuel reliance
- Continued support for growth in peak and average demand will require continued investment to bolster distribution assets for a few extreme demand events such that it fails to deal with the potential for sharply increasing residential electricity prices
- With no emissions of CO_2 nuclear power is effective in reducing carbon emissions significantly
- The high capital cost of nuclear generation provides a barrier to renewing the generator fleet
- With long-standing community antipathy to nuclear and fears heightened as a result of the Fukushima crisis, this scenario does not represent a public preference for renewable forms of energy
- With global focus on photovoltaic and renewable investment, the nuclear scenario fails to address the technology trends that are gathering momentum globally. Nuclear technology development has been hampered by the costs and risks involved such that technological breakthroughs have been slow to materialize. This, however, is a matter that can only be addressed at a global scale with Australia contributing in proportion to its ability to provide skills and investment as required.

2.7. Summary of scenarios

Categories	1	2	2	3	3
Scenarios	*Business-as-Usual*	*Large-scale renewable*	*Consumer action*	*Nuclear power*	*Carbon capture & storage*
Setting the scene	• Represents the pursuit of options as set out in the Australian Government's Energy White Paper • Carbon prices will shift generation to gas • Renewable Energy Target will deliver 20% from renewable generation by 2020, mainly from wind • With the reduction in rebates for domestic PV and the difficulties experienced by the concentrated Solar Flagship projects, little growth in solar generation • Insignificant deployment of EVs	• Transmission infrastructure to support remote renewable energy hubs for concentrated solar thermal and geothermal energy • Concentrated solar thermal with storage rolled out in preference to coal and gas to meet increased demand • Geothermal technology feasible by 2025 • Existing coal and gas generation retired when age and carbon price dictates	• Implementation of distributed generation through the deployment of PV, micro turbines, co- and tri-generation • Existing coal and gas generation retired when carbon price dictates	• Large global take-up • Bipartisan support for roll-out of nuclear power • Upskilling, review and planning requirements will be resolved and roll-out of technology to start by 2025 • Nuclear power will be deployed in preference to coal and gas to meet base-load requirements after 2025 • Gas will be deployed to meet demand prior to 2025 • Renewable generation and EV deployment will be as detailed in *Business-as-Usual* scenario	• Technology is proved feasible by 2025 – large global take-up • New investment constructed to be CCS retro-fittable and CCS deployable after 2025 • Renewable generation, EV deployment and carbon price will be as detailed in *Business-as-Usual* scenario
Summary of findings	• Ave cost: – $154 • Fuel source: – Coal 42% – Gas 42% – Renew 17% • Fuel used (PJ) – 2372 • Generation investment: $61 bn • Emissions (mtpa$CO_2$) – 167	• Ave cost: – $150 • Fuel source: – Coal 42% – Gas 11% – Renew 47% • Fuel used (PJ) – 1740 • Generation investment: $198 bn • Emissions (mtpa$CO_2$) – 133	• Ave cost: – $150 • Fuel source: – Coal 41% – Gas 20% – Renew 38% • Fuel used (PJ) – 2565 • Generation investment: $85 bn • Emissions (mtpa$CO_2$) – 144	• Ave cost: – $169 • Fuel source: – Coal 38% – Gas 12% – Renew 17% – Nuclear 34% • Fuel used (PJ) – 2558 • Generation investment: $115 bn • Emissions (mtpa$CO_2$) – 119	• Ave cost: – $142 • Fuel source: – Coal 40% – Gas 45% – Renew 15% • Fuel used (PJ) – 2374 • Generation investment: $104 bn • Emissions (mtpa$CO_2$) – 129
Cost of uncertainty analysed	• RET maintained – Ave cost $146 – Extra 3GW wind – Less 15TWh gas – Investment $65 bn – Emissions 165mtpa • Low gas price – Ave cost $91 – Coal 16%, Gas 68% – Investment $62 bn – Emissions 132mtpa • High carbon price – Ave cost $188 – Coal 16%, Gas 67% – Investment $62 bn – Emissions 130mtpa	• High carbon price – Ave cost $215 – Coal 42%, Gas 11% Renew 47% – Invest $198 bn – Emissions 130mtpa • Renew + DG – Ave cost $126 – Coal 31%, Gas 15% Renew 54% – Invest $160 bn – Emissions 101mtpa	• Storage – Ave cost $105 – Coal 43%, Gas 22% Renew 35% – Invest $89 bn – Emissions 145mtpa • High carbon price – Ave cost $136 – Coal 21% Gas 37% Renew 42% – Invest $94 bn – Emissions 106mtpa	• Uranium prices high – Ave cost $197 – Coal 38%, Gas 12% Nuclear 33% – Invest $115 bn – Emissions 121mtpa • High carbon price – Ave cost $164 – Coal 20%, Gas 28% Nuclear 35% – Invest $116 bn – Emissions 95mtpa	• Coal retrofit – Ave cost $141 – Coal 42%, Gas 43% – Invest $117 bn – Emissions 97mtpa • High carbon price – Ave cost $146 – Coal 18%, Gas 67% – Invest $123 bn – Emissions 77mtpa

3. How the scenarios address the forces facing the Australian power industry

3.1. Increasing fuel prices

Reliance on fuels that are vulnerable to global energy trends increases the risk of rising wholesale electricity prices. The Changing Technological Landscape scenarios, especially the *Large-scale renewable* scenario, provide increased security from being affected by rising global energy prices.

