2013 PLANNING CONSULTATION METHODOLOGY AND INPUT ASSUMPTIONS

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Contents

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1.0	30/1/2013	Supply Forecasting	Initial release

1 Introduction

This document provides an overview of the assumptions employed for the Australian Energy Market Operator's (AEMO) 2013 planning reports, including:

- The 2013 National Transmission Network Development Plan (NTNDP).
- The 2013 Electricity Statement of Opportunities (ESOO).
- The 2013 Gas Statement of Opportunities (GSOO).
- The 2013 South Australian Electricity Report (SAER).
- The 2013 Victorian Annual Planning Report (VAPR).

These reports comprise AEMO's long-term view on the evolution of the National Electricity Market (NEM) and the Eastern and South East Australian gas transmission network. Where appropriate, other short- and medium-term planning reports published by AEMO may use differing or supplemental data assumptions, depending on the requirements of the models used in their development and the scope of the work being undertaken.

This document describes the classes of data that form the inputs to AEMO's long-term modelling. Actual data is located in referenced documents summarised in Appendix A and accompanying workbooks, available from AEMO's Web site.[1,2] This document supersedes *2012 Modelling Methodology and Assumptions* published on 30 January 2012.[3]

1.1 Data sources and flow

Assumption data originates from many sources, both externally and as a result of AEMO's activities in the national gas and electricity markets. Two appendices to this document outline where data originates and how data feeds from its origin through AEMO's modelling. *Appendix A - Summary of information sources* presents all data sources and the items taken from each. *Appendix B - Data flow* presents a series of diagrams with representative process flows that show how data and modelling activities relate to reports.

Different classes of data become available at different times of the year. Each planning report uses the latest data that is available when modelling begins.

2 Scenarios

AEMO's long term planning begins with the development of a series of credible global economic and technological development scenarios.[4] These scenarios are designed to cover a wide range of potential future development pathways, and describe the environment in which Australia's energy networks may operate for up to 20 years into the future.

AEMO does not consider any one scenario to be more or less likely than another. Instead, the scenarios are intended to explore the boundary of credible futures, with each scenario based on themes of development such as fast or slow economic growth, high or low technology costs, or relaxed or strict carbon policies.

Five scenarios are described in detail in *2012 Scenarios Descriptions*, published on 4 July 2012.[5] These are summarised in Table 1. Modelling performed in 2013 will use a subset of these five, selected for appropriateness to the problem under study.

Scenario descriptions will not be refreshed in 2013, however specific data under each item in Table 1 may be updated to ensure consistency with the current state of Australia's energy networks. For example, while the

[1] http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Planning-Reports.

[2] http://www.aemo.com.au/Gas/Planning.

[3] http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/2418-0002%20pdf.ashx.

[4] In the context of AEMO planning, a scenario is a self-consistent set of assumptions covering economic and policy settings, estimates of generation technology costs, fuel and carbon cost trajectories, price-demand relationships and other externalities that influence but are not materially affected by the generation expansion plans developed by capacity expansion modelling.

[5] http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/2012_Scenarios_Descriptions.ashx.

Fast Rate of Change scenario will still consider “high” economic and population growth, the interpretation of what constitutes “high” for the purposes of projecting energy and maximum demand will be revisited as part of AEMO’s national demand forecasting activities.

Table 1 – Summary of scenario drivers

		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
		Fast rate of change	Fast world recovery	Planning	Decentralised world	Slow rate of change
Economic	Economic growth	Higher	Higher	Predicted	Predicted	Lower
	Commodity prices	High	High	Medium	Medium	Low
	Productivity growth	High	High	Medium	Medium	Low
	Population growth	High	High	Medium	Medium	Low
Greenhouse	Reduction Target (below 2000 levels)	25% reduction by 2020 80% reduction by 2050	5% reduction by 2020 80% reduction by 2050	5% reduction by 2020 80% reduction by 2050	5% reduction by 2020 80% reduction by 2050	Zero reduction by 2020 80% reduction by 2050
	Carbon Price Assumption	Treasury high scenario	Treasury core scenario	Treasury core scenario	Treasury core scenario	Treasury core scenario for first 3 years, then $0/tCO2_e$ onwards
	Renewable Energy Target	Remains	Remains	Remains	Remains	Remains
	GreenPower	Falling	Rising	Flat	Rising	Flat
Fuel	International coal prices	High	High	Medium	Medium	Low
	East Coast gas prices	High trending to low	High trending to medium	Medium trending to high	Medium trending to medium	Low trending to high
	LNG East Coast Production	High	High	Medium	Medium	Low
Technology	R&D support	Strong	Moderate	Moderate	Weak	Moderate
	Distributed generation penetration	Strong	Moderate	Moderate	Strong	Weak
	Electric Vehicles	Strong	Strong	Moderate	Strong	Weak

3 Models

AEMO maintains four planning models: three for electricity and one for gas. These models incorporate the assumptions about future development described by the scenarios, and simulate the operation of energy networks to determine a reasonable view as to how those networks grow under different demand, technology, policy and environmental conditions.

3.1 Topology

Each model implements a simplification of the physical energy network, to maintain the size of solutions at reasonable levels while capturing important aspects that materially affect future network development.

The NEM is comprised of five electricity regions, generally (but not exactly) corresponding to the five Commonwealth States of Queensland, New South Wales, Victoria, South Australia and Tasmania, referred to as *regions* and shown in Figure 1. AEMO's electricity modelling duplicates these regions, representing the network as a system of five regional reference nodes connected by inter-regional flow paths. The regional topology allows the model to respond to regional changes in demand, and to optimise regional generation and inter-regional transmission expansion. This arrangement also mirrors the operation of the National Electricity Market Dispatch Engine (NEMDE), which is responsible for directing generation dispatch in the NEM.

A regional representation cannot account for differences in energy resources and infrastructure within a region. To incorporate these aspects AEMO's electricity modelling defines sixteen zones, shown in Figure 2, each of which displays a characteristic demand and resource pattern. The South West Queensland (SWQ) zone, for example, has low local demand but sizable solar, coal and gas resources: electricity export is the major challenge in this zone. The neighbouring zone to the east, South East Queensland (SEQ), has high demand, limited access to generation fuels and limits on infrastructure development to maintain the amenity of Brisbane, its suburbs and nearby coastal tourist centres. Energy import is the major challenge in this zone.

Energy resource availability and cost, along with generation build limits are defined according to these zones. Network constraint equations capture transmission limits between zones. Lower-cost zones will receive new generation first, provided that network limits do not unduly constrain that generation. In some cases, the low cost of generation in a particular area will justify both investment in generation infrastructure and investment in transmission infrastructure to supply power elsewhere.

Major gas transmission and production infrastructure is shown in Figure 3. The gas supply-demand outlook model incorporates major gas transmission pipelines, demand centres and production facilities in a representation that closely mirrors the real world, as shown in Figure 4.

Figure 1 – NEM regions

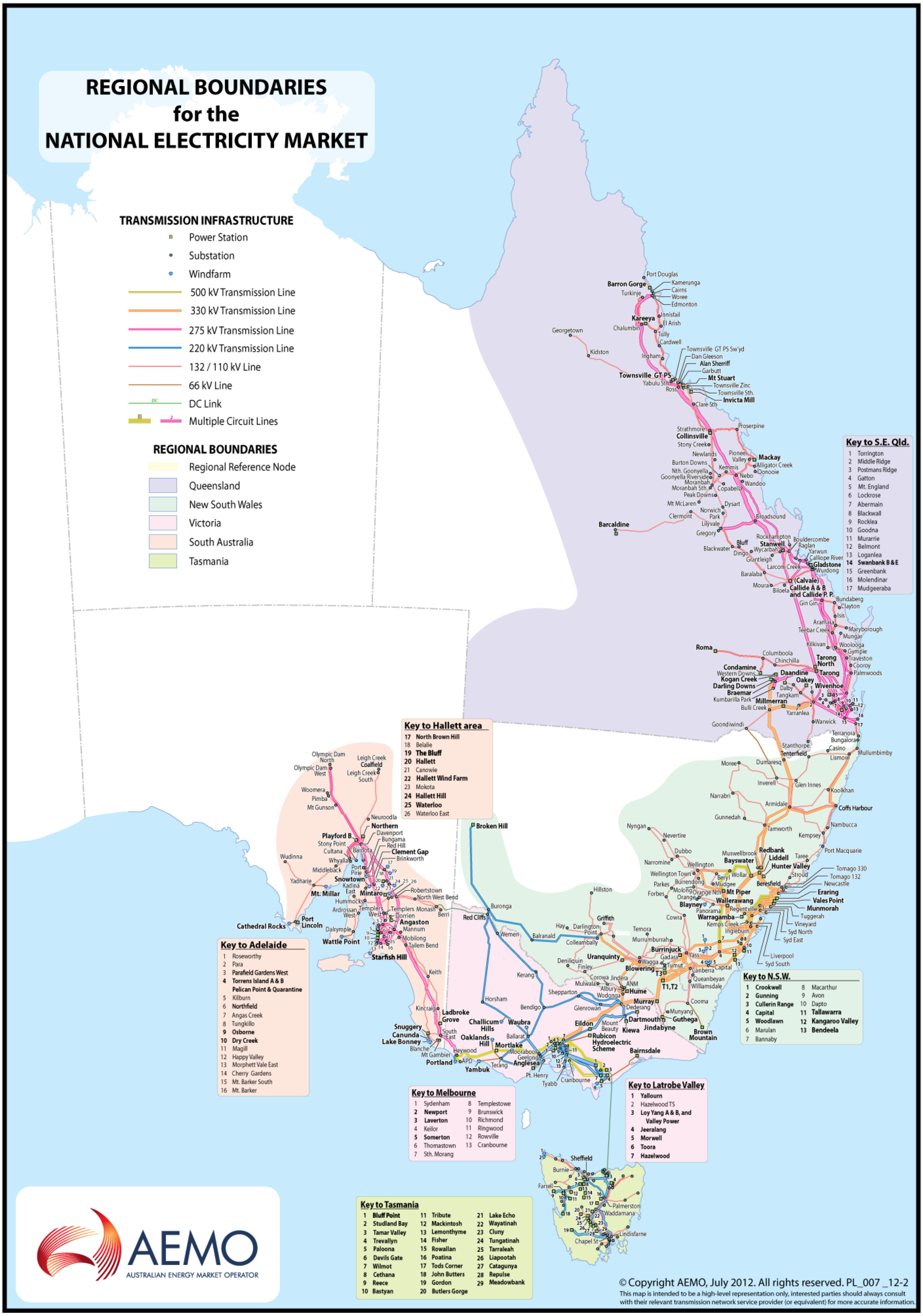


Figure 2 – Electricity planning zones

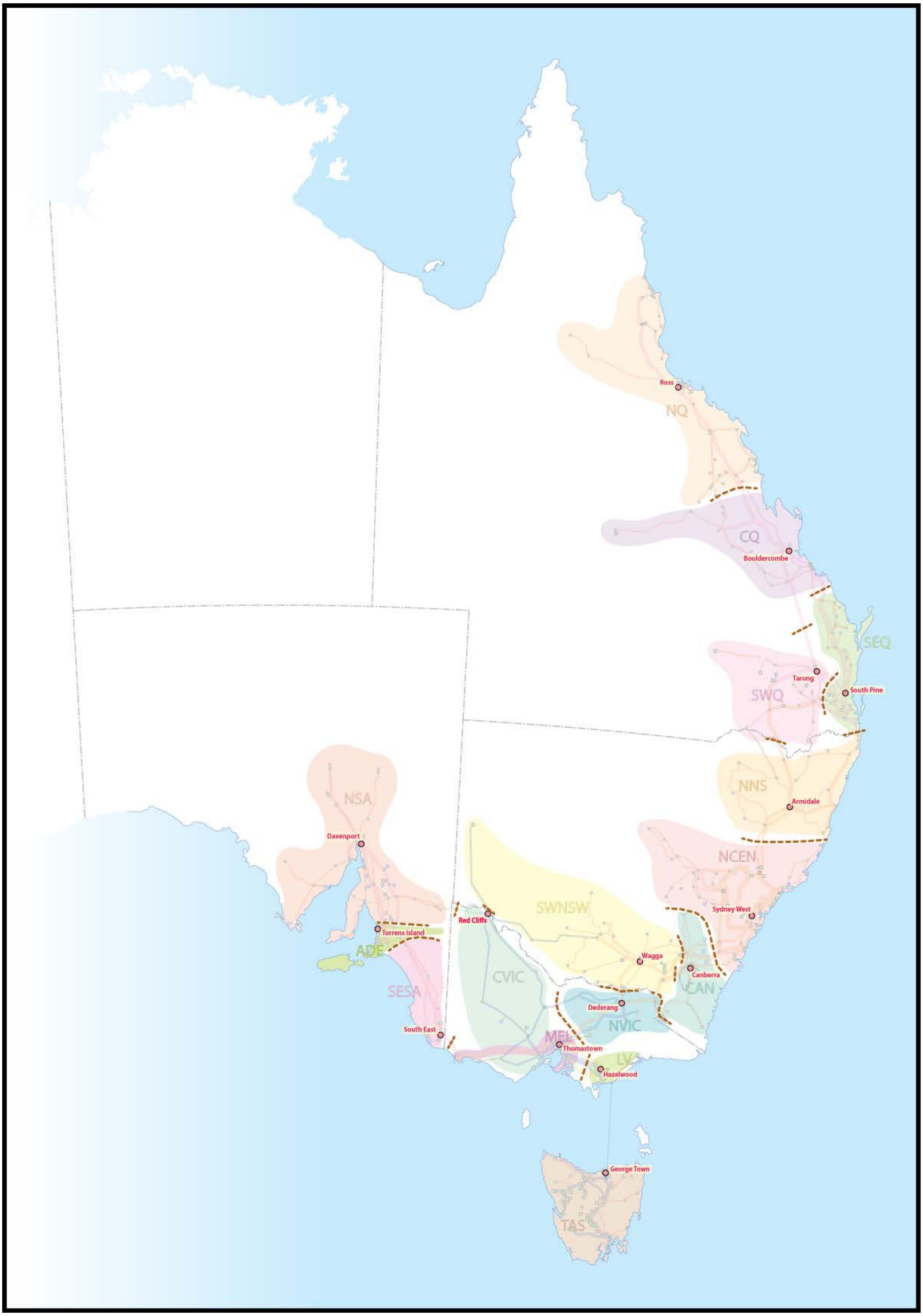


Figure 3 – Eastern and south-eastern Australian gas production and transmission infrastructure

