What this assessment is about

This infrastructure capability assessment is one of a series of supporting documents that Infrastructure Victoria (IV) has used to assist them in developing their paper - *Laying the Foundations, Setting objectives and identifying needs for Victoria’s 30-year infrastructure strategy.*

This assessment sets out to:

• Identify the major assets in the sector and provide the wider context in which assets operate, including the interconnections between assets, identification of key stakeholders and current industry trends in the sector

• Provide a base of quantitative data as a foundation from which IV can start developing the strategy in relation to asset value, historical and forecast investment, infrastructure performance and current/future capacity in each sector

• Identify the future challenges and opportunities associated with the sector, specifically related to how existing infrastructure can be used to accommodate future demand.

This assessment represents an initial view on infrastructure in the sector and has been prepared based on publicly available information and in consultation with the stakeholders with whom we have engaged to date. Data collection has been based on consolidation of existing and available information as opposed to undertaking new primary research.

This assessment is intended to set the scene for broader discussion and is complemented by a range of other technical documents available at [www.infrastructurevictoria.com.au](http://www.infrastructurevictoria.com.au). It is IV’s intention that this work serves as one of the platforms for further engagement and refinement of Victoria’s infrastructure needs as IV progresses its 30 year infrastructure strategy development further.

What this assessment is not about

This assessment did not seek to and does not identify solutions. It does not propose options for meeting Victoria’s infrastructure needs or make recommendations to Infrastructure Victoria.

In preparing the assessment we acknowledge and understand that there is likely to be additional information available that could help influence future thinking. The findings and analysis through this assessment are an initial starting point and may be subject to change as alternate views and information is identified.
**Key Findings**

1. Victoria’s energy sector is almost entirely under private ownership.
2. At a high level, energy infrastructure in Victoria is considered to be in reasonable condition and has been performing within acceptable limits.
3. Energy infrastructure is critical for Victoria. Networks and generation are planned within the National Electricity Market to provide resilience.
4. Under a medium growth forecast, it is anticipated electricity reserves will not meet the Australian Energy Market Operator (AEMO) reliability standard by 2024-25.
5. There is no significant impact on the energy demand forecast that can be attributed or being influenced by other sectors.

<table>
<thead>
<tr>
<th>Infrastructure use</th>
<th>Infrastructure service performance</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Under a medium energy growth forecast, there is sufficient capacity for the next 8 years, it is anticipated electricity reserves will not meet the AEMO reliability standard by 2024-25. AEMO will issue annual Statements of Opportunity that will indicate the shortfall in supply and where in the network it is preferred. The market will then respond with projects accordingly.</td>
<td>• The sector overall has been performing within acceptable limits.</td>
</tr>
<tr>
<td>• The Victorian gas supply to NSW is expected to continue to increase via the Victorian Northern Interconnect Expansion (VNIE) and Eastern Gas Pipeline (EGP). This will increase the use of the South West Pipeline (SWP) and Iona Gas Storage Plant. This does not pose a risk to Victoria’s gas supply.</td>
<td>• ICT forms an essential component of the efficient operation of the National Electricity Market (NEM). The ICT infrastructure is largely owned by utility providers and supported by independent communication system infrastructure. This ensures a reliable and efficient service.</td>
</tr>
<tr>
<td>• Many liquid fuel pipeline assets are soon to reach the end of their design life and commercial decisions will be made by owners and operators whether to enter into an upgrade or replacement program to extend the service life and licensed life.</td>
<td>• ICT to support Smart meters will play a key role in facilitating the move to a more automated grid (Smart Grid). As smart meters become more integrated into automating homes the demand on interaction with the “Internet of Things” will increase.</td>
</tr>
<tr>
<td>• The growth of small scale renewable energy storage (Batteries, Tesla wall, electric vehicles) will significantly impact the future design of the distribution grid (Smart Grid).</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Operational criticality &amp; resilience</th>
<th>Assets, expenditure &amp; governance</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Energy infrastructure is critical for Victoria and it’s economy with networks and generation planned within the NEM to achieve overall levels of resilience.</td>
<td>• The energy sector is largely under private ownership.</td>
</tr>
<tr>
<td>• Typically networks are planned and operated to achieve full redundancy for loss of single elements, accounting for failure across the network.</td>
<td>• Growth investment in renewables, energy storage, electricity distribution connections is key to lowering carbon emissions.</td>
</tr>
<tr>
<td>• Available funding for end-of-life and remediation works at the existing Latrobe Valley power stations is currently unclear, presenting a cost pressure.</td>
<td>• Thermal generation, electricity transmission network, gas networks and major liquid fuel pipelines investment is predominantly in asset renewal and replacement phase creating an opportunity to invest in lower carbon emitting technologies.</td>
</tr>
<tr>
<td></td>
<td>• Operating in the National Electricity Market, AEMO provides planning and operation input at the overall market level.</td>
</tr>
<tr>
<td></td>
<td>• Operating and maintenance expenditure is generally considered reasonable compared to inter-jurisdictional benchmarking results. At a high level, energy infrastructure in Victoria is considered to be in reasonable condition. This is driven by solid condition ratings for renewable generators and the electricity and gas networks. Liquid fuels pipelines score below average due to known capacity constraints and increased reliance on overseas supply.</td>
</tr>
<tr>
<td></td>
<td>• Maintenance in the energy sector is generally aligned with service performance outcomes and condition based asset management practices.</td>
</tr>
</tbody>
</table>
# Future challenges and opportunities

The key challenge for Victoria's energy sector is migrating from an abundant, low cost, easily accessible, brown coal fuel source for electricity energy generation to low carbon, environment encompassing, renewable energy sources. An integral challenge is to encourage the innovation required to develop a dynamic grid which facilitates, both technically and commercially, emancipated consumers as energy producers.

<table>
<thead>
<tr>
<th>Sector</th>
<th>Challenges</th>
<th>Opportunities</th>
</tr>
</thead>
</table>
| **Thermal Generation** | • Ageing power generation assets: the average age of Victorian coal fired power stations is more than 34 years. As plants approach their end-of-life, either significant expenditure is required to refurbish ageing plant or replacement plant must be built. Reserved funding for site remediation is unclear.  
• High carbon dioxide emissions from brown coal presents environmental challenges. | • Victoria has one of the world’s largest reserves of brown coal. These resources combined with carbon capture and storage (CCS) offer an opportunity for the State to identify and pursue a course of action that could provide an alternative competitive advantage in a low carbon economy. The realisation of this opportunity is contingent on the commercialisation of CCS, bringing with it substantial technical challenges.  
• Existing strong grid connections from the Latrobe Valley to Victoria’s major loads would make the development of new generation in this area easier and less costly as it can utilise the existing grid.  
• Augmenting existing gas generators (open cycle configurations) to achieve greater efficiency (combined cycle configurations) could assist in replacing brown coal generation. |
| **Liquid Fuels** | • The jet fuel supply to Melbourne Airport is currently constrained.  
• Australia’s stockholding for liquid fuels is currently less than the International Energy Agency (IEA) requirements (of which Australia is a member).  
• Commercial justification of additional liquid fuel import facilities. | • Expansion of liquid fuel import facilities to Victoria. |
| **Electricity Transmission** | • Opportunities for augmentation of grid interconnections with neighbouring states to facilitate growth in large-scale renewable from other states.  
• Grid connection restricts future or proposed development of large-scale renewables in the western part of Victoria. | • Using smart grids to develop ‘self-healing’ networks. |
| **Electricity Distribution Renewables** | • Increased penetration of embedded generation and demand management affects distribution networks. The key to addressing this challenge will be the uptake of smart meters, smart grids and local energy storage. | • Enabling and utilising the full capabilities of advanced metering infrastructure (smart meters) and extension to gas and water utilities.  
• Continued focus on the implementation of the power-line bushfire safety program resulting from the Victorian Bushfire Royal Commission.  
• Facilitate development and uptake of electrical energy storage technologies. |
| **Gas supply and transmission** | • Ensuring liquefied natural gas (LNG) export opportunities do not threaten domestic supply. At present Victoria is exporting gas for conversion to LNG for international export via Queensland. | • Facilitate development and uptake of further gas storage. |
1.1 Introduction

Energy infrastructure is critical for Victoria and its economy, providing essential services to residential, commercial and industrial customers. The majority of Victoria’s energy sector is under private ownership and, at a high level, energy infrastructure in Victoria is considered to be in a reasonable condition and has been performing within acceptable limits.

Victorian energy infrastructure incorporates a number of interconnected networks and energy sources which are planned, connected and operated within the National Electricity Market. The approach to planning and managing the network provides resilience across Victoria, accommodating planned and unplanned shutdowns in the network.

The purpose of this report is to identify pressures on Victoria’s energy infrastructure and assess its capacity to meet forecast future demands.

1.2 Sector overview

The energy sector in Victoria is considered through analysis of the following sub-sectors:

- **Electricity**
  - **Generation**
    - Thermal: Coal fired generators, gas fired plants
    - Renewables: Windfarms, hydroelectric, solar, biomass, waste to energy
  - **Electricity transmission**
    - High voltage transmission lines and terminal stations including interconnectors to neighbouring states
  - **Electricity distribution**
    - Networks include sub-transmission lines, zone substations, distribution lines and cables to supply electricity to homes and businesses.

- **Gas**
  - **Gas supply and transmission**
    - Offshore pipelines for gas and condensates (combination of gas and liquid supply lines), onshore gas transmission pipelines and medium pressure gas transmission pipelines and liquefied and underground gas storage
  - **Gas distribution**
    - Local distribution low pressure lines.

- **Liquid Fuels**
  - Limited to critical petroleum liquid pipelines such as jet fuel supply lines and diesel feed lines.

1.3 Scope

Where appropriate, each energy sub-sector is separated where appropriate in order to structure the Infrastructure Capability Assessment discussion. Analysis of the energy sector includes the current assets, expenditure and governance, infrastructure condition, service performance, operational criticality and infrastructure use.

An overview of Victoria’s overall energy sector is formed by aggregating data from the various sub-sectors. Key challenges and opportunities have been identified for the sector.

Note: Australian Energy Regulator’s *State of the Energy Market Report 2014* was referenced for this report. The 2015 report has only been released today and has not been reviewed.
Assets, expenditure and governance
## 1. Current major infrastructure assets

### Background

- Both the Victorian electricity and gas industries are privately owned. The electricity network is part of the National Electricity Market grid and is economically regulated. Electricity generators operate in the National Electricity Market trading environment.
- The State Electricity Commission of Victoria (SECV) was disaggregated in 1994, with retail businesses, five distribution businesses and a transmission business sold to the private sector over the next few years.
- Victoria’s Gas and Fuel Corporation was disaggregated in 1997. The distribution, retail and transmission arms were sold to the private sector in 1999.
- The Victorian Government Department of Economic Development, Jobs, Transport and Resources (DEDJTR) provides energy policy advice to the Victorian Minister for Energy and Resources, including in support of national energy policy development through the COAG Energy Council.
- The Australian Energy Regulator (AER) is responsible for the economic regulatory functions, enforcement and market monitoring for electricity and gas networks.
- The Australian Energy Market Operator (AEMO) is responsible for operating the National Electricity Market, electricity transmission network planning in Victoria and operating the Victorian Gas Transmission System including conducting planning reviews and scheduling the Wholesale Gas Market.
- The Essential Services Commission is the independent regulator of the retail energy industry in Victoria.
- Energy Safe Victoria is responsible the regulation of electricity and gas safety in Victoria.

### Assets expenditure and governance

<table>
<thead>
<tr>
<th>Type</th>
<th>Description</th>
</tr>
</thead>
</table>
| Thermal generation | Four main coal based generators, concentrated in the Latrobe valley  
Eight main gas based generators |
| Renewables | 12 renewable generators centrally dispatched by the Australian Energy Market Operator  
Predominantly wind and hydroelectricity |
| Gas supply and transmission | High pressure and medium pressure pipelines  
Interconnectors to NSW, SA and Tasmania  
Liquid gas storage |
| Gas distribution | Four gas distribution network service providers  
Geographically segregated |
| Electricity transmission | One predominant transmission network service provider  
Interconnectors to NSW, South Australia and Tasmania |
| Electricity distribution | Five electricity distribution network service providers  
Geographically segregated |
| Liquid Fuels | Strategically important pipelines include Westernport, Altona, Geelong (WAG) oil pipeline and the Joint User Hydrant Installation (JUHI) providing jet fuel to Melbourne Airport |

**Victoria’s energy sector is almost entirely under private ownership**
1. Current major infrastructure assets

Victoria’s electricity generation mix

Victoria’s base load power is largely sourced from brown coal sources, with power plants concentrated in close proximity to coal deposits in the Latrobe Valley region.

Gas fired plants are commonly used as peaking plant to provide energy during short periods of high demand. These plants are located closer to gas transmission pipelines.

Victoria has 12 renewable generators that are classified as scheduled or semi-scheduled (those which are centrally dispatched by AEMO. The predominant renewable sources are hydroelectricity plant in the Snowy Mountains region and wind turbines located in the western region of the state.

Registered electricity generation capacity by fuel source in Victoria

1. Current major infrastructure assets

Background

Electricity market reform commenced in 1993 when the Victorian Government embarked on a program to disaggregate and corporatise the SECV (the state owned electricity utility). Once this was completed the corporatised components (including power generation assets) were sold to private entities. The gross proceeds from the sales were $23 billion. Since the initial sale of assets, most have subsequently changed hands at least once. Generation assets were overvalued at the time of the original sales based on flawed projections of future electricity prices.

Thermal generation

Coal fired plants

Victoria is rich with significant reserves of brown coal. As the coal is located close to the surface, the mining process is relatively inexpensive. The low fuel cost meant that from the 1950s onwards this resource was exploited for inexpensive base load electricity. Most of the coal based power generation infrastructure was constructed between the 1960s and 1980s by SECV.

The main coal base power generation assets are listed in the table to the right. The table includes the capacity and number of units as well as the commissioning year(s), operator and ownership details.

This table shows that the newest units are at Loy Yang B and were commissioned in 1993 and 1996. The oldest station, Hazelwood, has units more than 45 years old.

The four main coal-based electricity generating assets are owned by three different organisations:

- AGL Energy (Loy Yang A)
- GDF Suez / Mitsui (Hazelwood and Loy Yang B)
- Energy Australia (Yallourn).

These organisations are profiled to the right.

<table>
<thead>
<tr>
<th>Plant name</th>
<th>Ownership</th>
<th>No. Units</th>
<th>Capacity per unit (MW)</th>
<th>Total capacity (MW)</th>
<th>Plant age (years)</th>
<th>Value - estimated replacement cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loy Yang A</td>
<td>AGL</td>
<td>4</td>
<td>1 x 530 3 x 560</td>
<td>2,210</td>
<td>27 - 31</td>
<td>$4.8 billion (AGL paid $0.6 billion for LYA and adjacent mine in 2012)</td>
</tr>
<tr>
<td>Hazelwood</td>
<td>GDF Suez 72% Mitsui 28%</td>
<td>8</td>
<td>200</td>
<td>1,600</td>
<td>45 - 51</td>
<td>$4.8 billion (International Power paid $2.35 billion for the plant in 1996)</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>GDF Suez 70% Mitsui 30%</td>
<td>2</td>
<td>500</td>
<td>1,000</td>
<td>22 and 19</td>
<td>$2.5 billion (In 2004 the plant was valued at just over $2 billion)</td>
</tr>
<tr>
<td>Yallourn</td>
<td>Energy Australia</td>
<td>4</td>
<td>2 x 360 2 x 380</td>
<td>1,480</td>
<td>41 and 33</td>
<td>$4.0 billion (PowerGen(UK)-led consortium paid $2.43 billion in 1996)</td>
</tr>
</tbody>
</table>

AGL Energy

AGL is a publicly–listed Australian company that provides energy products and services to the Australian economy. The company is involved in both the generation and retailing of electricity for residential and commercial use. AGL Energy generates electricity using coal, natural gas, wind power, hydroelectricity and coal seam gas sources. The company began operating in Australia in 1837 as the Australian Gas Light Company.

GDF Suez

Engie (known as GDF Suez prior to April 2015) is a French multinational electric utility company, which operates in the fields of electricity generation and distribution, natural gas and renewable energy. It has more than 73 gigawatt (GW) of electricity generation worldwide. It has owned Hazelwood since 1996 and Loy Yang B since around 1997.

Mitsui

Mitsui & Co. (Australia) Ltd. is the wholly owned Australian subsidiary of Mitsui & Co., a Japanese trading company listed on the Tokyo Stock Exchange. It has been active in Australia since 1956 and has interests in coal mines, gas production and power generation.

Energy Australia

Energy Australia is a subsidiary of the Hong Kong-based and listed CLP Group. CLP has 22GW of electricity generation across Asia, India and Australia. Other generation assets owned by Energy Australia include 1,000 megawatt (MW) of gas fired generation in Victoria (discussed later in this report), gas fired plants in South Australia and NSW as well as the Mount Piper and Wallerawang coal fired plants in NSW.
1. Current major infrastructure assets

**Thermal generation**

**Gas fired plants**

As stated above, no new baseload plant has been commissioned since Loy Yang B in 1996. As a result, a number of gas fired plants have been built as peaking plant to provide energy during short periods of high demand. With the exception of Newport, all of the current gas fired plants use open cycle gas turbine (OCGT) technology.

A gas or combustion turbine is typically an axial flow rotary engine with a combustion chamber located between an upstream compressor and a downstream turbine. A traditional OCGT compresses air in a gas compressor, then adds energy to the compressed air by combusting liquid or gaseous fuel in the combustor. This produces power to drive the turbine rotor. OCGT is a mature technology, with development and efficiency improvements focusing mainly on operating at higher firing temperatures and high-pressure ratios.

**Ownership**

The plants listed in the table to the right have a number of different owners:

- AGL Energy (Somerton)
- Ecogen (owned by Industry Funds Management) (Jeeralang A&B, Newport)
- Alinta Energy (Bairnsdale)
- Origin Energy (Mortlake)
- Snowy Hydro (Laverton North, Valley Power).

Profiles of AGL Energy and Energy Australia were provided above in the discussion of the coal assets. Profiles for IFM, Alinta Energy, Origin Energy and Snowy Hydro to the right.

Energy Australia has hedge arrangements for the generation capacity of Newport and Jeeralang through the Ecogen Master Hedge Agreement until 2019 (refer www.energyaustralia.com.au).

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### Table: Current major infrastructure assets

<table>
<thead>
<tr>
<th>Plant Name</th>
<th>Ownership</th>
<th>No. Units</th>
<th>Capacity per Unit (MW)</th>
<th>Total Capacity (MW)</th>
<th>Year(s) Commissioned</th>
<th>Technology</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Somerton</td>
<td>AGL Energy</td>
<td>4</td>
<td>40</td>
<td>160</td>
<td>2003</td>
<td>‘E’ OCGT</td>
<td>$125 million¹</td>
</tr>
<tr>
<td>Jeeralang A</td>
<td>Ecogen (IFM)</td>
<td>4</td>
<td>51</td>
<td>204</td>
<td>1977 - 79</td>
<td>‘F’ OCGT</td>
<td>IFM bought 73% of 3 sites from BBP for $87 million in 2008². Total value therefore ~$120 million (2008)</td>
</tr>
<tr>
<td>Newport</td>
<td>Ecogen (IFM)</td>
<td>1</td>
<td>500</td>
<td>500</td>
<td>1981</td>
<td>Thermal (boiler-turbine)</td>
<td></td>
</tr>
<tr>
<td>Bairnsdale</td>
<td>Alinta Energy</td>
<td>2</td>
<td>47</td>
<td>94</td>
<td>1996</td>
<td>Aero-derivative OCGT</td>
<td>$810 million (2012) reported on opening⁴</td>
</tr>
<tr>
<td>Mortlake</td>
<td>Origin Energy</td>
<td>2</td>
<td>283</td>
<td>566</td>
<td>2012</td>
<td>‘F’ OCGT</td>
<td>$150 million⁵</td>
</tr>
<tr>
<td>Laverton North</td>
<td>Snowy Hydro</td>
<td>2</td>
<td>156</td>
<td>312</td>
<td>2006</td>
<td>‘E’ OCGT</td>
<td>In 2005 Snowy Hydro paid $243 million³</td>
</tr>
<tr>
<td>Valley Power</td>
<td>Snowy Hydro</td>
<td>6</td>
<td>50</td>
<td>300</td>
<td>2002 (reinstalled)</td>
<td>Aero-derivative OCGT</td>
<td></td>
</tr>
</tbody>
</table>

**Ecogen**

IFM Investors was established over 20 years ago and is owned by 30 major not-for-profit pension funds. It manages funds across four asset classes – infrastructure, debt investments, listed equity and private capital.

**Alinta Energy**

Alinta grew out of the Western Australia gas industry. It had interests in generation, gas transmission and electricity distribution. It was bought in 2007 by a consortium led by Singapore Power. Singapore Power took ownership of the gas and electricity network infrastructure. Babcock and Brown took ownership of Alinta’s generation infrastructure.

**Origin Energy**

Origin Energy (a publicly listed Australian company) was formed in February 2000, as a result of a demerger from the Australian company Boral Limited. Origin operates one of Australia’s largest power generation portfolios with 6,010 MW of capacity.

**Snowy Hydro**

Snowy Hydro was responsible for the construction of the Snowy Mountains Hydro-electric scheme. It is owned by the Commonwealth Government (15 per cent), the NSW Government (58 per cent) and Victorian Government (29 per cent). Plans for privatisation were dropped in 2006.
1. Current major infrastructure assets

Renewables

Victoria has 12 renewable generators that are classified as scheduled or semi-scheduled (those which are centrally dispatched by the Australian Energy Market Operator). There are also a number of non-scheduled generators, which are typically for local use and whose output rarely exceeds 30 MW (AEMO). However, there are also a few large, non-scheduled renewable generators. Information on all Victorian scheduled and semi-scheduled generators and non-scheduled generators over 50 MW is shown in the table below.

<table>
<thead>
<tr>
<th>Power station</th>
<th>Ownership</th>
<th>Operator</th>
<th>Nameplate capacity (MW)</th>
<th>Fuel Type</th>
<th>Estimated Cost ($m)</th>
<th>Dispatch</th>
</tr>
</thead>
<tbody>
<tr>
<td>Murray 1</td>
<td>Snowy Hydro Ltd (New South Wales Government (58%), Vic Government (29%), Commonwealth Government (13%))</td>
<td>Snowy Hydro Ltd</td>
<td>950</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Murray 2</td>
<td>As above</td>
<td>As above</td>
<td>552</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Macarthur</td>
<td>Malakoff Corp. Berhad, H.R.L. Morrison &amp; Co</td>
<td>AGL</td>
<td>420</td>
<td>Wind</td>
<td>924</td>
<td>SS</td>
</tr>
<tr>
<td>Bogong / Mackay</td>
<td>AGL</td>
<td>AGL</td>
<td>310</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Dartmouth</td>
<td>AGL</td>
<td>AGL</td>
<td>185</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Eildon</td>
<td>AGL</td>
<td>AGL</td>
<td>135</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Mt Mercer</td>
<td>Meridian Energy Australia</td>
<td></td>
<td>131.2</td>
<td>Wind</td>
<td>299</td>
<td>SS</td>
</tr>
<tr>
<td>Bald Hills p1</td>
<td>Mitsui and Co. Australia Ltd</td>
<td></td>
<td>106.6</td>
<td>Wind</td>
<td>255</td>
<td>SS</td>
</tr>
<tr>
<td>Golds Hill</td>
<td>AGL</td>
<td>AGL</td>
<td>67.2</td>
<td>Wind</td>
<td>172</td>
<td>SS</td>
</tr>
<tr>
<td>West Kieva</td>
<td>AGL</td>
<td>AGL</td>
<td>60</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Hume VIC</td>
<td>Trustpower</td>
<td>Trustpower</td>
<td>29</td>
<td>Hydro</td>
<td></td>
<td>S</td>
</tr>
<tr>
<td>Mildura Power Station</td>
<td>Solar Systems Pty Ltd</td>
<td></td>
<td>1.5</td>
<td>Solar</td>
<td></td>
<td>SS</td>
</tr>
<tr>
<td>Challicum Hills</td>
<td>Pacific Hydro</td>
<td>Pacific Hydro</td>
<td>52.5</td>
<td>Wind</td>
<td>138</td>
<td>NS</td>
</tr>
<tr>
<td>Portland Stage 2-3 Cape Bridgewater and Cape Nelson South</td>
<td>Pacific Hydro</td>
<td>Pacific Hydro</td>
<td>102</td>
<td>Wind</td>
<td>246</td>
<td>NS</td>
</tr>
<tr>
<td>Waura</td>
<td>Acciona</td>
<td>Acciona</td>
<td>192</td>
<td>Wind</td>
<td>422</td>
<td>NS</td>
</tr>
</tbody>
</table>

| Total |  | 3,341 |

Inter-jurisdictional comparison

The total nameplate capacity of installed renewable generators in Victoria is 3,341 MW. The table below compares Victoria to the other states in the National Electricity Market (for scheduled and semi-scheduled generators and non-scheduled generators over 50 MW)

<table>
<thead>
<tr>
<th>State</th>
<th>Number of renewable generators</th>
<th>Total nameplate capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Victoria</td>
<td>16</td>
<td>3,341</td>
</tr>
<tr>
<td>New South Wales</td>
<td>15</td>
<td>3,351</td>
</tr>
<tr>
<td>Queensland</td>
<td>5</td>
<td>771</td>
</tr>
<tr>
<td>South Australia</td>
<td>15</td>
<td>1,392</td>
</tr>
<tr>
<td>Tasmania</td>
<td>18</td>
<td>2,429</td>
</tr>
</tbody>
</table>

Source: AEMO

Victoria’s renewable generation capacity is very similar to NSW. It is significantly greater than the other States. It is important to note, however, that consistent with AEMO methodology Snowy Hydro (capacity of 1,502) is included in Victoria’s capacity figures.

Source: AEMO, Participant categories in the National Electricity Market.