Figure 4 shows the projected industry fuel costs for the scenarios. It demonstrates the increased fuel cost associated with some of the high carbon price sensitivities as a result of the carbon price causing a substantial shift to gas-fired generation. It also shows that around half of the distributed generatation (DG) fuel costs are domestically sourced renewable fuels, which should not be as vulnerable to global price fluctuations as non-renewable fuels.

3.2. Emissions constraints

Each of the scenarios offers a different approach to reducing emissions. The *Business-as-Usual* scenario offers little abatement despite a shift toward less emissions-intensive gas generation. Both the Changing Technological Landscape and the Non-Renewable Centralised Power scenarios offer considerably better abatement than the *Business-as-Usual* scenario. Figure 5 offers a graphical view of the emissions trajectory of the scenarios and the goal of 80 percent reduction by 2050. None of the scenarios appear to be on a reasonable trajectory to reach a goal of 80 percent reduction by 2050.

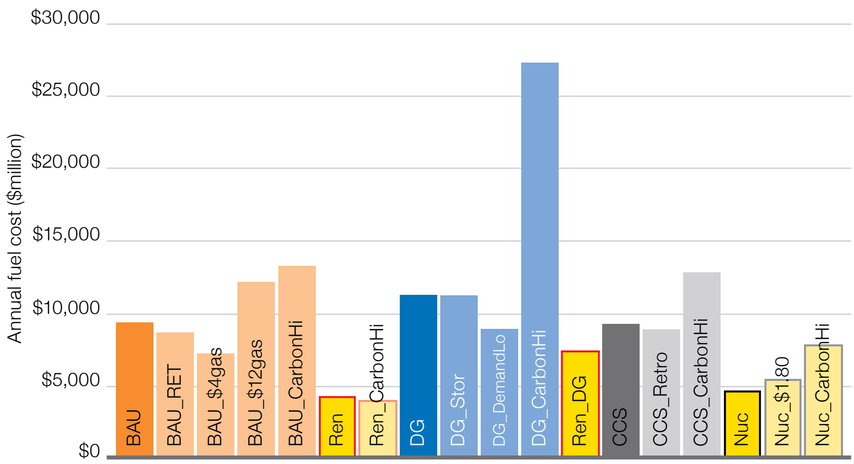
Calculating abatement cost at a point in time more than two decades into the future is challenging. It is proposed that two rudimentary but informative metrics can assist with comparisons.

The first metric compares the amount of abatement gained for capital outlaid.

Table 31 shows that the *Business-as-Usual* scenario does not offer the cheapest capital outlay to gain carbon emission reductions unless it is coupled with a very low gas price or a very high carbon price.

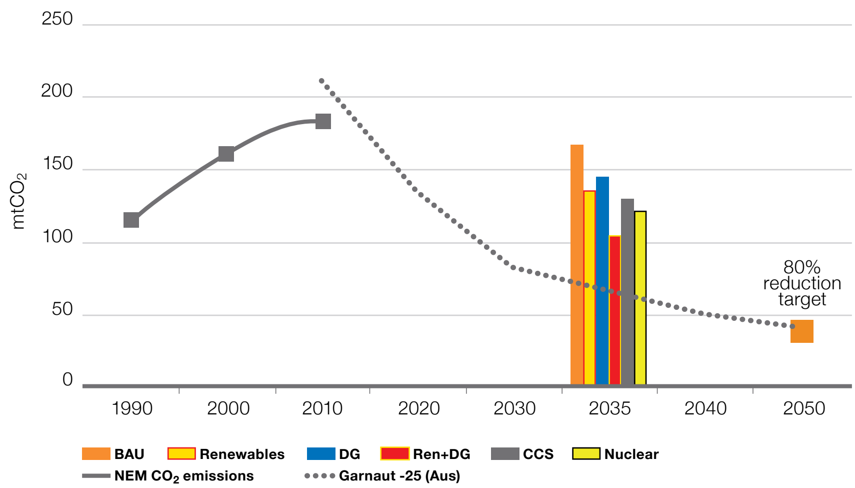
The *Consumer action* (DG) scenario offers a more affordable abatement cost with a lower capital investment requirement than both the *CCS* and *Nuclear power* scenarios.