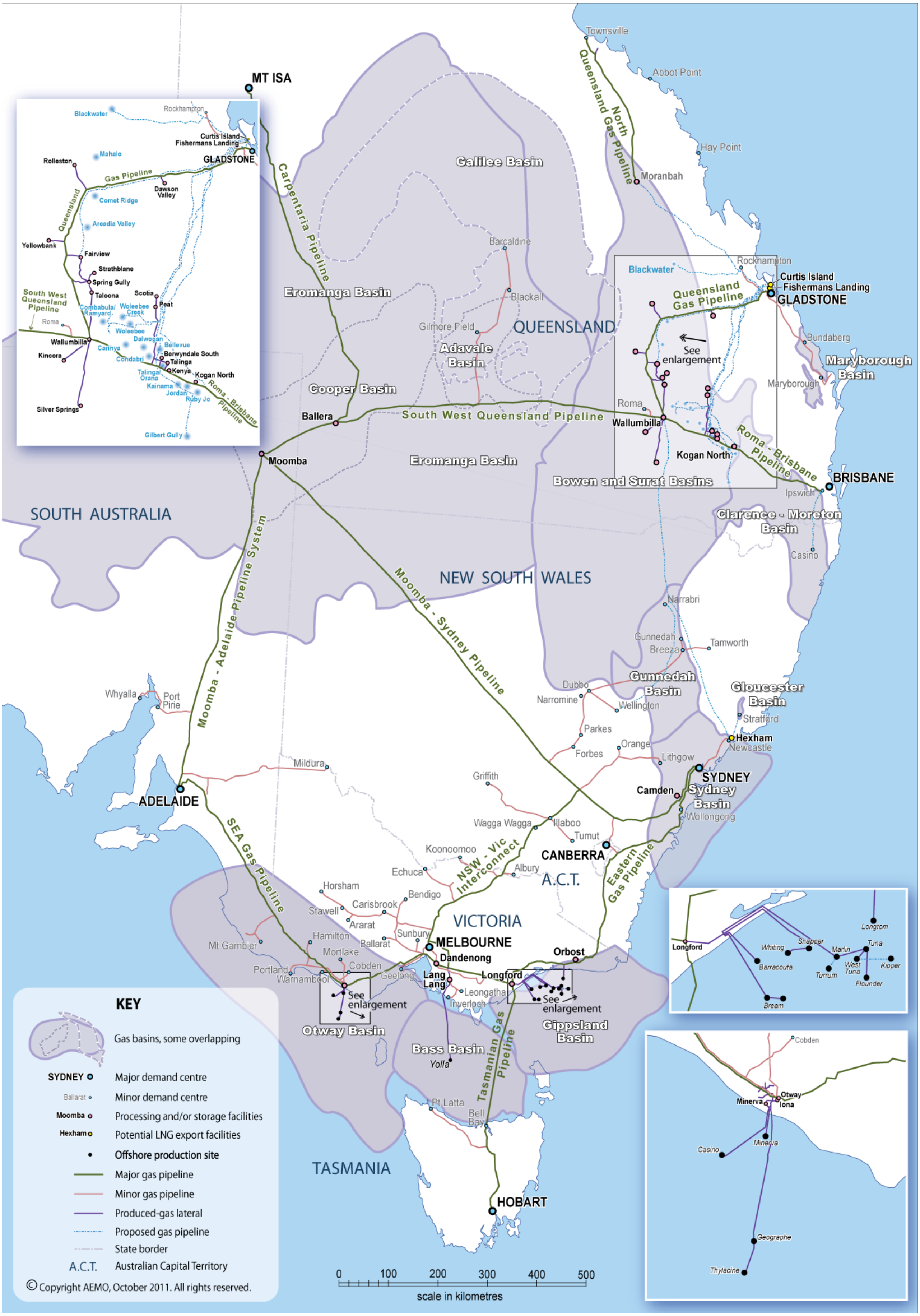
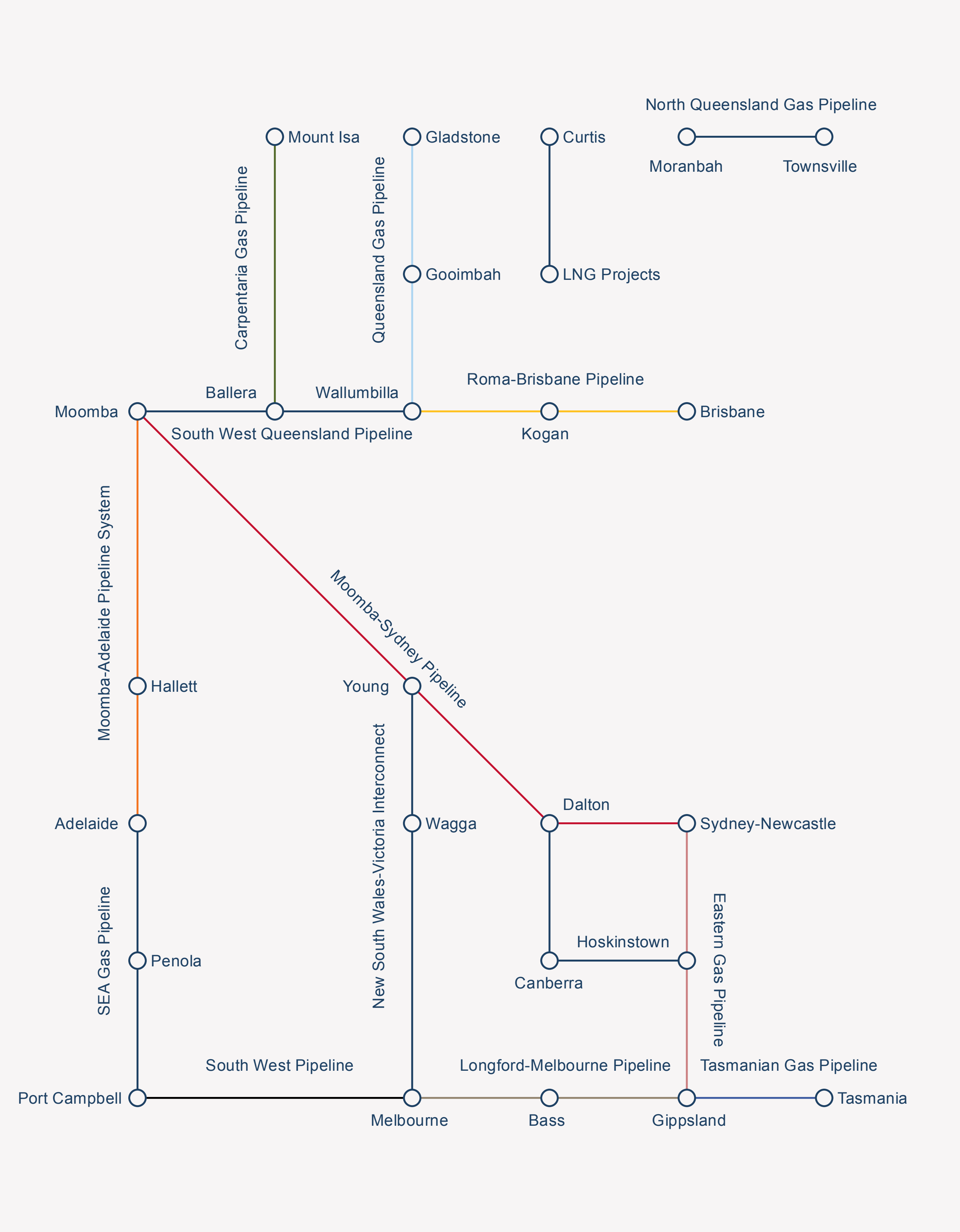


Figure 4 - Gas model topology

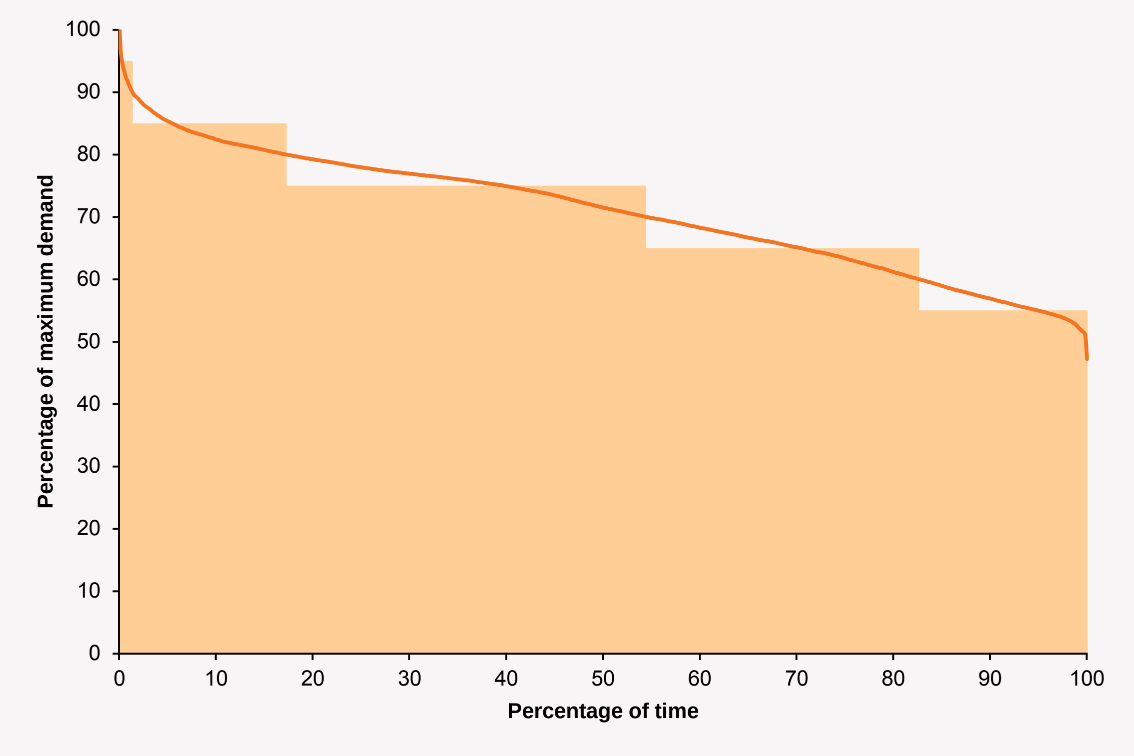


3.2 Capacity expansion model

The capacity expansion model is also referred to as the least-cost model. It is used to develop plans for generation and transmission expansion suitable to each scenario. It does so by co-optimising electricity generation and transmission investment to determine the lowest total generation and transmission cost, including both capital expenditure and operating costs. The model is rich in options for the location of new generation, the technology employed by new generation, generation that may retire and projects that increase transmission capability.

Limits to computing resources mean that the capacity expansion model cannot consider every combination of every option for every time period in every scenario over a modelling horizon that may extend up to 25 years. The capacity expansion model reduces problem complexity by reducing the number of instants of time it considers. To ensure that this reduction is representative of the total period of time in the modelled horizon, the load duration curve is partitioned into blocks, as shown in Figure 5.

Figure 5 – A load duration curve partitioned into five load blocks



Blocks are generated from the load duration curves of each region in each month in each modelled year. The monthly partitioning captures seasonal variation while the yearly partitioning captures growth in demand. To ensure supply capacity adequacy, 10% probability of exceedence (POE) demand curves are used.

Other time-varying data (for example, assumed output of wind generators) is similarly treated in the capacity expansion model.

The capacity expansion model is implemented using the PLEXOS for Power Systems software from Energy Exemplar. The 2012 model is available at AEMO's 2012 Planning Assumptions and Inputs web page.[6] An updated model will be published with the NTNDP in 2013.

3.3 Time-sequential model

The capacity expansion model, while considering a large number of options, produces relatively coarse estimates of generation, flow and price that may be used to assess market benefits or report on network performance. The generation and transmission expansion plan developed by the capacity expansion model is validated using a time-sequential model that mimics the dispatch process used by NEMDE.

[6] http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs.

The time-sequential does not perform decision-making about new investment, but does consider the modelled time horizon at much higher resolution compared to the capacity expansion model. The time-sequential model performs optimised electricity dispatch for every hour in the modelled horizon, allowing the development of metrics of performance of generation (by location, technology, fuel type or other aggregation) and transmission (flow, bounding constraint equations), resulting in more realistic assessments of the market benefits of specific augmentations.

The high time resolution allows this model to better capture effects of inter-regional demand diversity and diversity between intermittent supply and demand.

The time-sequential model is implemented using the Prophet software from Intelligent Energy Systems. The model will be published with the NTNDP in 2013.

3.4 Electricity supply-demand calculator

The electricity supply-demand calculator assesses regional peak day capacity and annual energy adequacy over a 10 year period. Unlike the capacity expansion model, which finds the most cost-effective combination of generation and transmission options to ensure system security and reliability is met, the supply-demand calculator reports the location and magnitude of supply shortfall, governed by existing and committed generation capacity, network constraint equations, minimum reserve levels and inter-regional reserve sharing. The electricity supply-demand calculator does not consider the availability of primary energy supply[7] and does not offer solutions regarding how supply shortfall should be addressed.

3.4.1.1 The electricity supply-demand calculator and minimum reserve levels

Up to and including 2012, supply adequacy in the ESOO was assessed by using the supply-demand calculator to compare available capacity and demand-side participation against regional demand and a safety margin of minimum reserves. These reserve requirements have historically been produced using a complex suite of market simulations, and need regular review to ensure they remain appropriate as the power system evolves.

AEMO is currently reviewing the methodology used to both calculate reserve requirements and assess supply adequacy. This review aims to identify accuracy and efficiency gains that may be possible by moving away from pre-calculated values, and instead integrating reserve requirement calculations within the supply adequacy assessment itself. AEMO believes this approach will deliver increased value to AEMO and its stakeholders by providing an improved method for assessing reserve adequacy that offers significant quality improvements for longer term assessments.

The review will confirm whether replacing the current supply-demand calculator approach with the time-sequential model that AEMO employs for detailed market modelling studies (such as the NTNDP) will deliver the following benefits:

- Increased value to stakeholders by significantly improving the quality of longer-term reserve adequacy assessments.
- Improved quality and accuracy of the Low Reserve Condition (LRC) points reported in the ESOO.
- Increased consistency between the ESOO modelling and other planning or operational studies such as the NTNDP and Energy Adequacy Assessment Projection (EAAP).
- Increased value, and amount, of information provided to stakeholders.

The use of the time-sequential model for the ESOO would remove the need for AEMO to prepare and maintain the Supply Demand Calculator for its own use.

AEMO is also investigating how a set of traditional minimum reserve requirements might be extracted from the above approach for use by:

- AEMO in running deterministic studies such as the Medium Term Projected Assessment of System Adequacy (MTPASA).
- Participants or interested parties in running their own deterministic studies.

[7] For example coal, gas, wind, water storage levels and inflows

As this investigation progresses, AEMO intends to provide stakeholders with further information on any proposed changes to the minimum reserve level calculation methodology.

3.5 Gas supply-demand outlook model

The gas supply-demand outlook model assesses reserves, production and transmission capacity adequacy over a 10 year period. The model performs gas network production and transmission optimisation at daily time intervals that minimises the total cost of production and transmission, subject to capacity constraints, according to the arrangement shown in Figure 4.

Assessment of reserves requires the gas supply-demand outlook model to consider the difference between production and transmission solutions to supply shortfall: an augmentation of production near supply shortfall may draw on a different reserve to a transmission augmentation solution, leading to different reserve depletion projections. For example, supply shortfall in Melbourne may be addressed by increasing production from the Gippsland Basin, increasing production from the Otway Basin, or increasing transmission capacity between the Moomba-Sydney Pipeline and Melbourne, which will ultimately source gas from north-eastern South Australia or Queensland.

The gas supply-demand outlook model does not contain cost-related information in sufficient detail to form a reliable view on transmission and production augmentation based on cost efficiency. Instead, AEMO reviews and models publicly-announced and generic augmentation projects and uses model outcomes to aid assessment of reserves adequacy.

The gas supply-demand outlook model is implemented using a combination of the General Algebraic Modelling System (GAMS), SQL Server database and a browser interface. It will not be published in 2013.

4 Variables

4.1 Demand growth

Change in demand for electricity and gas is a key driver of the evolution of energy production and transmission systems. Demand can change in two ways:

- The amount of energy that must be provided over the course of time.
- The amount of power that must be provided instantaneously.

For electricity, these are referred to as *energy* and *maximum demand* (MD) respectively, and are measured in megawatt-hours (MWh, energy) or megawatts (MW, power). For gas, where instantaneous demand has a lesser impact on supply, the concept of instantaneous power is less relevant and gas demand is often expressed in terms of a specific timeframe: maximum hourly quantity (MHQ), maximum daily quantity (MDQ) or annual quantity. All are measured in gigajoules (GJ), terajoules (TJ) or petajoules (PJ) depending on the length of time under consideration.

AEMO uses scenario descriptions to develop regional electricity and gas demand projections to suit long term planning timeframes. The *National Electricity Forecasting Report*[8] is published by AEMO mid-year, and presents 10% and 50% POE MD and energy projections for each NEM region up to twenty years into the future. These projections are extended to a twenty five year range for use in the NTNDP.[9] The 50% POE projections reflect an expectation of typical MD conditions. The 10% POE projections reflect an expectation of extreme MD conditions. Projected energy is the same in each case.

In electricity modelling, the energy and MD projections in each region are combined with a typical hourly demand profile for that region, using a time series from a reference historical financial year, to produce hourly demand profiles that cover the full modelling period. When investigation into the sensitivity of outcomes to demand diversity is required, other reference years may be used as the basis for future demand profiles.

[8] Available from: http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/2012%20National%20Electricity%20Forecasting%20Report.ashx

[9] The average growth in demand over the final ten years of the NEFR projections is used to extend the NTNDP projections to a twenty-five year horizon.

Energy and MD projections published in the NEFR incorporate some generation that is explicitly modelled in the capacity expansion and time-sequential models. When developing demand profiles, the projections must be adjusted to avoid double counting. A detailed description of demand profile development is given in *2012 NTNDP Demand Trace Development*, available from the 2012 NTNDP Assumptions and Inputs web page.[6]

Gas demand forecasts are produced by combining data from four sources: mass market (residential and commercial) customers, large industrial facilities, gas powered generation and LNG export facilities. Mass market and large industrial demand is developed by AEMO each year and published in the GSOO. Demand from gas powered generation is developed in modelling undertaken for the NTNDP. In 2012, demand for LNG export was developed in consultation with CORE Energy Group.[10]

These data will be reviewed in 2013.

4.1.1 Small-scale generation

Demand projections are developed based on the demand that appears on the transmission system. Non-significant non-scheduled generators that are connected to a distribution network appear to the transmission system as a reduction in demand from that distribution network. The market model includes representations of scheduled, semi-scheduled and significant non-scheduled generators. Non-significant non-scheduled generators, which are not represented in the market model, are incorporated into the energy and MD projections.

The 2012 National Electricity Forecasting Report (NEFR) tables the non-scheduled generators that are incorporated into energy and MD projections (those that are used in annual energy forecasts and *not* part of operational demand). [11]

4.1.2 Rooftop solar photovoltaic uptake

An analysis of the uptake of rooftop solar photovoltaic (PV) generation was undertaken by AEMO in 2012, published as the Rooftop PV Information Paper[12]. The outcomes of that analysis will be used as the basis of rooftop PV modelling in 2013.

Rooftop PV modifies the shape of the demand curve, as a larger portion of demand is removed from sunny times of the day as the amount of installed rooftop PV increases. The uptake of rooftop PV is also projected to occur at a different rate than the change in underlying demand.

Rooftop PV is treated in the market models similarly to non-significant non-scheduled generation. That is, there is no explicit representation of rooftop PV in the model, rather, the expected generation from rooftop PV is subtracted from the demand profile.

To accommodate modification to the demand profile and different rates of demand growth and rooftop PV uptake, the reference demand curves are adjusted to remove the effect of rooftop PV prior to growing future demand profiles. Rooftop PV generation profiles are developed independently, taking changes in uptake into account. This generation is subtracted from the PV-adjusted demand curves to produce a demand curve that incorporates both growing demand and increasing uptake of rooftop PV.

4.1.3 Weighting factors

In time-sequential dispatch modelling, both the 10% POE and 50% POE demand conditions are used to contribute to reported generation and transmission network performance metrics. Outcomes from two simulations are combined to produce a single-figure result.

When it is assumed that demand follows a normal distribution, and that 50% POE results have broadly similar outcomes to 90% POE outcomes, the weighting factors are 30.4% on 10% POE outcomes and 69.6% on 50% POE outcomes.

[10] Reports and data are available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections.