1. Wind costs estimated based on benchmark capital cost, does not include network connection.
2. Dispatch arrangements: Scheduled (S), Semi-scheduled (SS), Non-scheduled (NS).
1. Current major infrastructure assets

**Electricity transmission**

The electricity transmission sector in Victoria transports electricity from power stations to major distribution points (terminal stations) via a high voltage network including large tower structures. Victoria’s transmission grid operates as part of the National Electricity Market with interconnections to New South Wales, South Australia and Tasmania.

The electricity transmission network in Victoria is currently owned and operated by AusNet Services Pty Ltd which is a listed company with significant holdings by Singapore Power International (31 per cent) and State Grid Corporation (20 per cent). On 4 August 2014, SP AusNet was rebranded as AusNet Services. AusNet Services also owns one of the five electricity distribution networks in Victoria.

The transmission network operates at voltages including 500 kilovolt (kV), 330 kV, 275 kV and 220 kV with alternating current (AC). Interconnectors to Tasmania (and South Australia via Mildura) comprise high voltage direct current (HVDC) links with converter stations to the main AC system.

The transmission network consists of a 500 kV backbone, running from the Latrobe Valley, through Melbourne and across south-west Victoria to Heywood. The backbone serves the major load centres and is reinforced by:

- a 220 kV ring around Melbourne
- inner and outer rings of terminal stations in country Victoria supplying the regional centres
- inter-state interconnections.

Only the largest industrial customers are connected directly to the transmission system, for example Portland Aluminium Smelter (~550 MW connected to the 500 kV network).

Smaller commercial and residential consumers are connected to the lower voltage distribution network.

Notes:

1. Current major infrastructure assets

Electricity distribution

There are five electricity distribution network operators segregated geographically within Victoria:

<table>
<thead>
<tr>
<th>Network</th>
<th>Customer Numbers</th>
<th>Electricity Delivered (GWh)</th>
<th>Maximum Demand (MW)</th>
<th>Overhead lines (km)</th>
<th>Zone substations</th>
<th>Poles</th>
<th>Asset Base ($ Million)</th>
<th>Owner</th>
</tr>
</thead>
<tbody>
<tr>
<td>AusNet Services</td>
<td>681,000</td>
<td>43,900</td>
<td>7,500</td>
<td>38,400</td>
<td>71</td>
<td>372,000</td>
<td>2,800</td>
<td>Listed company (Singapore Power International 31%, State Grid Corporation 20%)</td>
</tr>
<tr>
<td>CitiPower</td>
<td>323,000</td>
<td>4,300</td>
<td>6,000</td>
<td>4,300</td>
<td>51</td>
<td>49,000</td>
<td>1,600</td>
<td>Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%</td>
</tr>
<tr>
<td>Jemena</td>
<td>319,000</td>
<td>6,100</td>
<td>4,300</td>
<td>4,400</td>
<td>25</td>
<td>98,000</td>
<td>1,000</td>
<td>Jemena (State Grid Corporation 60%, Singapore Power International 40%)</td>
</tr>
<tr>
<td>Powercor</td>
<td>754,000</td>
<td>73,900</td>
<td>10,600</td>
<td>75,900</td>
<td>89</td>
<td>488,000</td>
<td>2,900</td>
<td>Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%</td>
</tr>
<tr>
<td>United Energy</td>
<td>657,000</td>
<td>12,900</td>
<td>7,900</td>
<td>10,100</td>
<td>46</td>
<td>215,000</td>
<td>1,800</td>
<td>DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%</td>
</tr>
<tr>
<td>Total</td>
<td>2,734,000</td>
<td>141,100</td>
<td>n/a</td>
<td>133,100</td>
<td>282</td>
<td>1,222,000</td>
<td>10,100</td>
<td>n/a</td>
</tr>
</tbody>
</table>


Electricity distributors convert electricity from the transmission network into medium and low voltages, delivering that electricity to homes and businesses across Victoria. Each of Victoria’s five distributors serve a different geographic area of Victoria: three encompass Melbourne and the inner suburbs and two cover the outer suburban areas and regional Victoria.

The map (right) shows the geographic reach of each of these networks. Importantly, AusNet Services and Powercor predominantly serve rural and regional Victoria, whereas Jemena, United Energy and CitiPower predominantly serve urban customers.

There is a distinction between electricity distribution network service providers (DNSPs) and energy retailers that send and manage electricity bills. Customers can choose from a number of energy retailers in Victoria, however the network that is physically used to provide the electricity to customers is governed by the geographic network area where the customer is located.

Notes:
1. Non-coincident, summated, raw system, annual maximum demand at the zone substation level.
2. Zone substation count compiled from 2014 Distribution Annual Planning Report for each network service provider.
3. Asset bases are at December 2013.
1. Current major infrastructure assets

Gas supply & transmission

There are two major asset classes in the gas transmission systems:

- **High pressure (HP)** transmission gas pipelines with sales quality gas over 7,000 kilopascals (kPa)
- **Medium pressure (MP)** gas distribution pipelines with sales quality gas from 1,000 kPa to 7,000 kPa.

Gas is also shipped into onshore gas process plants from off shore production platforms. The offshore gas pipelines are not included in this study.

The sources of gas into Victoria include1,2:

- Offshore Bass Strait gas fields (Otway, Gippsland, Bass basins) are the main source of gas. Otway Basin is processed at Iona, Minerva, and Otway Gas Plants. Bass Basin is processed at the Lang Lang Gas Plant (BassGas). Gippsland Basin is processed at Orbost Gas Plant (currently shutdown) and Longford Gas Plant.
- Dandenong Liquid Natural Gas (LNG) Gas Storage Facility, a peak demand trimming facility
- Iona Underground Storage (Port Campbell), also used for peak demand adjustment into linepack*
- Cooper Basin Gas (and Queensland and NSW coal seam gas) via the Moomba-Sydney Pipeline (MSP) and NSW-Victoria Interconnect.

### Victorian gas supply and transmission pipelines

<table>
<thead>
<tr>
<th>Product</th>
<th>Owner</th>
<th>Number of Licenced Pipelines</th>
<th>Aggregate Length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HP Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>APA</td>
<td>26</td>
<td></td>
<td>1,621</td>
</tr>
<tr>
<td>Jemena</td>
<td>2</td>
<td></td>
<td>283</td>
</tr>
<tr>
<td>SEA Gas Pipeline</td>
<td>1</td>
<td></td>
<td>268</td>
</tr>
<tr>
<td>GPV</td>
<td>1</td>
<td></td>
<td>182</td>
</tr>
<tr>
<td>MultiNet</td>
<td>3</td>
<td></td>
<td>76</td>
</tr>
<tr>
<td>Tasmanian Gas Pipeline</td>
<td>2</td>
<td></td>
<td>25</td>
</tr>
<tr>
<td>Santos</td>
<td>1</td>
<td></td>
<td>13</td>
</tr>
<tr>
<td>BHP/Esso</td>
<td>3</td>
<td></td>
<td>12</td>
</tr>
<tr>
<td>AGS</td>
<td>10</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>Minerva</td>
<td>1</td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>IPM</td>
<td>1</td>
<td></td>
<td>13</td>
</tr>
<tr>
<td>AGN</td>
<td>9</td>
<td></td>
<td>9</td>
</tr>
<tr>
<td>MP Gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>APA</td>
<td>20</td>
<td></td>
<td>494</td>
</tr>
<tr>
<td>AGN</td>
<td>28</td>
<td></td>
<td>262</td>
</tr>
<tr>
<td>AGS</td>
<td>20</td>
<td></td>
<td>151</td>
</tr>
<tr>
<td>MultiNet</td>
<td>12</td>
<td></td>
<td>83</td>
</tr>
<tr>
<td>BHP/Esso</td>
<td>2</td>
<td></td>
<td>7</td>
</tr>
</tbody>
</table>

*When more gas is entered into a pipeline that is being withdrawn, the pressure is increased, creating more storage capacity by "packing" more gas into the system. This is used to meet short term peak demand requirements as the ‘packed’ gas can subsequently be withdrawn when needed.

Notes:
1. Gas Statement of Opportunities (GSOO), April 2015, AEMO
2. APA Website
1. Current major infrastructure assets (continued)

Gas supply & transmission

Victoria’s gas supply and transmission system is connected interstate via the following major pipelines:

- **South Australia**: SEA Gas Pipeline
- **NSW**: Eastern Gas Pipeline, NSW-VIC Interconnect Pipeline
- **Tasmania**: Tasmanian Gas Pipeline (TGP).

Victoria operates on the east coast gas market, providing bilateral flow of gas to service market demand. Generally gas is exported out of Victoria through these pipelines and the Iona gas plant. These pipelines can inject limited quantities of gas into Victoria from linepack.

The owner of the Tasmanian Gas Pipeline is planning to construct a facility to enable TGP linepack to also be injected into Victoria.

The SEA Gas Pipeline is not able to withdraw gas from the Declared Transmission System – gas is injected by the Iona Gas Plant, Otway and Minerva Gas Plants.

![Network map](image-url)
1. Current major infrastructure assets (continued)

Gas supply & transmission

The Australian gas market is currently undergoing a shift due primarily to the recent completion of coal seam gas (CSG) gas fields in Queensland and new LNG production plants also recently commissioned in WA, plus other plants scheduled to come on stream in WA and NT.

In 2016 the balance of local consumption versus export of gas will see a dramatic change and a five-fold increase in gas production, with most gas destined for overseas consumption.

The current local consumption of gas for residential and industrial gas is expected to decrease in time whilst unconventional gas mainly destined for export will increase.

Note: the United Kingdom is shown on the map to contextualise the scale of the Australian system.
1. Current major infrastructure assets

Gas distribution

Four gas networks operate in Victoria as shown in the table below:

<table>
<thead>
<tr>
<th>Network</th>
<th>Owner</th>
<th>Area</th>
<th>Customers</th>
<th>Pipeline (km)</th>
<th>Asset Base ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MultiNet</td>
<td>Diversified Utility and Energy Trust (DUET Group)</td>
<td>Melbourne’s inner and outer east, the Yarra Ranges and South Gippsland</td>
<td>665,000</td>
<td>164 km of transmission pipelines and 9,866 km of distribution mains</td>
<td>1,038</td>
</tr>
<tr>
<td>AusNet Services</td>
<td>AusNet Services (Singapore Power International 31%, State Grid Corporation 20%)</td>
<td>South west Victoria from Bendigo to Anglesea and Portland to Horsham</td>
<td>605,000</td>
<td>9,400</td>
<td>1,255</td>
</tr>
<tr>
<td>Australian Gas Networks (Victoria) (formerly Envestra)</td>
<td>Cheung Kong Infrastructure</td>
<td>Northern, outer eastern, and southern areas of Melbourne, the Mornington Peninsula, rural communities in northern, eastern, and north-eastern Victoria and south-eastern rural townships in Gippsland</td>
<td>575,000</td>
<td>9,900</td>
<td>1,100</td>
</tr>
<tr>
<td>Australian Gas Networks (Albury) (Note: operates in parts of Victoria)</td>
<td>Cheung Kong Infrastructure</td>
<td>Albury and its environs</td>
<td>20,000</td>
<td></td>
<td>34.8</td>
</tr>
</tbody>
</table>

Gas has played, and continues to play, a significant role in Victorian household energy consumption. In 2014, about 83 per cent of Victorian households were connected to gas, which was significantly higher than the next highest State (Western Australia with a penetration of 69 per cent). The percentage of households connected to gas in each state is shown below.

![Percentage of households connected to gas, 2014](image)

Source: ABS, 4602055001DO001_201403 Environmental Issues: Energy Use and Conservation, Mar 2014

In Victoria the proportion of households connected to gas has varied slightly over time, increasing from around 81 per cent in 2005 to 83 per cent in 2014. Over the three year period from 2011-14, this represents an additional 111,300 gas connections.
1. Current major infrastructure assets

**Liquid fuels**

The petroleum industry is split into two sectors:

- **Upstream** – exploration and production of crude oil (unrefined product)
- **Downstream** – refining and distribution of refined products. These products include jet fuel, diesel, petrol, lubricating oil and others.

ExxonMobil are currently in the last phase of gaining approvals to replace the existing pipeline between Longford and Long Island.

The Westernport, Altona, Geelong (WAG) pipeline is strategically important to Victoria as it supplies crude oil from Exxon Mobil’s Longford processing plant via the Long Island terminal to Mobil’s refinery in Altona and Viva/Shell’s refinery in Geelong.

Refined liquid fuels is manufactured at the Esso Altona Refinery or the Viva/Shell Geelong refinery. Both of these refineries also receive crude from overseas sources to supplement indigenous stock.

Another strategic pipeline is the single source of jet fuel from the two refineries and import connections at Newport. This system is currently constrained and is being considered for upgrades so adequate stock levels of jet fuel can be transferred to Tullamarine without relying on road tankers to supplement demand and stock levels.

Petroleum refined product pipelines supply jet fuel, diesel, petrol to oil companies and independent terminal operators with terminals at Newport (Caltex and Viva/Shell), Yarraville (Mobil/BP JV), Somerton (Mobil/BP/ Viva/Shell) and Hastings (United).

Various liquid fuels pipelines supply feedstocks to petrochemical complexes. The petrochemical industry is based mainly at Altona and Coode Island.

Liquid fuels are transported through port terminals at Port Melbourne, Williamstown, Hastings, Geelong, Portland (Otway Basin) and Barry Beach (Gippsland Basin).

For strategic reasons there are a number of liquid fuels pipelines that are now redundant due to rationalisation of oil company terminal facilities and refinery closures. As examples these include a pipeline from the dismantled BP refinery at Westernport and the refined pipeline from the Port of Melbourne to Altona.

<table>
<thead>
<tr>
<th>Product</th>
<th>Owner</th>
<th>Number of Licenced Pipelines</th>
<th>Aggregate Length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Unrefined Products</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BHP/Esso</td>
<td>15</td>
<td></td>
<td>653</td>
</tr>
<tr>
<td>WAG</td>
<td>1</td>
<td></td>
<td>136</td>
</tr>
<tr>
<td>Origin</td>
<td>6</td>
<td></td>
<td>94</td>
</tr>
<tr>
<td>Santos</td>
<td>3</td>
<td></td>
<td>23</td>
</tr>
<tr>
<td>Mobil</td>
<td>6</td>
<td></td>
<td>11</td>
</tr>
<tr>
<td>Minerva</td>
<td>1</td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>APT</td>
<td>1</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td><strong>Refined Products</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Viva/Shell</td>
<td>4</td>
<td></td>
<td>121</td>
</tr>
<tr>
<td>JUHI</td>
<td>2</td>
<td></td>
<td>45</td>
</tr>
<tr>
<td>Mobil</td>
<td>8</td>
<td></td>
<td>39</td>
</tr>
<tr>
<td>Crib Point Terminal</td>
<td>1</td>
<td></td>
<td>37</td>
</tr>
<tr>
<td>BP Australia</td>
<td>2</td>
<td></td>
<td>11</td>
</tr>
<tr>
<td>Joint User</td>
<td>3</td>
<td></td>
<td>5</td>
</tr>
<tr>
<td>Caltex</td>
<td>3</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Stolthaven</td>
<td>1</td>
<td></td>
<td>2</td>
</tr>
</tbody>
</table>

Notes:

1. ACIL Tasman, 2009, *Petroleum import infrastructure in Australia*
1. Current major infrastructure assets

Other chemicals & liquid fuels

There are a number of licenced pipelines in Victoria in addition to the major oil & gas supply to the distribution network and refineries. These are generally to and from various chemical plants.

The ethane pipeline from Esso's Long Island Point plant is a major pipeline that feeds the chemical plant complex in Altona. This pipeline is maintained by intelligent pigging* every five years. It is a single pipeline which some years ago was involved in third party damage which resulted in the Altona petrochemical industry being shut down for a considerable period.

Whilst the listed pipelines are major infrastructure, they are specific to particular industries or customers. If any of these pipelines fail, the products can generally transported using road tankers. Product can also be drawn from other sources.

<table>
<thead>
<tr>
<th>Owner</th>
<th>Product</th>
<th>Number of licenced pipelines</th>
<th>Aggregate length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BHP/Esso</td>
<td>Ethane</td>
<td>1</td>
<td>78</td>
</tr>
<tr>
<td>Elgas</td>
<td>LPG</td>
<td>1</td>
<td>43</td>
</tr>
<tr>
<td>BOC</td>
<td>Nitrogen, Hydrogen, Propylene, Compressed Air</td>
<td>7</td>
<td>25</td>
</tr>
<tr>
<td>Air Liquide</td>
<td>Oxygen, Nitrogen</td>
<td>4</td>
<td>18</td>
</tr>
<tr>
<td>Coogee</td>
<td>Methanol</td>
<td>2</td>
<td>10</td>
</tr>
<tr>
<td>Viva/Shell</td>
<td>LPG</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>Qenos</td>
<td>LPG</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Chemicals Australia</td>
<td>Sulphuric Acid</td>
<td>1</td>
<td>0.9</td>
</tr>
<tr>
<td>Incitec</td>
<td>Sulphuric Acid</td>
<td>1</td>
<td>0.38</td>
</tr>
</tbody>
</table>

Notes:
1. ACIL Tasman, 2009, Petroleum import infrastructure in Australia

* A ‘pig’ is a device used to perform various maintenance operations on a pipeline, without stopping the flow of the product. Modern intelligent or ‘smart’ pigs include sensors and electronics to collect data for later analysis since the pig is unable to communicate by radio (as a result of the distance underground and/or the pipe’s materials).
2. Current asset investment

*Growth investment in renewables, electricity distribution connections, gas networks and major liquid fuels pipelines. Thermal generation and electricity transmission network investment is predominantly in asset renewal and replacement.*

Capital investment in energy infrastructure typically involves large and lumpy projects for asset renewal and replacement (sustain) or to expand capacity (growth). Although demand forecasts for gas and electricity are modest, network upgrades will still be required to accommodate geographic shifts of load centres. A summary of current asset investment is provided here and further details including inter-jurisdictional comparisons are carried out at the sub-sector level.

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Sustain</th>
<th>Growth</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation</strong></td>
<td>$1.18 billion renewal</td>
<td>$100 million</td>
<td>In the near term, generation investment interest is focused on wind generation, with 24 project proposals totalling more than 2,750 MW. The only committed project is at Ararat (240 MW) which is due to be commissioned in May 2017. In the medium term, a new gas combined cycle plant is under consideration (up to $3.8 billion for new gas based assets). This may allow the 1,600 MW Hazelwood Power station, which is &gt;46 years old and suffers from poor environmental performance, to be shut down. Note that no closure date has been announced for Hazelwood. Depending on plant age, some expenditure has already been undertaken on some plants for performance improvement and life extension in the past 10 years.</td>
</tr>
<tr>
<td><strong>Electricity Distribution</strong></td>
<td>$500 million</td>
<td>$750 million</td>
<td>Network expenditure was approximately $1.25 billion in 2014. The most significant proportion of expenditure has been on expansion, which includes connections (36 per cent), advanced metering infrastructure (AMI) (35 per cent) and augmentation capex to expand the network's capacity (29 per cent). Replacement expenditure is the next largest proportion of expenditure.</td>
</tr>
<tr>
<td><strong>Gas Supply and Transmission</strong></td>
<td>$200 million</td>
<td>$50 million</td>
<td>Per annum, approved within current regulatory period for 2014 and 2015 ($ real, 2013).</td>
</tr>
<tr>
<td><strong>Liquid Fuels</strong></td>
<td>~ $50 million</td>
<td>TBA</td>
<td>Approximate annual spend. The only pipeline requiring growth investment is the JUHI pipeline system to Melbourne Airport. Several studies are occurring on how best to provide this additional capacity.</td>
</tr>
</tbody>
</table>
## 2. Current asset investment

### Thermal generation

<table>
<thead>
<tr>
<th>Asset</th>
<th>Renewal &amp; replacement</th>
<th>Growth</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Coal based assets</strong></td>
<td>All assets are in the ‘Asset renewal’ phase of their lifecycle. Depending on plant age, some expenditure has already been undertaken on some plants for performance improvement and life extension in the past 10 years:</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Hazelwood</td>
<td>Since 1996, operational and environmental initiatives have resulted in significant efficiency and reliability improvements.</td>
<td>n/a</td>
<td>$1,000 million(^7)</td>
</tr>
<tr>
<td>Yallourn</td>
<td>High and Intermediate Pressure (HIP) turbine replacements improved unit efficiency by ~3 per cent and provided for another 25 years life on the HIP turbines. Unit 3: 2010; Unit 4: 2011; Unit 1: 2014.</td>
<td>n/a</td>
<td>$100 million (Aurecon estimate)</td>
</tr>
<tr>
<td><strong>Yallourn A</strong></td>
<td>A seven year, ICMS digital control system conversion project was completed in October 2014</td>
<td>n/a</td>
<td>$60 million(^8)</td>
</tr>
<tr>
<td><strong>Loy Yang B</strong></td>
<td>Unit 2 generator –core replacement and stator &amp; rotor rewinding carried out in 2000.</td>
<td>n/a</td>
<td>$20 million(^6) (Aurecon estimate)</td>
</tr>
<tr>
<td><strong>Gas based Assets</strong></td>
<td>New gas combined cycle capacity under consideration(^6):</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Tarrone Power Station</td>
<td>500 to 600 MW CCGT</td>
<td>n/a</td>
<td>$0.6 billion(^1)</td>
</tr>
</tbody>
</table>
| **Shaw River Power Station** | • Option 1: 3 x 500 MW combined cycle gas turbine (CCGT)  
• Option 2: 3 x 255 MW open cycle gas turbine (OCGT) for later conversion to CCGT | n/a                | $0.8 billion\(^1\)            |
| **Yallourn CCGT**            | The proposed 2000 MW gas fired combined cycle plant will displace brown coal generation as base load capacity | n/a                | $1.8 billion\(^3\)            |
| **Mortlake stage 2**         | CCGT 450 MW                                                                           | n/a                | $0.56 billion\(^2\)           |
| **Carbon Net**               | n/a                                                                                    | Asset enhancement  | $0.1 billion\(^4\)            |

Notes:
4. guides-1008_CarbonNet_Project_Brochure%20(3).pdf

# Due to the age of Hazelwood (>46years) and its poor environmental performance, a number of new gas combined cycle plants are being considered which will allow the 1,600 MW Hazelwood Power Station to be shut down\(^5\). Gas prices will be a key factor in the financial evaluation of new gas fired electricity generation projects. Demand growth is modest and generation capacity is currently sufficient for a ten year medium growth scenario. Investment in gas based assets is likely to be scheduled to align with retirement of coal based assets.
2. Current asset investment

Electricity transmission

AusNet Services’ capex forecast only relates to the replacement of shared transmission network assets and transmission connection assets. It excludes any expenditure to augment the transmission system. As outlined in the section on Infrastructure planning and maintenance (Item 4), AEMO is responsible for planning and procuring the augmentation (growth expenditure) of the shared transmission network. The five Distribution Businesses have responsibility for planning the augmentation of transmission connections to their distribution networks.

Growth

AEMO’s National Transmission Network Development Plan (AEMO 2015) includes the following committed augmentation projects which contribute to the growth expenditure in this sector:

<table>
<thead>
<tr>
<th>Project</th>
<th>Target completion</th>
<th>Total cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heywood interconnector upgrade*</td>
<td>Mid 2016</td>
<td>$107.7 million (real, 2012)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>including $45 million for the Victorian component</td>
</tr>
<tr>
<td>Additional Moorabool – Ballarat 220 kV transmission line</td>
<td>Early 2017</td>
<td>$27.8 million (real, 2013/14)</td>
</tr>
<tr>
<td>Brunswick terminal substation 66kV connection</td>
<td>Late 2016</td>
<td>$271.0 million (real, 2010)</td>
</tr>
<tr>
<td>Deer Park terminal station</td>
<td>Late 2017</td>
<td>$125.0 million (real, 2012)</td>
</tr>
</tbody>
</table>

Notes:
- Total cost figures sourced from RIT-T submissions for each project.
- * Heywood interconnector upgrade project driven by growth and market benefit

Source: AEMO, National Transmission Network Development Plan, 2015; Deloitte Touche Tohmatsu © 2016 - Infrastructure Capability Assessments

Sustain – renewal and replacement

AusNet Services actual and forecast capex for the previous, current and next regulatory periods ($M, real 2016-17)

<table>
<thead>
<tr>
<th>Period</th>
<th>Expenditure</th>
</tr>
</thead>
<tbody>
<tr>
<td>FY2009-14</td>
<td>386</td>
</tr>
<tr>
<td>FY2015-17</td>
<td>610</td>
</tr>
<tr>
<td>FY2018-22</td>
<td>562</td>
</tr>
</tbody>
</table>

Breakdown of capex forecast into driver categories for 2017-22 regulatory period

Note: expenditure in the table is the sum of major stations and asset replacement components of the chart (right).

AusNet Services historical and forecast capex ($ million, real 2016-17)

Notes:
- Chart sources: AusNet Services, Transmission Revenue Review 2017-22, 30 October 2015, p.59
- Total cost figures sourced from RIT-T submissions for each project.
2. Current asset investment

Electricity transmission

Inter-jurisdiction comparison

In comparing capital expenditure for transmission network service providers in Australia, it is important to consider that there are differences between the operating environments including differences in:

- Size and voltages of networks
- Network terrain
- Climate
- Jurisdiction specific requirements
- Maximum demand served
- Business structures and operating models under public and private ownership.

There is also variability in capital expenditure for electricity transmission networks from year to year. This variability means that the comparison is sensitive to the time period selected. It will also depend on where each transmission network is in its network asset lifecycles. For example, those transmission networks with older assets are likely to spend more on asset replacement than those transmission network service providers (TNSPs) with relatively young assets.

The graphs below show historical capital expenditure (left) and the value of the regulated asset base (right) for transmission network operators in the National Electricity Market. Normalising factors have not been considered in this analysis.

Notes:

1. In the capital expenditure graph (left), the values for AusNet Services exclude the augmentation (growth) expenditure that is determined by AEMO’s Victorian transmission network planning functions. Therefore the inter-jurisdictional comparison of results for AusNet Services should be interpreted with caution.
2. Current asset investment

Electricity distribution

Electricity distribution networks have recently completed an asset growth cycle, indicated by lower forecast demand growth. As such, the focus for upcoming asset investment has shifted towards asset management, asset renewal and replacement, smart grids, and innovation.