Figure 4 Fuel cost comparison



Note: The *Consumer action* scenario is represented as DG

Figure 5 Scenarios' proximity to 80% reduction

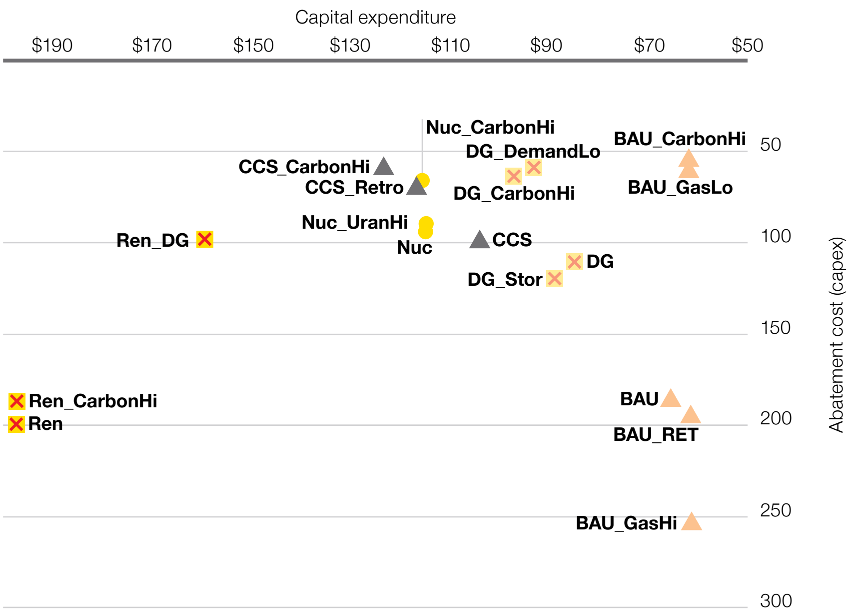


Note: The *Consumer action* scenario is represented as DG

Table 31 Comparing capital spend with abatement achieved

Scenario	Investment cost $ bn	Annual Abatement $mtCO_2e$	Abatement cost $\$/tCO_2e$
Business-as-Usual	$61	16	$194
With RET	$65	17	$187
With low gas price	$61	51	$60
With high gas price	$61	12	$253
With high carbon price	$62	53	$58
Large-scale renewable	$198	50	$198
With high carbon price	$197	53	$188
Consumer action	$85	39	$110
With storage	$89	37	$119
With low demand	$97	77	$63
With high carbon price	$94	77	$61
Renewable + consumer action	$160	82	$98
CCS	$104	53	$97
Coal Retrofit	$117	85	$69
With high carbon price	$123	106	$58
Nuclear power	$115	63	$91
With high uranium costs	$115	62	$93
With high carbon price	$116	88	$66

Figure 6 Cost of abatement (capex)



Note: The *Consumer action* scenario is represented as DG

The *Large-scale renewable* scenario by this metric shows a high abatement cost. The combined *Renewable plus consumer action* scenario demonstrates a fairly high capital cost but a favourable abatement cost.

Figure 6 shows the comparison between the scenarios of the amount of abatement gained for capital outlay. The capital expenditure required by each scenario and sensitivity analysis is plotted with the abatement cost as calculated in Table 31.

The best options are in the upper right-hand corner. BAU with low gas price and BAU with high carbon price are best placed but the *Consumer action* scenario and all its sensitivities are also very well placed.

However, this metric fails to take into account the other influences on cost of generation like fuel cost and carbon price. Therefore, the table below is included, which considers the annual increased wholesale cost associated with reduced annual emissions from 2010 emissions intensity.

The second metric compares the amount of abatement gained from the emissions intensity in 2010 with the increased cost of generation as a result of increased wholesale prices.

Table 32 shows the increase in generation cost from 2010 generation cost for each scenario and sensitivity analysis, abatement compared to 2010 emissions intensity, and the abatement cost as the product of increased generation cost and abatement. What is noticeable is that generation costs do not vary greatly between the base scenarios. This provides a very different picture of the abatement cost of each scenario.

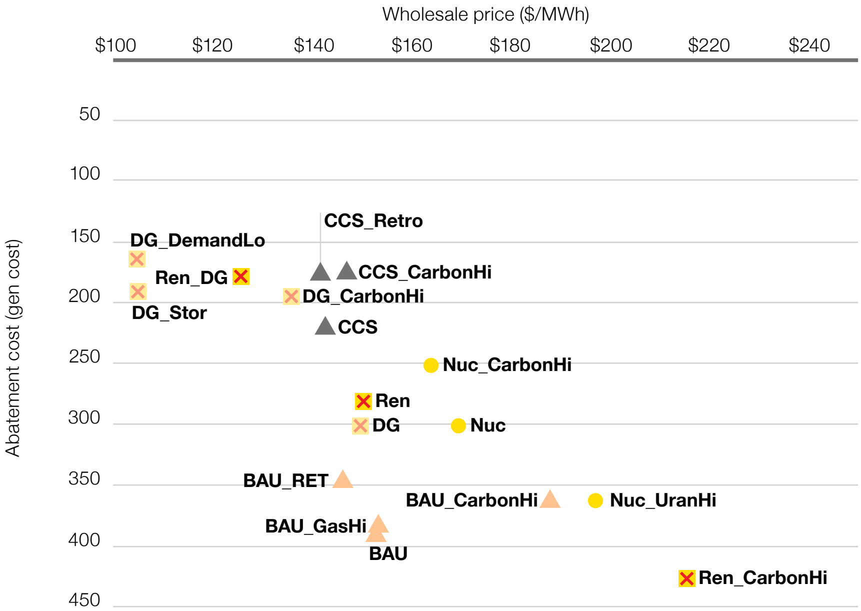
Using this metric, the *Business-as-Usual* scenario once again does not show evidence of providing the cheapest route to emissions reductions unless it is coupled with very low gas prices. *CCS Retrofit* and *Renewable plus consumer action* offer the lowest abatement cost scenarios.