[11] 2012 National Electricity Forecasting Report, Appendix C. Available from: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.

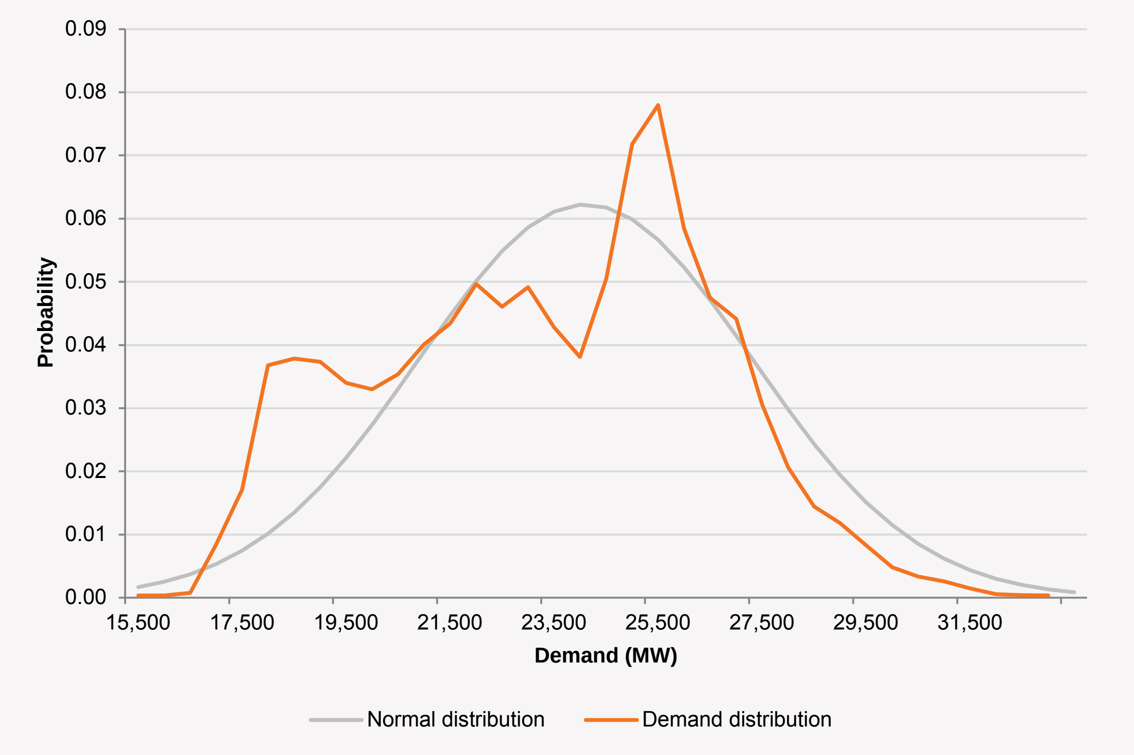
[12] Rooftop PV Information Paper. Available from http://www.aemo.com.au/Electricity/Planning/Forecasting/Information-Papers-2012.

Figure 6 shows the probability density function of the load duration curve in Figure 5, together with a normal distribution developed using the demand data's mean and standard deviation. The data does not conform exactly to a normal distribution curve, and weighting factors may be made more appropriate by considering an alternative distribution assumption. AEMO is investigating whether the shape of demand probability densities materially affect the weighting factors used to determine simulation results.

Preliminary investigation has shown that introducing a 5% POE profile to the weightings can improve the accuracy of the weighted results, particularly when considering unserved energy outcomes. The most appropriate weighting factors under this arrangement are approximately 7% on 5% POE outcomes, 23% on 10% POE outcomes, and 70% on 50% POE outcomes.

AEMO intends to use 5%, 10% and 50% POE demand conditions for the purposes of calculating supply adequacy in the ESOO, and is reviewing the need to apply this approach more broadly to other time-sequential modelling studies.

Figure 6 – Probability density of the load duration curve in Figure 5



4.1.4 Scaling factors

In previous modelling, regional energy projections were calculated based on energy injected into the transmission system (sent out), while maximum demand projections were calculated based on demand to be met at generator terminals (generator terminal). The difference between these two is the power that must be supplied back to the generator for its own operation (auxiliary load). To ensure that energy and maximum demand projections were expressed on the same basis, the MD projections were adjusted by scaling factors to remove generator auxiliary load and express MD on a sent out basis.

The 2012 NEFR now incorporates information regarding auxiliary load at the regional scale, and adjustment to MD projections is no longer required to make them suitable for modelling. As a result, scaling factors that were published previously are now no longer required and will not be published from 2013.

4.1.5 Electric vehicles

Electric vehicles are expected to become a significant new source of electricity demand within the typical timeframes of AEMO's long term planning.

AEMO has engaged Energeia to assess the location and magnitude of electric vehicle uptake and assumptions about charging behaviour consistent with AEMO's scenario descriptions as a component of the 2013 NEFR.

Electric vehicle demand is incorporated into the models by developing a daily charging profile consistent with charging behaviour assumptions, growing the profile to accommodate growth in demand due to increased uptake, and adding the resulting profiles to the projected regional demand profiles in each scenario. Unlike rooftop photovoltaic generation, there is presently no significant penetration of electric vehicles in any NEM region, and reference year demand profiles are assumed not to contain time of day distortions due to electric vehicle load. In this case, reference year historical demand profiles are not adjusted prior to application of projected future electric vehicle charging load profiles.

4.2 Emissions reduction policies

4.2.1 Renewable energy targets

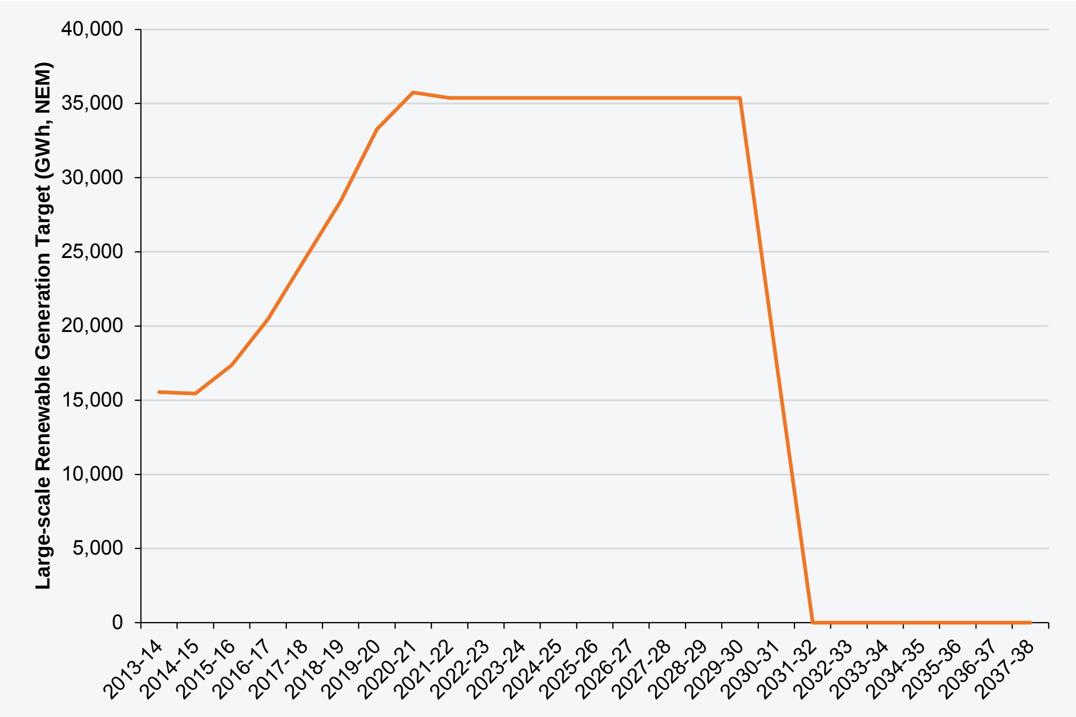
The Australian Government sets targets for energy generated by renewable sources through the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). These targets are encouraged by requiring wholesale purchasers of electricity to purchase Renewable Energy Certificates (RECs) which, from 1 January 2011, are classified as either Large-scale Generation Certificates (LGCs) or Small-scale Technology Certificates (STCs) for the purposes of meeting the LRET and the SRES respectively. [13]

In the capacity expansion model, the LRET is enforced by setting an annual energy target that must be met by renewable generation. To incorporate the LRET into the capacity expansion model, two adjustments are made to the published LRET figures:

- The number of LGCs that are required to meet the target is scaled by an amount that reflects the energy generated in the NEM compared to the amount of energy generated Australia-wide.
- The calendar-year targets defined by the LRET are converted to financial year targets by averaging the targets in adjacent calendar years.

LRET targets are published in the accompanying *2013 additional modelling data* workbook and are shown in Figure 7. The LRET is undefined beyond 2030. AEMO assumes that the LRET falls to zero after this time, noting that renewable generation established prior to 2031 will continue to provide significant energy to the NEM after the LRET expires.

Figure 7 – Large-scale Renewable Energy Target



[13] Australian Government. *Fact Sheet: Enhanced Renewable Energy Target*. Available from: http://www.climatechange.gov.au/government/initiatives/renewable-target/fs-enhanced-ret.aspx.

The majority of STCs are generated by domestic rooftop solar installations. The uptake of rooftop solar power is modelled as part of the demand projections (see Section 4.1.4), so no explicit representation of STCs is included in any of the models.

4.2.2 Banking of Renewable Energy Certificates

The 2012 ESOO highlighted an existing surplus of large-scale generation certificates (LGCs) in renewable energy certificate markets, driven by a faster-than-expected growth in renewable generation and contracting demand. A surplus of certificates can defer renewable generation investment, and may need to be considered for electricity capacity expansion modelling.

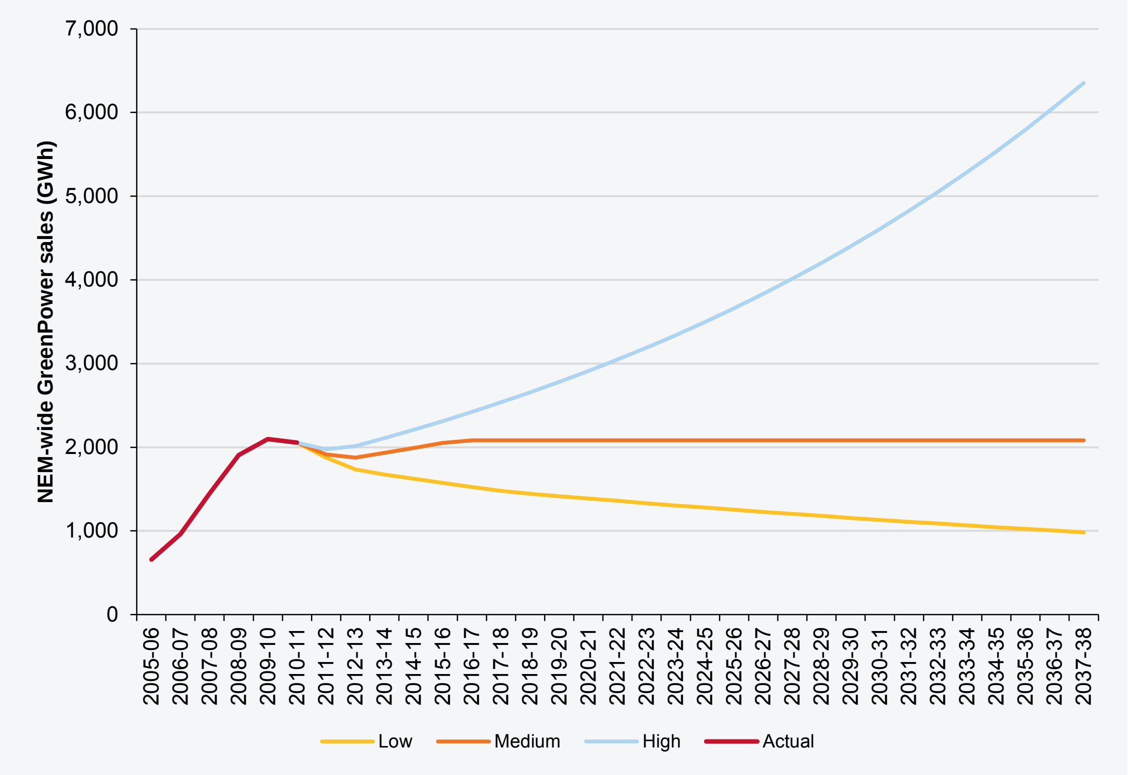
AEMO is investigating the value of incorporating certificate banking into capacity expansion modelling.

4.2.3 GreenPower

GreenPower is a federal government program to empower consumers to purchase electricity from renewable sources. Sales of GreenPower electricity represent an additional requirement for renewable generation over and above the targets imposed by the LRET and the SRES. The capacity expansion and time-sequential models use renewable generation targets that are adjusted to include GreenPower sales.

AEMO's modelling scenarios define three GreenPower sales trajectories: rising, falling and flat. These trajectories are shown with historical sales in Figure 8, where the low trajectory incorporates contraction of sales by 2% per year, and the high trajectory incorporates expansion of sales by 4.7% per year. GreenPower sales trajectory data is available in the *2013 additional modelling data* workbook.

Figure 8 – GreenPower sales trajectories



4.2.4 Desalination

Power for desalination plants can represent a significant component of demand. Additionally, all major desalination plants in Australia are committed to purchasing renewable energy over and above the requirements of the LRET.

In 2012, desalination load was added to the LRET. The end of drought conditions in eastern Australia has resulted in all major desalination plants being placed in standby mode. LGC purchase agreements for desalination plants usually apply in the long term, and are not affected by the plants' operational status. It is assumed that LGCs purchased under such agreements will be re-sold, however, so demand for LGCs from desalination plants do not add to the LRET when plant are non-operational.

In 2013, demand for LGCs from desalination plants is assumed to be zero.

Table 2 outlines the major desalination plants in eastern Australia, their maximum water output and power and energy consumption at maximum output when operational.

Table 2 – Major desalination plants in the NEM

Plant	Region	Production (GL/year)	Power consumption (MW)	Energy consumption (GWh/year)
Tugun	Qld	45	17	150.5
Kurnell	NSW	91	48	420
Port Stanvac	SA	100	57	500
Wonthaggi	Vic	150	98	860

4.2.5 Carbon permits

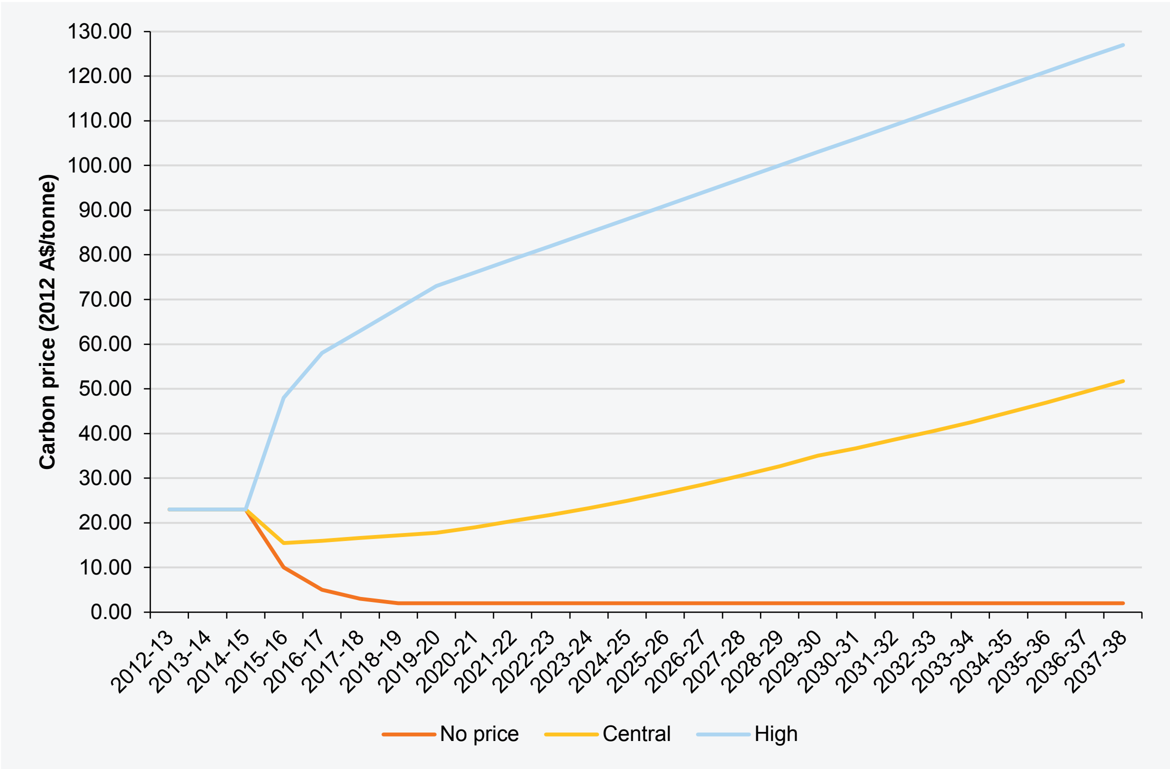
On 28 August 2012 the Minister for Climate Change and Energy Efficiency announced a suite of planned changes to the carbon pricing mechanisms that we introduced on 1 July 2012. Under these changes the price ceiling and price floor, to be introduced in 2015-16, will be abolished from 1 July 2018. Australian carbon permit prices will be linked to European permit prices from 1 July 2018. To ensure that emissions reductions occur in Australia, liable businesses will be required to source at least half of their permits domestically. Arrangements prior to 1 July 2018 will remain unchanged.