The figure below shows the Victorian electricity distribution network service providers’ (DNSP) actual expenditure from 2009-14.

Network expenditure increased from 2009-2013, reaching a height of $1.45 billion before falling to $1.38 billion in 2014.

The most significant proportion of expenditure has been on expansion, which includes connections (36 per cent), meters (35 per cent) and augmentation capex to expand the network’s capacity (29 per cent). Replacement expenditure is the next largest proportion of expenditure.

The distribution networks recently received preliminary decisions by the AER for the 2016-2020 regulatory period. The AER preliminary decisions are lower than the capex proposed in the original submission by the distributors as outlined in the adjacent table.

Victoria has had a considerable investment of $2.8 billion (whole-of-life cost) in Advanced Metering Infrastructure (AMI). This was an important undertaking to facilitate the benefits of a smart grid.

Inter-jurisdictional comparison

The figure below shows the asset cost per customer. This is the sum of annual depreciation and return on capital.

Asset cost per customer compared to customer density (average 2009-2013)

The Victorian DNSPs (PCR, UED, JEN, CIT, AND) are the most efficient in the National Energy Market because they have the lowest asset cost per customer regardless of customer density (AER, 2014).
## 2. Current asset investment

### Gas supply & transmission

<table>
<thead>
<tr>
<th>Asset</th>
<th>Sustain</th>
<th>Renewal &amp; replacement</th>
<th>Growth</th>
<th>Average per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>HP and MP gas pipeline network</td>
<td>$25 million</td>
<td>$175 million</td>
<td>$50 million</td>
<td>$250 million</td>
</tr>
<tr>
<td>New laterals to new customers, part</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>replacement of section of lines where</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>maintenance is no longer viable to</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>maintain licence conditions (MAOP)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance on existing pipelines where</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>coatings are repaired and CP</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>systems replaced</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New or looped pipelines to meet growing</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>demand. Expenditure spread over several</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>years per project</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>An average of $250 million is invested</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>each year to keep the transmission network operational.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Gas transmission investment typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping or extension) or to construct new infrastructure.

Significant investment in the regulated and unregulated transmission sector has occurred since 2010. Additionally, a number of major projects are under construction or have been announced for development.

Investment in distribution and transmission networks in eastern Australia – including investment to augment capacity – is forecast at around $2.7 billion (AER, 2013) in the current access arrangement periods. These are typically five years. The underlying drivers include rising connection numbers, the replacement of aging networks, and the maintenance of capacity to meet customer demand.

### Pipeline investment – five year period

![Pipeline investment - five year period](image)

Notes:
2. GHD Infrastructure Maintenance (2015)
2. Current asset investment

Gas distribution

Capex make-up

Over the five year regulatory period from 2013-17, Victorian DNSPs sought funding for around $1.17 billion ($ real, 2012) of capex. Of this, growth capex is forecast by the DNSPs to account for the largest proportion of expenditure as shown in the figure below.

Inter-jurisdiction comparison

The figure below outlines the actual and forecast capex for Victorian DNSPs (from 2008-12) and the total capex for the major gas DNSP in NSW, Jemena Gas Networks (from 2010-14).

The following table outlines forecast capex by DNSP and by capex category:

<table>
<thead>
<tr>
<th>Asset</th>
<th>Sustain</th>
<th>Growth</th>
<th>Non network</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>AusNet</td>
<td>$138 million</td>
<td>$218 million</td>
<td>$133 million</td>
<td>$489 million</td>
</tr>
<tr>
<td>MultiNet</td>
<td>$69 million</td>
<td>$100 million</td>
<td>$94 million</td>
<td>$263 million</td>
</tr>
<tr>
<td>AGN (Vic)</td>
<td>$149 million</td>
<td>$186 million</td>
<td>$85 million</td>
<td>$421 million</td>
</tr>
</tbody>
</table>

Source: AER Victorian Access Arrangements 2013-17, Deloitte analysis

Growth capex includes capex for new connections and augmentation, i.e. assets that expand the capacity of the network. The next most significant category is sustain assets, which includes mains and meter replacements. Non-network capex includes overheads and IT related capex.
2. Current asset investment

Liquid fuels

Capital investment figures are generally not publically available. However, around $50 million is spent on average across all sections of liquid fuels annually, with the majority of spend in renewal and replacement.

<table>
<thead>
<tr>
<th>Asset</th>
<th>Sustain</th>
<th>Renewal &amp; replacement</th>
<th>Growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude pipelines</td>
<td>No activity envisaged.</td>
<td>Existing lines will remain under close surveillance until no longer serviceable at which time alternative shipping will be employed to move final indigenous crude to production.</td>
<td>With declining indigenous crude no expansion or capacity increase envisaged.</td>
</tr>
<tr>
<td>Refined product pipelines</td>
<td>It is expected that the only new investment for refined product transfer and distribution pipelines will be by independent operators.</td>
<td>The refined product network is aged and is being replaced in part as sections are no longer viable to be maintained.</td>
<td>The only pipeline network requiring growth is the JUHI pipeline system to Melbourne Airport.</td>
</tr>
<tr>
<td>Jet fuel pipelines</td>
<td>New connecting pipelines are under construction to permit additional import stock to be transferred from Melbourne based terminals.</td>
<td>The refined product network is aged and is being replaced in part as sections are no longer viable to be maintained.</td>
<td>Several studies are occurring on how best to provide this added capacity and how to fund the enhanced system.</td>
</tr>
<tr>
<td>Other category pipelines</td>
<td>Replacement of aged pipelines will be based on economic analysis and if not viable to keep up maintenance or replace the pipelines will be gradually abandoned or mothballed.</td>
<td>The “other” category of pipelines have over half being over 40 years old and are reaching the end of serviceable life.</td>
<td>With the closing of major industry in Victoria it is expected little investment will be made in additional pipelines.</td>
</tr>
</tbody>
</table>
3. Current major infrastructure projects

Coal based generation

The major impediment to additional coal based generation in Victoria is the high greenhouse gas intensity associated with brown coal. It is around 50 per cent more carbon dioxide intensive than black coal, so although the fuel cost is significantly lower than black coal, it is unlikely that any new or additional plants will be constructed unless there can be either:

• an advanced technology yielding lower CO₂ emissions than a black coal fired unit. There is significant research being conducted to explore ways that the low cost brown coal resource may be exploited. Projects such as Oxy-Fuel Combustion Technology and the Direct Injection Carbon Engine (DICE) may provide opportunities for brown coal.

• Some form of carbon dioxide capture and storage to mitigate atmospheric CO₂ emissions. The Carbon Net Project (see box on right) if implemented will enable a significant reduction in carbon emissions from electricity in Victoria.

Gas based generation

There are four large gas-fired generation projects which have gained environmental consent, but which construction work is yet to commence. These plants are aimed to progressively replace brown coal fired plant. Yallourn CCGT, Tarrone, Shaw River and Mortlake Stage 2 are base load combined cycle plants which may replace Hazelwood (brown coal) power station. Consent for Shaw River and Tarrone were obtained in 2008 and 2012 respectively. Gas prices will be a key factor in whether these projects will proceed.

<table>
<thead>
<tr>
<th>Project</th>
<th>Proponent</th>
<th>Plant</th>
<th>Cost ($m)</th>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tarrone Power Station</td>
<td>AGL</td>
<td>480 MW open cycle gas turbine</td>
<td>400</td>
<td>Approved in 2012. Construction yet to commence.¹</td>
</tr>
<tr>
<td>Shaw River Power Station</td>
<td>Santos</td>
<td>1500 MW (built in 3 stages of 500MW CCGT)</td>
<td>800</td>
<td>2014 - project stalled.¹ Construction date not announced</td>
</tr>
<tr>
<td>Mortlake Stage 2</td>
<td>Origin Energy</td>
<td>450 MW CCGT</td>
<td>560</td>
<td>Commencement dependent on electricity demand ²</td>
</tr>
<tr>
<td>Yallourn CCGT</td>
<td>Energy Australia</td>
<td>2000 MW CCGT</td>
<td>2,000 (est)</td>
<td>Approved in 2012. Construction yet to commence.³</td>
</tr>
</tbody>
</table>

Notes:

Carbon Net Project

The CarbonNet Project is investigating the potential for establishing a large-scale carbon capture and storage network. The network would bring together multiple carbon dioxide (CO₂) capture projects in Victoria’s Latrobe Valley, transporting CO₂ via a shared pipeline and injecting it into deep, underground, offshore storage sites in the Gippsland region of Victoria. CCS is being investigated as part of a suite of solutions with the potential to mitigate greenhouse gas emissions and help address climate change. It involves capturing CO₂ released by power stations or other emitters, compressing it and then transporting it to an injection site to be sequestered deep underground for safe, long term storage in suitable geological formations – similar to the way oil and gas has been stored underground for millions of years. Refer to Slide 103 for additional information.

CarbonNet is investigating the potential for CCS in Gippsland as the region is widely recognised as a world-class location offering significant potential for CCS. The nearby Latrobe Valley is home to the power stations responsible for generating more than 90 per cent of the state’s electricity. The adjacent offshore Gippsland Basin has been found to have the highest technical ranking of 25 major basins across Australia and the largest storage potential of any east coast basin. The project is exploring the potential to capture and store one to five million tonnes of CO₂ per year, with the potential to scale up. Successful implementation of this project could be the starting point for an expanding commercial scale carbon transportation and storage system, enabling a significant reduction in carbon emissions from electricity in Victoria. A key factor will be the impact of the CCS capital and operating costs on the overall electricity production costs when compared to the cost of renewable energy.

CarbonNet is managed by the DEDJTR. It is at feasibility and commercial definition stage with extensive research, engineering and commercial studies being undertaken, including modelling of potential CO₂ storage sites. The project is funded by the Australian and Victorian Governments.

- Contains the world’s 2nd largest brown coal deposit
- Produces around 88 per cent of Victoria’s electricity
- Storage potential of 20gt

3. Current major infrastructure projects

Renewables

There are two committed renewable generators in Victoria: the Ararat Wind Farm and Coonooer Bridge. Details are shown in the table below.

Committed renewable generation—Victoria

<table>
<thead>
<tr>
<th>Power Station</th>
<th>Owner</th>
<th>Nameplate capacity (MW)</th>
<th>Fuel type</th>
<th>Commercial date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ararat</td>
<td>Ararat Wind Farm Pty Ltd</td>
<td>240</td>
<td>Wind</td>
<td>May 2017</td>
</tr>
<tr>
<td>Coonooer Bridge</td>
<td>Windlab Systems Pty Ltd</td>
<td>20</td>
<td>Wind</td>
<td>March 2016</td>
</tr>
</tbody>
</table>

Source: AEMO

In Victoria there are another 27 projects (totalling around 2,960 MW) that have reached various stages of commitment with most of these, however, having only been publically announced.

When compared to the amount of renewable energy generation supported by the Renewable Energy Target (discussed in Item 5), it becomes clear that a number of the proposed generators are unlikely to proceed in the foreseeable future. This is demonstrated by the figure to the right which shows the renewable energy target (RET) compared to existing and proposed renewable generator output that contributes to the RET* (calculated based on their nameplate capacity and a blended capacity factor).

In the figure, committed and proposed generators with a capacity under 150 MW are aggregated. Those over 150 MW are shown by State, with the Victorian committed and proposed generators over 150 MW listed separately.

*Renewable generation that has been in operation pre-1997 do not contribute to the RET.
3. Current major infrastructure projects

Electricity transmission

The following table provides a summary of the major infrastructure projects planned for the Victorian electricity transmission system:

<table>
<thead>
<tr>
<th>Project Type</th>
<th>Completion period</th>
<th>Total cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Committed projects (growth) [refer Item 2]</td>
<td>By late 2017</td>
<td>~ $500 million</td>
</tr>
<tr>
<td>Large asset renewal projects proposed</td>
<td>By 2021</td>
<td>&gt; $500 million</td>
</tr>
<tr>
<td>New terminal stations for generation connection including Ararat, Mt Gellibrand, Stockyard Hill and Crowlands Terminal Stations.</td>
<td>Ararat Terminal Station: 2016 Others: To be announced</td>
<td>Not disclosed</td>
</tr>
</tbody>
</table>

Indicative transmission major projects timing for AusNet Services (AusNet Services 2015a)

Major project case study: Deer Park terminal station

**Service date:** Late 2017  
**Total cost:** circa $125.0M (real, 2012)

A new 220 kV terminal station is in development at Deer Park to address constraints at terminal stations servicing distribution networks in the western Melbourne metropolitan area. The first stage of the project involves installing two 225 mega volt amp (MVA) 220/66 kV transformers and connection to the existing Geelong–Keilor No.2 220 kV line in 2017.

A joint regulatory test was undertaken and demonstrates that the works are prudent and efficient and that the option selected maximises the net economic benefit to consumers.

TransGrid (NSW transmission network operator) was the successful bidder for the construction, ownership and operation of the new terminal station.

Notes:
Sources: AEMO, Victorian Annual Planning Report, June 2015  
3. Current major infrastructure projects

Electricity distribution

**Major project case study: Metro and CBD Security of Supply**

**Cost:** $36.7 million expenditure 2015/16 to end of 2017 (real, 2015)
**Completion:** End of 2017
**Distributor:** CitiPower

The Metro and CBD Security of Supply projects will see the installation of 21 kilometres of cables over a distance of 7 kilometres from Brunswick to Carlton and the construction of a new Zone Substation Waratah Place in the CBD.

These projects address two key issues: increased electricity supply to Melbourne’s north-east CBD, and extra protection against outages across the CBD.

Due to residential and commercial growth in the north-east region of the CBD, there has been an increased electricity demand for that area.

CitiPower’s Metro Project is increasing the network’s capacity to supply electricity to this part of the CBD.

**Major project: Craigieburn Zone Substation**

**Cost:** $14.8 million (real, 2015)
**Completion:** End 2019
**Distributor:** Jemena Electricity Network

Jemena’s network is experiencing rapid load growth in the Northern Growth Corridor.

The outcome of analysis undertaken by Jemena was that building a new Craigieburn zone substation is the optimal solution. It will augment the distribution network in the required areas and provide sufficient capacity to meet forecast load growth while maintaining supply reliability.

**Major project: Truganina Zone Substation**

**Cost:** $14.5 million (real, 2015)
**Completion:** 2017
**Distributor:** Powercor

The new zone substation will reinforce supply, remove load and energy at risk and improve reliability of supply.

The Regulatory Test undertaken for the project concluded that the preferred option is the construction of Truganina zone substation containing two 66/22 kV transformers, as well as the construction of two 66 kV sub-transmission lines and five 22 kV feeders.


**Victoria Bushfire Royal Commission**

On Saturday 7 February 2009 (“Black Saturday”), Victoria experienced devastating bushfires.

The Victorian Bushfires Royal Commission was established to inquire and report on the causes and circumstances of the fires. In September 2010 the Powerline Bushfire Safety Taskforce was formed to investigate the optimal way of implementing these recommendations.

The Taskforce recommended that the risk of powerlines starting bushfires could be reduced by:

- Installing new technology that greatly reduces bushfire risk; that is, by installing:
  - Rapid Earth Fault Current Limiters (REFCLs) at specific points in the network to reduce the risk of polyphase powerlines starting fires.
  - New generation Automatic Circuit Reclosers (ACRs) on Single Wire Earth Return (SWER) lines to reduce the risk of SWER lines starting fires.
- Putting powerlines underground or insulating conductors in the areas of highest bushfire risk.

In December 2011 the Government accepted the Taskforce’s recommendations and committed to a $750 million Powerline Bushfire Safety Program (PBSP).

Examples of ‘asset installation measures’ undertaken to date include:

- Replacement of 88.1 kilometres of bare-wire powerline with safer alternatives in high bushfire risk areas
- Deployment of 1,390 automated network protection devices
- Installation of back-up power generators at 115 facilities to protect vulnerable residents from the adverse impact of power outages.

CitiPower, News about Waratah Place zone substation project, Issue 1, November 2014.
3. Current major infrastructure projects

Gas supply & transmission

Victorian Projects
- Victorian Northern Interconnect Expansion (VNIE). Construction contracts for stages 6-9 have been awarded to the Spiecapag Lucas JV with construction work expected to begin in February 2016. Refer to the right for more information.
- Mount Cottrell Custody Transfer Meter (CTM), recently completed.
- Bannockburn CTM, recently completed.
- Winchelsea CTM, recently completed.
- Thewlis Road CTM in Pakenham, recently completed.
- Warragul Pipeline, currently in development stage with proposed completion of June 2016.
- SWP to Anglesea Pipeline (APA/AusNet), currently at concept stage with proposed completion pre-winter 2018.

Interstate Projects
As the Victorian declared transmission system (DTS) is connected to those in other states, additional projects of note include:
- numerous projects to increase gas supply to Queensland to support expected demand increase due to LNG export projects.
- Tasmanian storage upgrade.

Notes:
1. AEMO, 2015, Gas Statement of Opportunities (GSOO).
3. Current major infrastructure projects

Gas distribution

Extensions

As noted, extension capex makes up the greatest proportion of forecast capex between 2013-17. The majority of this capex is for residential connections – $357 million (real, 2012).

As discussed in the case study to the right, the Victorian Government has committed funding, in addition to the DNSPs’ regulatory allowance, to improve regional gas access which is driving gas extension capex. Given the current gas consumption levels are low, Government subsidies are typically needed to make network expansions viable.

Mains replacement

Victorian DNSPs are collectively forecasting to spend around $290 million on their mains replacement programs from 2013-17. This is one of the largest capex drivers over this period. Within this program, the major driver is the replacement of low pressure mains with high pressure mains.

This replacement will reduce leaks and safety risks associated with aging cast iron and unprotected steel pipes. It will also improve the DNSPs’ ability to manage demand growth.

Over 2013-17, MultiNet has received regulatory funding allowance to undertake 255 kilometres of mains replacement, AGN (Vic) has been funded for 359 kilometres and AusNet has been funded for 415 kilometres (AER, 2013).

Notes:
1. AER, Access arrangement final decision 2013-17, Victorian DNSPs
3. Victorian Government, “Regional Gas Infrastructure program”
3. Current major infrastructure projects

**Liquid fuels**

Major liquid fuels projects in Victoria:

- ExxonMobil is planning a new jet fuel pipeline from Yarraville Terminal connecting to the existing Somerton Pipeline\(^1,2\).

- A new pipeline is required between Newport and Somerton as the existing line is aged and has reached capacity.

- A new fuel pumping station project on Viva/Shell’s existing pipeline between the Geelong Refinery and Newport Terminal\(^4\) is soon to be commissioned to assist in capacity from Geelong refinery and Melbourne terminals. The pumping station will service only one of the two pipelines from the refinery. The second pipelines is scheduled for part replacement and upgrade.

- Viva/Shell and ExxonMobil are conducting feasibility studies for new import storage tanks\(^5\).

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### Yarraville Jet Fuel Upgrade\(^1,2\)

- The Somerton pipeline needs to carry 2.4 million litres of jet fuel per day and in 20 years time this volume will increase to 3.5 million litres per day.

- Currently there is a shortfall of one million litres of jet fuel per day. This is resolved using road tankers.

- ExxonMobil is planning a new jet fuel pipeline from Yarraville Terminal to connect the existing Somerton Pipeline\(^1\).

- The new pipeline when built will take 15 trucks per day off the road from the Yarraville Terminal to the airport.

- Construction is due for completion early 2016. This pipeline will allow Mobil to import Jet fuel into Yarraville to compensate for shortfall of Jet supplies from the refinery.

---

Notes:

### 4. Infrastructure planning and maintenance

**Victoria’s energy sector is almost entirely under private ownership. Operating in the National Electricity Market, AEMO provides input to planning and operation at the overall market level.**

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Name / Description of Assets</th>
<th>Management</th>
<th>Responsibility for Planning</th>
<th>Operation</th>
<th>Maintenance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity Generation</strong></td>
<td>Coal based assets Gas based assets Renewable assets</td>
<td>Generally plant owners. An exception to this is the Jeeralang (A&amp;B) and Newport power stations which are owned by IFM but operated and maintained by EnergyAustralia.</td>
<td>AEMO</td>
<td>• Plant operator submits price bids in the NEM • AEMO determines dispatch in accordance with demand and bid prices</td>
<td>• Plant operator (minor maintenance) • Contractors • Original Equipment Manufacturers (OEMs)</td>
</tr>
<tr>
<td><strong>Electricity Transmission</strong></td>
<td>High voltage electricity transmission network</td>
<td>AusNet Services</td>
<td>Australian Energy Market Operator (AEMO), AusNet Services, Transmission customers</td>
<td>AusNet Services</td>
<td>AusNet Services</td>
</tr>
<tr>
<td><strong>Electricity Distribution</strong></td>
<td>Five distribution networks</td>
<td>Network service providers (CitiPower, Jemena Electricity Networks, Powercor, AusNet Services, United Energy Networks)</td>
<td>Network service providers</td>
<td>Network service providers</td>
<td>Network service providers</td>
</tr>
<tr>
<td><strong>Gas Supply</strong></td>
<td>Longford Gas Plant, Iona Underground Gas Storage Plant,</td>
<td>Plant owners (Esso, QIC)</td>
<td>Plant owners, informed by AEMO through VGPR</td>
<td>Plant owners</td>
<td>Plant owners</td>
</tr>
<tr>
<td><strong>Gas Transmission</strong></td>
<td>Victorian Declared Transmission System (DTS) and four major pipelines</td>
<td>Pipeline owners (APA GasNet, Jemena, South East Australia Gas Pty Ltd, Tasmanian Gas Pipeline (TGP) Pty Ltd, Gas Pipelines Victoria Pty Ltd)</td>
<td>Pipeline owners, informed by AEMO through GSOO report</td>
<td>AEMO operates the Victorian Transmission System subject to the Service Envelope Agreement with APA GasNet, the system owner</td>
<td>APA GasNet maintain their own assets.</td>
</tr>
<tr>
<td><strong>Gas Distribution</strong></td>
<td>Four gas distribution networks</td>
<td>Private network operators</td>
<td>Private network operators</td>
<td>Private network operators</td>
<td>Private network operators</td>
</tr>
<tr>
<td><strong>Liquid Fuels</strong></td>
<td>All pipelines are privately owned by either oil companies or manufacturers of exotic gases etc.</td>
<td>Some lines are joint owned with one company acting as operator.</td>
<td>Self controlled by companies according to commercial interest</td>
<td>By owning entity</td>
<td>By owning entity</td>
</tr>
</tbody>
</table>
4. Infrastructure planning and maintenance

**Electricity generation**

**National Electricity Market (NEM)**

The NEM spans Australia's eastern and south-eastern coasts and comprises five interconnected states: Queensland, NSW, South Australia, Victoria, and Tasmania. The NEM’s transmission network carries power from electricity generators to large industrial energy users and local electricity distributors across the five states. The NEM is a wholesale commodity exchange for electricity across the interconnected states. Electricity cannot be stored easily, so the electricity market works as a “pool”, or spot market, where power supply and demand is matched instantaneously in real time through a centrally coordinated dispatch process. Generators offer to supply the market with specified amounts of electricity at specified prices for set time periods, and can re-submit the offered amounts at any time. From all the bids offered, the Australian Energy Market Operator (AEMO) decides which generators will be deployed to produce electricity, with the cheapest generator put into operation first.

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Name/Description of assets</th>
<th>Management</th>
<th>Responsibility for Planning</th>
<th>Operations</th>
<th>Maintenance</th>
</tr>
</thead>
</table>
| Thermal Generation | Coal based assets | The management of both coal and gas based assets is generally carried out by the plant owners. Although Newport and Jeeralang are owned by Ecogen, EnergyAustralia (EA) has hedge arrangements for their capacity through the Ecogen Master Hedge Agreement until 2019. Under the arrangement, EA provides the fuel and markets the output of the plants. | The Australian Energy Market Operator (AEMO) is responsible for the assessment of the adequacy of existing and committed generation capacity in the National Electricity Market to meet maximum demand and annual operational consumption forecasts over the next 10 years. AEMO publishes an Annual Electricity Statement of Opportunities (ESOO) which identifies generation capacity needs.² | • Plant operator submits price bids to NEM  
• AEMO determines dispatch in accordance with demand and bid prices | • Plant operator (minor maintenance)  
• Contractors |
| | Gas based assets | | | | • Plant operator (minor maintenance)  
• Contractors  
• Original Equipment Manufacturers (OEMs) |
| Renewables | Renewable | Plant owners | | | |

Notes:
4. Infrastructure planning and maintenance

Electricity transmission & distribution

National Electricity Market (NEM)

- **Australian Energy Market Commission (AEMC)**
  The AEMC makes rules under the National Electricity Law, the National Gas Law and the National Energy Retail Law. These rules impact on how companies can operate and participate in the competitive generation and retail sectors. They also govern the economic regulation of electricity transmission and distribution network services and gas pipelines.

- **Australian Energy Market Operator (AEMO)**
  AEMO is the electricity and gas system operator and is responsible for the National Transmission Planning.
  In Victoria, the transmission arrangements differ to those of the other states in that the transmission network is owned and maintained by AusNet Services, but AEMO makes the decisions to invest in expansions of the transmission network. As such, responsibility for planning of transmission network services is shared by three different parties:
  - AEMO as the body solely responsible for planning the shared network and procuring network support and shared network augmentations
  - AusNet Services as the asset owner
  - Transmission customers (distribution companies, generation companies and directly connected industrial customers) undertaking joint planning to determine the augmentation requirements for their respective transmission connection assets.

- **Australian Energy Regulator (AER)**
  The AER is responsible for the economic regulatory functions and enforcement of the electricity and gas networks - including the NEM. In relation to electricity transmission, the AER is responsible for approving revenue for services. The AER collects, analyses and reports on information provided by regulated businesses about their past, present and future performance.