Figure 7 shows the comparison between the scenarios of the amount of abatement gained for increased generation cost. The increased generation cost over 2010 generation cost required by each scenario and sensitivity analysis is plotted with the abatement cost as calculated in Table 32. The best options would be in the upper left-hand corner. *Renewable plus consumer action* is best placed to offer the cheapest abatement.

Table 32 Comparing increased generation cost with abatement achieved

Scenario	Increased generation cost \$ bn	Abatement from 2010 emissions intensity $mtCO_2e$	Abatement cost $\$/tCO_2e$
Business-as-Usual	\$42	108	\$383
With RET	\$38	111	\$346
With low gas price	\$19	142	\$133
With high gas price	\$40	105	\$387
With high carbon price	\$52	143	\$363
Large-scale renewable	\$43	153	\$283
With high carbon price	\$67	156	\$428
Consumer action	\$42	140	\$301
With storage	\$25	132	\$190
With low demand	\$21	127	\$165
With high carbon price	\$33	170	\$196
Renewable + consumer action	\$32	176	\$179
CCS	\$37	169	\$220
Coal Retrofit	\$37	208	\$176
With high carbon price	\$41	233	\$176
Nuclear power	\$48	160	\$301
With high uranium costs	\$57	159	\$363
With high carbon price	\$46	183	\$252

Figure 7 Cost of abatement (generation cost)



Note: The *Consumer action* scenario is represented as DG

3.3. Infrastructure renewal

The scenarios offer very different investment profiles. The *Business-as-Usual* scenario offers the lowest capital investment followed by the *Consumer action* scenario. The *Large-scale renewable* scenario requires the highest level of capital investment.

It should be noted that the *Large-scale renewable* scenario high capital costs negate the requirement for fuel costs over the life of the plant.

3.4. Public support for renewables

The Changing Technological Landscape scenarios offer the best opportunity to meet public support for renewables.

Figure 8 Capital investment comparison

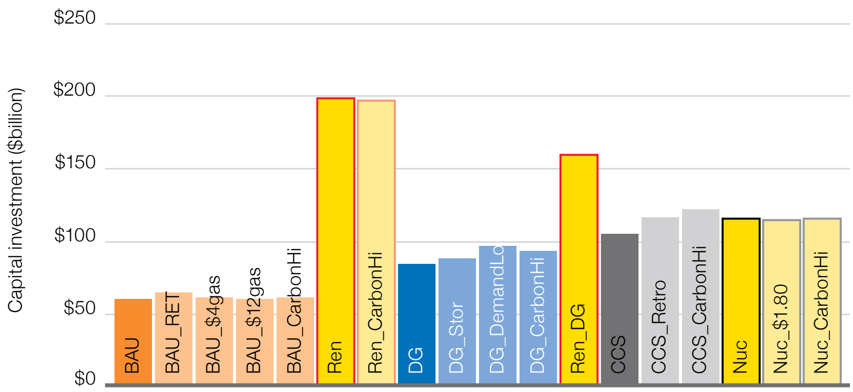
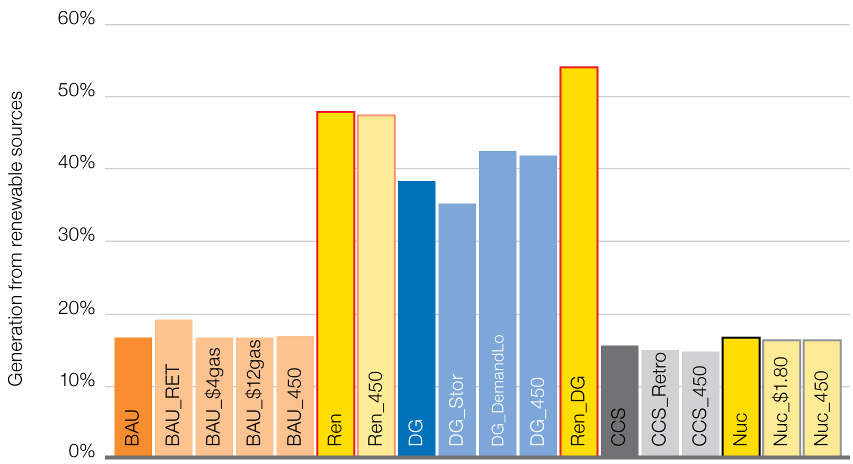