Modelling for 2013 will incorporate the same carbon price trajectories as those used for the 2013 NEFR, provided changes in the economic or policy environments do not introduce material change to those trajectories' underlying assumptions. These trajectories were developed in consultation with the National Institute of Economic and Industry Research (NIEIR). NIEIR revised carbon price trajectories release by Treasury to incorporate a number of economic and policy developments that occurred in 2012:

- The removal of the $15 floor price on carbon under the emissions trading system.
- The continued weak outlook for the European economies and the implications of this on the European emissions trading carbon prices.
- The stalling of the contract for closure program and its flow-on effects into electricity prices.
- Weaker energy sales in Australia reflecting slow or falling mass market sales in response to high energy prices and major load losses in established markets.

Carbon price trajectories are available in the *2013 additional modelling data* workbook, and are shown in Figure 9. These carbon price trajectories do not reference updates to Treasury carbon price trajectories released on 21 January 2013.

Figure 9 – Zero, central and high carbon price trajectories



4.3 Price elasticity of demand

The energy and MD projections incorporate the response of consumers to electricity prices, based on the price outcomes of the reference year (that is, the prices that were reported in the reference year already incorporate consumers' response to price, because demand and prices would have been higher were there no consumer response present). Consumer response to price modifies the shape of the demand curve, which is strongly correlated with price. This shape is maintained by the market model, even as energy and MD projections change on a year by year and scenario by scenario basis. It is assumed that the modelled price outcomes will continue to be correlated to demand, and as such no further consumer price elasticity to demand is modelled.

4.3.1 Demand side participation

Further to the price elasticity of demand present in projections of energy and MD is the concept of demand-side participation (DSP). DSP is an agreed, additional change in demand beyond price elasticity that can occur when the power system becomes stressed. It is often provided by industrial customers that have interruptible loads.

The capacity expansion and time-sequential models incorporate DSP by reducing the generation required when modelled prices reach specific levels[14]. Absolute amounts of available DSP (in MW, in each region) depend on scenario, and are listed in the accompanying *2013 additional modelling data* workbook. These amounts are activated in three price bands:

- 30% at $1,000/MWh.
- 30% at $3,000/MWh.
- 40% at $5,000/MWh.

[14] Very high prices are assumed to indicate times when reserves of available power in a region are approaching their limit.

That is, demand will be reduced by 30% of available DSP when the modelled price reaches $1,000/MWh. DSP is assumed to be available in all trading intervals and 100% reliable.

4.4 Minimum reserve levels

The capacity expansion model and the electricity supply-demand calculator both contain a representation of minimum reserve levels. Minimum reserve levels represent a safety margin of spare capacity that must be maintained at all times to ensure the power system operates within long-term reliability standards.

In the capacity expansion model, minimum reserve levels adjust the amount of generation that must be available in each region relative to the value of peak demand. The capacity expansion model brings new generation online when the sum of the maximum demand and the minimum reserve level exceeds the available generation[15].

In the electricity supply-demand calculator, minimum reserve levels are used in conjunction with peak demand to determine low reserve condition (LRC) points. AEMO is currently reviewing the methodology used to both calculate reserve requirements and assess supply adequacy. This review aims to identify accuracy and efficiency gains that may be possible by moving away from pre-calculated minimum reserve levels and the supply-demand calculator approach, in favour of using the same time-sequential model that AEMO employs for detailed market benefit assessments.

The time-sequential model performs a probabilistic sampling of generator outages, so an assessment of system reliability is a direct output of the model, without the need for an intermediate set of minimum reserve levels.

This approach increases quality, efficiency, and transparency in the ESOO’s supply adequacy assessment.

4.5 Gas prices

Gas costs fall into a number of categories:

- Gas production cost: the cost incurred to bring gas out of reserves and treat it to a specification suitable for transport.
- Gas transport cost: the cost incurred to compress and move gas from the place of production to the place of consumption.
- Gas volume cost: the premium paid by consumers based on the volume of gas consumed, with higher volumes incurring lower premiums.

The sum of these costs represents the gas price paid by consumers.

Prices for gas were estimated by ACIL Tasman for the 2012 NTNDP, published in August 2012.[16] ACIL Tasman developed two forms of gas price (spot price and levelised cost of energy), and a range of price sensitivities dependent on rates of expansion of gas powered generation. AEMO uses the spot price trajectories, to avoid assumptions about gas contract timeframes present in the levelised trajectories. AEMO will select an appropriate price sensitivity from the seven provided, to align with generation expansion outcomes.

Gas price data will not be updated in 2013.

[15] Reserve can be shared between regions, so a transmission project may be used to supply reserve available in a neighbouring region, instead of establishing new generation in the region experiencing shortfall.

[16] Available at http://www.aemo.com.au/Consultations/National-Electricity-Market/Open/~/media/Files/Other/planning/Fuel_cost_projections_Natural_gas_and_coal_outlooks.ashx.

4.5.1 Gas production cost

As part of the 2012 GSOO, AEMO undertook consultation to describe gas production costs in eastern and south eastern Australia. The consultation, by CORE Energy Group, was published in August 2012[17], and includes estimates of the cost to produce at existing facilities and new facilities based on expected return from announced capital investments.

AEMO is reviewing the need to update this data in 2013.

4.5.2 Gas transport cost

As part of the 2012 GSOO, AEMO undertook consultation to describe gas transport costs in eastern and south eastern Australia. The consultation, by CORE Energy Group, was published in June 2012[18], and includes estimates of the cost to transport gas in existing pipelines and the cost to construct new pipelines based on the expected return from announced capital investments.

AEMO is reviewing the need to update this data in 2013.

4.5.3 Gas volume cost

Gas-fired power stations are end-consumers of gas, and the fuel costs they incur are a key input to the electricity capacity expansion model. In general, the cost of fuel to a power station is composed of a production cost, a transport cost and a volume cost, where the volume cost reflects market conditions. Gas-fired power stations with low power output or low capacity factor incur higher volume costs than higher-power, higher capacity factor plant.

In the capacity expansion and time-sequential models, open-cycle gas turbine (OCGT) generators are assumed to operate at a lower capacity factor and at lower power output compared to combined-cycle gas turbine (CCGT) generators. OCGT generators subsequently pay higher volume costs compared to CCGT generators.

Gas production and transport costs developed by CORE Energy Group use a bottom-up, cost-of-development approach, whereas the wholesale fuel cost projections developed by ACIL Tasman use international pricing signals as the basis for determination of domestic prices for wholesale consumers.[19] The difference between these two constitutes the gas volume cost. Gas-fired power stations will pay the wholesale price as projected by ACIL Tasman in the electricity capacity expansion and time-sequential modelling.[20]

[17] Available at http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Production-Costs.

[18] Available at http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Transmission-Costs.

[19] This approach implicitly assumes that domestic prices are directly affected by international prices. This assumption is compatible with the position of eastern Australian gas markets once LNG export facilities are established.

[20] Available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx.

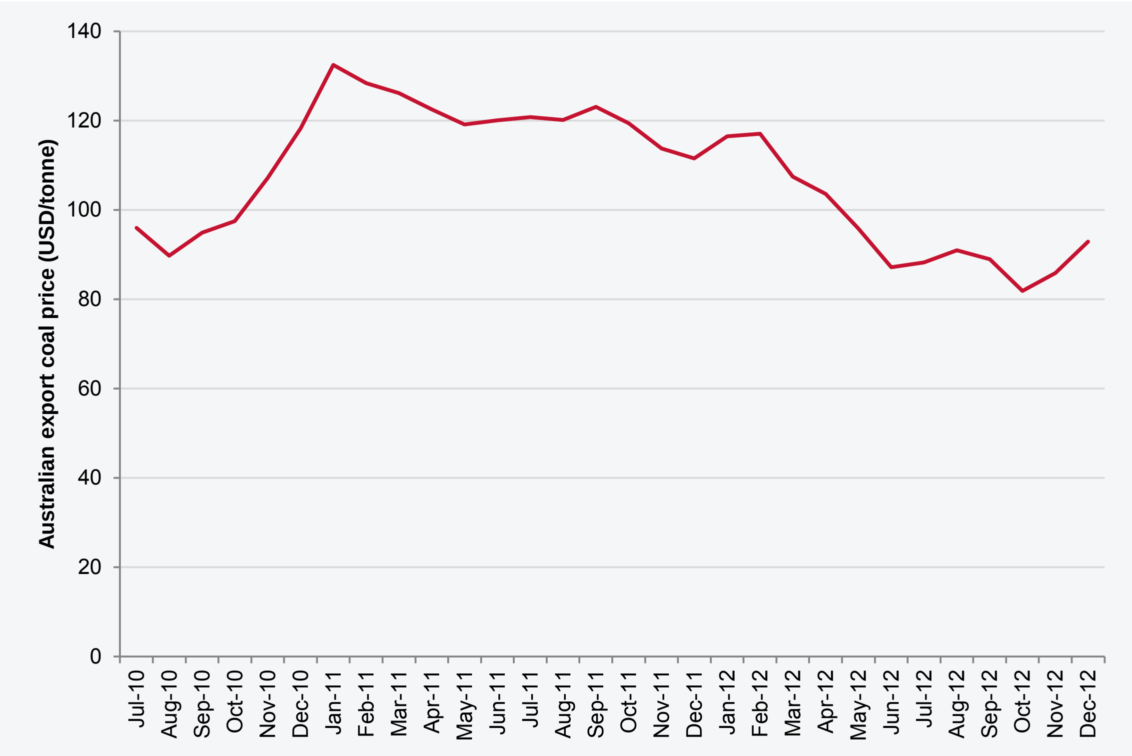
4.6 Coal prices

Prices for black and brown coal were estimated by ACIL Tasman for the 2012 NTNDP, published in August 2012.

Coal prices projected by ACIL Tasman were based on the thermal coal price index published by Treasury in *Strong Growth, Low Pollution – Modelling a Carbon Price*[21] in July 2011. These projections anticipated a fall in export thermal coal price cost of between $6 and $8 per tonne between 2012-13 and 2013-14 (a fall of 5.3% in real terms in the Planning scenario) This view represents a further easing of the high prices experienced in 2011, shown in Figure 10.

Coal price projections will not be updated in 2013.

Figure 10 – Australian export coal prices 2010 to 2012 (source: World Bank)



[21] Available at http://archive.treasury.gov.au/carbonpricemodelling/content/report.asp.

4.7 Renewable resources

4.7.1 Wind

In 2009 the Inter-Regional Planning Committee developed the concept of a wind bubble to model the wind resource available to the NEM. A wind bubble defines a geographical area where wind speeds are considered sufficient to be attractive for new wind development.

Modelled wind bubbles are shown in Figure 11.

For each wind bubble, a typical hourly wind speed profile is developed that covers a single trading year, based on proprietary data provided by the Commonwealth Scientific and Industrial Research Organisation (CSIRO). The wind speed profile is re-applied without modification in each modelled year.

Wind speed profiles are converted to normalised[22] wind turbine power output profiles based on a generic turbine power conversion curve. New wind generation generates according to a combination of the normalised power output profile and its modelled capacity.[23]

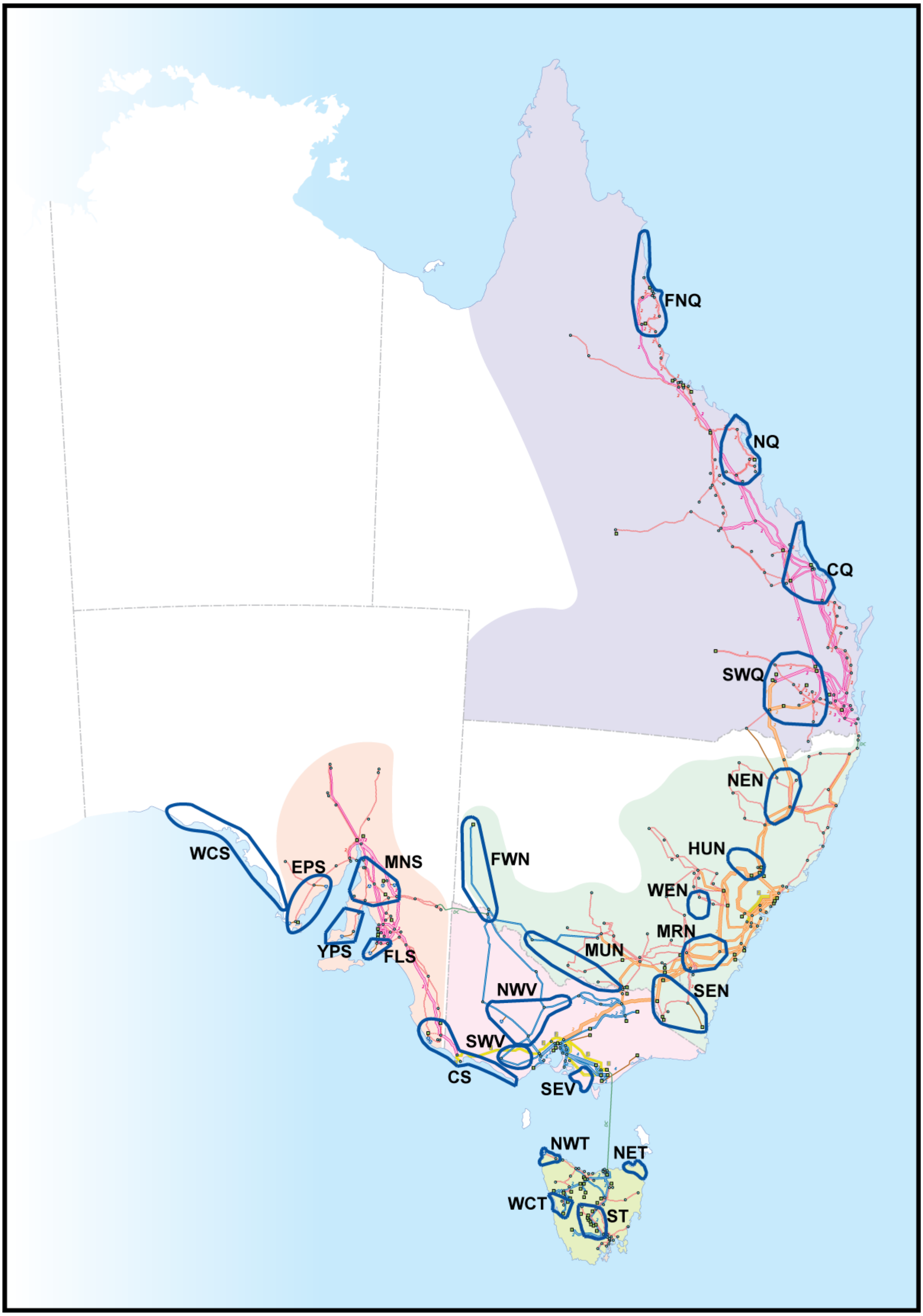
For existing semi-scheduled wind generation, power output is available in AEMO's Market Management Systems (MMS) database, from which a single typical year[24] is used to determine a power output profile for modelling. The power output of small, non-scheduled wind generation is included in the demand profiles as a reduction in demand.

[22] Where the maximum output is 1, and the minimum output is 0.

[23] Subject to network constraints.

[24] The 'typical year' is the same as the reference year for demand profiles.

Figure 11 – Wind bubbles



4.7.1.1 Contribution of wind to peak demand

Wind generation forecasts available for dispatch are not available over the long term. Without certainty about the power output of wind generators at times of high demand, models that do not implement generation profiles (such as the capacity expansion model and the electricity supply-demand calculator) cannot determine whether wind generators are contributing a large or small amount of capacity to meet that demand.

To manage the uncertainty of wind generation supply during times of high demand, AEMO studies the historical correlation between wind generation and high demand, and determines an average regional contribution to peak demand that can be used for capacity expansion planning. For example, in Victoria the long-term average availability of wind generation during summer peak demand is approximately 6.5% of the total installed wind capacity in that region. During winter peak demand, approximately 7.2% of total installed wind generation is available to meet demand, on average.

The capacity expansion model and electricity supply-demand calculator use these values to determine what portion of total installed wind capacity is available to meet peak demand, informing decision-making about when to establish new generation or when LRC points occur, respectively.

The contribution of wind to peak demand was most-recently reported in *Wind Contribution to Peak Demand 2012*.[25] This data will be updated in 2013.

4.7.2 Insolation

The capacity expansion and time-sequential models each contain a representation of large-scale solar power stations so that they may be considered for future generation expansion.[26] Estimation of the moment to moment power availability of solar power stations requires knowledge about the solar resource.

In the short term, the presence of clouds or aerosols in the atmosphere can make the solar resource highly variable and uncertain. Over the long term, information about the typical behaviour of weather systems in an area provides a reasonably accurate view of future solar energy availability.

Improvements to modelling of the solar resource were introduced in 2012, as a consequence of work undertaken for the 100% Renewable Energy Study currently being undertaken for the Department of Climate Change and Energy Efficiency. A detailed report and datasets are available from the input assumptions web page for that study.[27] AEMO will use the solar profiles developed for the 100% Renewable Energy Study in 2013.

4.7.3 Water storages and rainfall

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales and Queensland, most of which are represented explicitly in the time-sequential model, along with their associated reservoirs and water inflows. For each reservoir, the capacity, initial levels and the expected inflows from rainfall all determine the availability of energy for hydroelectric generation.

The time-sequential model will incorporate the latest available storage capacity and water level information at the time of modelling, using values provided by hydroelectric generators.[28]

Inflows to hydroelectric generation storage reservoirs are based on long-term rainfall statistics. AEMO is considering the need to update this data in 2013.