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Name / Description of assets</th>
<th>Management</th>
<th>Responsibility for Planning</th>
<th>Operations</th>
<th>Maintenance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity</td>
<td>High voltage electricity transmission network</td>
<td>AusNet Services</td>
<td>AEMO, AusNet Services, Transmission customers</td>
<td>AusNet Services</td>
<td>AusNet Services</td>
</tr>
<tr>
<td>distribution</td>
<td>Five distribution networks</td>
<td>Network service providers (CitiPower, Jemena Electricity Networks, Powercor, SP AusNet, United Energy Networks)</td>
<td>Network service providers</td>
<td>Network service providers</td>
<td>Network service providers</td>
</tr>
</tbody>
</table>


4. Infrastructure planning and maintenance

Gas supply & transmission\(^1,2\)

- National Gas Law (NGL) and National Gas Rules (NGR) set out the regulatory framework.
- AER regulates tariffs in some cases. Economic regulations apply only to ‘covered’ pipelines.
- AEMO produces the Victorian Gas Statement of Opportunities (GSOO) planning report that includes supply and demand forecasts. The GSOO is intended for energy stakeholders and potential gas industry investors to inform about the current state of the gas industry in Eastern and South Eastern Australia, particularly gas system constraints, future developments and opportunities for investment.
- AEMO also produces the Victorian Gas Planning Report (VGPR). This report provides information on the DTS, including an overview of the system, pipeline and production facility capacities and the capacity of the DTS as a whole (system capacity).
- AEMO operates the Declared Wholesale Gas Market in Victoria.
- Unconventional gas (coal seam, shale and tight gas) exploration and production is currently on hold in Victoria. A ban on use of BTEX chemicals is also in place\(^1\).
- AEMO’s integrated role as Victorian gas market and system operator is unique; elsewhere AEMO operates the gas Short Term Trading Market, but gas system infrastructure is operated by facility owners\(^4\).

Notes:
4. AEMO, 2013, VGPR

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Name/Description of assets</th>
<th>Management</th>
<th>Responsibility for Planning</th>
<th>Operations</th>
<th>Maintenance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Supply</td>
<td>Longford Gas Plant</td>
<td>Esso</td>
<td>By owning entity, informed by AEMO through VGPR</td>
<td>By owning entity</td>
<td>By owning entity</td>
</tr>
<tr>
<td></td>
<td>Iona Processing Plant &amp; Underground Gas Storage Plant</td>
<td>QIC Ltd</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Dandenong LNG Gas Storage Facility</td>
<td>APA</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas Transmission</td>
<td>Victorian Declared Transmission System (DTS)</td>
<td>APA GasNet Australia (Operations) Pty Ltd</td>
<td>By owning entity, informed by AEMO through GSOO report</td>
<td>By owning entity with the exception of the DTS, AEMO operates the DTS subject to the Service Envelope Agreement with APA GasNet, the system owner.</td>
<td>By owning entity</td>
</tr>
<tr>
<td></td>
<td>Eastern Gas Pipeline (EGP)</td>
<td>Jemena</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>SEA Gas Pipeline</td>
<td>South East Australia Gas Pty Ltd</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Tasmanian Gas Pipeline (TGP)</td>
<td>Tasmanian Gas Pipeline (TGP) Pty Ltd</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Horsham Carisbrook Ararat Pipeline</td>
<td>Gas Pipelines Victoria Pty Ltd</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

\(^{1,2}\) Gas supply & transmission refers to the national and state-level regulations governing the gas industry. The GSOO report and the VGPR provide comprehensive data on gas system capacities and future developments. A ban on BTEX chemicals affects unconventional gas exploration and production. AEMO's role is unique in managing the gas market and system infrastructure compared to other states. Unconventional gas exploration and production are on hold due to the ban on BTEX chemicals.
4. Infrastructure planning and maintenance

Gas distribution

The primary responsibility for planning, operating and maintaining the gas distribution networks fall to the private network operators. In undertaking these activities network operators must comply with a number of standards outlined in guidelines and legislative instruments.

For example, under the Gas Distribution Code, DNSPs must:

- Use reasonable endeavours to maintain the capability of its distribution system
- Use its best endeavours to connect a customer’s gas installation
- Establish operational and system security standards
- Maintain the delivery pressure of gas from the distribution system to ensure the minimum supply pressure is maintained
- Meet the prescribed standards of quality.

Another example is the Pipelines Regulations 2007, administered by Energy Safe Victoria, which prescribe Australian Standards for the construction and operation of pipelines and the elements that must be contained in Safety Management Plans.

AEMO assists network operators plan their network by forecasting gas demand (such as in the National Gas Forecasting Report) and providing information on the adequacy of the industry (such is in the GSOO report and the VGPR). However, it does not direct the operators to augment their networks.

The AER similarly does not have a specific role in planning, operating or maintaining the network. Gas DNSPs outline a raft of proposed activities to the AER as part of the process to seek revenues; however, the AER has no power to compel a DNSP to undertake any such activity.

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Name / Description of assets</th>
<th>Management</th>
<th>Responsibility for Planning</th>
<th>Operations</th>
<th>Maintenance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas distribution</td>
<td>Four gas distribution networks</td>
<td>Private network operators</td>
<td>Private network operators</td>
<td>Private network operators</td>
<td>Private network operators</td>
</tr>
<tr>
<td>Liquid fuels</td>
<td>All pipelines are privately owned by either oil companies or manufacturers of exotic gases etc.</td>
<td>Some lines are joint owned with one company acting as operator.</td>
<td>Self controlled by companies according to commercial interest.</td>
<td>By owning entity</td>
<td>By owning entity</td>
</tr>
</tbody>
</table>

Notes:

1. IEA, 2009, Oil & Gas Security
5. Pricing schemes

**Generation – thermal**
Generators either sell their energy on the spot market or via offtake contracts. The spot market operates as a reverse auction, where generators make bids to sell electricity. To meet demand, AEMO directs the generators with the lowest bids to generate electricity. The price received by generators is the highest bid that is needed to meet demand at the time. A dispatch price is determined every five minutes, and six dispatch prices are averaged every half-hour to determine the ‘spot price’ (AEMO).

In the absence of networks constraints, interstate trade brings prices across the regions towards alignment. There may be some disparity due to transmission losses associated with transporting electricity, and when the demand on the interconnectors (which connect States) exceed capacity. In this case a regional specific electricity spot price prevails (AER, 2007). Electricity wholesale prices that generators receive are subject to a price floor of minus $1,000 per megawatt hour (MWh) and a price cap of $13,800 per MWh (AEMC, 2015). The negative price floor allows generators to pay to stay online when that cost is lower than the cost of shutting down and subsequently re-starting their plants.

There are rules governing generators’ bidding behaviour, which affects how they price electricity. Generators may submit ‘rebids’ up until five minutes prior to dispatch to reflect changing circumstances, including changes in demand, plant availability or network constraints. Rebids, however, must be made in ‘good faith’—meaning that at the time the rebid is made, the generator must have a genuine intention to honour the rebid if the material conditions and circumstances upon which the rebid was based remain unchanged (Maddocks, 2015). In effect, this rule seeks to prevent generators from strategically bidding up wholesale prices. These rules are under review with the intention that they are strengthened to further prevent generators from strategically bidding up wholesale prices (AEMC, 2015).

The wholesale generation market is competitive meaning prices are likely to reflect costs.

**Generation – renewable**
The pricing arrangements of scheduled and semi-scheduled renewable generators (accounting for the majority of larger renewable generators) are the same as described above for thermal generators. However, one practical difference is that renewable generators typically have a higher level of contracted electricity as these offtake contracts underpin their initial construction. Unlike thermal generators, renewable generators (other than some hydro) cannot choose when to generate electricity, meaning it is more difficult for them to exploit the high wholesale prices that sometimes prevail, typically when demand is high.

There are also specific incentives to develop renewable generators, which may indirectly affect their pricing. These incentives are discussed in the next slide.

AEMC, FACT SHEET, The National Electricity Market.
AEMC, DRAFT RULE DETERMINATION, National Electricity Amendment (Bidding in Good Faith) Rule 2015, Rule Proponent(s) Minister for Mineral Resources and Energy (South Australia), 17 September 2015
5. Pricing schemes

Renewables

There are a number of regulatory schemes that provide incentives for developers to construct renewable generation. These do not directly affect how generators price their generated electricity, but they increase the commerciality of the project development. The most notable scheme that applies is the Renewable Energy Target (RET) which applies throughout Australia.

Renewable Energy Target

The RET was designed to encourage both large and small scale renewable energy generation in Australia. The RET now comprises of two schemes—the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

The LRET operates to incentivise renewable generation from sources such as solar, wind, geothermal, wood and agricultural waste, bagasse and landfill gas (Clean Energy Regulator, 2015). Under the LRET eligible power stations are able to create Large-scale Generation Certificates (LGC) based on the amount of renewable electricity generated (above a baseline—zero for renewable energy generators that commenced generation after 1 January 1997). One LGC equals to one MWh of renewable energy generated.

The LRET specifies a national target for renewable energy generation (above baseline) up to 2030 and requires liable entities (typically electricity retailers) to procure LGCs for every year of the scheme. The target has been revised downwards to 33 terawatt-hours (TWh) in 2020.

As shown below, significant renewable generation needs to be constructed to meet the LRET Australia wide. It is not clear, at this stage, what proportion of this will be constructed in Victoria.

<table>
<thead>
<tr>
<th>Year</th>
<th>Surplus used</th>
<th>Wind</th>
<th>Hydro</th>
<th>Other</th>
<th>Small scale generation</th>
<th>Solar</th>
<th>Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2012</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2013</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2014</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2015</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2016</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2017</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2018</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2019</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
<tr>
<td>2020</td>
<td>0</td>
<td>0</td>
<td>5,000,000</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>15,000,000</td>
</tr>
</tbody>
</table>

Solar funding

In September 2015 the CEFC and ARENA announced $250 million and $100 million of funding allocation respectively to support large scale solar projects (ARENA, 2015; CEFC, 2015). Queensland is seeking to ensure up to 60 MW of these solar developments are constructed in Queensland by further supporting the developments (Queensland Government, 2015; Reneweconomy, 2015).

http://www.cleanenergyregulator.gov.au/RET/Scheme-participants-and-industry/Power-stations/Eligibility-criteria
5. Pricing schemes

Energy efficiency

There are a number of regulatory schemes that provide incentives by way of rebates, tariff incentives and efficiency labelling and awareness programs. The Energy Saver Incentive (ESI) is also known as the Victorian Energy Efficiency Target (VEET) scheme. The Essential Service Commission (ESC) operates the VEET. The ESI scheme will continue to be strengthened in 2016. This will include broad community and industry consultation. On 25 August 2015 the Victorian Government announced that the ESI scheme target for 2016 are 5.4 million in tonnes CO2e GHG abatement. This ramps up to a target of 6.5 million in 2020. New VEET targets have been legislated out to 2025 and future targets will be set by regulation thereafter.

**VEET Activity by sector**

The activity of VEET in the residential and business sectors is shown in the table. Activity targeting the Business (industrial commercial sector) is limited.

Electricity usage in this sector is approximately 66 per cent of energy consumed.

The uptake of household photovoltaics (PV) may reduce the incentive for residential efficiency improvements.

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5. Pricing schemes

Gas and electricity transmission and distribution

Legislative background—electricity and gas

Electricity and gas network operators are subject to economic regulation, which affect the revenues these businesses receive and the prices they charge. The regulatory framework is underpinned by the National Electricity Law (NEL) and the National Gas Law (NGL), which are passed by the South Australian Parliament. To provide a consistent National framework, each State then passes legislation adopting the law as set out by the South Australian Parliament.

The AEMC then makes rules under the NEL and NGL, being the National Electricity Rules (NER) and National Gas Rules (NGR) respectively. These rules detail the operation of the regulatory framework and market. The economic regulatory functions are undertaken by the AER.

Regulatory approach—electricity and gas

Gas and electricity TNSPs and DNSPs are regulated via the building blocks approach – a form of incentive based regulation. The key characteristic of this type of regulation is that NSPs are provided with financial rewards for pursuing desirable objectives, particularly the efficient operation of their networks. NSP that achieve efficiency improvements are rewarded financially for doing so.

The AER sets revenue allowances for NSPs over a 5 year period. It does this by assessing and forecasting the capex, opex and rate of return that an efficient NSP would need to operate the network. If a NSP underspends its capex and opex allowances (all other things being equal) it receives revenue based on the forecast allowance (during that period) but does not incur the costs underlying that forecast. In isolation, this provides an incentive to expend as little as possible but this is offset by three factors:

• Actual capital expenditure is rolled into the Regulated Asset Base (RAB) at the end of the regulatory period and the NSPs receives the regulated rate of return on the actual capex in subsequent periods. If the rate of return is higher than the firm’s cost of capital, which has arguably been the case historically, then additional returns are achieved by expending capex with the aim of increasing the RAB.
• The AER gives some credence to the revealed cost approach. This means that there is a relationship between actual expenditure in the previous period and forecast expenditure in the next regulatory period. As such, cutting expenditure in one period will generally result in lower allowances in subsequent periods.
• The Service Target Performance Incentive Scheme penalises NSPs for decreases in supply reliability. This provides a mechanism to ensure that NSPs do not underspend on their networks at the expense of reliability. Note that this incentive scheme applies only to electricity NSPs and no similar scheme applies to gas NSPs.

Revenues to tariffs (prices)

The revenue allowance determined under the building block formula is ultimately translated to network tariffs. This can be done in one of two ways: a price cap or a revenue cap.

A price cap translates forecast revenue into prices that the DNSP can charge. Importantly, the price cap places no upper or lower limit on the revenue recovered by a NSP in any given year. That is, if revenue recovered under the price cap is greater than the expected revenue (for example due to higher than anticipated demand), the NSP keeps that additional revenue. The converse also holds.

Under a revenue cap, the amount the NSP can earn in any year is determined by the AER. The amount of revenue actually received will vary from the allowed amount as a result of forecasting errors. The AER accounts for differences and deducts additional revenue in future years. In this manner the revenue cap ensures that a NSP cannot over or under recover the revenue allowance determined by the AER.

For the 2016 to 2020 regulatory period, the AER has decided to move Victorian electricity distribution businesses from a price cap to a revenue cap for the provision of standard network services as well as for metering services to residential and small business customers. The situation in the gas industry is less clear in part due to the mixture of regimes in Australia ranging from Market Carriage in Victoria, through to covered and unregulated transmission pipelines.

Source: Deloitte
5. Pricing schemes

Liquid fuels

Liquid fuels pipelines are generally owned by single entities. When there is surplus capacity available, commercial arrangements for storing or processing occur. There is no local requirement for access.

Terminal charges are based on supply chain costs that can include shipping and port charges, capital costs associated with storage and facilities and terminal operating costs. Some of these costs, such as port charges and leases, are outside the direct control of terminal operators.

The economics of petroleum import supply chains and the lumpiness of investment in new capacity mean that the short run marginal cost of servicing additional growth in the market is generally less than the long run marginal cost of adding capacity. Under such circumstances, existing suppliers can provide small additions to supply at a lower additional cost than a new entrant.

An independent fuel supplier has three options for entering or expanding activities in the petroleum product market:

1. contract product from an existing refiner marketer
2. enter into a hosting arrangement with an existing terminal owner (under such an arrangement, an independent would need to source imported product either from sellers offering product or by arranging the shipping and delivery of the fuel to the hosting terminal)
3. either lease import capacity from another independent or invest in additional terminal capacity itself.
Infrastructure condition
### 6. Annual operating and maintenance expenditure

*Operating and maintenance expenditure is generally considered reasonable compared to inter-jurisdictional benchmarking results.*

#### Annual operating and maintenance expenditure

<table>
<thead>
<tr>
<th>Sub-sector</th>
<th>Infrastructure maintenance</th>
<th>Service operations</th>
<th>Total</th>
<th>Inter-jurisdictional benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Generation</td>
<td>Breakdown not available</td>
<td>Breakdown not available</td>
<td>$832 million</td>
<td>Annual O&amp;M spend on NSW coal fired plants of a similar age is less than that on the Victorian plants.</td>
</tr>
<tr>
<td>Renewables</td>
<td>Breakdown not available</td>
<td>Breakdown not available</td>
<td>$65 - 100 million (wind generation)</td>
<td>Benchmarking rate for wind generation in Victoria. Australia is typically higher than in the US and Europe due to the industry being smaller and the relative unavailability of third party O&amp;M providers.</td>
</tr>
<tr>
<td>Electricity Transmission</td>
<td>$41 million</td>
<td>$50 million</td>
<td>$91 million</td>
<td>Victoria generally achieves higher productivity output for the operating expenditure spent compared to other National Electricity Market participants.</td>
</tr>
<tr>
<td>Electricity Distribution</td>
<td>$151 million</td>
<td>$596 million</td>
<td>$746 million</td>
<td>AER benchmarking indicate that for operating expenditure, the Victorian businesses are currently among the most efficient service providers in the National Electricity Market.</td>
</tr>
<tr>
<td>Gas Supply and Transmission</td>
<td>Breakdown not available</td>
<td>Breakdown not available</td>
<td>$34.3 million (forecast 2016)</td>
<td>AER benchmarking indicate that Victorian gas transmission businesses have a higher operating expenditure. This is likely to Victoria having a more extensive network.</td>
</tr>
<tr>
<td>Gas Distribution</td>
<td>Breakdown not available</td>
<td>Breakdown not available</td>
<td>$180 million</td>
<td>Meaningful benchmark comparisons are not available due to data limitation and significantly different operating environments.</td>
</tr>
<tr>
<td>Liquid Fuels</td>
<td>Difficult to obtain accurate values</td>
<td>Difficult to obtain accurate values</td>
<td>Difficult to obtain accurate values</td>
<td>Benchmark comparisons are not available due to data limitations.</td>
</tr>
</tbody>
</table>
6. Annual operating and maintenance expenditure

**Thermal generation**

**Coal Assets**

**Annual Operating Expenditure**
- This data is not published directly by each asset owner as it would be commercially sensitive information.
- Values have been estimated using data from AEMO (i.e. 2014-15 annual generation in GWh for each Unit) and data from ACIL Allen (fixed & variable operations and maintenance (O&M) costs for each Australian Power Plant).
- The table provides a summary of calculated annual O&M expenditure for each coal asset.
- The table provides non-fuel operating and maintenance costs.
- Loy Yang A (LYA) has a disproportionately higher spend than Loy Yang B (LYB) because LYA conducts all mining operations and ash disposal operations across both stations.
- From the same source data, the annual O&M spend on NSW coal fired plants of a similar age is less than that on the Victorian plants. However Victorian coal is unique and additional expenditure is required for sootblowing and ash removal. O&M may include operational costs associated with coal mine operations and maintenance.
- The total estimated annual O&M spend on the assets is **$783.9 million**.

<table>
<thead>
<tr>
<th>Power station</th>
<th>Total MW</th>
<th>Annual GWh (2014-15)</th>
<th>Fixed O&amp;M $/MW</th>
<th>Fixed O&amp;M $M</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Variable O&amp;M $M</th>
<th>Total Annual O&amp;M $m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hazelwood</td>
<td>1600</td>
<td>11,003</td>
<td>131,539</td>
<td>210</td>
<td>1.11</td>
<td>12.2</td>
<td>222.7</td>
</tr>
<tr>
<td>Loy Yang A</td>
<td>2210</td>
<td>16,275</td>
<td>122,144</td>
<td>246</td>
<td>1.11</td>
<td>18.1</td>
<td>263.6</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>1000</td>
<td>8,712</td>
<td>87,738</td>
<td>88</td>
<td>1.11</td>
<td>9.7</td>
<td>97.4</td>
</tr>
<tr>
<td>Yallourn</td>
<td>1480</td>
<td>11,268</td>
<td>126,842</td>
<td>188</td>
<td>1.11</td>
<td>12.5</td>
<td>200.2</td>
</tr>
</tbody>
</table>

**Gas Assets**

<table>
<thead>
<tr>
<th></th>
<th>Total MW</th>
<th>Annual GWh</th>
<th>Fixed O&amp;M $/MW</th>
<th>Fixed O&amp;M $M</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Variable O&amp;M $M</th>
<th>Total Annual O&amp;M $m</th>
</tr>
</thead>
<tbody>
<tr>
<td>Somerton</td>
<td>160</td>
<td>11</td>
<td>12,214</td>
<td>1.8</td>
<td>2.0</td>
<td>0.10</td>
<td>2.1</td>
</tr>
<tr>
<td>Jeeralang A</td>
<td>204</td>
<td>6</td>
<td>12,214</td>
<td>2.7</td>
<td>2.5</td>
<td>0.05</td>
<td>2.5</td>
</tr>
<tr>
<td>Jeeralang B</td>
<td>228</td>
<td>17</td>
<td>12,214</td>
<td>2.9</td>
<td>2.8</td>
<td>0.14</td>
<td>2.9</td>
</tr>
<tr>
<td>Newport</td>
<td>500</td>
<td>95</td>
<td>37,583</td>
<td>18.8</td>
<td>18.8</td>
<td>0.20</td>
<td>19.0</td>
</tr>
<tr>
<td>Bairnsdale</td>
<td>94</td>
<td>148</td>
<td>12,214</td>
<td>1.1</td>
<td>1.1</td>
<td>0.31</td>
<td>1.5</td>
</tr>
<tr>
<td>Mortlake</td>
<td>566</td>
<td>1,164</td>
<td>12,214</td>
<td>6.7</td>
<td>6.9</td>
<td>9.00</td>
<td>15.9</td>
</tr>
<tr>
<td>Laverton North</td>
<td>320</td>
<td>1</td>
<td>12,214</td>
<td>3.9</td>
<td>3.9</td>
<td>0.01</td>
<td>3.9</td>
</tr>
<tr>
<td>Valley Power</td>
<td>300</td>
<td>5</td>
<td>12,214</td>
<td>3.7</td>
<td>3.7</td>
<td>0.04</td>
<td>3.7</td>
</tr>
</tbody>
</table>

- Although annual MWh generated by gas turbines is low, number of starts contributed to maintenance requirements.
- Newport uses boiler / steam turbine technology (no gas turbine). So maintenance cost structure is different to GT plant (more like coal fired plant).

Notes:
2. Dummy text
3. Newport, although gas fired is a steam plant so the maintenance regime is more like the coal fired plants.
6. Annual operating and maintenance expenditure

Renewables

Renewable generators are typically privately run and not regulated, meaning opex is not published. However, benchmarks are available, particularly for wind farms. We have applied these benchmarks to the Victorian wind farms that are scheduled, semi-scheduled and non-scheduled over 50 MW. The nameplate capacity of the windfarms has been translated into an energy per annum energy output using the individual windfarm capacity factors published by AEMO (AEMO, 2013).

International opex costs have been examined using international benchmarks and then have been applied to Victoria’s windfarm capacity to compare them on a like basis.

Opex benchmarks are quoted as a $/MW cost, or split between fixed (or planned) and variable (or unplanned) opex. Fixed opex is related to the size, or capacity of the plant and unplanned opex is related to the amount of electricity generated. Types of fixed opex include wages, insurances, other overheads and periodic maintenance. Variable opex is related to wear and tear.

Opex estimates based on benchmarks are presented on a $/MWh basis in the tables below.

International comparison

There is considerable variability in the benchmarks which makes international comparisons difficult. However, opex in Australia is typically higher than in the US and Europe due to the Australian industry being smaller with third party O&M providers relatively unavailable (ACIL Allen, 2015).

International—benchmark opex

<table>
<thead>
<tr>
<th>Country</th>
<th>Benchmark</th>
<th>International opex AUD$/MWh ($ real, 2015)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Europe</td>
<td>KIC InnoEnergy (2014)</td>
<td>$16.7 - 19.5</td>
</tr>
<tr>
<td>US</td>
<td>As above</td>
<td>$7.7 - 23</td>
</tr>
</tbody>
</table>

KIC InnoEnergy, Future renewable energy costs: onshore wind, 2014

Victoria—benchmark opex (wind energy)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ACIL Allan (2014)</td>
<td>$27.3</td>
<td>$100.7 million</td>
</tr>
<tr>
<td>C02/CRC, CSIRO et al (2015)</td>
<td>$17.5</td>
<td>$64.3 million</td>
</tr>
</tbody>
</table>

C02/CRC, Australian Power Generation Technology Report, 2015

AEMO, INTEGRATING RENEWABLE ENERGY - WIND INTEGRATION STUDIES REPORT: For the National Electricity Market (NEM), 2013
6. Annual operating and maintenance expenditure

Electricity transmission

Electricity transmission operating expenditure (average per annum 2017-22) ($M, real 2016-17)

<table>
<thead>
<tr>
<th>Category</th>
<th>Infrastructure maintenance</th>
<th>Service operations</th>
<th>IT</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Controllable Opex¹</td>
<td>40.6</td>
<td>50.0</td>
<td>10.2</td>
<td>100.8</td>
</tr>
</tbody>
</table>

The table above is based on AusNet Services proposal to the AER for the 2017-2022 regulatory period. The level of operating expenditure is yet to be approved by the AER. It is noted that for Victoria’s five electricity distributors, the AER preliminary decision on regulatory proposals was to reduce the overall opex levels by 16 per cent from that proposed. Significant reductions were also observed for the recent TransGrid (NSW electricity transmission network operator) regulatory determination.

Inter-jurisdictional comparison

The figure below indicates that operational expenditure for the AusNet Services transmission network is lower than the transmission operators in New South Wales (TransGrid) and Queensland (Powerlink). This reflects the considerable difference in geographical size of these networks. Comparison using a normalising factor of weighted number of customer connections indicates that AusNet Services is reasonably cost efficient.