Figure 9 Generation from renewable sources

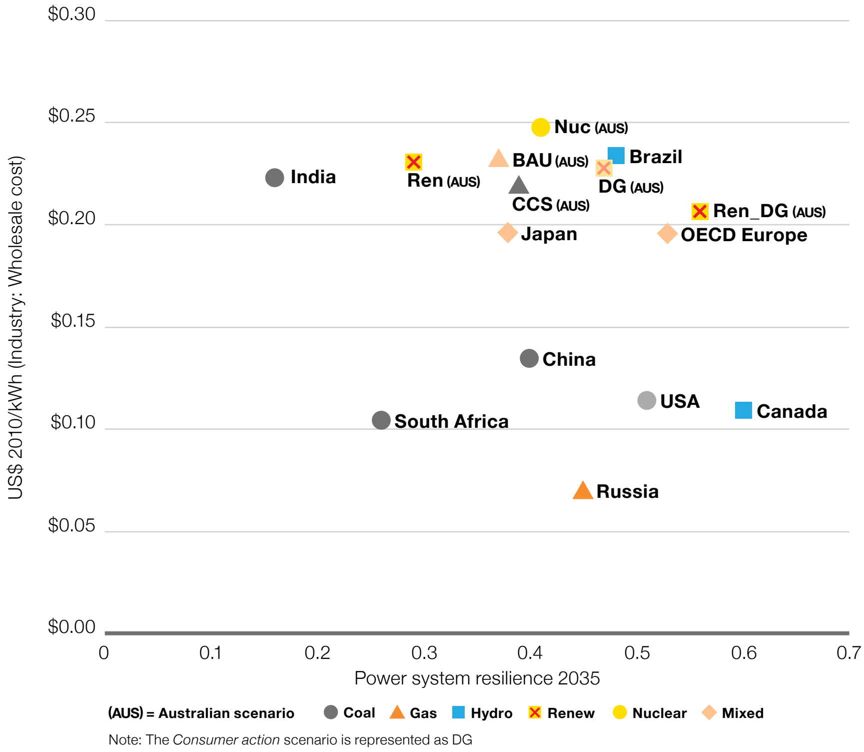


3.5. Australia's global position in 2035 under each of the scenarios

Figure 10 provides an indication of the NEM's resilience in comparison to the IEA's projection for our competitors.

All the scenarios improve on the NEM's current resilience although the *Large-scale renewable* scenario provides only a marginal improvement. Whilst the *Large-scale renewable* scenario's lack of resilience is surprising, it is solely as a result of a lack of spare capacity, which is a shortcoming of predominantly renewable systems that could be alleviated with the deployment of storage systems.

Figure 10 Power system resilience in 2035



3.6. Optimal mix of generation technologies to maximize resilience

Figure 11 shows that each scenario has particular strengths and weaknesses, with none providing an immediate solution that cuts through complexities. China's projected resilience is used as the benchmark.

In all cases, except *Nuclear power*, the *Consumer action* and the *Renewable plus consumer action* scenarios, NEM resilience remains lower than China's resilience. All scenarios indicate that Australian electricity will be more expensive than the average industrial price in China by more than 30 percent.

Figure 11 Comparative resilience of each Australian scenario

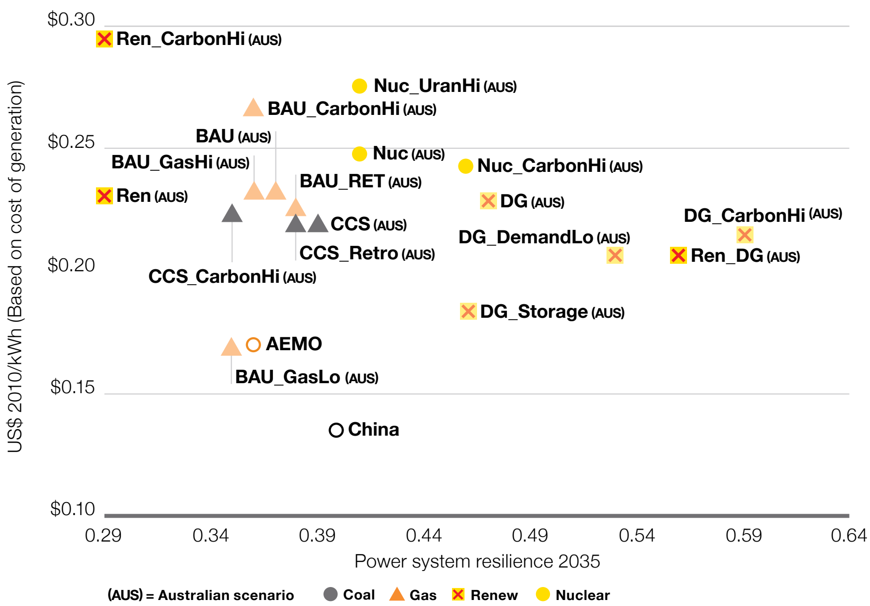
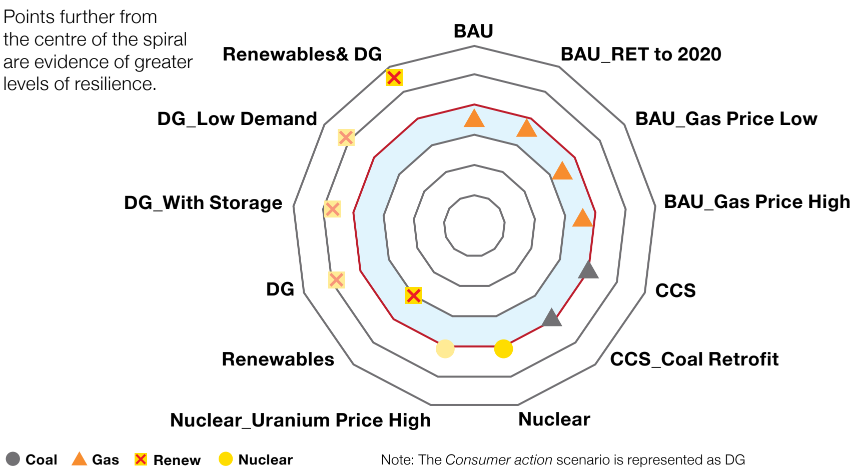