4.7.4 Geothermal

The capacity expansion and time-sequential models each contain a representation of large-scale geothermal power stations so that they may be considered for future generation expansion.

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[25] Available from: http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand.

[26] Australia's first large-scale solar power stations are expected to be commissioned in 2015 or 2016 (Source: AGL – see http:// http://agk.com.au/brokenhill/).

[27] Available at http://www.climatechange.gov.au/government/initiatives/aemo-100-per-cent-renewables/aemo-input-assumptions.aspx.

[28] For Snowy Hydro: http://www.snowyhydro.com.au/water/lake-levels-calculator/. For Hydro Tasmania: http://www.hydro.com.au/water/energy-data. For Victoria: http://www.g-mwater.com.au/water-resources/storages. For Queensland: http://www.stanwell.com/hydro.aspx.

Geothermal generation is not energy-limited like wind and solar generation, so a detailed view of energy availability is not required in this case. The geothermal resource is limited, however, to specific places where subsurface heat is of a quality required for power generation. The capacity expansion model limits the zones in which geothermal generation can be established to NQ, CQ, SWQ, NCEN, MEL, LV and NSA. The time-sequential model assumes that the geothermal resource is not depleted within the timeframes covered by any model (coal and gas is treated in the same way).

Geothermal generators do not incur any fuel costs in their operation, but have much higher than normal auxiliary loads compared to conventional thermal power stations due to the requirement for pumping a working fluid long distances.

4.7.5 Biomass

In the context of AEMO's planning, biomass is waste vegetation that may be burned in thermal generators.[29] There are two major sources of biomass in Australia. In Queensland and New South Wales, sugar cane crops generate significant biomass at times of harvest.[30] In Victoria, South Australia and Tasmania, biomass is currently sourced from landfill sites, sewerage treatment plants and some specialty operations such as paper mills and is available all year round.

All existing biomass generators in the NEM are non-scheduled, and are not explicitly modelled. Biomass generators established as part of future generation expansion plans are assumed to have fuel available all year round.

Biomass for generation is assumed to be a waste product, and power generation facilities are assumed to be co-located with processing facilities, resulting in the cost of fuel for biomass generators being very low. Fuel costs for biomass generation were developed by ACIL Tasman in 2010 for Energy White Paper modelling.[31]

AEMO will review the need to update this data in 2013.

4.8 Technological development

The capacity expansion model develops plans for new generation and transmission investment. In a forward view of generation investment over the modelled timeframes, technological advances can have a significant impact on new generation investment. Such advances may include increased efficiency of existing processes, the emergence of entirely new technologies or pre-commercial technologies, or reducing costs due to scales of economy and manufacturing learning.

In 2012 AEMO engaged WorleyParsons to develop technology availability and cost data, based on the guidance of the scenario drivers outlined in Table 1. The same data will be used in 2013.

The scale of growth of a new generation technology has a strong influence on the costs to build that technology. A doubling of megawatts installed results in a fall in price of between 20% and 4%, depending on how mature the technology is[32]. The projection of technology costs developed by WorleyParsons used the Global and Local Learning Model (GALLM) developed by CSIRO, which produces both technology cost and technology penetration as co-dependent solutions. The technology costs so developed were incorporated into AEMO's modelling but, due to the timing of technology cost and modelling reporting, the outcomes of the 2012 generation and transmission expansion planning were not aligned with the technology penetration that accompanies the cost projections.

AEMO is investigating whether technology cost modelling can be effectively integrated into the generation and transmission expansion planning.

[29] AEMO does not model biomass used for heat generation which in turn may offset electricity demand for heating.

[30] In New South Wales, the cane harvest is undertaken from late July to early November. In Queensland, the harvest is undertaken from late May to mid-November.

[31] See *Preparation of energy market modelling data for the Energy White Paper*, available from www.aemo.com.au/planning/0400-0019.pdf, and *NTNDP Modelling Assumptions: Supply Input Spreadsheets* (2010), available from: http://www.aemo.com.au/Consultations/National-Electricity-Market/Closed/~/media/Files/Other/planning/0410-0029%20zip.ashx.

[32] Hayward, J., Graham, P. and Campbell, P. 2011. *Projections of the future costs of electricity generation technologies*. CSIRO.

4.9 Existing production and transmission

4.9.1 Electricity generation

4.9.1.1 Capacities

Seasonal availability of modelled generators will be sourced from AEMO's Generator Information Page[33], using the latest information available when modelling begins.

4.9.1.2 Ramp rates

All rotating machinery develops inertia during operation, depending on the mass of the rotating equipment. Time is required to change rotation from a state of rest to operational speeds or from operational speed to rest. Additionally, thermal equipment develops heat inertia associated with the heating and cooling of components or working fluids. The rate at which a generating unit can increase or decrease its power output in response to ambient conditions or dispatch commands is referred to as its ramp rate.

The time-sequential model contains a representation of the ramp rate of generating units. Other models cannot use ramp rates because they do not treat time continuously.

Ramp rates for modelled generators are contained in the accompanying *2013 existing generation data* workbook.

4.9.1.3 Generator auxiliary load

The capacity expansion and time-sequential models contain representations of the auxiliary load developed by generating units during operation.

Generating units typically consume a material proportion of their output during operation. Major components of auxiliary load include water pumping, pollution control systems, flue gas handling and fuel handling, with different technologies developing different auxiliary load profiles. In the models, auxiliary load is expressed as a percentage of total output.

Regional average auxiliary loads are reported as part of the *National Electricity Forecasting Report*. Auxiliary loads for existing generators and each class of new generator are reported as part of the *Cost of Construction New Generation Technology* report.

4.9.1.4 Fixed and variable operating costs

The capacity expansion and time-sequential models contain representations of the fixed and variable operating costs of all existing generating units and all classes of new generating units.

Fixed operating costs are incurred by generating units that are available for dispatch, regardless of whether they are or are not dispatched in any modelled trading interval. They reflect components of cost such as retention of staff and maintenance of buildings – any cost that is incurred in keeping a power station ready to generate. Units that retire do not incur fixed operating costs after their retirement.

Variable operating costs are incurred by generating units whenever their output is non-zero. They reflect "use" of the generating units such as costs incurred for equipment maintenance, having staff on-shift and consumable items such as lubricating oil. They do not include fuel or emissions costs, which are modelled separately.

4.9.1.5 Emission factors

Under the Clean Energy Legislative Package[34], generating units that emit atmospheric pollutants are required to purchase carbon permits for every tonne of carbon dioxide-equivalent emissions. The capacity expansion and time-sequential models calculate power output for each generating unit over their defined time horizons, and a carbon emission intensity factor is used to calculate the amount of emissions that are produced so that the cost of complying with emissions reduction legislation can be determined.

[33] Available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

[34] Available from http://www.cleanenergyfuture.gov.au/clean-energy-future/our-plan/.

Previously, emissions factors (for existing generators) were determined in consultation with ACIL Tasman, last reported in *Fuel resource, new entry and generation costs in the NEM 2009*.

Under the *National Greenhouse and Energy Reporting Act 2007* (NGER) generators are required to report their emissions to the Clean Energy Regulator (CER) for the purposes of greenhouse abatement auditing. The CER publishes emissions data aggregated to registered corporations each financial year. This database provides the definitive source for carbon emissions information, however the aggregation by corporation means that the publicly-available data is not suitable for inclusion in AEMO's models, which require intensity factors for each individual facility.

Section 49 of the *Clean Energy Regulator Act* permits the CER to disclose protected information to AEMO to assist in the performance of AEMO's functions. AEMO is not permitted to publish confidential emissions data.

Section 51 of the *Clean Energy Regulator Act* creates a mechanism by which liable entities may consent to the release of protected data held by the CER, allowing otherwise confidential data to be published. Using this, AEMO intends to ask all registered fossil fuel generators to grant consent to release of the emissions intensity data to AEMO for use in planning studies and calculating the CDEII. Where consent is not given, AEMO will consult with third parties to develop an updated set of emissions factors.

4.9.1.6 Bidding

The capacity expansion and time-sequential models contain representations of generator bidding to model reasonable behaviour and ensure that generator costs are recovered.

The capacity expansion model treats existing and new generation differently:

- Existing generators bid according to their short-run marginal cost (SRMC), the total additional cost over a short time period for a small change in output. In the model, SRMC is a combination of variable operating costs, fuel costs and emissions costs. The lower bound for SRMC for any generator is its fixed operating costs, which are incurred at an output of 0 MW. SRMC does not take into account the capital liability position of any existing generator.
- New generation bids according to its long run marginal cost (LRMC), which incorporates capital expenditure, to ensure that the cost to build new generation is recovered by the model. Once a new generator is installed, it bids in the same way as existing generators, reflecting the sunk cost of investment.

The time-sequential model may use either SRMC bidding or more detailed bidding offer curves that assign specific amounts of generation to price bands in the same way as NEMDE. The bidding offer curves do not represent the real bidding behaviour of generators in the NEM, which are not expected to continue unchanged over the timescales covered by the models. Rather, the curves are tuned such that the modelled regional price outcomes closely match historical outcomes and modelled generator capacity factors match historical capacity factors when historical conditions are modelled. This process is referred to as 'backcasting'. Any specific modelling exercise that requires the inclusion of bidding offer curves will incorporate a backcasting exercise.

Once set, bidding offer curves remain static throughout the modelled horizon.

Fixed and variable operating costs are published as part of the *Cost of Construction New Generation Technology* report. Fuel costs are published in the *Fuel cost projections: Natural gas and coal outlooks for AEMO modelling* report. Emissions costs are calculated according to modelled generation, carbon permit costs and emissions factors.

4.9.1.7 Water values

The SRMC and bidding offer curve of hydroelectric generators is dependent on the value of water in storage. As storages decrease, the value of water increases due to its substitutable value in agricultural or environmental contexts, and the SRMC changes appropriately.

In capacity expansion modelling, the SRMC of a hydroelectric generator is calculated from the value of water as a varying 'fuel' cost. In time-sequential modelling, the historical bid offer curves of hydroelectric generators may not adequately reflect future response to price, because the price of electricity and the price of water are not as closely coupled as the price of electricity and the price of fuel. That is, if the price of electricity rises but the value of water does not, hydroelectric generators may over-generate, resulting in unreasonably low storage levels.

AEMO is investigating improvements to time-sequential modelling in 2013, to incorporate dynamic response of water value to electricity pricing signals.

4.9.1.8 Minimum generation levels

The capacity expansion and time-sequential models contain a representation of the minimum stable operating point that generators are able to maintain, for both existing and new generators. These minimum generation levels reflect both the:

- Physical limitations of generating units, for example due to water hammer or furnace stability.
- Desire for generating units with large thermal inertia to avoid frequent shutdown and start-up cycles when spot prices are too low to recover variable operating costs.

In some cases, the minimum stable operating point of a generating unit is adjusted to a level below what is expected under real operational conditions. The models treat the cost of each generating unit in a power station as being equal, and when the power station is the marginal generator all of its units are simultaneously marginal. The models do not contain decision-making information that allows them to decide between units, and seeks to run all units equally. Under real conditions of frequent marginality it is expected that generator operators will seek to shut down individual units where that decision is economic, and operate the remaining units closer to their optimal levels. The model is not capable of making equivalent operational decisions, so a lower minimum generation level on all units is substituted as a functionally-equivalent approach[35].

Minimum generation levels are published in either the accompanying *2013 existing generation data* or *2013 new entry generation data* workbook as appropriate.

4.9.1.9 Outage rates

The time-sequential model uses Monte Carlo simulation to study the effect of generator outages on power system costs. Monte Carlo simulation randomly assigns a value to a variable, repeating with different random values. As the number of simulations increases, the simulation result converges to a stable value that best reflects the statistical likelihood of unpredictable events. In this case the random selection is the set of generators that are in or out of service.

AEMO collects forced outage data for each generator in the NEM, including whether a plant is entirely or partially out of service while dispatched, and the time taken to correct outages and return generation to service. This information is aggregated to form outage probability and mean time to repair statistics for each generator technology class, and used to control the Monte Carlo simulation.

The capacity expansion model does not represent time in a manner that facilitates reasonable Monte Carlo simulation. Instead, forced outage probability and mean time to repair statistics are used to reduce the capacity of generation by a small amount in every modelled time block for energy supply adequacy modelling. Forced outage information is not used for supply capacity adequacy, instead a representation of minimum reserve levels maintain generation capacity at levels that are robust to generator failure. The time-sequential model and Monte Carlo simulation are used to ensure that capacity expansion plans are reasonable under outage conditions.

In 2013, AEMO will use the most-recently collected forced outage data, published in the *2013 additional modelling data* workbook.

4.9.1.10 Solar energy storage

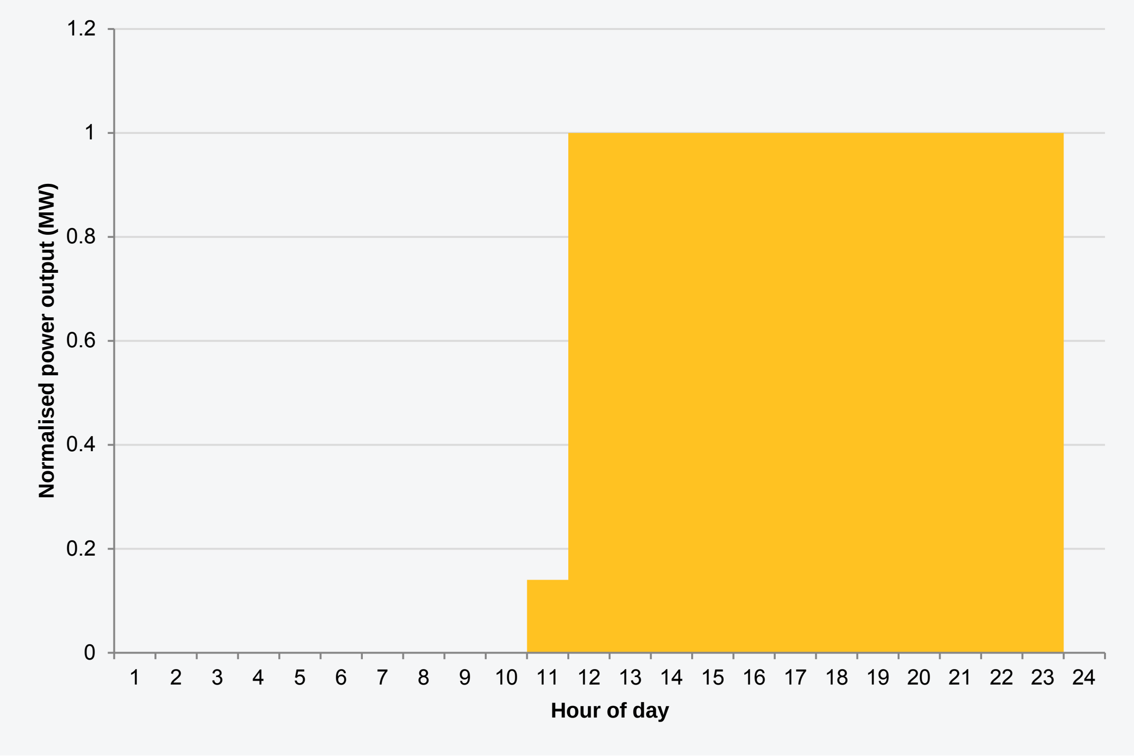
Solar thermal power plants have the capability of storing energy in the heat of their working fluid. Where storage systems are fitted to solar thermal plant, the behaviour of operators is expected to change from simply generating when energy is available to generating opportunistically based on price and the efficiency loss associated with directing energy into and retrieving energy out of storage.

Opportunistic generation depends on operators developing a forward view of price and solar energy availability long enough to inform the decision to divert energy to storage. The time-sequential model does not implement automatic look-ahead features that would enable such behaviours to be modelled explicitly.

[35] Capacity expansion and time-sequential models use single-value heat rates for each generating unit. When this is the case, two units operating at half their true minimum generation level is functionally equivalent to one unit operating at its true minimum generational level and one unit shut down.

To model opportunistic behaviour of solar generators with storage, prices are assumed to be high during the evening demand peak. The available solar energy in any day is distributed either side of this peak such that solar generators generate at maximum output during these times. This is illustrated in Figure 12 for a solar power station in Mildura with 6 hours of energy storage, on December 21. Generation is deferred to the end of the day to allow the storage to be replenished during the first half of the day, and storage is assumed to be empty at the end of each day. The total amount of energy generated is larger than that for a plant with the same power output in the same location but without storage because the presence of storage implies a larger array of mirrors (and a higher build cost) for a given maximum output.

Figure 12 – Solar output of a theoretical 1 MW power plant with 6 hours storage (Mildura, December 21)



4.9.1.11 Retirement candidates

The capacity expansion model allows for existing coal-fired generators to retire if simulated market signals indicate that costs may be minimised by replacing existing capacity with new capacity with a combination of lower fuel, emission or operating costs, or a location proximal to demand (reducing costs due to losses).

Generation may also be withdrawn from participation in the model if a generator has advised AEMO of its intention to decommission generating capacity.

In the capacity expansion model, very low capacity factors were observed for some coal-fired generators under some conditions during modelling in 2012, without triggering retirement. To correct for generators operating with unreasonable duty cycles, minimum capacity factor constraints were applied to the capacity expansion model.

While more robust techniques are available to manage the phenomenon of coal-fired generators becoming marginal, all require either more detailed collection of data (for example, the modelling of true heat rate curves or tuning of fixed costs), or result in significantly longer computation time (for example, modelling unit commitment, where individual units in a power station may be turned off for a period, while others continue to operate). AEMO is investigating whether additional value is provided by using more robust, but more costly techniques in 2013.