[Graph showing inter-jurisdictional comparison]

Source: AER, Annual transmission benchmarking report, 2014, p.33

Notes:
1. Controllable opex is for prescribed transmission services and excludes insurance and easement land tax.
2. Values for sub-categories of controllable opex determined by applying a historical percentages of actual spend on controllable opex to forecast controllable opex total figure.
3. Service operations figure includes sub-elements of system operations, support services, finance, health and safety, human resources, management fees, other corporate and taxes and leases.
6. Annual operating and maintenance expenditure

**Electricity distribution**

*Electricity distribution operating expenditure (average per annum 2017-22) ($M, real 2015)*

<table>
<thead>
<tr>
<th>Asset</th>
<th>Infrastructure maintenance¹</th>
<th>Service operations¹²</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>AusNet Services</td>
<td>33.9</td>
<td>186.9</td>
<td>220.8</td>
</tr>
<tr>
<td>Powercor</td>
<td>63.5</td>
<td>169.3</td>
<td>232.8</td>
</tr>
<tr>
<td>United Energy</td>
<td>20.1</td>
<td>111.9</td>
<td>131.9</td>
</tr>
<tr>
<td>Jemena</td>
<td>7.5</td>
<td>70.5</td>
<td>78.0</td>
</tr>
<tr>
<td>CitiPower</td>
<td>25.5</td>
<td>57.1</td>
<td>82.7</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>150.5</strong></td>
<td><strong>595.7</strong></td>
<td><strong>746.3</strong></td>
</tr>
</tbody>
</table>

The above table is based on the preliminary decisions made by the AER on the proposals from each distributor for the 2016-2020 regulatory period. It is noted that the AER preliminary decisions are approximately 16 per cent lower than the opex proposed in the original submission by the distributors. This decision was made on the basis of the opex criteria: the costs that a prudent operator—with efficient costs and a realistic expectation of demand and cost inputs—would need to operate its network safely and comply with its obligations and service standards.

AER benchmarking indicates the Victorian distribution utilities have been operating relatively efficiently compared to other service providers in the National Electricity Market. As such the efficient base year selected for the period was generally 2014. The main difference between the AER preliminary decisions and distributor proposals is the rate of change applied to the efficient base year opex and also the exclusion of opex for advanced metering infrastructure from standard control services.

Notes:
1. Values for sub-categories of opex determined by applying a historical percentages of actual spend obtained from 2014 RIN submissions.
2. Service operations figure includes sub-elements of vegetation management, emergency response, non-network, network overheads, corporate overheads and other (refer figure bottom-right).
6. Annual operating and maintenance expenditure

Electricity distribution

Inter-jurisdictional comparison

AER benchmarking results show that for operating expenditure, the Victorian businesses are currently among the most efficient service providers in the National Electricity Market. This is reflected not only in the overall opex by distributor (figure left), but also when considering the normalising factors of opex per MW of maximum demand and customer density (figure right).

In comparing operating expenditure for distribution network service providers in Australia, it is important to consider that there are differences between operating environments including the size, network terrain, climate and jurisdiction specific requirements.

Source: AER, Electricity distribution network service providers: Annual benchmarking report, November 2014, p.35

Source: AER, Electricity distribution network service providers: Annual benchmarking report, November 2014, 39
6. Annual operating and maintenance expenditure

Liquid Fuels, Gas Supply and Transmission

The total annual operating and maintenance expenditure for the APA transmission pipeline network is $34.3 million (forecast value 2016). A breakdown on this value is not publically available.

General practice is that pipeline owners invest around 5 per cent of the capex value annually on operations and 1–10 per cent on maintenance (increasing as the pipelines age).

The indicative cost of each category of asset is an approximation based on average total installed cost in current dollars.

Annual operating and maintenance expenditure on other gas pipeline assets such as Jemena’s transmission pipeline network, Iona peak storage and SEA gas pipeline are not publically available.
6. Annual operating and maintenance expenditure

Gas distribution

Historical opex - Victoria

Historical opex has been reported by the AER for Victorian gas DNSPs, however, this was done under a framework established (and previously applied) by the ESC. Given this framework was Victorian specific, this information is only available for Victorian gas DNSPs. Further, the AER has ceased reporting under this framework.

Operating expenditure includes costs associated with functions such as:
• maintenance
• network operations
• billing and revenue collection
• market development activities
• customer connections
• maintenance of meters
• management and administration.

Opex of the Victorian gas DNSPs from 2008-12 is shown below:

![Historical differences between actual and forecast opex](source)

Only forecast, rather than actual opex is available for more recent periods. This is forecast by the DNSPs and the AER as part of the AER’s price setting process. Regulatory forecast and actual opex will differ as shown in the following figure.

Of particular note is a large variance for MultiNet in 2012, which it explained as an allowance ‘set by the ESCV...too low to operate the network in a safe and reliable manner’.

Notwithstanding the historical differences, as information on DNSPs operating costs is revealed to the AER over time, we would expect any differences to reduce. We have presented the forecast opex for the Victorian DNSPs and NSW DNSPs below.

![Actual and forecast opex per customer (VIC 2013-17, NSW 2016-20)](source)

Meaningful comparisons for gas distribution are not available due to data limitations outlined above and significantly different operating environments.

Opex per customer in all Victorian distribution areas is lower than in NSW.
At a high level, energy infrastructure in Victoria is considered to be in reasonable condition. This is driven by strong ratings for renewable generators and the electricity and gas networks. Liquid fuels pipelines score below average due increased reliance on overseas supply.

Asset Condition Assessment
The approach adopted within the Sector and each Sub-Sector was to measure based on the desktop research and stakeholder engagement:

- **Physical Condition**: Measures the level of maintenance required to maintain full functionality.
- **Fit for purpose**: Measures the ability of the asset, including infrastructure, technology and fit-out, to meet current and likely future user needs.

Ratings were assigned to sub-sectors from 1 to 5 where:

- 1 is poor condition insufficient to meet current demands and use requirements
- 5 is superior condition sufficient to be suitable for future demands and use requirements for the following 30 years.

Physical condition
- Life extension of coal fired generation plant is being undertaken. Gas fired plant are generally low duty machines and renewables are relatively young.
- Electricity network assets have good performance results indicating that asset management is effective.
- Physical condition of gas networks and liquid fuels pipelines is considered an important factor due to the high consequences of failure.

Fit for purpose
- Traditionally the electricity network has been designed to transmit energy from large generation sources to load centres. Fuel sources are moving (e.g. renewables now predominantly in the west of Victoria) and distributed generation is being introduced.

(Capacity - not included in ratings)
- Capacity constraints exist for Jet fuel supply to Melbourne airport.
- Large scale electricity storage is currently not available and hence capacity of the electricity network is an important consideration.
- Declining demand for gas annually means networks score highly for this aspect in spite of peak demand slowly increasing.

### Ratings
<table>
<thead>
<tr>
<th>Sub-sector</th>
<th>Physical condition</th>
<th>Fit for purpose</th>
<th>Sub-sector score</th>
<th>Weighting in overall sector</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermal Generation</td>
<td>3.7</td>
<td>2.6</td>
<td>3</td>
<td>30%</td>
</tr>
<tr>
<td>Renewables</td>
<td>3.6</td>
<td>3.6</td>
<td>3.6</td>
<td>10%</td>
</tr>
<tr>
<td>Electricity Transmission &amp; Distribution</td>
<td>4.5</td>
<td>3.6</td>
<td>4</td>
<td>20%</td>
</tr>
<tr>
<td>Gas Transmission &amp; Distribution</td>
<td>3.2</td>
<td>4.1</td>
<td>3.5</td>
<td>20%</td>
</tr>
<tr>
<td>Liquid Fuels</td>
<td>2.8</td>
<td>2.2</td>
<td>2.5</td>
<td>20%</td>
</tr>
</tbody>
</table>

Notes:
1. This assessment is of current asset condition and weightings of sub-sectors are selected accordingly. Within this framework, renewables is weighted lower than thermal generation as currently it is not considered as critical in terms of supply capacity. It is important to note that this is not an assessment of future importance of the sub-sectors.
7. Infrastructure condition

**Thermal generation - peaking gas**

The graph on the right shows the age profile of the gas fired plants. Although almost 40 per cent of the gas based assets are less than 10 years old, 40 per cent are between 40 to 50 years old. As the duty requirement of all gas plants is peaking, the elapsed operating hours of these plants is relatively low. Many of the assets are only operated for a few hundred hours per year.

**Thermal generation – base load coal**

The condition of the coal fired plant has been assessed with respect to power industry asset management practice:

- The typical design life of a large coal fired power plant is 25 years.
- However international practice is to operate plants until 40-50 years; this needs to be accompanied by appropriate mid-life condition assessment and replacement of critical components.

The graph on the right illustrates the age profile of the Victorian brown coal fired plant fleet. No new base load coal fired plant has been built in Victoria since 1996 when the second Loy Yang B unit was commissioned. It can be seen that more than 80 per cent of the generating capacity is greater than 25 years of age. Hazelwood, which provides around 25 per cent of the state’s coal based generation is 47 years old. As plants age beyond their design life, reliability would be expected to suffer and the unplanned outage rate increase.

The table below provides a summary of major overhaul / replacement works that have been carried out at each plant. Details were provided in earlier slide. The capacity factor has been calculated from the AEMO generated GWh for 2014-15.

<table>
<thead>
<tr>
<th>Asset</th>
<th>Age (yrs)</th>
<th>Capacity factor</th>
<th>Condition rating</th>
<th>Recent overhaul / replacement works</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hazelwood</td>
<td>~47</td>
<td>79%</td>
<td>2.3</td>
<td>The owners state that $1billion has been spent in last 20 years on improvements. Considering age of plant, 79% capacity factor suggest good reliability.</td>
</tr>
<tr>
<td>Yallourn P.S</td>
<td>~37</td>
<td>87%</td>
<td>3.0</td>
<td>In the past 5 years there has been significant replacement and upgrade works conducted on turbines. The condition of the boilers is not known.</td>
</tr>
<tr>
<td>Loy Yang A</td>
<td>~30</td>
<td>64%</td>
<td>3.1</td>
<td>It is believed that turbines were upgraded about 15 years ago.</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>~20</td>
<td>99%</td>
<td>3.5</td>
<td>Limited public information on recent plant expenditure. No significant expenditure required at present given age of plant.</td>
</tr>
</tbody>
</table>

**Age of coal fleet**

- The average age of the east coast Australian power generation fleet is provided (table right).
- The Victorian plant is very similar in age to the NSW fleet.
- With the construction of 4 new plants since 2001 in Queensland, the average age of this fleet is about 10 years lower.
- For an international comparison:
  - Average age of U.S coal fired fleet is 37 years
  - Average age of German coal fired fleet 30 years.

Notes:
7. Infrastructure condition

Renewables

The physical condition is given a rating of 4. The majority of renewable generators physically located in Victoria are wind generators. The ATO publishes an ‘effective life’ for wind turbines of 20 years. The effective life reflects ‘how many years the asset will reasonably be expected to produce income according to its actual likely use’. As such it is a reasonable proxy for the actual life of the asset, albeit, based on our market knowledge we consider that around 25 years is more reasonable. Many of the wind farms in Victoria have been commissioned in the last 5 years. This is was largely driven by the expansion of the RET in 2009 to 45,000 GWh by 2020. This means the current assets are likely to have a remaining life of around 20 years.

Victoria and Australia attract major renewable generator developers. As such, there is nothing to suggest Victorian generators are not developed to a level consistent with other Australian and international benchmark standards. However, there are fewer operators in Australia than in Europe, which has a more developed wind market. The sector therefore receives a rating of 4 for fitness of purpose.

Although the capacity is not rated in this section, from a market perspective there is no particular need for renewable generation in the short term (in Victoria or Australia), as there is currently excess generation capacity. However, the RET is driving the need for significantly more renewable generation by setting a target of 33 TWh by 2020. The RET puts in place a mechanism to meet the target, however, the timeframe is challenging and the scale significant.
7. Infrastructure condition

Electricity transmission

Victoria’s Transmission assets are generally in good condition and are being appropriately maintained as “Fit for purpose”. AusNet’s assets on average are older than other benchmarked utilities, however AusNet benchmarks well on asset performance as indicated in a number of areas.

- Transmission networks are required to meet strict availability and reliability indexes which are financially driven by the regulator. AusNet benchmarks in the top quartile in these areas.
- AusNet was the first Australian company to be ISO55001 accredited for asset management competence. This is reflected positively in their opex benchmarked costs and reliability measures.
- Significant capex has been and continues to be spent on renewing substations, including transformers and circuit breakers since the ITOMS 2013 benchmark of asset age.
- AusNet’s asset management strategy for the next regulatory period will be focusing on their transmission line equipment which overall will require less spend than previous periods.
- Average age of the transmission lines is 45 years, useful lives are expected to be in the order of 90 years.

<table>
<thead>
<tr>
<th>Electricity transmission and distribution condition assessment</th>
<th>Physical condition</th>
<th>Fit for purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>4.5</td>
<td>3.6</td>
</tr>
</tbody>
</table>

Inter-jurisdiction comparison

International benchmarking indicates that the Victorian transmission system provides strong composite service levels at average composite cost levels compared to other Australian and international transmission network operators. The 2013 ITOMS results indicate that AusNet Services (SPA):

- **Overall composite performance**: Compares favourably with the overall benchmarked average performance of other transmission companies in terms of transmission network service level and equivalent operating costs.
- **Transmission line maintenance composite performance**: Benchmarked performance for transmission lines maintenance has deteriorated compared with the 2009 survey, both in terms of cost and performance measures. Hence AusNet’s focus on transmission lines for the next regulatory period.
- **Substation maintenance composite performance**: Benchmark performance for substations maintenance has deteriorated compared with the 2009 survey and hence the recent large spend on renewals for this asset class.
7. Infrastructure condition

Electricity distribution

Like the transmission assets, Victoria’s distribution assets are generally in good condition and are being appropriately maintained as “Fit for Purpose”. The distribution assets on average are older than other benchmarked utilities.

The regulatory economic drivers together with a privatised business model, ensures that the Victorian assets are operated to the end of their useful economic lives. This tends to reflect the lower rate of asset renewals, longer asset lives and slight poorer network reliability than in other states.

The fact that the assets are managed to the end of their useful economic lives reflects in lower NUOS, Network Use Of System Charges across the Victorian DNSPs.

Maintenance expenditure on aged condition equipment such as substations and transformers is being adequately managed within the risk context explained above and the budget in the regulatory allowance.

Maintenance expenditure on the “poles and wires” has recently been given increased priority as a result or the Powerline Bushfire Safety Taskforce. Additional funding has been made available.

Average Australian network asset ages

Source: CitiPower Regulatory Proposal 2016-2020, 2015, p.45. Note: Jemena (incorrect format) and United Energy (inclusive of disposed assets) have been excluded from this analysis.

Source: St Vincent de Paul Society and Alviss Consulting, The NEM – Wrong way, go back?, September 2014

Average annual network vs. non-network use of system charges for electricity distributors (2009 – 2014)

Source: St Vincent de Paul Society and Alviss Consulting, The NEM – Wrong way, go back?, September 2014

<table>
<thead>
<tr>
<th>Distributor</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aurora (Transend)</td>
<td>Tas</td>
</tr>
<tr>
<td>Ausgrid</td>
<td>NSW</td>
</tr>
<tr>
<td>CitiPower</td>
<td>Vic</td>
</tr>
<tr>
<td>Endeavour</td>
<td>NSW</td>
</tr>
<tr>
<td>Energex</td>
<td>Qld</td>
</tr>
<tr>
<td>Ergon</td>
<td>Qld</td>
</tr>
<tr>
<td>Essential</td>
<td>NSW</td>
</tr>
<tr>
<td>Jemena</td>
<td>Vic</td>
</tr>
<tr>
<td>Powercor</td>
<td>Vic</td>
</tr>
<tr>
<td>SA Power Networks</td>
<td>SA</td>
</tr>
<tr>
<td>SP AusNet</td>
<td>Vic</td>
</tr>
<tr>
<td>United Energy (UE)</td>
<td>Vic</td>
</tr>
</tbody>
</table>
7. Infrastructure condition

Electricity distribution

Inter-jurisdiction comparison

Victorian DNSPs apply a probabilistic approach to the planning of network security. This planning criteria allows the DNSP to accept the loss of electric load based on a judgment on the economic value of that lost load. The DNSP then will balance the investment on infrastructure and asset management for the optimum outcome.

Benchmark data shows this as slightly higher Average Minutes Off supply per Customer or higher interruptions per customer than other states DNSPs but at a lower cost to the consumers.

\[\text{Total cost per customer against unplanned minutes off supply per customer (average 2010–2014)}\]

\[\text{Average number of interruptions per customer (2010–2014)}\]

Notes:
1. The effect of major events, planned outages and transmission outages have been excluded from the results reported in this figure.

7. Infrastructure condition

Gas supply and transmission

As a pipeline operator it is a licencing requirement that the operator must have state approved Safety Management Plans and Environment Management Plans.

In the first 10-20 years of the life of a high pressure (HP) licenced pipeline, revenue expenditure is contained to inspection, auditing and reporting.

After the first 20 years it is common that some Cathodic Protection (CP) systems need replacement and that the first signs of coating failures start to appear. Most long distance pipelines however have impressed current CP systems which do not require replacement of anodes.

After 40 years in the ground, some pipelines start to fail at weld joint coating locations and on occasion due to general coating defects. However, with modern pipelines (those built since the 1970s) pipelines which are properly maintained and inspected can last in excess of 100 years.

As can be seen from graphs to the right, the majority of high pressure pipelines are less than 40 years old and are expected to have long operating lives with minimal maintenance other than statutory periodic inspections, testing and auditing.

For the older HP pipelines the owners will continue to monitor condition and carry out upgrades as required at a slightly higher revenue expenditure.

With the medium pressure (MP) lines over half are over 40 years of age and thus fall in the category of higher maintenance costs.

With either type of transmission pipeline, one can expect them all to have long operating lives of 50 years and over.

---

**Gas transmission and distribution condition assessment**

<table>
<thead>
<tr>
<th>Physical condition</th>
<th>Fit for purpose</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
<td>4.1</td>
</tr>
<tr>
<td>1.5</td>
<td>3.2</td>
</tr>
<tr>
<td>2.0</td>
<td></td>
</tr>
<tr>
<td>2.5</td>
<td></td>
</tr>
<tr>
<td>3.0</td>
<td></td>
</tr>
<tr>
<td>3.5</td>
<td></td>
</tr>
<tr>
<td>4.0</td>
<td></td>
</tr>
<tr>
<td>4.5</td>
<td></td>
</tr>
<tr>
<td>5.0</td>
<td></td>
</tr>
</tbody>
</table>

**HP Gas Pipeline Age Brackets**

- 0-19
- 20-39
- 40+

**MP Gas Pipeline Age Brackets**

- 0-19
- 20-39
- 40+

---

Data Source: Australian Pipeline Licence Directory (2015)
7. Infrastructure condition

Gas distribution

Network life

The table below displays the weighted average (based on asset value) age and remaining life of each Victorian network at the beginning of the last regulatory period (2013 in Victoria). Using the remaining economic life as reported to the AER is a proxy for the age of the network because the asset lives used for regulatory purposes reflect the assets’ useful life.

Given that the DNSPs continue to upgrade and maintain their networks, we would consider the average remaining life to stay fairly constant over time.

AusNet’s network is the oldest of the Victorian networks. However overall, the spread is not large, with AusNet being only around 4 years older than the Victorian average.

<table>
<thead>
<tr>
<th>Asset / Equipment</th>
<th>Age</th>
<th>Remaining life</th>
</tr>
</thead>
<tbody>
<tr>
<td>MultiNet</td>
<td>17.8</td>
<td>29.9</td>
</tr>
<tr>
<td>AusNet</td>
<td>24.6</td>
<td>31.3</td>
</tr>
<tr>
<td>AGN (Vic)</td>
<td>17.7</td>
<td>37.2</td>
</tr>
<tr>
<td>AGN (Albury)</td>
<td>20.5</td>
<td>33.7</td>
</tr>
</tbody>
</table>

Inter-jurisdiction comparison

The Victorian networks’ average remaining life and average age is very similar to NSW as shown below.

![Graph showing average network age comparison between Vic and NSW](image-url)

Source: AER Post-tax revenue models (PTRMs)
7. Infrastructure condition

Liquid fuels

The liquid fuels pipeline network is generally connected to Major Hazard Facilities which are regulated and licenced premises under WorkSafe Victoria. The offshore pipelines are licenced with the National Offshore Petroleum Safety Authority and onshore pipelines with the Department of Primary Industry and Energy Safe Victoria.

The facilities and pipelines are all regulated and are required to be operated and maintained to a safe condition under various acts and regulations. The operators generally self-administer the required level of auditing and compliance. Self regulation of the pipeline condition is determined from Pipeline Integrity Management Plans. The operational aspects are covered under Environmental plans which are required as a means of ensuring emergency procedures are in place in the event of an incident.

As can be seen to the right, almost 50 per cent of unrefined product pipelines are over 40 years old and 75 per cent of refined product pipelines are over 40 years old.

Although the capacity is not rated in this section, constraints exist for the current Jet fuel supply to Melbourne Airport. Condition of this infrastructure is considered sufficient for 10-15 years with regular prescribed maintenance regimes. Capacity to refine fuels is reducing, increasing reliance on overseas supply. Storage capacity is currently limited. The industry is considered to be operating at an average practice level that in time will become substandard.
### 8. Costs of asset maintenance and renewal

**Thermal generation**

<table>
<thead>
<tr>
<th>Asset group</th>
<th>Renewal requirements ¹</th>
<th>Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal based generating facilities</td>
<td>- Coal based plant typically has a design life of 25 years</td>
<td>- Actual cost of plant life extension works will depend on required scope of works</td>
</tr>
<tr>
<td></td>
<td>- After around 20 years of operation it is normal to carry out a 'plant life extension' study to identify, budget and plan component replacement or upgrade necessary to extend plant life to ~40 years</td>
<td>- Cost may be up to 25 per cent of the overall plant replacement cost</td>
</tr>
<tr>
<td></td>
<td>- Many Australian PF plants of around 20 – 30 years of age have benefitted from a turbine upgrade, which provides both a more efficient turbine and extends plant life</td>
<td>- Critical factors will be the condition of pressure parts as damaged or thinned tubes and headers can represent a significant safety risk.</td>
</tr>
<tr>
<td></td>
<td>- Extent of work required on boiler depends on original design, coal properties and the operating history of the plant</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- For example a number of NSW and Queensland plants have required economiser replacements at 10 to 20 years of age (at an average cost of $10million per unit).</td>
<td></td>
</tr>
<tr>
<td>Gas turbine plant</td>
<td>- Gas turbine manufacturers provides a schedule of inspections which determines the condition of the components and, depending on the condition, the repairs/replacements activities which should be carried out to enable continued safe operation for a specified period of time</td>
<td>- For an open cycle GT plant, gas turbine replacement may be up to 85 per cent of overall plant replacement cost</td>
</tr>
<tr>
<td></td>
<td>- Depending on duty of plant (including operating hours, output, number of cold starts) the turbine may require replacement at its end-of-life.</td>
<td>- Once replaced, the plant can be assumed to have an additional design life equivalent to its original design life.</td>
</tr>
</tbody>
</table>

Notes:

8. Costs of asset maintenance and renewal

**Electricity transmission**

The expenditure is further defined for each asset category in AusNet Services planned submission to the AER for the 2017-22 regulatory determination:

**Stations**
- Circuit breakers replacements – around 70 circuit breakers (including 500 kV, 220 kV and 66 kV) with an unacceptable risk of failure require replacement in the forecast period.
- Disconnector replacements and refurbishments – the program involves replacing 75 units and refurbishing 50 units. Replacements are targeted at units which have previously failed or may physically fail during operation. This poses reliability and safety risks. Refurbishment is targeted at units which have been identified to be not operating reliably.
- Life extension of power transformers – this program involves works to extend the life of ageing power transformers. While the average age of power transformers is forecast to reduce over the regulatory period due to replacements undertaken as part of rebuild projects, the proportion of the transformer fleet over 50 years increases from 14 per cent in 2017 to 34 per cent in 2022. Life extension works include corrosion mitigation, replacement of defective fittings, replacing seals and installing on-line gas analysers.
- Civil infrastructure – involves the replacement or renewal of civil infrastructure and station facilities such as buildings, access roads and drainage systems, hand rails, retaining walls, station service transformers, air conditioning systems, and oil/water separating systems.

**Lines**
- Ground wire replacements – a limited program of groundwire replacements is forecast to target poor condition spans. This involves the replacement of sections of deteriorated steel ground wire totalling 226 km on 14 different circuits.
- Tower strengthening – a program to strengthen 48 towers on the 330 kV Murray Switching Station to Dederang Terminal Station lines; a section of the main interconnector between NSW and Victoria.

**Secondary and protection**
- Modernisation – replacement of relays as a progression to a modern standardised design for station equipment using integrated functions in an intelligent device and serial communication.
- Compliance – with the NER and AEMO Protection & Control Requirements (PCRs).
- Obsolescence – replacement of relays that are inadequate, obsolete, failing, aged and unsupported.

**Communications**
- Replace network bearers such as powerline carrier systems, network technologies such as digital multiplexers, and supporting infrastructure such as battery back-up systems. Some powerline carrier systems have been in service for more than 25 years and are planned for replacement with either optical fibre groundwire or radio links as the existing systems can no longer be maintained and have limited capacity to enable new generator connections.

---

**Average annual expenditure on asset renewal (replacement and refurbishment) programs (real 2016-17)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Stations</th>
<th>Lines</th>
<th>Secondary and protection</th>
<th>Communications</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014-17</td>
<td></td>
<td></td>
<td>38%</td>
<td></td>
</tr>
<tr>
<td>2017-22</td>
<td></td>
<td>28%</td>
<td>10%</td>
<td>24%</td>
</tr>
</tbody>
</table>

*Sources: AusNet Services, Transmission Revenue Review (TRR) 2017-22, p.94*
8. Costs of asset maintenance and renewal

**Electricity distribution**

Expenditure on asset renewal is assessed by the AER for prudence and efficiency in delivering the capex criteria. The following are summarised from the DNSP proposals to the regulator for the 2016-2020 regulatory period.

**AusNet Services’** proposed forecast repex was $901 million, driven by:

- Deterioration in asset condition associated with increasing asset age, environmental conditions (such as the Gippsland floods) and identified fleet problems (such as string bark wooden poles)
- Reduced opportunity to replace poor condition assets as part of augmentation related projects
- Asset failure risk, which may cause reliability impact, risk of collateral asset damage, safety risk to public and field personnel, environmental damage from asset failure (oil spills)
- Technical obsolescence
- Third party damage.

**CitiPower’s** proposed forecast repex was $260 million, driven by:

- Completion of refurbishment works which they intended to take place during the current regulatory period but were delayed
- Increasing replacement of poles and cross-arms and other key assets in line with increasing defect rate
- Compliance with environmental regulations
- Replacement of protection relays and lines based on condition
- Replacement or refurbishment of large plant and equipment based on condition.