Figure 12 Resilience comparison



The sensitivity analyses that include high carbon prices tend to indicate that the wholesale cost of electricity increases with little increase in resilience except in the *Consumer action* scenario where high carbon prices shift generation to renewable fuels. This would tend to suggest that policies similar to those being discussed in Great Britain at present, where diversity of generation is encouraged through separate incentives, could bring the benefits of diversity at much lower costs than by applying a very high carbon price.

Figure 12 provides a simple comparison of resilience under each of the scenarios and sensitivity analyses, excluding the high carbon price analyses. Once again, China is the benchmark. The shaded area indicates the range of expected resilience that is between current levels of Australia's resilience and China's expected level of resilience.

Points further from the centre of the spiral are evidence of greater levels of resilience. The scenarios that involve risk in terms of technological maturation and investment cost, Nuclear Power and CCS show good improvement in resilience.

The DG and Renewable Plus DG scenarios show excellent improvement in resilience with the *Business-as-Usual* scenarios showing improved resilience without reaching the benchmark resilience level expected for China.

3.7. Strategies for reducing risk

3.7.1. Efficiency and investment in renewables have paved the way for spare capacity

There is currently considerable spare capacity in the NEM. It is expected that no further large generation investment will be required before 2020. This spare capacity has come about as a result of efficiency measures and investment in wind energy and PV panels. Having spare capacity is good for wholesale prices, resilience and gives Australia the luxury of having time to make considered decisions about the future.

3.7.2. Benefits of hedging

Current responses to the forces facing the industry appear quite divergent. The Australian Energy Market Commission (AEMC) has released a report entitled the "Power of Choice – giving consumers options in the way they use electricity", which seeks to encourage consumer action to manage consumption. Regulatory bodies are contemplating tariffs that could act as disincentives to DG. Distribution companies are considering limiting the roll-out of DG, citing grid stability as their motivation. Many industry stakeholders are attempting to influence the regulatory requirement for renewable energy to reduce their costs. There is little evidence of any industry strategy to meet the requirements of a competitive power system many decades into the future.

As a result of the analysis conducted, it is suggested that the following initial steps are needed to ensure that all options remain open to lay the foundation for a transition to a diversified, nimble electricity industry.

- Where the technology is not yet technically available, it is reasonable to wait until the technology is proven. However, in the case of CCS, in order to keep open the option of sequestering and storing carbon, Australia should invest in exploration and appraisal of CO_2 storage resources.
- Nuclear power remains an option for Australia but it does not lend itself to small deployments. It may have implications for competition in the NEM and will require substantial community engagement to resolve issues of location of reactors, storage and regulation. Notwithstanding these barriers, it is logical to invest in nuclear skills and expertise such that the option of nuclear power remains available.
- Concentrated solar thermal (CST) power is available but expensive in terms of capital outlay. It does however remove reliance on non-renewable fuel sources and future uncertain energy prices. In light of its enviable solar resource, Australia should keep open the option of significant energy from solar by investing in utility-scale CST deployments immediately to gain knowledge and experience in technical and market operations.
- Geothermal offers significant potential for base-load renewable generation. Australia should begin the regulatory approval process for transmission infrastructure to remote locations where geothermal and CST power stations would be located.
- Facilitating the roll-out of distributed generation offers the most pragmatic approach to preparing for an unknown future. Instead of large, centralised decisions, many small decisions could provide a significant proportion of Australia's future energy supply. In order to reduce large investments in the power infrastructure, it is imperative to commission an in-depth study into the effect of distributed generation (DG) on the distribution network and facilitate the roll-out of storage options for grid stability.

4. Conclusion

This study seeks to address the options facing the Australian power industry by representing different scenarios of how the industry might change by 2035.