4.9.2 Gas production

The gas supply-demand outlook model contains a representation of 27 gas production facilities that inject gas into the eastern and south eastern Australian gas transmission network. The representation is limited to the connection point and maximum supply capacity of each facility.

The gas supply-demand outlook model does not contain information about forced outages, production ramp rates or maintenance schedules.

Figure 13 shows the locations of modelled existing gas processing facilities, with the size of circles indicating the relative processing capacity of each facility.

In 2012, AEMO engaged CORE Energy Group to report on existing and potential gas production facilities[36]. AEMO is reviewing the need to update facility data in 2013.

4.9.2.1 Production costs

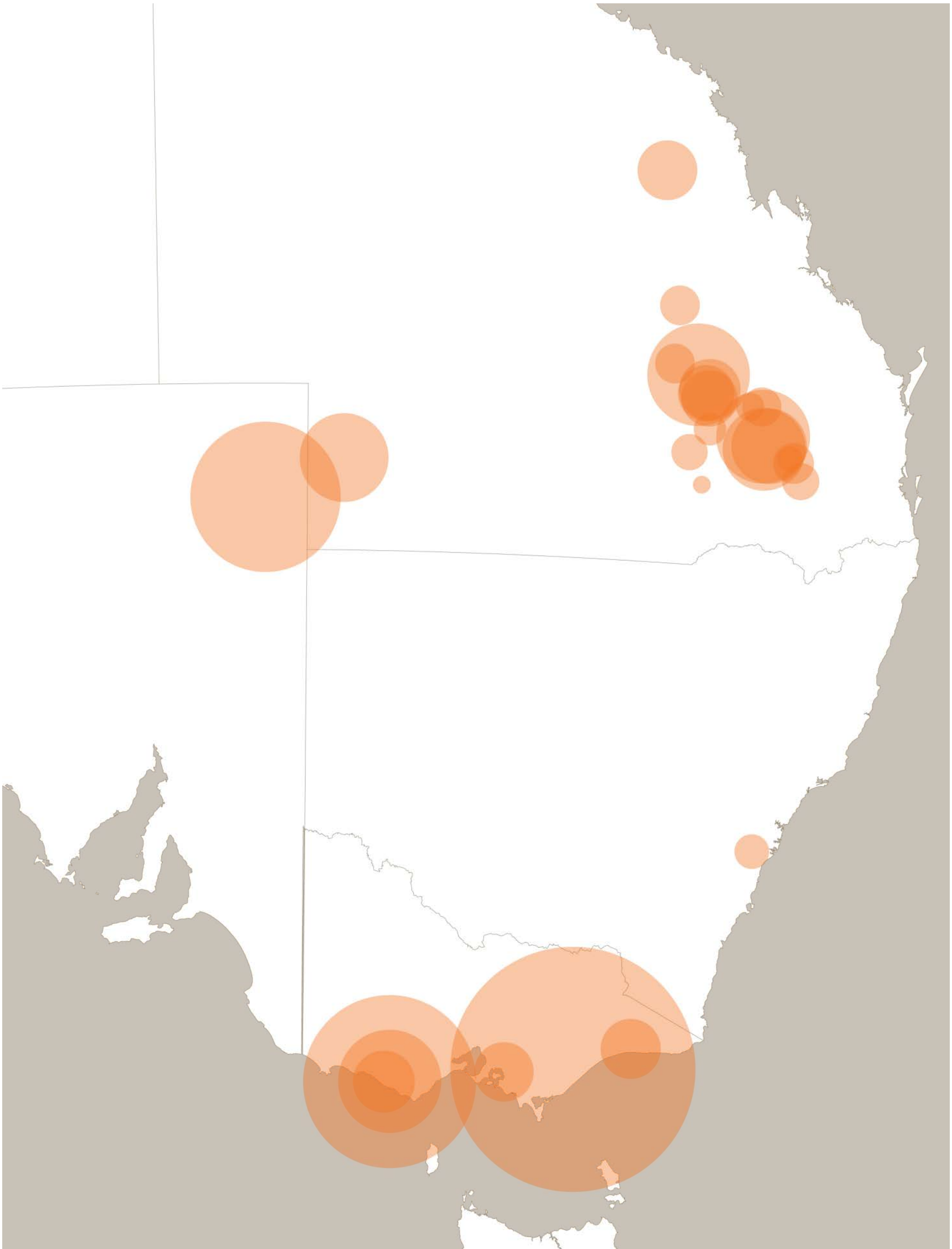
The gas supply-demand outlook model uses a representation of the cost of gas production at each facility to optimise network flows.

AEMO engaged CORE Energy Group in 2012 to estimate gas production costs for existing and new gas production facilities, published in *Gas Production Costs*[37]. AEMO is reviewing the need to update production cost data in 2013.

[36] Available from: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Processing-Transmission-and-Storage-Facilities.

[37] Available from: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Production-Costs.

Figure 13 – Gas processing facility location and relative capacity – existing facilities



4.9.3 Gas reserves

The gas supply-demand outlook model reports on the adequacy of gas reserves to meet demand in a range of future development scenarios. Reserves development is associated with gas production quantities and costs: higher production and higher costs allow more intense exploration activities which result in higher estimates of reserves. This effect is captured by the reserves to production (R/P) ratio, reported in the GSOO.

AEMO engaged CORE Energy Group in 2012 to estimate existing and potential future gas reserves, published in *Eastern & Southern Australia: Existing Gas Reserves & Resources* and *Eastern & Southern Australia: Projected Gas Reserves*[38].

Reserves data will be updated in 2013.

4.9.4 Electricity transmission

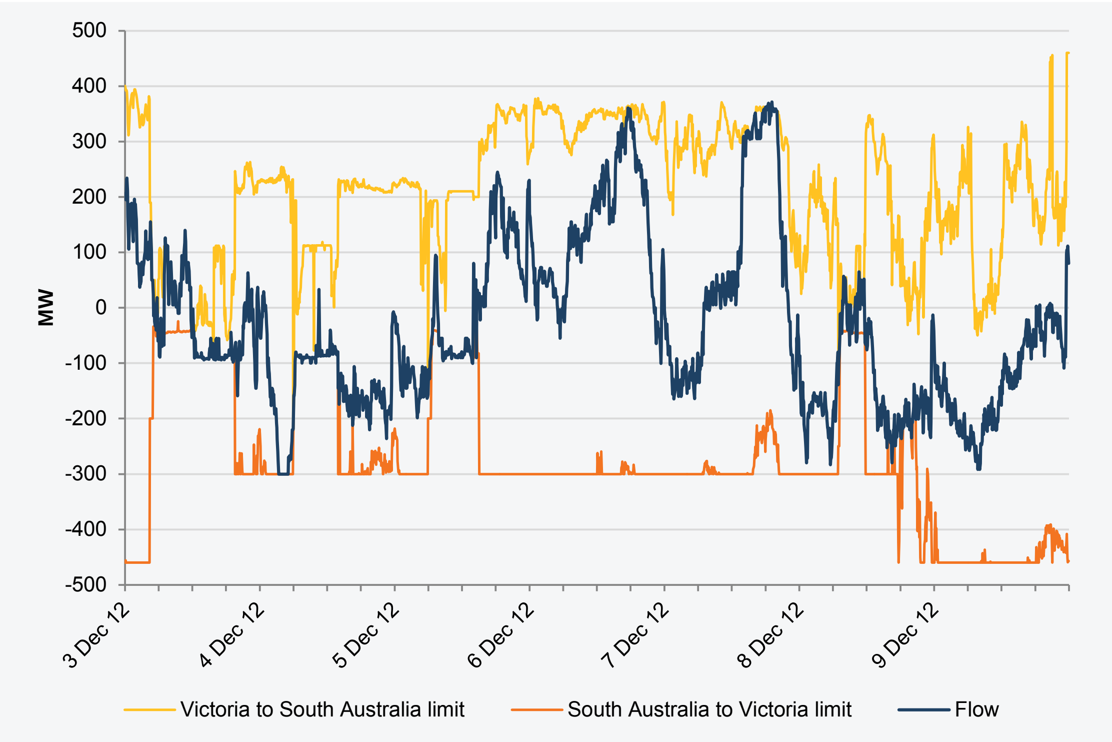
The capacity expansion and time-sequential models contain constraint equation-based representations of the electricity network. With the NEM explicitly modelled only on a regional basis, constraint equations model important aspects of the intra-regional networks not captured by the regional structure. This is the same approach to that used operationally in NEMDE.

4.9.4.1 Inter-regional transfer capability

All three electricity models incorporate a representation of the forward and reverse[39] transfer capability of interconnectors. These are static limits that set the maximum flow allowable in the models.

In practice, interconnector flow limits change in response to network conditions. Figure 14 shows 5-minute limits and flow on the Victoria-South Australia (Heywood) interconnector for one week in December 2012. The limits are shown to vary significantly from the static limits used in the planning models (in 2012, these were 400 MW from Victoria to South Australia, and 350 MW from South Australia to Victoria).

Figure 14 – Interconnector limits in actual operation, Heywood interconnector, 3 December to 10 December 2012



[38] Available from: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2012-Supporting-Information.

[39] Each interconnector has a conventional ‘forward’ direction. For example, on Basslink positive or forward direction flow is from Tasmania to Victoria.

Operational interconnector limits change in response to a significant number of real-time variables that are impractical to consider in the context of long-term modelling. The application of static limits is a compromise that is simple to implement but can lead to over- or underestimation of flows. In 2012, AEMO investigated whether a new set of constraint equations could improve the modelled specification of interconnector transfer limits without imposing full operational complexity. A more complex set of constraint equations were found not to materially affect the generation and transmission expansion plans produced by the capacity expansion model, and will not be incorporated into future modelling.

4.9.4.2 Loss factors

The capacity expansion and time-sequential models' regional representation of the NEM explicitly includes each regional reference node and each interconnector. Generators and demand are 'connected' in the model to the regional reference nodes. In reality, generators are not located at the regional reference node, and the intervening network characteristic and flow pattern affects how energy that is generated at a generator appears from the perspective of the regional reference node.

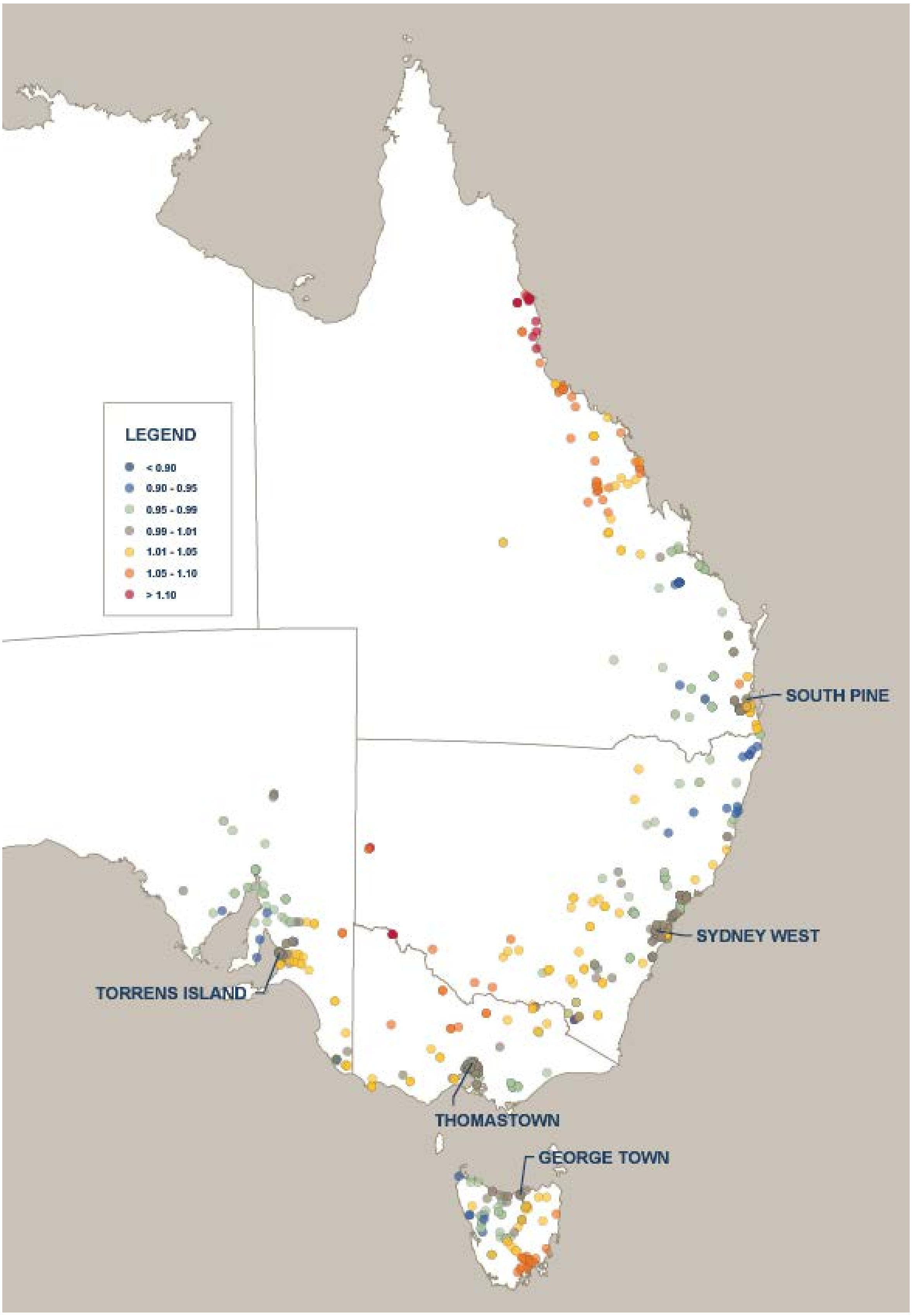
To account for this difference between the true and modelled location of generators, the capacity expansion and time-sequential models contain a representation of marginal loss factors (MLFs) – the same approach used by NEMDE. These values are used to modify the amount of energy that must be dispatched from any generator, and the amount a generator is paid based on the regional reference price.

Operational MLFs are calculated by AEMO each year and published in April[40]. A geographical representation of MLFs for 2012-13 (including demand at transmission node identities (TNIs), which are not modelled) is shown in Figure 15. In the figure, warm colours indicate MLFs greater than 1 and average power flow away from the regional reference node, while cool colours indicate MLFs less than 1 and average power flow towards the regional reference node.

MLFs are modified by significant changes in network flow that may be influenced by new generation, new network projects or changes in dispatch patterns. Because the capacity expansion model introduces large-scale changes to the power system, MLFs are expected to diverge from their present-day values. This divergence was studied in the 2011 NTNDP (Chapter 5 - NTNDP outlook marginal loss factors) based on expansion plans developed for the 2010 NTNDP, and was found in most cases to be relatively stable. Changes of MLF that respond to new generation and transmission will not be modelled in 2013.

[40] The 2012-13 report is available from: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/~/media/Files/Other/loss+factors/MLF_2012_13_Main_Report_16_MLf.ashx.

Figure 15 – 2012-13 Marginal loss factors for demand and generation



4.9.4.3 Constraint equations

A regional representation of the NEM is not explicitly capable of considering intra-regional power flows, either as a model result or for the purposes of modelling the physical limitations of the power system. In NEMDE, a series of network constraint equations control dispatch solutions to ensure that network limitations are accounted for. The time-sequential and electricity supply-demand calculator contain a subset of the NEMDE network constraint equations to achieve the same purpose.

The subset of network constraint equations includes approximately 1,000 pre-dispatch[41], system normal equations that model important aspects of network operation and include contingency for maintaining secure operation in the event of outage of a single network element. To ensure that modelled outcomes are suitable for the timescales considered, the selected network constraint equations represent ‘usual’ network capability, and specifically do not represent short-lived events such as network outages.

The set of constraint equations used are published in the *NTNDP Constraint Workbook*[42]. This data will be updated in 2013.

4.9.4.4 Proportioning inter-regional losses to regions

The capacity expansion and time-sequential models represent the NEM as a radial network with regions connected by notional interconnectors. Interconnectors are not perfect conductors, and power transfer between regions results in a loss of energy. AEMO uses proportioning factors to assign losses on interconnectors to regions. Operationally, this is used to determine settlement surplus. In long term modelling, proportioning factors are used to allocate losses to demand in each region.

Proportioning factors are derived from marginal loss factors, as describe in *Proportioning of Inter-Regional Losses to Regions*.[43] Proportioning factors are given in the annual *List of Regional Boundaries and Marginal Loss Factors* report.[40]

4.9.5 Gas transmission

The gas supply-demand outlook model contains a reduced representation of the eastern Australian gas transmission network, shown in Figure 3 and Figure 4.

In 2012, AEMO engaged CORE Energy Group to report on existing gas transmission and potential gas transmission augmentations[36].

AEMO is reviewing the need to update transmission infrastructure and project proposal data for 2013.

4.9.5.1 Transmission costs

AEMO engaged CORE Energy Group in 2012 to estimate gas transmission costs for existing and new gas transmission pipelines, published in *Gas Transmission Costs*[44].

AEMO is reviewing the need to update transmission cost data in 2013.

4.10 New production and transmission

Each model defines a set of new generation or gas production projects that may be included in capacity expansion, time-sequential or gas supply-demand outlook simulations.