**Jemena’s** proposed forecast repex was $224 million, driven by:

- An ageing asset profile which places Jemena in the initial phase of a replacement cycle for many assets
- Need to address a number of areas where they say safety has deteriorated during the 2011–15 regulatory control period.

**Powercor’s** proposed forecast repex was $722 million, driven by:

- Increased replacement of poles and cross-arms to mitigate the increasing failure rate
- Re-commencement of the replacement of high-voltage overhead conductor program
- Additional replacement of transformers and switchgear in the network given the Health Indices are forecasting increased network risk.

**United Energy’s** proposed forecast repex was $585 million, driven by:

- Requirements to comply with mandatory regulatory obligations
- Age profile of their assets which is impacted by substantial network investment during the 1960s and 1970s
- Desire to address a trend decline in reliability performance.

**Notes:**

8. Costs of asset maintenance and renewal

**Gas supply and transmission**

General industry practice is to spend between 1 – 10 per cent per year in maintaining pipelines. In early years of life, only patrolling and auditing is required whilst in later years coating defects occur, requiring lines to be dug up and repaired or replaced.

Once a major rehabilitation or partial/full replacement occurs, generally after 40 years, the maintenance returns to early values of 1 per cent.

An average cost of 2 per cent p.a. of the current day replacement cost of a pipeline can be assumed as an industry norm (over the life of the asset).

Note: The level of detail on expenditure is not as well recorded as in the electricity industry.

**Liquid fuels**

The refined product pipelines in many cases are nearing the end of design life. Owners are replacing and upgrading lines which are still essential to their business. There are examples of pipelines which no longer remain connected to service the transfer of liquid fuels which are now in a care and maintenance mode due to the strategic location of the lines or the inability to replace the lines in the future. These lines will remain until either economic pressure rules that the lines should be abandoned altogether or alternatively the lines may be sold off as general service ducts.

Due to the number of owners of single pipelines it has not been possible to obtain actual maintenance costs but it is normal that owners need to spend (an average of a number of years) between 1 – 10 per cent of the replacement cost of a pipeline as they age. Some years will require considerable costs for integrity inspections and coating defect repairs whilst in other years the annual cost will be lower.

An average cost of 2 per cent p.a. of the total replacement value in 2015 dollars can be assumed as an industry norm.
9. Maintenance standards

Maintenance in the energy sector is generally aligned with service performance and condition based asset management practices

<table>
<thead>
<tr>
<th>Electricity Generation</th>
<th>Electricity Transmission and Distribution</th>
<th>Gas and Liquid Fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>There are strong economic drivers for generators to achieve high availability.</td>
<td>Economic regulation of network service providers links performance KPI’s to financial outcomes. This is in addition to mandatory safety standards regulated by the ESV.</td>
<td>Licensed pipelines are required to be maintained to high standards using a combination of risk assessment, physical inspection and non-destructive testing.</td>
</tr>
</tbody>
</table>

Gas turbine plants

- Gas turbine manufacturers have well defined maintenance regimes. The timing is typically based on accumulated equivalent operating hours (EOH). EOH are the service hours of the gas turbine weighted upward depending on service factors such as the number of starts, trips, load shedding, fuel and load-up rate. The more ‘stressful’ the operating history the higher the EOH and maintenance should be conducted more frequently. For a peaking plant at say 5 per cent capacity factor, outage frequency may be at approximately two years depending on as-found condition at inspection outages and machine history.
- Each manufacturer provides a schedule of inspections which determines the condition of the components and, depending on the condition, the repairs/replacements activities which should be carried out to enable continued safe operation for a specified period of time\(^1\).

Steam power plants

- The steam power plants (coal based and Newport) are typically maintained within an established asset management framework similar to other Australian power stations utilising a mixture of in-house and contracted services.
- Most brown coal fired plants have a major outage on each unit every 4 to 8 years and minor boiler clean and inspection outage every year. The work conducted during these outages is typically outsourced to specialist Contractors.
- Some plant areas (such as coal pulverising mills) require more frequent maintenance and overhaul work is scheduled such that overall plant output is not impacted.

Economic regulation of network service providers links performance KPI’s to financial outcomes. This is in addition to mandatory safety standards regulated by the ESV.

In 2013, a new Australian Standard AS5577 was published for Electricity Network Safety Management Systems. State legislation mandates conformance to this standard.

**Transmission**

AusNet Services’ asset management system is certified compliant with ISO 55001\(^2\), an indicator of international best practice in asset management including outcome-based service levels.

Compliance with ISO 55001 requires the demonstration of robust and transparent asset management policies, processes, procedures, practices and a sustainable performance framework.

**Distribution**

Distribution network service provider asset management systems are intended to align with the general principles of ISO 55001, however only AusNet Services has achieved certified compliance.

Notes:

9. Maintenance standards

Electricity transmission and distribution: Innovation case studies

Adoption of innovation technology in the energy sector is being largely driven by regulatory incentives. Innovative technologies are being deployed to improve network inspections and operation. Distribution networks are enabling the capabilities of Advanced Metering Infrastructure (AMI) to allow remote monitoring of performance and to improve response times for fault identification, repair and restorations. The transmission network is using helicopters and trialling drones with high resolution cameras to improve the efficiency and effectiveness of line inspections.

**Case study: LiDAR technology**

Light detection and ranging (LiDAR) is a laser based surveying technique which can create a three dimensional digital topology of a transmission line and its easement corridor to quantify the physical clearances between the electrical phases of a transmission circuit, the extent of conductor movement and the physical clearances to vegetation, ground and encroachments in the line easement.

AusNet Services has used this inspection technique to assess the condition of vegetation and the adequacy of easement dimensions as well as validating conductor to ground clearances under varying loading conditions. As the cost of LiDAR surveys is becoming more economic, its usage will grow allowing a greater level of surety over vegetation clearances, electrical safety clearances and transmission line ratings.


**Case study: Substation secondary systems**

The dominant trend in zone substation secondary systems is toward the application of digital technology devices and systems with in-built intelligence and integrated functionality. IEC61850 is an electrical substation design standard which is widely seen as an enabler for the modernisation of high speed protection and control systems.

The standard allows for the merging of communication capabilities of all intelligent electronic devices (IEDs) within a substation, providing benefits for data gathering and remote control.

The digital technology platform adds value by:

- Increasing functionality, reliability and availability through the use of microprocessors, solid-state devices, digital technology and optic fibre-based communication systems
- Embedding intelligent diagnostic software that optimises operation and improves asset management condition monitoring
- Rationalising equipment via functional integration and multiple signal processing capability
- Providing remote management facilities for network elements based on real-time data communications
- Reducing the amount of internal wiring required within substations
- Facilitate the smart grid landscape

Jemena is currently implementing IEC 61850 technology at two new zone substations, namely Broadmeadows South and Tullamarine.

**Case study: Overhead line corrosion detector**

An accurate assessment of the condition of aluminium conductor steel reinforced (ACSR) bare conductor for overhead lines is difficult to achieve through visual inspection. Traditionally, to assess the steel core condition has required conductor removal, disassembly, testing and analysis of multiple representative samples. Such an approach is costly, involves lengthy circuit outages and resource intensive.

AusNet Services has recently been trialling an overhead line corrosion detector (OHLCD) unit to measure levels of steel core deterioration on targeted ACSR phase conductors and aerial earth wires. The OHLCD unit is a remote controlled, radio-linked eddy current device that is placed upon the phase conductor. The alternating flux induces a voltage in the pick-up coil that is processed to give an output voltage, the magnitudes of which depends upon the quality of the galvanised or aluminium clad layer. This data is then used to gauge remaining service potential of conductors tested and supports robust asset management decision making.

Two programs of conductor assessments have been successfully implemented using an OHLCD unit obtaining results for more than 170 spans. The results were generally good and indicated that only two per cent of spans tested had lost more than 50 per cent of galvanising from the steel strands. Although the benefits of using OHLCD to assess the condition of ACSR are clear, the technology is still in the development stage and there remains some doubt as to accuracy.

AusNet Services is removing samples of conductor already tested using the OHLCD and undertaking laboratory inspections in order to calibrate the accuracy of the OHLCD process and to assist in determining the extent of further OHLCD inspections.
Infrastructure service performance
## 10. Infrastructure performance

**Infrastructure in the energy sector has been performing within acceptable limits. A summary for each sub-sector is outlined below:**

<table>
<thead>
<tr>
<th>Electricity generation</th>
<th>Electricity transmission</th>
<th>Electricity distribution</th>
<th>Gas transmission and distribution</th>
<th>Liquid fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>There is strong oversight of the generation sector’s performance. The sector as a whole, and Victoria specifically, has been performing within acceptable limits.</td>
<td>Transmission network performance can be measured by the number of outages and the duration of those outages. When considering system minutes off supply (energy not supplied divided by maximum demand multiplied by 60) it can be seen that Victoria’s transmission network is among the best performers in the NEM.</td>
<td>System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) are the key performance measures. Victoria’s performance is considered on par with other states in the NEM.</td>
<td>It is evident that NSW DNSPs have experienced more leaks per kilometre when compared to Victorian DNSPs. In 2012, Victorian DNSPs experienced an average of around 1.2 leaks per kilometre compared to around 1.8 in NSW.</td>
<td>Liquid fuels pipelines in Victoria largely perform as required with the exception of the jet fuel pipeline to the Melbourne Airport, where demand is higher than the current supply capability. Australia’s stockholding is currently less than the International Energy Agency (IEA) requirements to which Australia is a member.</td>
</tr>
</tbody>
</table>
10. Infrastructure performance

Generation
Legislative oversight exists for the performance of the power system, with many of the provisions concerning generation. Chapter 4 of the National Electricity Rules ‘Power System Security’ provides the framework for achieving a secure power system (NER, chapter 4). In so doing, makes provision for (NER, cl 4.8.9):

‘AEMO may require a Registered Participant to do any act or thing if AEMO is satisfied that it is necessary to do so to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.’

There is a high degree of oversight over this aspect of the market.

Reliability Performance
Each year the AEMC’s Reliability Panel reports on the performance, reliability, security and safety of the power system (AEMC, 2015). The reliability reporting is concerned with whether the system has sufficient generation and transmission capacity (interconnector capacity in particular) to meet demand.

Generation performance is measured by the amount of Unserved Energy (USE)—the amount of energy demanded by customers that was not met. This is shown in the following table.

### Unserved energy (percent)

<table>
<thead>
<tr>
<th>Region (gen)</th>
<th>Standard</th>
<th>2012-13</th>
<th>2013-14</th>
</tr>
</thead>
<tbody>
<tr>
<td>VIC</td>
<td>0.002</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>QLD</td>
<td>0.002</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>NSW</td>
<td>0.002</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>SA</td>
<td>0.002</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>TAS</td>
<td>0.002</td>
<td>0.000</td>
<td>0.000</td>
</tr>
</tbody>
</table>

Source: AEMC, Annual Market Performance Review


The National Electricity Market’s USE target is 0.002, which represents 10.51 minutes of unsupplied energy. As shown, for the last two years the NEM has experienced no unserved minutes—exceeding its target. As such, the Reliability Panel concluded that notwithstanding the reduction in overall generation capacity that has occurred, reliability has not been reduced to a level below the standard and there is sufficient capacity (AEMC, 2015). The last time that Victoria experienced USE was in 2008-9, when it exceeded the standard with USE of 0.004 per cent.

Security
Network security can be measured by frequency and voltage levels. The frequency reflects the balance between power system demand and adequacy of generation. In 2013-14 there was one frequency event that did not comply with the standards, caused by a generator in NSW (AEMC, 2015). Voltage limits represent the minimum or maximum safe operating level of a network asset. In 2013-14 secure voltage limits were not exceeded.

### Summary

There is strong oversight of the generation sector’s performance. The sector as a whole, and Victoria specifically, has been performing within acceptable limits.
10. Infrastructure performance

Electricity transmission

Transmission network performance can be measured by the number of outages and the duration of those outages. In Victoria, there is a degree of variability in the outage duration experienced, with size outages in 2013 and only one outage being experienced in 2014 as shown below. The average duration of outages in Victoria increased sharply in 2012 to around 230 minutes. In 2013 and 2014 the duration then returned to a level more consistent with historical outage durations.

When translated into the single measure of system minutes off supply (energy not supplied divided by maximum demand multiplied by 60) it can again be seen that Victoria's transmission network is among the best performers in the NEM.

![Graph showing average outage duration and number of outages for AusNet](image)

![Graph showing state comparison between 2013-14 average outage duration and number of outages](image)

In 2013-14, Victoria experienced both fewer outages than most other States and a shorter outage duration as shown below.

In 2014 the AER published a report benchmarking the performance of TNSPs. It showed that AusNet Services, the Victorian TNSP, has performed in line with other TNSPs in terms of supply interruption (although noting it was the worst performer in 2012). This is shown in the figure below.

![Transmission network unsupplied minutes table](image)

![Estimated customer cost of energy unsupplied due to supply interruptions (million nominal)](image)
10. Infrastructure performance

Electricity distribution

The figures to the right outline the average minutes off supply and number of supply interruptions per customer by distributor.

On both measures, Ergon (QLD) and Essential Energy (NSW) perform relatively poorly. CitiPower, Victoria’s CBD distributor outperforms all other DNSPs. In general, Victoria’s supply performance is on par with other States.

The AER’s 2014 benchmarking report outlines the cost of the network per customer against the unplanned minutes off supply that customers experience. It shows that Victorian DNSPs are amongst the lowest cost DNSPs, and that their customers experience relatively few minutes off supply (with Powercor and AusNet (AND)—the most rural DNSPs—experiencing the most minutes off supply as expected). As such, the AER finds that ‘Victorian and South Australian distributors appear the most productive [in this measure]’ (AER, 2014). These results are shown below.

### Average minutes-off-supply per customer (2010–2014)

<table>
<thead>
<tr>
<th>Term</th>
<th>Title</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACT</td>
<td>ActewAGL (ACT)</td>
</tr>
<tr>
<td>AGD</td>
<td>Ausgrid (NSW)</td>
</tr>
<tr>
<td>AND</td>
<td>AusNet Services (distribution) (Vic)</td>
</tr>
<tr>
<td>CIT</td>
<td>CitiPower (Vic)</td>
</tr>
<tr>
<td>END</td>
<td>Endeavour Energy (NSW)</td>
</tr>
<tr>
<td>ENX</td>
<td>Energex (Qld)</td>
</tr>
<tr>
<td>ERG</td>
<td>Ergon Energy (Qld)</td>
</tr>
<tr>
<td>ESS</td>
<td>Essential Energy (NSW)</td>
</tr>
<tr>
<td>JEN</td>
<td>Jemena Electricity Networks (Vic)</td>
</tr>
<tr>
<td>PCR</td>
<td>Powercor (Vic)</td>
</tr>
<tr>
<td>SAPN</td>
<td>SA Power Networks (SA)</td>
</tr>
<tr>
<td>TND</td>
<td>TasNetworks (distribution) (Tas)</td>
</tr>
<tr>
<td>UED</td>
<td>United Energy Distribution (Vic)</td>
</tr>
</tbody>
</table>

### Average interruption frequency per customer (2010–2014)

Source: AER, DNSP benchmarking report, 2015
10. Infrastructure performance

Gas sector performance

The regulatory regime for gas TNSPs and DNSPs does not include an incentive scheme for performance and so less information is available when compared to the electricity sector.

Gas DNPSP reliability performance

Victorian gas DNSPs were regulated by the Essential Services Commission (ESC) prior to this being undertaken by the AER. The ESC developed a performance reporting framework for Victorian DNSPs. After the regulatory function passed to the AER, the AER continued to report on DNSPs’ performance under this framework until 2014 when its last report, capturing 2012 performance, was published.

The AER reported that in 2012, the average Victorian customer experienced supply interruption’s equivalent to once every 36 years, which was a 14.6 per cent decrease compared to 2011 (AER, 2014).

The following figure shows the average number of minutes off supply that Victorian customers experienced. The AER noted that:

- According to Envestra (now AGN) the change in unplanned interruptions from 2010 reflects a change in reporting to include all supply interruptions (also meaning results are also not directly comparable to other businesses)
- Increase in planned interruptions for Envestra and SP AusNet (now AusNet) reflect the increased level of mains renewal works completed in 2012.

Source: AER performance report, 2014

Prescriptive performance requirements

DNSPs must comply with the Gas Safety Act 1997. Under this Act DNSPs must conduct manage and operate its facilities to minimise hazards and risks to the public and property DNSPs must also, ensure that its gas meets various standards of quality, report incidents to ESV and submit a safety case. This Act therefore prescribes certain performance standards in respect of safety with which DNSPs must comply.

Notes:

10. Infrastructure performance

**Liquid fuels**

**Pipelines**

There are no performance values required by legislation. Pipelines are built for a purpose of transferring products safely and efficiently.

Large and frequent ‘assignments’ are required for a pipeline to be viable as compared to road tanker transport. Pipelines are thus justified on an all-of-life basis against transport by road tankers.

Liquid fuels pipelines in Victoria largely perform as required with the exception of the jet fuel pipeline to the Melbourne airport, where demand is higher than the current supply capability.

**Stockholding**

Australia is a member of the International Energy Agency (IEA) as a signatory to the International Energy Program (IEP) Treaty. As a member of the IEA, Australia is required to hold 90 days of the previous year’s net liquid fuels imports (IEA, 2015).

Australia is the only IEA-member country that does not currently meet the 90-day requirement (The Age, 2015). This situation has arisen due to an increasing demand for liquid fuels and decreasing indigenous oil production.

The current definition by IEA of stockholding does not include ‘stocks on water’. This currently represents more than a quarter of stock held by oil companies in Australia. It is estimated that 2 – 3 weeks worth of stock is on the water (AIP, 2015).

Options that will assist in rectifying this issue are (IEA, 2015):

- Government-owned stocks
- Agency-owned stocks
- Obligating the liquid fuels industry to meet this 90-day stockholding, as is done in 20 out of the 29 IEA member countries.

The trend in Australia’s liquid fuels industry is to expand storage facilities, which will help Australia achieve its 90-day requirement. These terminals were traditionally operated and owned by producer companies, however there is now a trend towards independent terminal operators constructing and expanding terminals.

Notes:

1. https://www.iea.org/topics/energysecurity/subtopics/stockholdingstructure/
11. Performance standards and requirements

**Electricity**

The Service Target Performance Incentive Schemes (STPIS) provide NSPs with financial rewards and penalties for improving or deteriorating performance standards. The targets are based on a 5 year historical average performance, meaning NSPs have a continuous incentive to improve. This is the major scheme underpinning incentives to improve performance.

There are also Guaranteed Service Levels (GSL) whereby DNSPs must make payment for poor service directly to affected customers. The DNSPs are provided a forecast GSL allowance based on past payments. DNSPs keep or pay the difference if the experience fewer or more GSL events.

**Liquid Fuels**

There are no known performance standards or requirements for hydrocarbons.

<table>
<thead>
<tr>
<th>Energy</th>
<th>Scheme</th>
<th>Metrics</th>
<th>How is community need taken into account?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity TNSP</td>
<td>STPIS</td>
<td>Service Component – incentive to reduce the frequency and duration of interruptions. Market Impact Component - incentive to minimise the impact of transmission outages that can affect wholesale market outcomes. Network Capability Component - encourage TNSPs to take steps to operate, maintain and improve their ability to deliver an appropriate level of network capability.</td>
<td>3.5 per cent of a TNSPs revenue is at risk under the STPIS. The scheme’s existence reflects that reliable supply is valued by the community, but the amount of the financial rewards or penalties does not specifically reflect community expectations.</td>
</tr>
<tr>
<td>Electricity DNSP</td>
<td>STPIS</td>
<td>System Average Interruption Duration Index (SAIDI) - the average number of minutes off supply each customer segment experiences. System Average Interruption Frequency Index (SAIFI) - a the average number of interruptions each customer segment experiences. Momentary Average Interruption Frequency Index (MAIFI) - average number of interruptions &lt;1min each customer segment experiences.</td>
<td>5 per cent of revenue at risk (but DNSPs may propose alternatives). Under this scheme, incentive rates which determine the size of rewards and penalties are based on a Value of Customer Reliability (estimated by AEMO via survey). As such, customers should be indifferent between receiving better/worse supply reliability and higher/lower electricity charges.</td>
</tr>
<tr>
<td>GSL</td>
<td>STPIS</td>
<td>Customer service parameters – incentives around telephone answering, streetlight repair, new connections and responses to written enquiries.</td>
<td>Accounts for only 1 per cent of revenue at risk combined. These recognise that good service is valued by customers. The AER notes that the scheme 'has a role in both improving service to customers receiving poor performance and providing recognition, through an appropriate payment, to customers that have received poor performance.'</td>
</tr>
</tbody>
</table>

STPIS

<table>
<thead>
<tr>
<th>Scheme</th>
<th>Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>STPIS</td>
<td>Customer service parameters – incentives around telephone answering, streetlight repair, new connections and responses to written enquiries.</td>
</tr>
</tbody>
</table>

GSL

<table>
<thead>
<tr>
<th>GSL</th>
<th>Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>GSLs include: Frequency of interruption – 9 interruptions (CBD and Urban areas) - $80 Frequency of interruption – 15 interruptions (rural areas) - $80 Duration of interruption 20 hours - $100 30 ours - $150 Streetlight repair - 5 days - $25</td>
<td></td>
</tr>
</tbody>
</table>
12. Supporting ICT infrastructure

ICT forms an essential component of the efficient operation of the National Electricity Market (NEM) and networks businesses. Energy sector ICT is supported by independent communications system infrastructure owned by the utilities.

Electricity

Key elements of the ICT and upcoming investments are outlined below:

<table>
<thead>
<tr>
<th>AEMO</th>
<th>Electricity Transmission</th>
<th>Electricity Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Energy Management System (EMS)</strong></td>
<td>Network management</td>
<td>Recent trends have been towards the integration of asset and work management systems through enterprise platforms.</td>
</tr>
<tr>
<td>The EMS is a computer system that gathers real-time telemetered information on the network, substations, generators and loads. The EMS provides the following functions: Supervisory Control and Data Acquisition (SCADA), display for Automatic Generation Control (AGC), display for real-time power system data, model of the power system and facility to study of the power system in real time and under any given conditions.</td>
<td>Technology lifecycle refreshes were undertaken recently on network management assets and systems to ensure continuity of service for control and operations facilities. Proposed over the next two years is a planned software upgrade of the SCADA network management system for AusNet Services. This will minimise the risk of failure, ensuring that systems components remain in vendor support. Investment will also be made in outage management reporting tools to allow AusNet Services to reduce the dependency on manual processes for transmission outage planning and management, and provide the appropriate reporting capabilities.</td>
<td></td>
</tr>
<tr>
<td><strong>Market Management System (MMS)</strong></td>
<td>The key outcomes planned / delivered to AusNet Services from the Network Management program are:</td>
<td>Proposed programs over the next five years include:</td>
</tr>
<tr>
<td>AEMO’s Electricity Market Management Systems are key components required to support the operation of the NEM. These systems are used for the transfer of information from participants to AEMO such as bids, and the dissemination of market information from AEMO to participants. The MMS plays a vital role in managing the wholesale electricity spot market, system security dispatch instructions and market statistics.</td>
<td>• Ability to maintain the quality, reliability and security of transmission electricity supply through proactive management of the network assets and reduced risk of system failure</td>
<td><strong>Network management</strong></td>
</tr>
<tr>
<td><strong>Market Settlement and Transfer Solutions (MSATS)</strong></td>
<td>• Demonstration of prudent management of key operational systems and ability to meet AusNet Services’ regulatory obligations through the continued provision of fit for purpose communications, monitoring and control facilities</td>
<td>• Smarter networks: building upon the Advanced Metering Infrastructure (AMI) smart grid foundation by using the implemented technologies to improve customer service, provide a safe network and deliver greater reliability</td>
</tr>
<tr>
<td>The systems and procedures published by AEMO which include those governing the recording of financial responsibility for energy flows at a connection point, the transfer of that responsibility between market participants and the recording of energy flows at a connection point.</td>
<td>• Enhanced data analytics to support responses to network outages</td>
<td>• Develop low voltage network management capability to further reduce manual interventions and optimise quality of supply and network reliability. This includes delivering feeder automation capabilities and fault identification / location</td>
</tr>
<tr>
<td></td>
<td>• Improve system security</td>
<td>• Develop advanced power modelling and load management, network analytics and visualisation capabilities including:</td>
</tr>
<tr>
<td></td>
<td>• Timely, accurate and transparent regulatory reporting on transmission outage and service performance</td>
<td>• Implementing a number of devices to monitor and control the low voltage network at a meter level</td>
</tr>
<tr>
<td></td>
<td>• Maintained customer satisfaction due to better works allocation and more proactive management of a growing network.</td>
<td>• Leveraging existing metering data warehouse infrastructure to aggregate the high volume of data into useful, manageable and consolidated information. This will enable advanced asset performance and management capabilities.</td>
</tr>
</tbody>
</table>

Field Mobility

Field mobility is the capability for field staff to access actionable information at any place and at any time.

• Field mobility will leverage the previous network and asset management investments to improve service performance and reliability, and improve safety providing operational functions to the field
• Use data analytics to better manage risk and provide the information required for better decision making.
12. Supporting ICT infrastructure

Generation

Digital Control Systems

A critical component of a large power plant is its control system. A generating unit represents a complex integration of boiler, turbine and generator systems. While these systems are clearly interconnected in terms of steam flow and mechanical connection, the integration of the control facilities managing these systems is crucial for the reliable and efficient operation of the plant.

Most plants built during the end of the 20th century were commissioned with Analogue control systems. These systems have an operating life of 10 to 15 years. As the systems age, unit reliability decreases and plant outages can be longer due to unavailability of spare parts. The status of the control systems used at the main coal fired plants is summarised below:

<table>
<thead>
<tr>
<th>Asset</th>
<th>Status of control system</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hazelwood</td>
<td>During 2012-13 Hazelwood retrofitted a digital control system (DCS).</td>
</tr>
<tr>
<td>Loy Yang A</td>
<td>A seven year, $60 million ICMS conversion project completed in October 2014, converted all AGL Loy Yang operating units from an ageing analogue system to a state of the art digital control system.</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>DCS upgrade completed on Unit 2 in 2011 and Unit 1 in 2012.</td>
</tr>
<tr>
<td>Yallourn</td>
<td>DCS upgrade (Bailey Infi 90 system) completed by 2008.</td>
</tr>
</tbody>
</table>

Remote operation of gas turbines

The open cycle gas turbines are only used for peaking operation. With low operational duty, many of the gas turbine sites are unmanned.