With a carbon price, even a high carbon price, the market does not deliver an Australian power system that will be able to meet an 80% emissions reduction in line with the country's overall 2050 emissions target. (Although the current Government emissions projections don't seek an 80% emissions reduction from the energy sector, instead rely on other measures including the purchase of offshore emissions reductions to meet targets).

The results of this study reveal that shifting generation away from coal increases generation cost, but there is no evidence of a cost premium for shifting between gas, CCS and large-scale renewable generation. *Consumer action*, or distributed generation (DG), shows potential for decreased wholesale costs, reasonable abatement and substantial improvements in resilience.

In addition, this study finds that the Changing Technological Landscape scenarios address more of the forces driving the power system than the BAU and Non-Renewable Centralised Power scenarios.

For these reasons, there is a strong rationale for pursuing Distributed Generation and Large-scale Renewable generation while waiting for technological advances in CCS and Nuclear.

Despite the benefits associated with the Changing Technological Landscape scenarios there are risks associated with the distribution network, which will have to be robust enough to be able to respond to intermittency and stability challenges. It is also concluded that an in-depth study into the effect of distributed generation on the distribution network is imperative and overdue.

Questions to be answered in Part 3

Armed with the results of this scenario analysis, the Global Change Institute will deliver a third paper in the series in 2013. The questions to be answered in this paper are:

- Which policies will be most effective in facilitating the transformation to improved resilience and competitiveness?
- What will energy and capital intensive industries be expecting from power economies in the next two decades?
- How might Australia fund substantial investment to shift to a resilient power economy?

This will enable GCI to present practical solutions for the Australian electricity sector to address the challenges of a changing global environment.

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Appendix 1: Technology Assumptions

Technology	Fuel Type	Economic life (years)	Auxiliary load (%)	Thermal efficiency 2035	FOM ($/MW/ year)	VOM ($/MWh sent-out)	Capital Costs 2035 $/kW	Percentage of emissions captured (%)
Supercritical PC – Brown coal	Brown coal	40	10.3%	37%	41,000	5.10	4,200	
Supercritical PC – Brown coal with CCS	Brown coal	40	23.9%	29%	67,000	16.40	7,144	90%
Brown coal: CCS retrofit	Brown coal		23.9%	29%	37,200	8.40	3,945	90%
Supercritical PC – Black coal	Black coal	40	9.8%	47%	33,000	4.60	3,100	
Supercritical PC – Black coal with CCS	Black coal	40	23.3%	37%	55,000	15.70	4,900	90%
Black coal: CCS retrofit	Black coal		23.3%	37%	31,000	7.00	2,244	90%
CCGT – Without CCS	Natural Gas	30	2.9%	57%	14,000	2.00	1,100	
CCGT – With CCS	Natural Gas	30	15.4%	46%	25,000	4.24	2,500	90%
OCGT – Without CCS[1]	Natural Gas	30	1.0%	41%	9,000	2.50	1,100	
Solar Thermal – Central Receiver w 6hrs Storage	Solar	30	10.0%	100%	78,000	0.00	6,200	
Wind	Wind	30	0.0%	100%	39,000	0.00	2,558	
Geothermal – Enhanced Geothermal System (EGS)	Geothermal	30	15.0%	100%	187,500	0.00	6,200	
Biomass	Biomass	30	0.0%	38%	40,000	3.50	4,500	
Nuclear	Uranium	50	8.0%	37%	88,750	7.50	5,500	

Sources: (EIA 2010; AEMO 2011; EPRI 2011)

1. It is assumed that OCGT technology will be deployed with the potential for upgrade to CCGT. For this reason we have used a high Capital Cost for OCGT.

Appendix 2: Distributed Generation Plant Costs

Technology name	Indicative size	Capital cost 2030 ($/kW)	O&M cost ($/MWh)	Fuel transport cost ($/GJ)	Aux. power usage (%)	Capacity factor (%)	Thermal efficiency HHV (GJ/MWh) sent-out	Power to heat ratio
Gas combined cycle w. CHP	30 MW	1543	35	1.35	5	65	7.45	0.8
Gas microturbine w. CHP	60 kW	2965	10	5.85	1	18	12.15	2.8
Gas reciprocating engine (Large)	5 MW	918	5	1.35	0.5	1	8.57	na
Gas reciprocating engine (Medium)	500 kW	918	2.5	5.85	0.5	3	9	na
Gas reciprocating engine (Small)	5 kW	918	2	11.2	0.5	1	9.4	na
Gas reciprocating engine w. CHP	1 MW	1577	7.5	1.35	1	65	8.57	1.1
Gas reciprocating engine w. CHP (Small)	500 kW	1774	5	5.85	1	18	9	1.1
Biomass steam w. CHP	30 MW	2527	30	24.6	6.5	65	12.15	1
Solar PV	varies	1247	0.5	na	na	na	na	na
Diesel engine	500 kW	460	5	1.55	0.5	3	8	na
Wind turbine (Large)	10 kW	1685	0.5	na	na	na	na	na
Wind turbine (Small)	1 kW	1402	0.5	na	na	na	na	na
Biogas/landfill gas reciprocating engine	500 kW	2068	0.5	0.5	0.5	80	9	na
Gas fuel cell w. CHP	2 kW	1369	70	11.2	na	80	5.2	0.36
Gas microturbine w. CCHP	60 kW	3389	15	5.85	1.5	43	12.15	2.8
Gas reciprocating engine w. CCHP (Large)	5 MW	3942	15	1.35	1.5	80	8.57	1.1
Gas reciprocating engine w. CCHP (Small)	500 kW	2218	10	5.85	1.5	43	9	1.1