In capacity expansion modelling, new generators are partitioned by fuel type, technology and location within the electricity planning zone framework shown in Figure 2. Each technology will take on specific values for

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[41] NEMDE contains equation sets for dispatch, pre-dispatch, ST PASA and MT PASA. Within these sets other sets cover specific network conditions such as outages, rate of change, frequency control ancillary services and network service agreements. Pre-dispatch equations are used because dispatch equations contain terms that rely on real-time SCADA measurements not available to simulation models.

[42] The 2012 workbook is available from: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_ConstraintWorkbook.ashx.

[43] Available from: http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/~/media/Files/Other/electricityops/0170-0003%20pdf.ashx.

[44] Available from: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Transmission-Costs.

parameters of importance such as thermal efficiency, emission characteristics, minimum stable generation levels, standard capacities, build costs, and appropriate earliest dates for which the technology is considered current[45]. Each location imposes different fuel costs that reflect the fuel availability and transport requirements applicable to each zone.

The time-sequential model uses the expansion plans developed by the capacity expansion model.

The electricity supply-demand calculator includes committed generation and transmission projects only.

The gas supply-demand outlook model includes committed production and transmission projects and a selection of proposals that are assessed for their efficacy in eliminating supply shortfall.

4.10.1 Committed, advanced, proposed and conceptual

New production and transmission projects fall into one of four classes of certainty:

- Committed: projects that will proceed, with known timing, satisfying all five of the commitment criteria outlined in Table 3. These criteria apply to electricity investments. There are no equivalent commitment criteria for gas projects; however the principals of commitment outlined in Table 2 are applied for the purposes of gas modelling. The costs of committed projects are considered sunk for the purposes of modelling: because there is no investment decision that is calculable for committed projects, their costs are not included in any of the market models.
- Advanced: projects that satisfy at least three, but not all of the commitment criteria, and for which commissioning timing is in doubt. In electricity modelling, advanced projects are tested for economic efficiency in the capacity expansion model. In gas modelling, advanced projects are considered as candidates to relieve supply shortfall for the purposes of reserves adequacy assessment.
- Proposals: projects that have fewer than three of the commitment criteria, uncertain timing, and which are strongly subject to changes in the commercial environment. In general, projects classed as proposals do not have sufficient definition to justify special consideration in capacity expansion or gas supply-demand modelling. AEMO uses generic conceptual projects in these cases.
- Conceptual: capacity that belongs to a technology class and which may be required to satisfy reserve requirements, but for which no proposal has been forwarded. Conceptual projects include items such as a generic OCGT or CCGT generator, or a pipeline project of a specific length, diameter and pressure class. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour.

Table 3 - Commitment criteria

Category	Criteria
Site	The proponent has purchased/settled/acquired land (or legal proceedings have commenced) for the construction of the proposed development.
Major components	Contracts for the supply and construction of the major components of plant or equipment (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) should be finalised and executed, including any provisions for cancellation payments.
Planning consents/ construction approvals/EIS	The proponent has obtained all required planning consents, construction approvals, and licences, including completion and acceptance of any necessary environmental impact statements (EIS).
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Final construction date set	Construction must either have commenced or a firm commencement date must have been set.

[45] Technologies that are not yet in commercial development are assigned an earliest build date.

4.10.2 New production projects

4.10.2.1 Electricity

Committed new generation projects will be sourced from AEMO's Generator Information Page, using the latest information available when modelling begins. Committed generation projects are included, with fixed timing and without build costs, in all electricity modelling.

Conceptual projects are developed using a combination of the data in *Cost of Construction New Generation Technology* and *Fuel cost projections: Natural gas and coal outlooks for AEMO modelling*. The capacity expansion model develops a generation expansion plan for each studied scenario, published with the NTNDP. The plant configurations selected as candidates for entry in expansion plans are included in the capacity expansion model. The 2012 capacity expansion model is available from the 2012 NTNDP Assumptions and Inputs web page[46]. For convenience, conceptual plant technical data is also available in the *2013 new entry generation* workbook available from the same web page. The 2012 generation expansion plans are available at AEMO's 2012 NTNDP Detailed Results web page[47].

A *2013 new entry generation data* workbook, containing updated information where applicable, accompanies this document.

4.10.2.2 Gas

For electricity, committed projects are those that satisfy AEMO's five commitment criteria, listed in Table 2. There are no equivalent commitment criteria defined for gas production, however the principals of commitment in Table 2 are applied to gas projects for modelling purposes.

In 2012 AEMO engaged CORE Energy Group to survey and report on gas production, storage and transmission projects[36].

AEMO is reviewing the need to update committed gas projects for 2013.

4.10.2.3 Production build limits

In capacity expansion modelling, the maximum amount of new generation of any technology type that can be established in any zone is limited in the model ("build limits"). New generation or production in other modelling is limited either to the generation expansion plan developed by the capacity expansion modelling (the time-sequential model), or the committed status of new generation projects (electricity supply-demand calculator and gas supply-demand outlook model).

4.10.3 New transmission projects

4.10.3.1 Electricity

Committed electricity transmission projects are incorporated into both the time-sequential and the capacity expansion models. The effect of committed projects on the network is implemented as modifications to the network constraint equations that control flow.

The capacity expansion model includes representations of the effect on the network and the cost of advanced and proposed electricity transmission projects. The model selects projects for inclusion in future network development based on their ability to reduce total costs.

AEMO surveys transmission projects suggested by jurisdictional planning bodies[48] in annual planning reports (APRs). These projects are summarised and published in the *Annual Planning Reports Project Summary* workbook[49]. A subset of these projects is selected for inclusion in the capacity expansion model. AEMO may also develop new transmission projects where study requirements are not met by the APR survey.

[46] http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs.

[47] http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Detailed-Results.

[48] In Queensland, Powerlink. In New South Wales, Transgrid. In Victoria, AEMO. In South Australia, ElectraNet. In Tasmania, Transend.

[49] Available from: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_APR_ProjectSummary.ashx.

4.10.3.2 Gas

The gas supply-demand outlook model considers the effect of new transmission projects on energy flow in the network. The model does not select from among a number of options like the capacity expansion model. Rather, when supply shortfall is reported that may be alleviated with a transmission project, the transmission project can be included to test its ability to restore supply.

In 2012, AEMO engaged CORE Energy Group to estimate the capability and costs of new gas transmission projects, and to survey committed gas transmission projects, published in *Review of Gas Facilities: Existing and New* and *Gas Transmission Costs*. Projects to alleviate supply shortfall were selected from the proposals listed in those documents.

5 Analysis

5.1 Market benefits

Some modelling exercises are designed to determine the benefit to the market delivered by specific augmentation projects.

Where calculation of market benefits is warranted, time-sequential modelling will be used to developed detailed hour-by-hour costs in both of:

- The case in which an augmentation project is not present.
- The case in which the augmentation is present.

The difference in cost between these two cases is the market benefit of the augmentation. Where an augmentation is expected to affect the development of generation, a generation expansion plan will be developed for each case.

The potential market benefits resulting from a selected augmentation are assessed through the market simulation outcomes, and may include capital cost deferral, operating cost, losses and reliability benefits.

5.1.1 Generation capital costs

An augmentation may defer generation capital expenditure, saving the cost to finance investment during the deferral period. In extreme cases, generation may not need to be built at all.

An augmentation may allow a less capital-intensive form of generation to be established in an alternate location.

Generation capital deferral benefits are determined by capacity expansion modelling outcomes.

5.1.2 Transmission capital costs

An augmentation may defer the need to build other transmission projects.

Transmission capital deferral benefits are determined by capacity expansion modelling outcomes.

5.1.3 Operating costs

An augmentation may relieve limitations on existing or new generation with lower fuel, emissions, fixed or variable operating costs, allowing lower-cost generation to operate more frequently.

Operating cost benefits are determined by time-sequential modelling outcomes.

5.1.4 Transmission system losses

An augmentation may allow generation to be dispatched closer[50] to the locations where energy is consumed, reducing the cost to transport energy on the network.

[50] Electrical proximity. That is, substituted generation may be physically further away, but connected to a lower-loss transmission line, or operates in a way that reduces total losses in delivering energy to the point of consumption.

An augmentation may change the flow patterns on interconnectors in ways that reduce losses when transferring power between regions.

Transmission system loss benefits are determined by capacity expansion modelling outcomes (when new generation is established closer to load centres) and time-sequential modelling outcomes (when changes in network limitations change interconnector flow patterns).

5.1.5 Changes in involuntary load shedding (reliability benefits)

The Reliability Standard[51] imposes a strict ceiling on the amount of unserved energy (USE) that can be tolerated by consumers in the power system. Within that ceiling, penalties are imposed when consumers are not supplied. The penalty is referred to as the Value of Customer Reliability (VCR). AEMO last reviewed the value of customer reliability in 2012.[52] A more detailed review is planned for 2013, following recommendations from the Productivity Commission[53] and the Senate Select Committee on Electricity Prices.[54]

An augmentation may reduce the amount of reported unserved energy, reducing the penalties associated with failing to supply consumers.

Reliability benefits tend to be small, because the Reliability Standard already imposes low limits on unserved energy that must be met.

Reliability benefits are determined by time-sequential modelling outcomes.

The sum of the reliability, operating cost, capital cost, and reduced loss benefits represents the total market benefits of an augmentation. Comparing these potential market benefits with the cost of the augmentation provides an insight into whether this project is likely to be justified under the Australian Energy Regulator's (AER) Regulatory Investment Test for Transmission (RIT-T).

In the presence of an augmentation, the individual cost components of market benefits may be greater or less than the same cost components in the case where the augmentation is absent. For example, it is common for large operating cost benefits to be associated with a negative capital cost benefit: money is spent to build new, more expensive generation that subsequently has much lower operating costs. Wind generation is an example of generation that may increase initial capital cost but greatly reduce operating costs compared to thermal plant that must pay fuel and emission costs for the duration of their working lifetime.

5.1.6 Option value and competition benefits

AEMO's planning modelling does not quantify option value or competition benefits. These value propositions require a specificity of analysis that is not practical for or aligned with AEMO's holistic view of network infrastructure.

5.2 Financial settings

Cost-benefit comparisons between augmented and unaugmented cases use a discounted cash flow (present value) calculation to determine the value to the market in the present day of spending that occurs in the future.

5.2.1 Inflation

Monetary values in the models refer to real value, as opposed to nominal value. That is, future values are not adjusted by assumptions about inflation, whereas values defined in the past are adjusted to account for

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[51] 0.002% of total annual energy per region per financial year. See http://www.aemc.gov.au/panels-and-committees/reliability-panel/guidelines-and-standards.html.

[52] Available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/National-Value-of-Customer-Reliability-VCR.

[53] Electricity Networks Regulatory Frameworks draft report. Available from: http://www.pc.gov.au/projects/inquiry/electricity/draft/key-points.

[54] Available from: http://www.aph.gov.au/Parliamentary_Business/Committees/Senate_Committees?url=electricityprices_ctte/electricityprices/report/report.pdf.

inflation. For example, in 2013 values are expressed in 2013-14 Australian dollars. Values that were originally expressed in 2012-13 dollars and re-used in 2013 will be adjusted upwards by 2.2% to account for inflation.[55]

5.2.2 Goods and Services Tax

Prices are exclusive of Goods and Service Tax.

5.2.3 Weighted average cost of capital

The capital cost of an investment is increased beyond its purchase price by the cost of finance. The weighted average cost of capital (WACC) is the rate that a company is willing to pay to finance its assets.[56] The WACC is the weighted sum of the cost of debt and the cost of equity, where the cost of debt is determined by interest rates, and the cost of equity is determined by reference against the returns received by other projects with similar risk.

AEMO uses real, pre-tax WACC values developed by ACIL Tasman for Energy White Paper modelling.[31] Values vary by scenario from 8.78% to 11.37%, reflecting the difficulty in obtaining credit under different economic conditions.

5.2.4 Discount rate

Present value calculations estimate all future cash flows which are discounted to account for the amount of cash that would need to be invested in the present day to yield the same future cash flow.

AEMO may use a range of discount rates to estimate future cash flows. Practically, lower discount rates emphasise market benefits that accrue later in the modelled horizon, while higher discount rates emphasise market benefits that accrue earlier in the modelled horizon. A higher discount rate can be used to accommodate the uncertainty inherent in the estimates of cost to operate modelled energy infrastructure, which increases with time. For example, the *Heywood Interconnector Regulatory Investment Test – Transmission: Project Assessment Conclusions Report* published in December 2012 assumed a standard discount rate of 10%, but studied discount rate sensitivities on market benefits of 6.13%, 13% and 16%.

5.2.5 Project lifetime

Augmentation costs are annualised over 40 years using a terminal value to represent annual costs beyond the final simulation year. The market simulations simulate up to a 25-year outlook period whereas the cost benefit analysis is performed over a 40-year period due to the long life of the assets involved. A terminal value is estimated to represent the value of ongoing annual market benefits from the end of the simulated outlook period through to the end of the net present value period. The terminal value is estimated by assuming that average market benefits observed in the final simulated years are the same as future years. In a context of growing demand, this constitutes a conservative assumption that growing demand does not result in higher utilisation of assets.

[55] Inflation is calculated from Australian Bureau of Statistics consumer price index adjustments (Catalogue item 6401.0).

[56] The return the company would expect to receive from an alternative investment with similar risk.

Appendix A. Summary of information sources

Table 4 – Summary of information sources

Information	Section	Source
Scenario descriptions	2	*2012 Scenarios Descriptions* Available from http://www.aemo.com.au/Consultations/National-Electricity-Market/Open/~/media/Files/Other/planning/2418-0005%20pdf.ashx. Scenario descriptions will not be updated for 2013
Adjustment to demand due to rooftop PV	4.1.4	*Rooftop PV Information Paper 2012* The 2012 report is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/Rooftop_PV_Information_Paper_20_June_2012.ashx This report will not be updated in 2013.
Regional electricity energy and maximum demand forecasts	4.1	Part of the *National Electricity Forecasting Report* The 2012 report is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/2012%20National%20Electricity%20Forecasting%20Report.ashx. Data is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/Forecasting-Data-2012. This report will be updated in 2013.
Generation inventory	4.9.1	AEMO-internal database. Relevant data may be obtained from AEMO's online Generation Information Page, available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. This data is updated as new information is received.
Minimum reserve levels	3.4.1.1	Reviewed by AEMO on an as-needed basis. The last review was performed in 2010. The latest reserve level discussion is available at http://www.aemo.com.au/Electricity/Market-Operations/Reserve-Management/Regional-Minimum-Reserve-Levels. This data will not be updated in 2013.
New generation technology costs	4.10.2	*Cost of Construction New Generation Technology* (Worley Parsons) The 2012 report is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/planning/WorleyParsons_Cost_of_Construction_New_Generation_Technology_2012%20pdf.ashx This data will not be updated in 2013.
Committed and proposed transmission augmentations	4.10.3	*Annual Planning Reports Project Summary* workbook The 2012 summary is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_APR_ProjectSummary.ashx This data will be updated in 2013.
Significant	4.9.4.3	*NTNDP Constraint workbook*

Information	Section	Source
constraint equations		The 2012 workbook is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_ConstraintWorkbook.ashx This data will be updated in 2013.
Emissions intensity factors	4.9.1.5	Existing plant: *Fuel resource, new entry and generation costs in the NEM* (ACIL Tasman) Emissions intensity factors were last published in 2009, and are available at www.aemo.com.au/planning/419-0035.pdf. For 2013, AEMO is investigating whether an improved dataset can be compiled using National Greenhouse and Energy Reporting data. New plant: *Cost of Construction New Generation Technology* (Worley Parsons) The 2012 report is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/planning/WorleyParsons_Cost_of_Construction_New_Generation_Technology_2012%20pdf.ashx This data will not be updated in 2013.
Marginal loss factors and proportioning factors	4.9.4.2	*List of Regional Boundaries and Marginal Loss Factors for the 2012-13 Financial Year* The 2012 report is available from http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/List-Of-Regional-Boundaries-And-Marginal-Loss-Factors-for-the-2012-2013-Financial-Year. This data will be updated in 2013.
Carbon price trajectories	4.2.4	Part of the *2013 National Electricity Forecasting Report* The 2012 report is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/2012%20National%20Electricity%20Forecasting%20Report.ashx. Data is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/Forecasting-Data-2012. 2013 carbon price trajectories are included in the *2013 additional* modelling *data* workbook
Renewable energy targets	4.2.1	*The Large-scale Renewable Energy Target (LRET)* (Clean Energy Regulator) LRET targets are available from http://ret.cleanenergyregulator.gov.au/About-the-Schemes/lret A review released in December 2012 (available from http://climatechangeauthority.gov.au/ret) indicated that renewable energy targets would not be adjusted to account for reduced demand growth.
Gas and coal prices	4.5 and 4.6	*Fuel cost projections: Natural gas and coal outlooks for AEMO modelling* (ACIL Tasman) The 2012 report is available from http://www.aemo.com.au/Consultations/National-Electricity-Market/Open/~/media/Files/Other/planning/Fuel_cost_projections_Natural_gas_and_coal_outlooks.ashx This data will not be updated for 2013

Information	Section	Source
Gas annual and peak day demand forecasts	4.1	*Gas Statement of Opportunities* The 2012 report and accompanying datasets are available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.
Existing and new gas production, storage and transmission infrastructure	4.9.2, 4.9.5, 4.10.2.2 and 4.10.3.2	*Review of Gas Facilities: Existing and New* (CORE Energy Group) The 2012 report is available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Amended_Review_of_Gas_Facilities_Existing_and_New.ashx. Accompanying data is available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Gas%20Facilities%20Accompanying%20Data%20xlsx.ashx. This data will be updated in 2013.
Gas production and transmission costs	4.9.2.1 and 4.9.5.1	*Gas Production Costs and Gas Transmission Costs* (CORE Energy Group) Latest reports and data are available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Production-Costs and http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Transmission-Costs. These data will not be updated for 2013.
Gas reserves	4.9.3	*Eastern & Southern Australia : Existing Gas Reserves & Resources* and *Eastern & Southern Australia : Projected Gas Reserves* (CORE Energy Group) Latest reports and data are available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2012-Supporting-Information This data will be updated in 2013.
Projections of demand for LNG export	4.1	*Eastern & South-Eastern Australia : Projections of Gas Demand for LNG Export* (CORE Energy Group) Latest reports and data are available from http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Liquid-Natural-Gas-Projections This data will be updated in 2013.
Wind contribution to peak demand	4.7.1.1	*Wind Contribution to Peak Demand* The latest report is available from http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Contribution-to--Peak-Demand This data will be updated in 2013
Demand side participation amounts	4.3.1	*2013 additional modelling data* workbook The latest dataset is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs This data will be updated in 2013
Auxiliary loads	4.9.1.3	Regional data is part of the *2012 National Electricity Forecasting Report* The 2012 report is available from

Information	Section	Source
		http://www.aemo.com.au/Electricity/Planning/Forecasting/~/media/Files/Other/forecasting/2012%20National%20Electricity%20Forecasting%20Report.ashx. Data is available from http://www.aemo.com.au/Electricity/Planning/Forecasting/Forecasting-Data-2012. This report will be updated in 2013. *Consolidated 2013 plant technical data* contains auxiliary load for each existing generating unit and each class of new generating unit
Generator ramp rates	4.9.1.2	*2013 existing generation data* workbook The latest dataset is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs
Forced outage rates	4.9.1.9	*2013 additional modelling data* workbook The latest dataset is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs
Water values	4.9.1.7	*2013 additional modelling data* workbook The latest dataset is available from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs
Reliability Standard	5.1.5	*Reliability Standards* (AEMC) Available from the AEMC website at http://www.aemc.gov.au/panels-and-committees/reliability-panel/guidelines-and-standards.html

Appendix B. Data flow

Data referenced in this report are used in a range of documents produced by AEMO. The following diagrams show the process flow of each major document, to facilitate understanding of how data is incorporated into modelling and reporting activities.