The Somerton 4 x 40 MW facility located in Northern Melbourne is one such plant. AGL Energy is able to operate the machines remotely from their control centre in central Melbourne. The control platform for the unified operator interface (UOI) is the GE Fanuc CIMPLICITY Human Machine Interface (HMI) system, which fully integrates:

- Interface to Triconex Turbine Controllers
- Balance of Plant (BOP) Control
- Interface to electricity market network (AEMO) for load dispatch.

It is a supervisory control and data acquisition (SCADA) based design that fully supports the AGL’s requirement for remote operation capability.
12. Supporting ICT infrastructure

Smart meters

The rollout of Advanced Metering Infrastructure (AMI or ‘smart meters’) to all homes and small businesses was mandated by the Victorian Government in February 2006 and commenced in late 2009. The AMI rollout involved the replacement of accumulation electricity meters with AMI at 2.7 million premises. Victoria’s five electricity DNSPs were required, via the AMI Cost Recovery Order, in to undertake the AMI rollout. This was originally due for completion by the end of 2013 but later extended to 30 June 2014. The prevalence of smart or interval meters varies in other States, but it is well below Victoria.

Benefits of Advanced Metering Infrastructure (AMI)

Smart meters enable time of use pricing and demand based pricing, whereby consumption during peak periods can be charged at a higher rate than off-peak consumption. Time of use pricing is one approach that can be used to reduce peak demand on the network and therefore reduce the costs incurred in meeting this demand. A range of other benefits can also flow from AMI meters including:

- Benefits derived from efficiencies in network operations, including remote reading and connection services, better outage management and monitoring of the network
- Provides the utilities with visibility of network to the individual connection (e.g. house) level
- Benefits generated by other innovative tariffs (such as Critical Peak Pricing and Rebates) and demand management
- Other smaller benefits (incorporating minor efficiencies in network and retail operations).

The roll out of AMI in Victoria was initially supported by a regulatory regime which, in practice, effectively guaranteed the recovery of AMI expenditure by DNSPs through separate metering tariffs. However, over time concerns emerged that the regulatory regime was too lax in providing DNSPs with incentives to rollout the AMI program efficiently. In 2013, the regime was amended by the Victorian government and, amongst other things, the onus of proof for testing whether overspending was prudent was effectively reversed, from being a requirement on the AER to establish costs are not prudent, to being a requirement for the DNSPs to demonstrate their expenditures are prudent.

There is now a material risk that some Victorian DNSPs may not recover all of their expenditure due to the more stringent regulatory arrangements. AusNet has indicated that it is likely to overspend in 2014 and 2015 by a total of $280m (AusNet, 2014).
12. Supporting ICT infrastructure

Gas transmission & distribution

In Victoria’s transmission network there are a number of Custody Transfer Meter (CTM) stations that monitor the transfer of gas at transmission delivery points into distribution networks. Four new CTM stations were constructed in Victoria in 2015.

The AEMO Gas Market System monitors transmission pipelines in real time via a distributed communication network into the AEMO Gas SCADA. The AEMO Gas Market System then uses actual gas demand and calculates linepack to forecast gas demand and schedule in gas supplies from gas production and storage facilities, and interconnected pipelines. There is very limited real time monitoring of industrial and commercial (Tariff D) gas users.

In Australia, no gas smart meters are currently used in the distribution network. Metering the distribution network is done via Meter Installation Reference Number (MIRN).

An Overview of the Gas Market Systems

Participants in the Gas Market

Notes:
2. Gas Pipelines Victoria, Carisbrook Transfer Station, accessed 20/01/2015
Operational criticality and resilience
13. Operational criticality and resilience

**Energy infrastructure is critical for the state of Victoria. Networks and generation capacity is planned within the National Electricity Market (including inter-state connectors) to achieve overall levels of resilience. Victoria can be self-sufficient in the supply and distribution of energy including gas, electricity and liquid fuels. Constraints do exist in the network interconnections between Victoria and other states, however these do not normally hinder the operation of the market. It is not currently possible to supply Victoria’s energy requirements solely through these interconnectors.**

**Thermal generation**

**Gas fired plant**

- All of the present gas fired plants operate as peaking plant (as their capital cost is relatively low but operating cost for fuel is high). Peaking power plants generally run only when there is a high demand for power. They supply power only for short periods when demand exceeds the capacity of plants with lower short-run marginal cost. The power supplied commands a much higher price per kilowatt hour than base load power and therefore can utilise expensive natural gas fuel.
- The following power stations have black start capability: Jeeralang
- A black start is the process of restoring a power station to operation without relying on the external electric power transmission network. Normally, the auxiliary power used within the plant is provided from the station's own generators. If all of the plant's main generators are shut down, auxiliary power is provided from the grid. However, if power supply from the grid is not available (due to system disturbance), 'black start' needs to be performed to get the power grid into operation.
- A number of the gas fired peaking plant are understood to have dual fuel capability: Bairnsdale, Laverton North, Jeeralang and Newport.
- Dual fuel capability means that in the event of a disruption to gas supplies, these plants can be operated on diesel oil for short periods while gas supplies are restored.

**Coal fired plant**

- The coal based assets were all designed and built (with the exception of Loy Yang B) by the Government owned SECV. They all have built-in margins and redundancy on both critical station equipment and unit auxiliaries to ensure reliable operation as base load plant or intermediate load plant.
- AEMO provides financial disincentives for unreliable plant (ie unplanned outages). Plant owners are required to plan outages well in advance.
- Plant designs allow for varying degrees of redundancy; for example:
  - Main coal conveyors (2 x 100 per cent duty)
  - Pulverising mills: usually n-1 or n-2 required for maximum output
  - 3x50 per cent duty boiler feed pumps
  - 2x100 per cent duty condensate pumps.

**Power system resilience**

The Victorian electricity grid delivers power to electrical loads throughout Victoria and carries inter-regional power flows between Victoria and Tasmania with its low carbon hydro power stations, and South Australia with its large capacity of wind generation, as well as interchange with NSW to the north. The interconnection with South Australia is critical for meeting the requirements of that state during times of low wind and for supply of renewable energy to the NEM at times of steady wind, including times when wind generation in South Australia can exceed South Australian demand.

AEMO is responsible for monitoring electricity consumption, energy flow, voltage and frequency to ensure system security. In the event of system limitations, AEMO makes adjustments and if required may issue notices to the market for additional generation or directly intervene as a last resort.

There is a formal reliability standard which is subject to ongoing review. This reliability standard is set by the Reliability Panel where reliability under the standard is measured in terms of maximum expected unserved energy (USE), which refers to the amount of energy that is required by customers but cannot be supplied. Currently the reliability standard is set at 0.002 per cent USE per region or regions per financial year, which means that out of 100,000 MWh of demand, no more than 2 MWh of outage would be allowed.

AEMO’s role also includes reserve management and planning for black start capabilities. AEMO has system restart ancillary services (SRAS) contracts in place to be able to restore auxiliary supply to sufficient generation within 90 minutes, enabling generation and transmission capacity to meet 40 per cent of peak demand within 4 hours.

Notes:

13. Operational criticality and resilience

Electricity

Network Management

AusNet Services SCADA/EMS Master Station platform incorporates a dual redundant computer system duplicated at two different data centres. The Control Room Operations Centre houses the prime users of the SCADA system. Information is managed by essential tools such as the wallboard display that enables decision making pertaining to the electricity network. The two data centres also play roles in emergency back-up control and disaster recovery facilities.

Transmission and distribution network planning criteria

Planned to meet reliability criteria including ability to provide secure supply under a wide range of contingencies.

Value of Customer Reliability is used as a measure for the cost-benefit analysis of capital expenditure projects.

Role of interconnectors within the NEM. Probabilistic standards require the transmission system to provide adequate and secure supplies of energy to customers under a wide range of contingencies each treated as a random event and taking into account the probabilities of contingencies occurring (e.g. transformer failure rates), and a range of possible operating conditions (e.g. demand levels and network topologies) with assigned probabilities.

AEMO and the Victorian DNSPs apply this approach to interconnectors in Victoria and use economic cost-benefit techniques to determine the economic viability of a proposed augmentation. It assesses the probability that events likely to cause constraints and load shedding in the transmission system will occur during the planning horizon.

Reliability of electricity supply is considered in planning network augmentations by estimation of the value that customers place on having uninterrupted electricity supply, known as the Value of Customer Reliability (VCR).

The VCR represents, in dollars per kilowatt hour (kWh), the willingness of customers to pay for the reliable supply of electricity. The VCR assists electricity planners, asset owners, and regulators to strike a balance between delivering secure and reliable electricity supplies and maintaining reasonable costs for customers.
13. Operational criticality and resilience

Gas supply and transmission

A number of improvements to the gas supply and transmission system have been completed since the Longford explosion and the following gas supply shortage. These include new connections such as South West pipeline, the VIC-NSW interconnect and the Eastern pipeline.

A major initiative that has occurred in Queensland may assist Victoria in times of gas supply disruptions or inability to supply. Several of the gas transmission pipelines in Queensland are now bi-directional and Wallumbilla is now a hub connecting the substantial Queensland CSG fields and the gas fields in central Australia to the Victorian pipeline network.

Liquid fuels

There is an alternative to the transfer of liquid fuels should commercial decisions rule it is no longer economically viable to continue with pipelines as the means transferring product. The alternative generally is road transport with only a small quantity of product being moved using rail networks. However there are some constraints over the transport of petroleum products by the alternative of road tankers due to traffic bans along some routes and also availability of surplus fleet.
14. Key demand drivers

A summary of the key demand drivers for each energy sub-sector are outlined below:

**Thermal generation**
- Income per capita
- GSP
- Rooftop PV
- Falling consumption per capita
- Possible tariff reforms
- Manufacturing closures
- Decreasing electricity prices in short term, rising in medium term

**Electricity transmission**
- Gross State Product
- Failing consumption per capita
- Possible tariff reforms
- Manufacturing closures
- Decreasing electricity prices in short term, rising prices in medium term

**Electricity distribution**
- Income per capita
- Rooftop PV
- Falling consumption per capita
- Possible tariff reforms
- Manufacturing closures
- Decreasing electricity prices in short term, rising in medium term

**Gas supply and transmission**
- Conversion of non-gas homes
- Higher gas prices
- Use per industrial closures
- Use per connection

**Gas distribution**
- Conversion of non-gas homes
- Higher as prices
- Use per connection

**Renewables**
(as for thermal generation plus)
- RET, subsidies / financing and community expectations

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Deloitte Touche Tohmatsu © 2016 - Infrastructure Capability Assessments
14. Key demand drivers

Thermal generation

Demand factors for thermal generation are the same as those considered for electricity transmission. However, generators compete in the National Electricity Market meaning it is relevant to examine the demand for generation at the market level. The supply of thermal generators currently exceeds demand in the NEM. In 2014 AEMO announced that due to declining operational electricity consumption (residential, commercial, and large industrial consumers) in Australia there is an oversupply of generation, and no additional baseload generation is forecast to be needed until at least 2024.

Current generation capacity in the NEM is around 51,363 MW (AEMO, 2015). There is potentially between 7,650 MW and 8,950 MW electricity generation overcapacity in 2014-15, with around 90 per cent of the overcapacity being in NSW, Queensland and Victoria (AEMO 2014). As a result, 968 MW of generation capacity has been withdrawn—including the Morwell/EnergyBrix and Anglesea Power Stations in Victoria (totalling 345MW). A further 3,317 MW is planned for withdrawal by 2022, comprising mainly coal and gas fired plants in NSW and SA.

Renewable generation

The drivers for renewable generation are the same as for thermal generation, but importantly, also include green policies such as the RET, subsidies / financing provided by organisations such as the CEFC and ARENA (refer Item 5) and changing community expectations towards clean generation technologies. It is these additional renewable policies that are underpinning the development of renewable generation—during a time at which otherwise renewable generation, or for that matter any generation, may not be commercial.

The Clean Energy Council estimates that to meet the 33,000 GWh RET target, an additional 6,000 MW of new renewable generation will need to be built by 2020. It expects this will create more than $40.4 billion worth of investment and more than 15,200 jobs (Renewable Energy Council 2015). It can therefore be seen that the RET is an important driver of demand for renewable generation.

Notes:
2. Source: Detailed summary of 2015 electricity forecasts, EAMO
3. AEMO, ELECTRICITY STATEMENT OF OPPORTUNITIES FOR THE NATIONAL ELECTRICITY MARKET, Published: August 2014
4. AEMO, ELECTRICITY STATEMENT OF OPPORTUNITIES FOR THE NATIONAL ELECTRICITY MARKET, Published: August 2015
14. Key demand drivers

Electricity transmission

The electricity transmission maximum demand and consumption figures have been calculated by summing data for industrial, residential, small NS generation and transmission losses (does not include rooftop PV).

Recovery in overall consumption is expected in the short, medium and long term outlooks.

This is driven by residential and commercial consumption, which constitutes the majority of the Victoria’s load. This is driven by population growth, rising income per capita in the longer term, and projected falling electricity prices. Offsetting some of this growth is continued uptake of rooftop PV and energy efficiency.

Falling industrial consumption is driven by decline in manufacturing sector including closures of vehicle manufacturing plants and the final closure of Point Henry smelter in July 2014. Falling industrial consumption is expected to continue in the short term, but flatten out in the medium to long term.

Source: AEMO, sourced from Detailed Summary of 2015 electricity forecasts, operational demand
14. Key demand drivers

Electricity distribution

The electricity distribution maximum demand and consumption figures have been calculated by summing data for residential, rooftop PV and small NS generation. Thus it is assumed that there is no industrial use of the distribution network.

Short term (2015–2019)

Strong underlying recovery is expected in residential and commercial consumption, driven by a relative decline in electricity prices, coupled with population and income growth. Continued uptake of rooftop PV and energy efficiency will partially offset this, and shift maximum demand to later in the day.

Medium term (2019–2024)

Electricity prices are forecast to rise, which will slow recovery in underlying consumption. Continued uptake of rooftop PV and energy efficiency will reduce overall consumption from the grid and offset some of this recovery.

Long term (2024–2034)

Population growth and increasing income per capita contributes to increasing consumption. Some of the increase due to population growth is offset by PV, as uptake continues at a slower rate.
14. Key demand drivers

**Gas supply / transmission**

Gas transmission includes Gas Powered Generation, industrial, losses and residential/commercial data.

**Historical (2010–2015)**

Decreases in overall consumption due to closure of Amcor’s Fairfield plant and Bluescope Steel’s Western Port hot strip mill, as well as a decrease in residential and commercial consumption.

**Short term (2015–2019)**

Decreases in annual consumption of gas is largely driven by decreases in industrial consumption, caused by closure of car manufacturers and the Alcoa Point Henry aluminium smelter. Also driven by reduction in Gas Powered Generation (GPG) due to high gas prices.

**Medium term (2019–2024)**

Further (but slower) decreases in annual consumption driven by reduced industrial consumption due to higher gas prices, but offset by increases in residential/commercial and GPG consumption.

**Long term (2024–2034)**

Small increases in consumption driven by continued growth in residential and commercial consumption.

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Notes:
2. Source: Detailed summary of 2015 electricity forecasts, AEMO
14. Key demand drivers

Gas distribution

Gas distribution figures have been calculated by subtracting industrial and Gas Powered Generation from the total demand and consumption recorded by AEMO.

Historical (2010-2015)

Historically, annual residential and commercial consumption reduced in 2010-15 by an annual average of 1.3 per cent, in part due to a warm winter season in 2013.

Future (short and long term)

Increase in gas network connections is expected due to new housing growth and fuel substitution from existing non-gas homes. A decline in average use per connection is expected to offset this, due to rising retail gas prices and federal energy efficiency savings.
14. Key demand drivers

Liquid fuels
As can be seen in the graph to the right, demand for liquid fuels in Australia has been increasing consistently for a number of years. Total oil demand is expected to grow in the coming years at an average of 1.3 per cent p.a.

Crude Oil
The demand for crude oil is refineries. As long as the Victorian refineries are operating there will be demand for Victorian crude oil.

Petrol (ULP, PULP), Diesel and LPG
Transport users are the main demand drivers of petrol, diesel and LPG. The demand for these liquid fuels are expected to grow with population in Victoria.

Jet Fuel
Airports are the main demand drivers of jet fuel. As air transport is expected to grow Australia-wide by 2.3 per cent p.a., so too will jet fuel demand. This will put pressure on existing pipelines that feed the Somerton terminal.

Notes:
1. Source: IEA, 2011, Oil & Gas Security - Australia
Infrastructure use
15. Future projected demand

Electricity

The independent market operator AEMO publishes annual National Electricity Forecast Reports (NEFR) providing independent electricity consumption forecasts over a 20-year period. The forecasts are developed based on low, medium and high scenarios that reflect different levels of consumer engagement and economic growth. The medium scenario is considered most likely.

Key observations for Victoria’s electricity forecast as published in AEMO’s 2015 NEFR include:

- Operational consumption in Victoria is expected to recover, driven by the residential and commercial sector
- Victoria does not recover to its historical high level of operational consumption until 2030–31
- Industrial consumption declines in the short term, due to the planned closure of vehicle manufacturing plants
- Maximum demand is forecast to decrease slightly in the short term, and then increase slightly across the medium term outlook.

**Consumption over the short, medium and long term in Victoria**

<table>
<thead>
<tr>
<th>Timeframe</th>
<th>Forecast (GWh)</th>
<th>Average annual change</th>
<th>Drivers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short term (2014/15 – 2017/18)</td>
<td>42,635 to 43,963</td>
<td>1.0%</td>
<td>A recent decline in average electricity prices due to the repeal of the carbon price drives recovery in average consumption, which offsets further decline in industrial consumption. Per capita consumption remains steady.</td>
</tr>
<tr>
<td>Medium term (2017/18 – 2024/25)</td>
<td>43,963 to 45,680</td>
<td>0.5%</td>
<td>Continued uptake of rooftop PV offsets a larger proportion of the residential and commercial underlying consumption, moderating recovery in this sector.</td>
</tr>
<tr>
<td>Long term (2024/25 – 2034/34)</td>
<td>45,680 to 50,315</td>
<td>1.0%</td>
<td>Population growth drives continued recovery in consumption from the residential and commercial sector, while per capita consumption remains flat.</td>
</tr>
</tbody>
</table>

**Summary of summer 10% POE1 maximum demand forecasts for Victoria**

<table>
<thead>
<tr>
<th>Timeframe</th>
<th>Forecast (MW)</th>
<th>Average annual growth</th>
<th>Drivers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short term (2014/15 – 2017/18)</td>
<td>10,034 to 10,011</td>
<td>-0.1%</td>
<td>Warm average temperatures in the 2014–15 summer pushed up demand, and demand is only expected to recover slowly to that level as population and GSP increase over time.</td>
</tr>
<tr>
<td>Medium term (2017/18 – 2024/25)</td>
<td>10,011 to 10,761</td>
<td>1.0%</td>
<td>Increasing population and GSP drives recovery in residential and commercial maximum demand</td>
</tr>
<tr>
<td>Long term (2024/25 – 2034/34)</td>
<td>10,761 to 12,100</td>
<td>1.2%</td>
<td>Increasing population and GSP continues to drive recovery in maximum demand.</td>
</tr>
</tbody>
</table>

Notes:

1. POE – Probability of exceedance, MW – Megawatts, GWh – Gigawatt hours
15. Future projected demand

Gas

The independent market operator AEMO publishes an annual National Gas Forecast Report (NGFR) providing annual gas consumption forecasts over a 20-year period.

The main demand drivers for the gas supply and transmission network are:
• Residential and commercial users
• Industrial users
• Gas-powered generation (GPG).

As shown in the figure on the right, the total annual gas supply demand is expected to decrease over both the short and medium term. This is due to the following trends:
• Residential use is expected to increase with population
• This increase is offset by a decrease in industrial use (car manufacturing plants and Alcoa Point Henry aluminium smelter closures) and GPG decrease due to expected higher gas prices.

1-in-20 year event maximum demand for Victoria (TJ/d)

<table>
<thead>
<tr>
<th>Forecast scenario</th>
<th>2016</th>
<th>2020</th>
<th>2035</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>1,304.2</td>
<td>1,171.5</td>
<td>1,203.3</td>
</tr>
<tr>
<td>Medium</td>
<td>1,304.4</td>
<td>1,257.5</td>
<td>1,345.9</td>
</tr>
<tr>
<td>High</td>
<td>1,307.9</td>
<td>1,304.7</td>
<td>1,468.6</td>
</tr>
</tbody>
</table>

Total annual gas consumption in Victoria over the short, medium, and long term

<table>
<thead>
<tr>
<th>Timeframe</th>
<th>Forecast (PJ)</th>
<th>Average Annual Growth</th>
<th>Drivers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short term (2014-19)</td>
<td>205.9 to 195.3</td>
<td>1.1% decrease</td>
<td>Decrease in industrial driven by closure of car manufacturing plants and Alcoa Point Henry aluminium smelter. Decrease in GPG consumption driven by reduced dispatch in electricity market due to rising gas prices.</td>
</tr>
<tr>
<td>Medium term (2019-24)</td>
<td>195.3 to 195.2</td>
<td>&lt;0.1% decrease</td>
<td>Industrial consumption decline due to higher gas prices, offset by increase in residential and commercial and GPG consumption.</td>
</tr>
<tr>
<td>Long term (2024-34)</td>
<td>195.2 to 208.3</td>
<td>0.7% increase</td>
<td>Continued growth in residential and commercial.</td>
</tr>
</tbody>
</table>

Residential use is peakier than industrial use, which results in greater linepack depletion in the transmission system throughout the day. This may result in the increased use of peak shaving gas injections from the Dandenong LNG storage facility or necessitate transmission system investment to increase available linepack.
15. Future projected demand

Gas

As the gas network is connected between the eastern states, it’s important to consider the Australia-wide demands and depletion rates.

Australia-wide demand over the long term is set to increase significantly for LNG.

Victoria has one LNG facility in Dandenong that is used as a peak shaving facility for times of high local gas demands.

LNG is not exported internationally out of Victoria.

Interstate export of gas from Victoria is expected to increase due to large LNG export projects commencing in Queensland, which will take a large portion of eastern Australia’s current gas supplies. This new market is highly competitive and may put pressure on supplies for local demands in Victoria.

Depletion of proven and probable conventional gas reserves depletion in Australia

Shortfalls in conventional gas reserves for the Queensland LNG plants will be made up by unconventional gas (coal seam, shale and tight gas) that is extracted using fracking technology.

Current legislation restricts exploration and production of these resources in Victoria due to environmental concerns.

Sources
1. AEMO, 2015, National Gas Forecasting Report
2. AEMO, 2015, Gas Statement of Opportunities
15. Future projected demand

Liquid fuels

Crude production in Australia peaked in 2000. As the prime source of product supply declines (such as the decline in Bass Strait crude oil and gas) the need for increased pipeline capability no longer exists. The reduced demands will enable the pipelines to be operated at lower pressures in the future and will accordingly result in longer operating life.

82 per cent of crude oil and other refinery feedstock in 2013-14 was imported. It is unlikely there will be any new refinery capacity developed in Australia in the foreseeable future. However as was seen with the closure and potential demolition of the Viva/Shell Geelong refinery market forces came into play and the refinery operations have been retained.

Demand for liquid fuels in general is expected to increase 1 per cent p.a. through to 2050, driven by population and economic growth.

Import of liquid fuels into Australia is expected to increase from mega-refineries in Asia.

<table>
<thead>
<tr>
<th>Forecast Scenario</th>
<th>Petrol (ULP, PULP)</th>
<th>Diesel</th>
<th>Jet Fuel</th>
<th>LPG*</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007-08</td>
<td>4,590 ML/a</td>
<td>3,120 ML/a</td>
<td>2,031 ML/a</td>
<td>713 kt/a</td>
</tr>
<tr>
<td>2014-15</td>
<td>5,173 ML/a</td>
<td>3,148 ML/a</td>
<td>2,424 ML/a</td>
<td>863 kt/a</td>
</tr>
<tr>
<td>2019-20</td>
<td>5,180 ML/a</td>
<td>3,539 ML/a</td>
<td>2,704 ML/a</td>
<td>936 kt/a</td>
</tr>
<tr>
<td>2024-25</td>
<td>5,091 ML/a</td>
<td>3,945 ML/a</td>
<td>3,009 ML/a</td>
<td>983 kt/a</td>
</tr>
<tr>
<td>2029-30</td>
<td>4,952 ML/a</td>
<td>4,369 ML/a</td>
<td>3,347 ML/a</td>
<td>1,033 kt/a</td>
</tr>
</tbody>
</table>

* LPG excludes petrochemical use. As Gippsland, Bass Basin and the two refineries are all producers of LPG, no issue with supply for the state is anticipated. Victoria is currently a significant exporter of LPG and should continue to be from the refineries.

Demand for import facilities is expected to grow and will most likely be provided by independent operators rather than the oil companies as traditionally occurred previously.

Jet fuel for aircraft operating from Melbourne Airport is expected to double over the next 15 years. Currently jet fuel is transferred to Melbourne Airport by a single pipeline fed from the two refineries at Geelong and Altona. Should the pipeline fail it would not be possible for road tankers to be able to replicate the daily volumes of fuel used at the airport.