Source: (Lilley, Reedman et al. 2012)

Appendix 3: Modelling Platform – Plexos for Power Systems

Electricity markets behave like other markets, with generators offering production and loads bidding for supply. However, the market must be cleared and balanced every trading period to ensure that supply meets demand because the physical delivery of electricity is subject to technical and economic constraints including minimum stable generation, ramp rate constraints, start costs and fuel costs.

Plexos provides an electricity market simulation platform. Customised versions of the platform are used extensively by market operators and generators to forecast and analyse market operations and performance. It uses deterministic linear programming techniques, demand projections, transmission and generating plant data to optimise the power system over a variety of time scales and determine the least cost dispatch of generating resources to meet a given demand. Modelers refer to this as optimising the Unit Commitment and Dispatch problem, which considers whether to turn a unit on or off and at what level to run the unit.

The core function of Plexos is the Optimal Power Flow (OPF) which uses linear approximations of the power system, mixed integer programming to solve generator technical constraints and cost recovery algorithms to model optimal generator dispatch, transmission line flows, congestion and nodal pricing.

On the capacity side, modelling the Optimal Power Flow (OPF) requires data from:

- current fleet installations
- the Long-Term Plan (LT Plan) to establish the optimal combination of new entrant generation and transmission, economic retirements and upgrades by minimising the Net Present Value of the total system over the long-term plan
- the Projected Assessment of System Adequacy (PASA) to schedule maintenance and random forced outages across regions

On the energy deployment side, modelling the OPF requires data from:

- current and future (derived from projections in demand) Load Duration Curves
- the Medium Term (MT) Schedule which calculates system adequacy, peak and off-peak load, volatility and coincident peak constraints, from fuel contracts, energy limits, storage management and emission abatement pathways based on the Load Duration Curves (LDC)
- the Short-Term (ST) Schedule which uses the optimum solution from MT and mixed integer programming to calculate daily market clearing dispatch and bids by generator to meet demand and optimise the market participant portfolio

The Optimal Power Flow models optimal generator dispatch, transmission line flows, congestion and modal pricing by performing:

- multiple iterations of the Long-Run Marginal Cost (LRMC) recovery algorithm, to simulate generator bidding strategy to recover fixed and variable costs over each year
- the Short-Run Marginal Cost (SRMC) recovery algorithm, to provide the lower bound, equilibrium price in a pure competitive market
- the Dispatch Algorithm, which calculates bids for 48 half-hourly daily trading periods from LRMC, to dispatch energy from the least to the highest cost generators until sufficient generation is dispatched to meet demand within each region. The marginal generating unit determines the marginal price for all six 5-minute intervals in that half-hourly trading period, aggregating them to determine the regional spot price and inter-regional losses for the trading period

<table>
<tr><th colspan="3">Plexos for Power Systems</th></tr>
<tr><th>Capacity data (Supply)</th><th>Optimal Power Flow algorithms</th><th>Energy deployed (Demand)</th></tr>
<tr><td rowspan="2">Installed base</td><td rowspan="3">LRMC (and SRMC)
(Generator bidding strategy)</td><td rowspan="2">Load Duration Curves
(Current and projected)</td></tr>
<tr></tr>
<tr><td rowspan="2">LT Plan
(Expansion)</td><td rowspan="2">MT Plan
(Constraint resolution)</td></tr>
<tr><td rowspan="3">Dispatch
(Energy dispatch and spot price)</td></tr>
<tr><td rowspan="2">PASA
(Maintenance)</td><td rowspan="2">ST Plan
(Unit commitment & market clearing)</td></tr>
<tr></tr>
</table>

Plexos is particularly well suited to modelling Distributed Generation in the form of small CCGT with CHP or cogen, gas micro turbines, biomass/landfill gas, solar PV, small wind turbines and battery storage and its effect on market prices and behaviour. Modelling for wind and solar is done in conjunction with climate forecasts from BoM to produce half-hourly energy forecasts for each year, which are then subtracted from forecasted.

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About the Global Change Institute

The Global Change Institute at The University of Queensland, Australia, is an independent source of game-changing research, ideas and advice for addressing the challenges of global change. The Global Change Institute advances discovery, creates solutions and advocates responses that meet the challenges presented by climate change, technological innovation and population change.

This technical report is published by the Global Change Institute at The University of Queensland. A summary paper is also available. For copies of either publication visit www.gci.uq.edu.au

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