Figure 16 – Electricity Statement of Opportunities process flow diagram

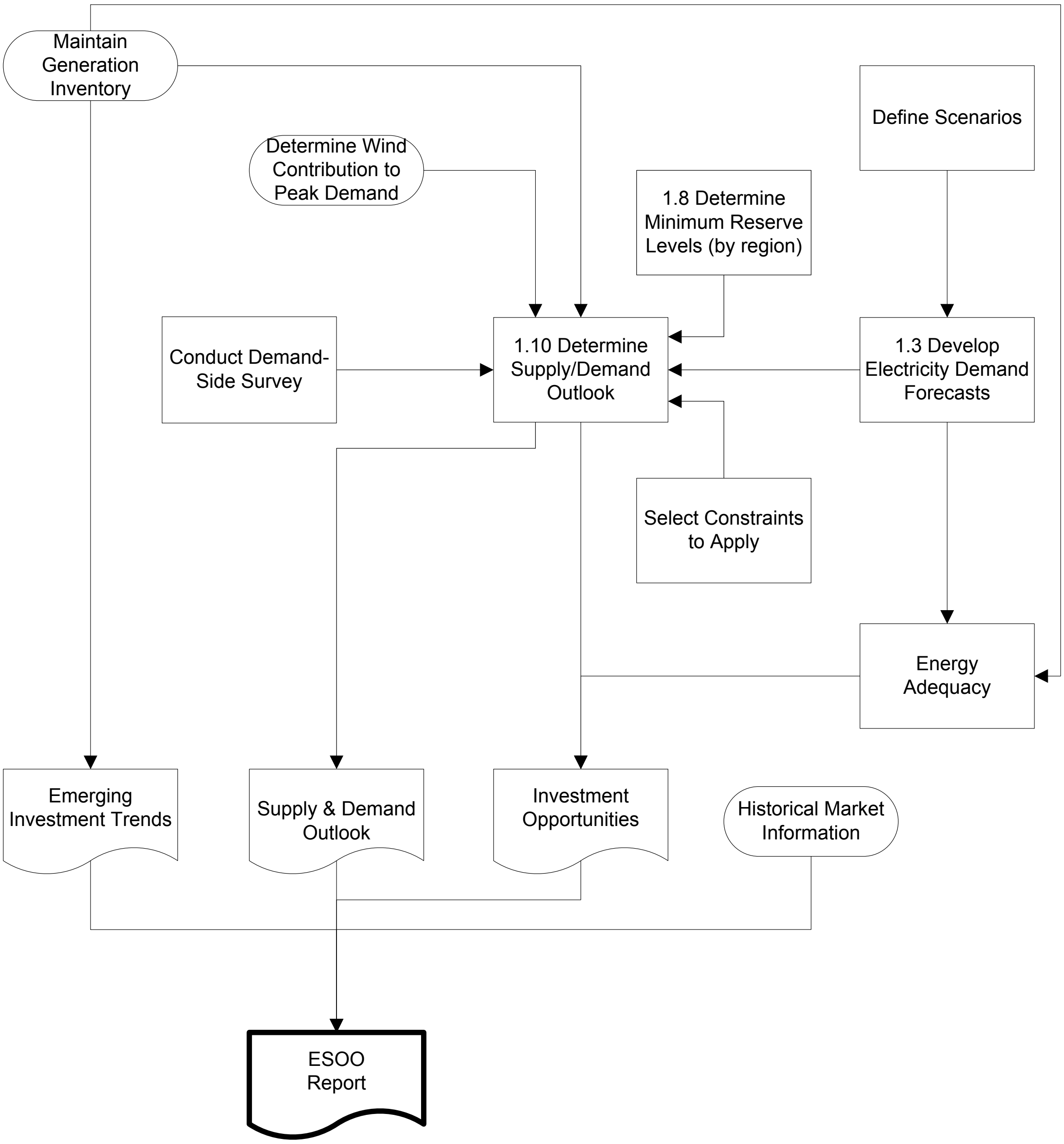

Figure 17 – Gas Statement of Opportunities process flow diagram

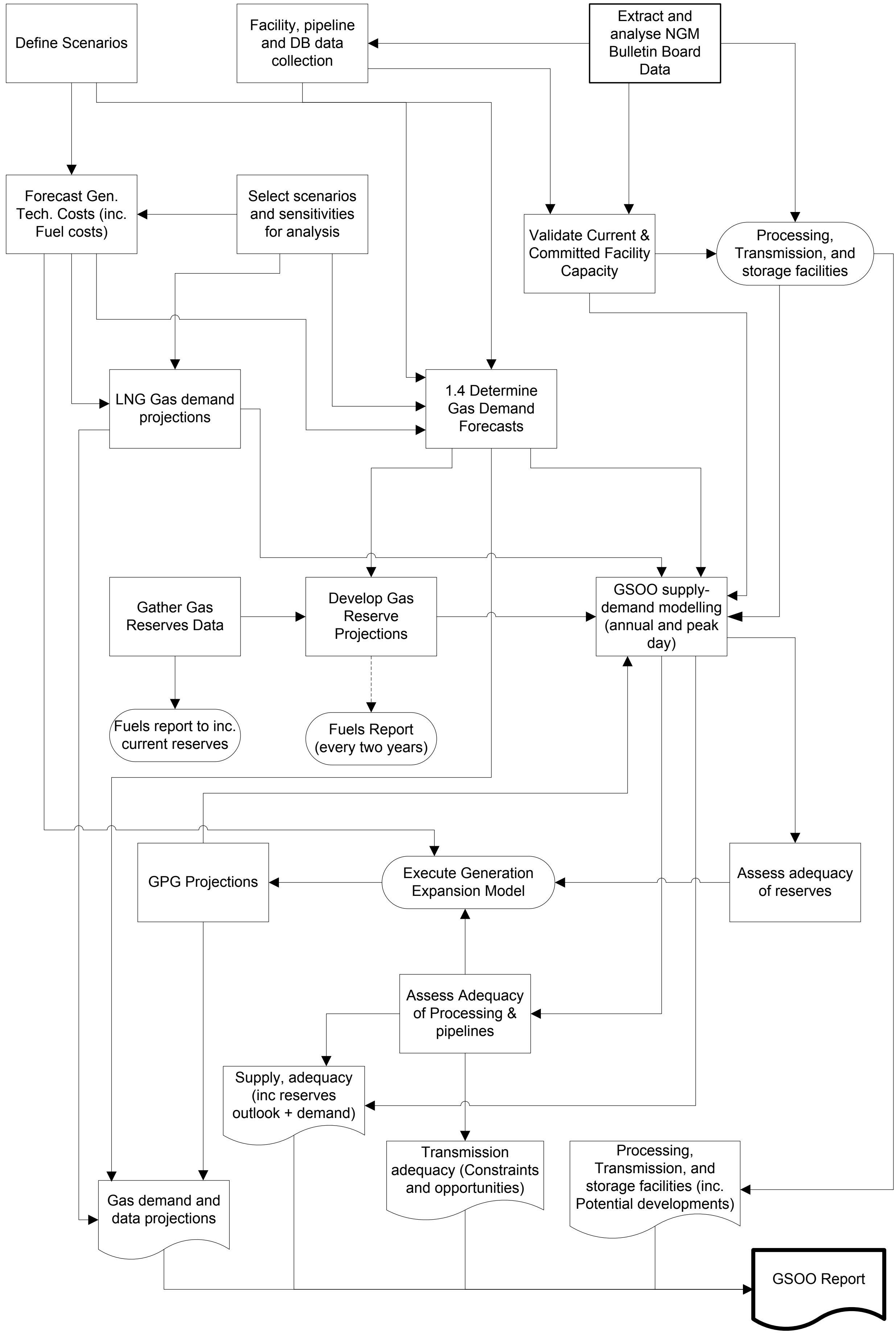

Figure 18 – National Transmission Network Development Plan process flow diagram

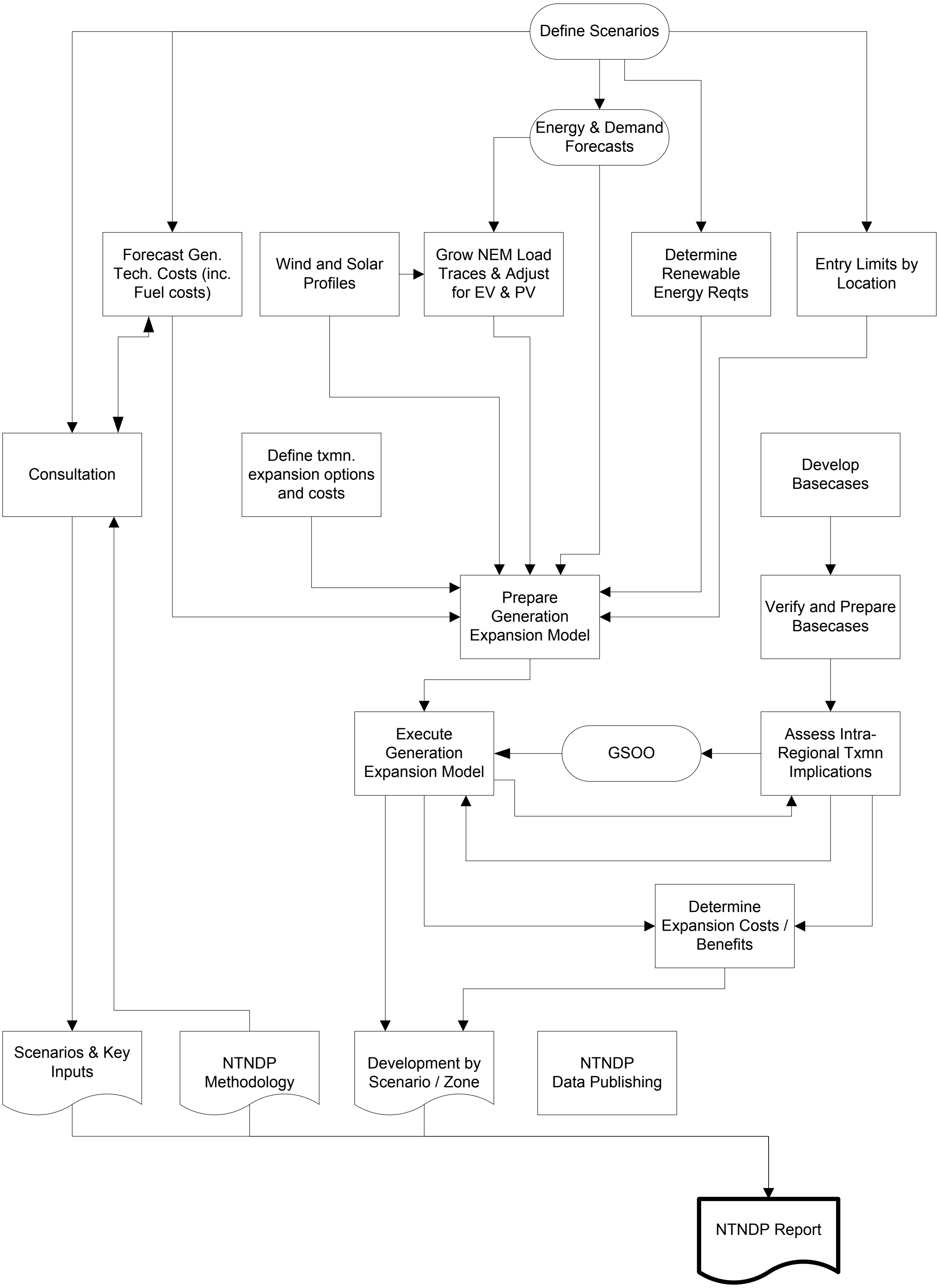

Figure 19 – South Australian Supply Demand Outlook process flow diagram

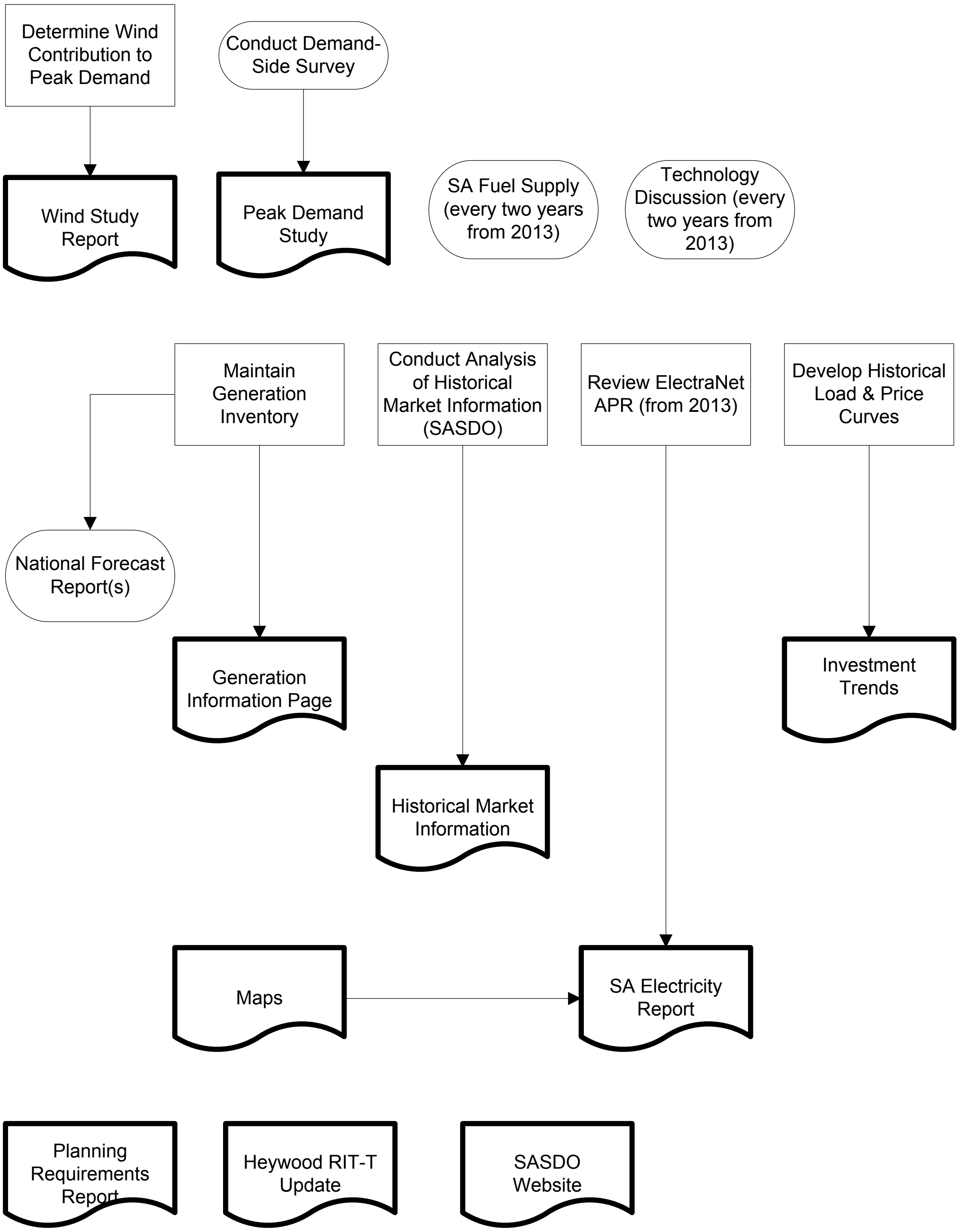

Figure 20 – Victorian Annual Planning Report process flow diagram