Notes:
1. Petroleum Import Infrastructure in Australia
2. IEA, 2011, Oil & Gas Security - Australia
16. Future projected infrastructure capacity

**Background**

The prediction of future electricity demand and assessment of current capacity to meet future needs is complex, due to a range of factors impacting infrastructure capacity demand:

- **Asset age**: As the coal based assets have an average age of 34 years, retirement of units will be required over the next 30 years.
- **Electricity demand**: Growth rate in Australian electricity consumption is declining. Part of the reason for this is the transition of the Australian economy from manufacturing to services based.
- **Renewable energy**: The rate of uptake of technologies such as wind and solar is very sensitive to price and government policy.
- **Global warming**: Concern over CO₂ emissions is particularly significant to Victorian coal based assets - present brown coal plants have a 50 per cent higher CO₂ intensity than black coal units.
- **Electric vehicles (EV)**: Increased use of electric vehicles is imminent. If these vehicles are recharged using grid based power it will place additional demands on the grid.
- **Battery storage**: The uptake of domestic battery storage (usually associated with rooftop PV) will potentially reduce maximum demand.

**Table 1** Forecast installed capacity of battery storage (MWh)

<table>
<thead>
<tr>
<th>Region</th>
<th>2017-18</th>
<th>2024-25</th>
<th>2034-35</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>1.029</td>
<td>2.482</td>
<td>4.784</td>
</tr>
<tr>
<td>New South Wales</td>
<td>1.571</td>
<td>2.013</td>
<td>4.235</td>
</tr>
<tr>
<td>South Australia</td>
<td>0.783</td>
<td>1.004</td>
<td>2.253</td>
</tr>
<tr>
<td>Victoria</td>
<td>1.131</td>
<td>2.274</td>
<td>5.102</td>
</tr>
<tr>
<td>Tasmania</td>
<td>0.127</td>
<td>0.196</td>
<td>0.529</td>
</tr>
<tr>
<td>NEM</td>
<td>5.198</td>
<td>8.593</td>
<td>18.246</td>
</tr>
</tbody>
</table>

**Table 26** Summary of projected number of EVs and the annual consumption for each NEM region

<table>
<thead>
<tr>
<th>Region</th>
<th>2017-18</th>
<th>2024-25</th>
<th>2034-35</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>1,927</td>
<td>26,063</td>
<td>85,323</td>
</tr>
<tr>
<td>New South Wales</td>
<td>2,351</td>
<td>37,495</td>
<td>118,728</td>
</tr>
<tr>
<td>South Australia</td>
<td>2,959</td>
<td>52,231</td>
<td>167,045</td>
</tr>
<tr>
<td>Victoria</td>
<td>3,521</td>
<td>46,877</td>
<td>146,999</td>
</tr>
<tr>
<td>Tasmania</td>
<td>154</td>
<td>2118</td>
<td>6,080</td>
</tr>
<tr>
<td>NEM</td>
<td>11,092</td>
<td>165,734</td>
<td>524,775</td>
</tr>
</tbody>
</table>

**Notes:**


Deloitte Touche Tohmatsu © 2016 - Infrastructure Capability Assessments
16. Future projected infrastructure capacity

Electricity

Under a medium forecast scenario, a low reserve condition point occurs in Victoria in 2024–25

Generation

AEMO prepares an annual statement of opportunities which uses information provided by industry to report on the adequacy of existing and committed electricity supply in the National Electricity Market to meet maximum demand and annual operational consumption forecasts over the period 2015–16 to 2024–25. Proposed generation or transmission projects not yet committed are not incorporated in the supply adequacy assessment. Summary of key findings for Victoria include:

• Under the medium scenario, a low reserve condition (LRC1) point occurs in Victoria in 2024–25 (see table and figure right).
• An LRC point is first seen in 2019–20 under the high scenario. Compared to the 2014 ESOO high scenario, this brings the LRC point forward at least three years.
• This change is attributed to an increase in exported energy to support South Australia and New South Wales after significant capacity withdrawal in those regions, and a maximum demand increase in Victoria.
• No LRC point occurs under the low scenario.

Transmission and Distribution

• Capacity is planned for the transmission and distribution network in five year regulatory periods. Capital expenditure required to augment the network for increased demand is recovered through a return on regulated asset base in the regulated pricing of electricity use for consumers (refer items 2, 3, 4 and 5).

Note: The ESOO does not consider market prices, profitability, or other costs and incentives, such as schemes supporting renewable energy generation, that affect commercial decisions to invest in or withdraw capacity.

Victorian generation and project capacity by generation type (MW)

<table>
<thead>
<tr>
<th>Status / Type</th>
<th>Coal</th>
<th>CCGT a</th>
<th>OCGT b</th>
<th>Gas other</th>
<th>Solar</th>
<th>Wind</th>
<th>Water</th>
<th>Bio mass</th>
<th>Other</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing 4</td>
<td>6,599</td>
<td>21</td>
<td>1,904</td>
<td>568</td>
<td>1.5</td>
<td>1,230</td>
<td>2,296</td>
<td>0.8</td>
<td>0.8</td>
<td>12,620</td>
</tr>
<tr>
<td>Committed</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>240</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>240</td>
</tr>
<tr>
<td>Proposed</td>
<td>-</td>
<td>500</td>
<td>1,150</td>
<td>-</td>
<td>60</td>
<td>2,765</td>
<td>34</td>
<td>-</td>
<td>-</td>
<td>4,509</td>
</tr>
<tr>
<td>Withdrawn</td>
<td>189</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>189</td>
</tr>
<tr>
<td>Publicly announced withdrawals 4</td>
<td>156</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>156</td>
</tr>
</tbody>
</table>

a. Combined-cycle gas turbine; b. Open-cycle gas turbine

1. Low reserve condition (LRC): When AEMO considers that a region’s reserve margin (calculated under 10 per cent Probability of Exceedance (POE) scheduled and semi-scheduled maximum demand (MD) conditions) for the period being assessed is below the Reliability Standard.
2. Reliability standard: The power system reliability benchmark set by the Reliability Panel. The maximum permissible unserved energy (USE), or the maximum allowable level of electricity at risk of not being supplied to consumers, due to insufficient generation, bulk transmission or demand-side participation (DSP) capacity, is 0.002 per cent of the annual energy consumption for the associated region, or regions, per financial year.

16. Future projected infrastructure capacity

Gas

With increased residential demand forecast, the future projected pipeline infrastructure capacity will likely increase to facilitate peak demands and increased exporting to NSW and SA.

The annual demand for gas supply and transmission in Victoria is forecast to remain relatively flat (refer to slide 93). However, the residential and commercial use is expected to increase. As residential use is peakier than industrial use, greater linepack depletion can be expected in the transmission system throughout the day.

This may result in the increased use of peak shaving gas injections from the Dandenong LNG storage facility or necessitate transmission system investment to increase available linepack.

Liquid fuels

Many pipeline assets are soon to reach the end of their design life and commercial decisions will be made by owners and operators whether to enter into an upgrade or replacement programme to extend the service life and licensed life.

Additional storage tank capacity of 270 million litres around Australia is currently planned, which represents approximately 9 per cent of total storage capacity in Australia.

In Victoria the following projects are planned:

- Tank conversion to ULP at a west Melbourne terminal
- Expansion of ethanol storage in Hastings.

Victoria is expected to have very small spare capacity at Melbourne terminals and approximately 20 per cent spare capacity in Hastings terminals.

There appear to be few serious current or emerging bottlenecks for fuel imports into Victoria. There are some constraints in tankage and berthing at Holden Dock and a need for expansion of the jet fuel line to Somerton, however this is not seen to be a major obstacle to meeting demand in Victoria.

Should market conditions justify further investment there is potential to increase import capacity at Hastings.
17. Asset utilisation

Electricity

Capacity factors for coal fired plant (refer table) provide an indication of utilisation of these generation resources.

The maximum capacity and demand graph for electricity (AEMO) provided under Item 16 also gives an indication of asset utilisation.

In considering “fit for purpose”, consideration is made to both the capacity factors of existing coal fired generators and the large reserves of brown coal available in Victoria. It is important to also consider the true costs to the environment (e.g. CO₂ emissions) which reduce the fitness for purpose of the coal assets.

Electricity networks operate with a certain level of redundancy to accommodate outages of lines or equipment. Probabilistic planning is applied to consider the value of customer reliability when considering augmentations to the networks. The electricity network currently has capacity that exceeds maximum demand. An indication of overall utilisation for distribution networks is provided in the adjacent graph.

Traditionally the network has been designed to transmit energy from fuel sources to load. Fuel sources are moving and distributed generation is being introduced.

Capacity factors for coal fired generators

<table>
<thead>
<tr>
<th></th>
<th>Annual MWh</th>
<th>Capacity factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hazelwood</td>
<td>11,000,000</td>
<td>78%</td>
</tr>
<tr>
<td>Loy Yang A</td>
<td>16,000,000</td>
<td>91%</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>7,500,000</td>
<td>86%</td>
</tr>
<tr>
<td>Yallourn</td>
<td>10,600,000</td>
<td>83%</td>
</tr>
</tbody>
</table>


DNSP historical network overall utilisation statistics (%)
17. Asset utilisation

Grid connections may restrict future or proposed developments of large-scale renewables in the western part of Victoria.

Electricity grid

Business cases for large scale renewables balance the requirements for good resources, consentable land and economically feasible grid connections. Development of renewable resources and consentable land can be restricted at times by the availability of solid and affordable grid connections.

The transmission network connecting the Latrobe Valley to the Melbourne area is sizable with multiple 500kV transmission lines. The existence of strong grid connections (multiple 500 kV lines) from the Latrobe Valley to Victoria’s major loads and the National Electricity Market grid favours the development of new generation in this area as it can utilise the existing grid.

A relatively strong grid connection also exists in the south-west with the 500kV line to South Australia. The grid in the region near Horsham and Red Cliffs is weak, limiting the feasibility of otherwise strong potential wind and solar projects.

500kV connections are typically orders of magnitude more expensive than lower voltage connections.

Note: Some developers are focusing on Large Scale Solar PV in the order of 20 MW. The advantages are that it is easier to obtain consent and connect to greater number of grid points. The down side is that greater economies of scale from large scale solar in the order of 200 MW and greater are not achieved. Conversely large scale projects (200 MW plus) have difficulty in obtaining consent and are limited by grid connection points.

Grid connections may restrict future or proposed developments of large-scale renewables in the western part of Victoria.
17. Asset utilisation

Carbon dioxide emissions from coal fired assets

Brown coal emissions intensity (t CO\textsubscript{2} / MWh generated)\(^{1}\)  

<table>
<thead>
<tr>
<th>Brown coal margins intensity (t CO\textsubscript{2} / MWh generated)</th>
<th>Brown coal and carbon dioxide emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brown coal emissions intensity (t CO\textsubscript{2} / MWh generated)</td>
<td>Brown coal and carbon dioxide emissions</td>
</tr>
<tr>
<td>---------------------------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>0.00</td>
<td>0.20</td>
</tr>
<tr>
<td>Angleslea</td>
<td>0.22</td>
</tr>
<tr>
<td>Energy Brix Complex</td>
<td>0.28</td>
</tr>
<tr>
<td>Hazelwood</td>
<td>0.32</td>
</tr>
<tr>
<td>Loy Yang A</td>
<td>0.36</td>
</tr>
<tr>
<td>Loy Yang B</td>
<td>0.40</td>
</tr>
<tr>
<td>Northern</td>
<td>0.44</td>
</tr>
<tr>
<td>Playford</td>
<td>0.48</td>
</tr>
<tr>
<td>Yallourn</td>
<td>0.52</td>
</tr>
</tbody>
</table>

Notes:

Impact on Australia’s total carbon dioxide emissions

- Emissions of CO\textsubscript{2} from brown coal based power generation was 68.5Mt (in 2013/14) out of Australia’s total CO\textsubscript{2} emission of 543Mt.
- Brown coal therefore accounts for 12.6 per cent of Australia’s total CO\textsubscript{2} emissions, and 38 per cent of Australia’s energy based CO\textsubscript{2} emissions.

Options for carbon dioxide emissions reduction

There are limited number of options for reducing the CO\textsubscript{2} emissions intensity of brown coal utilisation. These options include:

- Efficient coal drying and dewatering: Removing the moisture from the coal prior to combustion can result in a significant reduction in carbon dioxide emissions. At present the technologies are expensive and energy intensive; however they may be suitable for retrofit to existing power plants.
- Advanced combustion/gasification technologies: Two technologies offer potentially lower CO\textsubscript{2} emission intensity:
  - Ultra-supercritical PF firing with coal drying (< 0.80 t CO\textsubscript{2} / MWh)
  - Integrated drying gasification combined cycle (IDGCC) (< 0.80 t CO\textsubscript{2} / MWh).
- Carbon capture and storage (CCS): CCS is a generic term to describe a set of technologies in which carbon dioxide is captured and separated at the source of its production, compressed to a liquid-like state, transported to a storage site and injected deep underground into a stable geological reservoir for long-term storage. CCS can be applied to carbon dioxide emissions from any source including gas and coal-fired power plants, as well as other concentrated sources of carbon dioxide emissions, such as in the cement industry.

Opportunity

Carbon Capture and Storage (CCS)

- Bass Strait features some of the world’s most suitable geological formations for the permanent underground storage of carbon dioxide emissions. A Commonwealth initiative, the national Carbon Storage Taskforce, has confirmed the State’s unique natural geological attributes for source-sink matching for CCS, and world class geological structures.
- Analysis to date has concluded that geological storage is the most viable option, with mineral and biological storage only viable in small applications where geological storage is limited. However, technology is evolving rapidly in these areas, and comparative costs and commercial feasibility may change.
- Together, Victoria’s brown coal assets and geological storage potential offer an opportunity for the State to identify and pursue a course of action that could provide a strong competitive advantage in a low carbon economy. The realisation of this opportunity is contingent on the successful commercialisation of CCS.
17. Asset utilisation

Gas

Gippsland

Although available peak day gas supply forecasts provided by market participants indicate approximately 1,000 TJ/d from Gippsland SWZ, the highest injection in the past three years is 920 TJ/d.

The capacity of the Longford pipeline is currently underutilised due to increasing amounts of gas from the Longford Gas Plant being sent to NSW via the Eastern Gas Pipeline (EGP). The EGP was expanded during 2015 through the construction of two new compressor stations, reducing the amount of Longford gas that is expected to flow into Victoria.

On the Warragul lateral, there was one occasion in 2014 when the pressure of the lateral dropped below the minimum due to an unexpected high load. This issue has been temporarily solved by increasing the supply pressure to the Lurgi pipeline from the Morwell backup regulator at Dandenong. Looping of the 4.87 km lateral would be a permanent solution to this localised issue, if high demand continues in the future.

Geelong

The South West Pipeline (SWP) capacity is 429 TJ/d. Before the commissioning of Winchelsea Compressor Station, the pipeline was reaching its capacity during high demand days. This was demonstrated by a number of Net Flow Transportation Constraints (NFTC) on the SWP during previous winters. Given the 62TJ/d capacity increase with the Winchelsea compressor, the pipeline is sufficient, based on the demand forecast for the next five years.

The withdrawal capacity at Iona has been eroded due to the demands of new connections off the BLP, such as the flow through the Plumpton PRS and Qenos load. However, the maximum withdrawal capacity is 92 TJ/d when both unit 11 and unit 12 compressors are in operation at Brooklyn.

Recent information provided by participants indicates that gas supply to the Iona Underground Storage (UGS) plant is in decline. This could have implications for the ability of the DTS to meet peak Victorian gas demand. Twice on 12 July 2015 the SWP reached its transportation limit to supply the DTS despite the Winchelsea compressor being available. AEMO is investigating and will update the market as soon as practical.

If the future requirement for Iona withdrawal increases, there are options to increase withdrawal capacity, such as by completing the Western Outer Ring Main project.

Northern Victoria

APA Group’s Victoria – New South Wales Interconnect expansion project has increased the export capacity to 118 TJ/d on a 1-in-20 peak system demand day. Construction of loops 6-9 is expected to start in February 2016. Refer to slide 32 for more information on the project.

Melbourne

No constraints have been identified in the Melbourne withdrawal zone.

Ballarat

No constraints have been identified in the Ballarat withdrawal zone.

Western Victoria

If there is no injection at Iona and Brooklyn Compressor Station is not available, minimum pressures at Portland and Iluka will be breached during increased system load.

AEMO plans to manage the risk with ongoing consultations with market participants to ensure that Brooklyn Compressor Station will be available when Iona is not injecting.

Long term solutions to the vulnerability include:
- A new system injection point south of Hamilton to allow gas from the SEA Gas Pipeline to be injected into the Western Transmission System (WTS)
- Additional compression or looping of the WTS.

AEMO produced a paper in October 2015 for the Gas Wholesale Consultative Forum (GWCF) that includes options for increasing the capacity of the South West Pipeline to flow to Port Campbell.

Notes:
1. AEMO, 2015, Gas Statement of Opportunities (GSOO) Attachment B Victorian Gas Planning Review
17. Asset utilisation

Liquid fuels

As can be seen in the table to the right, most of the liquid fuels terminal storage facilities Australia-wide are close to full capacity.

There are a number of liquid fuels pipelines that have been mothballed and are now redundant due to rationalisation of oil company terminal facilities and refinery closures. Examples of these include a pipeline from the dismantled BP refinery at Westernport and the refined pipeline from the Port of Melbourne to Altona.

<table>
<thead>
<tr>
<th>State</th>
<th>Region</th>
<th>Storage (ML)</th>
<th>Capacity Utilisation</th>
<th>Constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>VIC</td>
<td>Melbourne terminals</td>
<td>327</td>
<td>Close to full capacity</td>
<td>Emerging constraints for ULP storage in west Melbourne. Holden dock around 80 per cent utilised. Need for increased pipeline capacity for jet fuel.</td>
</tr>
<tr>
<td>VIC</td>
<td>Hastings</td>
<td>91</td>
<td>80% utilisation</td>
<td>Space for additional storage if market conditions justify</td>
</tr>
<tr>
<td>NSW</td>
<td>Sydney</td>
<td>610</td>
<td>Close to full capacity</td>
<td>Berth and pipeline constraints. JUHI pipeline requires further capacity.</td>
</tr>
<tr>
<td>NSW</td>
<td>Newcastle</td>
<td>144</td>
<td>Close to full capacity</td>
<td>Caltex pipeline close to capacity</td>
</tr>
<tr>
<td>Queensland</td>
<td>Brisbane</td>
<td>241</td>
<td>Close to full capacity</td>
<td>Berth and pipeline constraints reported.</td>
</tr>
<tr>
<td>Queensland</td>
<td>Regional</td>
<td>586</td>
<td>Close to full capacity</td>
<td>Constraints in Mackay and Gladstone. Some shipping constraints.</td>
</tr>
<tr>
<td>Western Australia</td>
<td>Perth</td>
<td>206</td>
<td>Significant spare capacity</td>
<td>Potential to increase imports through independent terminals at Kwinana.</td>
</tr>
<tr>
<td>Western Australia</td>
<td>Regional</td>
<td>319</td>
<td>Some spare capacity and some constraints</td>
<td>Spare capacity at Geraldton and Broome. Constraints at Port Hedland, Esperance and Dampier.</td>
</tr>
<tr>
<td>South Australia</td>
<td>Adelaide</td>
<td>176</td>
<td>Close to full capacity</td>
<td>Draught limitations at Birkenhead terminal.</td>
</tr>
<tr>
<td>South Australia</td>
<td>Port Lincoln</td>
<td>22</td>
<td>Some spare capacity</td>
<td>Shipping frequency is a bottleneck</td>
</tr>
<tr>
<td>Tasmania</td>
<td>Hobart</td>
<td>60</td>
<td>Close to full capacity</td>
<td>Devonport experiences shipping frequency constraints. Marstel recently recommissioned around 40ML of storage at Bell Bay.</td>
</tr>
<tr>
<td>Tasmania</td>
<td>North</td>
<td>105</td>
<td>Some spare capacity at Bell Bay</td>
<td>Small increases in throughput possible.</td>
</tr>
<tr>
<td>Northern Territory</td>
<td>Darwin</td>
<td>124</td>
<td>Close to full capacity</td>
<td>Terminals mainly service mining operations.</td>
</tr>
<tr>
<td>Northern Territory</td>
<td>Mining</td>
<td>157</td>
<td>At full capacity</td>
<td></td>
</tr>
</tbody>
</table>

Notes:

1. ACIL Tasman, August 2009, Petroleum import infrastructure in Australia
18. Infrastructure charges

Electricity and gas—general overview

Prices can be cost reflective to varying degrees. The regulatory regimes for electricity and gas TNSPs and DNSPs ensure that charges are broadly reflective of costs. Furthermore, the Victorian Government does not subsidise the regulated network prices (other than a few minor exceptions discussed below) unlike in some States such as Western Australia. Therefore, while prices are generally cost reflective, the costs for some regulated services are spread, or averaged, over customer groups. As such, prices are cost reflective to varying degrees when examining the ‘second layer’ of cost reflectivity. Some specific elements of each network are discussed below.

Electricity transmission

Transmission services can be ‘negotiated’ or ‘prescribed’ services. The charges for negotiated services are negotiated with the individual user(s) of the service in accordance with a negotiation framework approved by the AER. These frameworks usually include provisions around negotiating in good faith. The negotiating process is likely to drive commercial outcomes.

Prescribed services are subject to economic regulation, meaning prices are also subject to the provision of the National Electricity Rules. Some prescribed services are contestable. In this case AEMO will hold a competitive tender for the completion of the works (AER, 2013). Through this competitive process, contestable services are likely to be reflective of costs.

Prescribed non-contestable services are subject to economic regulation. As discussed in Item 4, AEMO is responsible for planning the transmission network in Victoria. Following from this, AEMO plays a role in network pricing for some prescribed services. While responsibility for pricing prescribed connection services rests with TNSPs (subject to regulations administered by the AER), responsibility for pricing the remaining prescribed services rests with AEMO (subject to the same regulations) (AER, 2013). As all prescribed services are subject to economic regulation, the pricing of these services must be done in accordance with the pricing principles in the NER. These principles include that ‘[a TNSPs’ revenue] must be allocated to each category of prescribed transmission services in accordance with the attributable cost share for each such category of services.’ That is, the prices are reflective of cost.

Gas transmission

Pipelines can be classified as ‘covered’ or ‘uncovered’. The prices charged for uncovered pipelines are not regulated. Pipeline owners that wish their pipeline to be uncovered can apply to the National Competition Council for a 15 year coverage exemption. Under Chapter 1 Part 1 Section 15 of the National Gas Law the criteria in deciding whether a pipeline should be covered include whether increased access to pipeline services provided would promote competition and whether it would be uneconomic for anyone to develop another pipeline.

Uncovered pipelines may be predominantly used by the pipeline owner. Where third parties use the pipeline capacity, prices are set by negotiation and agreement will therefore be made on commercial terms.

Covered transmission pipelines are subject to economic regulation and tariffs must be set in accordance with the National Gas Rules. In so doing, TNSPs must demonstrate the relationship between costs and tariffs in accordance with section 72(1)(j) of the rules, and have regard to the revenue and pricing principles in the laws which include setting tariffs to promote the efficient use of the pipeline. While AEMO is the gas transmission planner as per its role in electricity transmission networks, the tariff setting process is conducted between the TNSP and the AER for the gas network.

Electricity distribution

Distribution charges can be broken into two groups—charges for ‘standard control services’ and charges for ‘alternative control services’. The charges for standard control services are spread over the DNSPs’ customer base, whereas alternative control services are charged directly to customers that incur the costs. The National Electricity rules provides the following example for classifying services:

‘In circumstances where a service is provided to a small number of identifiable customers on a discretionary or infrequent basis, and costs can be directly attributed to those customers, it may be more appropriate to classify the service as an alternative control service than as a standard control service.’

Examples of standard control services are ‘Constructing the distribution network’ and ‘Maintaining the distribution network’ whereas alternative control services include ‘Service truck visits’ and ‘Photovoltaic installation’ (AER 2010).

Therefore, for alternative control services, network charges closely reflect costs. For standard control services, customers with similar characteristics pay an average charge rather than a customer specific charge. This average charge, however, is still cost reflective. For example, the applicable pricing principles include that ‘tariffs that a Distribution Network Service Provider charges... should reflect the Distribution Network Service Provider’s efficient costs of providing those services to the retail customer.’

Recent changes to the National Electricity Rules will make these charges more cost reflective still although Victoria will require an opt-in implementation of the rule change until at least 31 December 2020. Currently, customers that have a high maximum electricity demand (driven by energy intensive devises such as air conditioners) and low consumption (such as having solar PV) are not paying their ‘fair share’ of network costs. This is because maximum demand is a significant driver of network costs, whereas electricity charges are based on consumption. A practical implication of the new rules are that a component of customers’ charges will be based on their maximum demand (CitiPower, 2015).

Gas distribution

The covered and uncovered classification that applies to gas transmissions networks similarly apply to distribution networks. Gas DNSPs must also comply with the pricing provisions in the National Gas Rules and Laws. As such, prices are generally cost reflective. However, as discussed in Item 5, there are cases where the Victorian Government has contributed to the costs of connecting new areas, meaning customers’ connection charges in these areas will be below cost.

AER, Citipower Pty Distribution determination 2011–2015, October 2010
AER, Draft decision SP AusNet Transmission determination 2014–15 to 2016–17, August 2013
18. Infrastructure charges

Generation

Spot market—thermal generation
The market for generation is competitive as described in Item 4. As a general rule, in a competitive market prices will reflect the marginal cost of generation. However, there are times when demand for electricity is high and generators are able to excise some market power and receive prices in excess of marginal cost. In general this should not be a concern, as generators that only ever recover their marginal cost will not recover their fixed capital costs, meaning there will be no incentives for further investment in the market (although noting that currently no additional investment in generation is needed as discussed in Item 16).

Spot market—Renewables
Renewable generators are subject to the same wholesale market bidding arrangements as thermal generators. In addition to receiving the electricity spot price, renewable generators may also sell their Renewable Energy Certificates (RECs) that are generated along with each MWh of electricity. As such, renewable generators receive a subsidy, meaning the price of electricity generated (as distinct from the total value they receive from electricity and RECs) may be lower than what would be considered cost reflective.

Contract market—thermal generation
Prices on the futures market may not necessarily be cost reflective, as risk (and risk mitigation) is also priced in. Nevertheless, prices are based on a competitive and commercial outcome and are therefore likely to be efficient. The current price of a MWh of electricity on the futures market in Victoria is around $36-38 in 2017 (ASX, 2015).

Contract market—renewable generation
Similar operation to thermal generators, however renewable generators are also able to sell their RECs.
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