GSOO METHODOLOGY

Methodology for the Gas Statement of Opportunities

2013

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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1. INTRODUCTION

AEMO continues to improve the focus and clarity of its planning publications, succinctly presenting key messages in the main document, and publishing accompanying information (including this methodology) separately. This document describes the methodology used to develop the 2013 Gas Statement of Opportunities (GSOO).[1]

The GSOO assesses the adequacy of gas supply and demand in eastern and south-eastern Australia over a 10-year outlook period for infrastructure, and a 20-year outlook period for reserves. The adequacy assessment is performed using a model of supply and demand (gas model) which includes representations of:

- Reserves and resources.
- Existing, committed, and some notional gas processing facilities.
- Existing, committed, and some notional gas transmission pipelines.
- Projections of gas demand for mass market (MM) and large industrial (LI) customers, gas-powered generation (GPG), and liquefied natural gas (LNG) export.

The gas model determines the supply and demand balance, subject to infrastructure and reserves limitations, on a daily basis over the 20-year outlook period. The supply–demand balance solution indicates the timing, location, and magnitude of potential shortfalls of supply, and consequently opportunities for investment in gas production or transmission. The analysis is repeated for a range of scenarios to determine the sensitivity of outcomes to changes in modelled assumptions.

2. SCENARIOS

To provide consistency between AEMO's planning publications, the 2013 GSOO considers AEMO's planning scenario as a best-estimate of the development of the economic environment surrounding the gas production and transmission system (gas system). The GSOO studies a range of possible futures by overlaying further assumptions regarding the status of new infrastructure projects, and the priority that producers place on demand for LNG export. However, all cases use AEMO's planning scenario assumptions as the basis for projected demand, a key driver in the adequacy determination.

The planning scenario:

- Is based on AEMO's best estimate of the future direction of the major drivers.
- Is designed to include any policy or other changes that can be predicted with reasonable certainty.
- Is designed as a central growth scenario.
- Includes currently legislated carbon policies based on the Australian Treasury's core scenario.
- Uses currently estimated rates of development of new technologies.

Table 1 lists the demand drivers underpinning the planning scenario. See the 2012 Scenarios Descriptions report[2] for further information.

[1] AEMO. *2013 Gas Statement of Opportunities*. 28 November 2013. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

[2] AEMO. *2012 Scenarios Descriptions*. 4 July 2012. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/2012_Scenarios_Descriptions.ashx. Viewed: 12 November 2013.

Table 1 — Overview of planning scenario demand drivers

Scenario	Economic growth	CO2-e reduction (%)	Carbon price	Green power	Coal price	LNG production	East coast gas prices
Planning	Medium	5% by 2020 80% by 2050	Treasury core scenario[a]	Flat	Medium	Medium	4.7 $/GJ to 13.67 $/GJ[b]

a. Increasing from 24.15 $/tCO2-e in 2013-14 to 46.22 $/tCO2-e in 2033-34 ($2013-14).

b. Prices vary in both time and location. The values provided represent the extremes of the range of prices considered.

The planning scenario parameters are used as an input into the gas demand forecasts for the 2013 GSOO. Development of gas demand forecasts is discussed in Section 4.7.

AEMO's Planning Assumptions webpage[3] provides detailed data sets used in AEMO's planning publications.

Gas price assumptions

Table 1 shows the range in gas price relevant to the planning scenario. Modelling conducted for the 2013 GSOO does not use gas price assumptions directly, instead considering gas production and transmission costs to determine least-cost solutions.

Assumed gas prices do affect model outcomes indirectly. Demand for GPG is developed during electricity modelling performed to support the 2013 National Transmission Network Development Plan (NTNDP). The NTNDP model uses the gas prices shown in Table 1, developing an hourly electricity dispatch solution over a 20-year outlook horizon, with gas prices determining how frequently GPG is dispatched. The hourly GPG dispatch is converted to daily GPG gas demand for use in the gas model.

For more information about representative eastern and south-eastern Australian gas prices for 2014 to 2033 see the Fuel Cost Projections report.[4]

Gas costs are also considered when developing the reserves projections (and are inputs into the supply–demand modelling), where gas costs, equity gas, and current contracts are used to determine the production profile. For more information about consideration of gas costs in reserve projection development, see AEMO's website.[5]

3. ASSESSING ADEQUACY

AEMO's adequacy assessment determines the capability of the gas system to supply demand over a 10-year infrastructure outlook period and a 20-year reserves outlook period. The gas model solves a network transport problem for each day in the outlook period, assessing:

- The capability of transmission system (gas pipelines) to deliver gas to demand centres.
- The capacity of gas processing facilities to supply sufficient gas into the transmission system.
- The availability of reserves to maintain gas processing facility throughput.

When any one of these elements is insufficient to meet demand, the gas model substitutes production with supply shortfalls. Shortfalls indicate times and locations where opportunities for investment occur.

[3] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions. Viewed: 12 November 2013.

[4] ACIL Tasman. *Fuel cost projections*. Available: http://www.aemo.com.au/en/Electricity/Planning/Related-Information/~/media/Files/Other/planning/ACIL_Tasman_Fuel_Cost_%20Projections_2012.ashx. Viewed: 16 October 2013.

[5] Available: http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf. Viewed: 12 November 2013.

Infrastructure assessment

Initially, the gas model considers existing transmission and production, and committed projects only for supply. As the model steps through the outlook period and demand grows, the system approaches and then exceeds its capacity to supply. No further development is assumed, and the location and timing of shortfalls are analysed and presented as opportunities for infrastructure development.

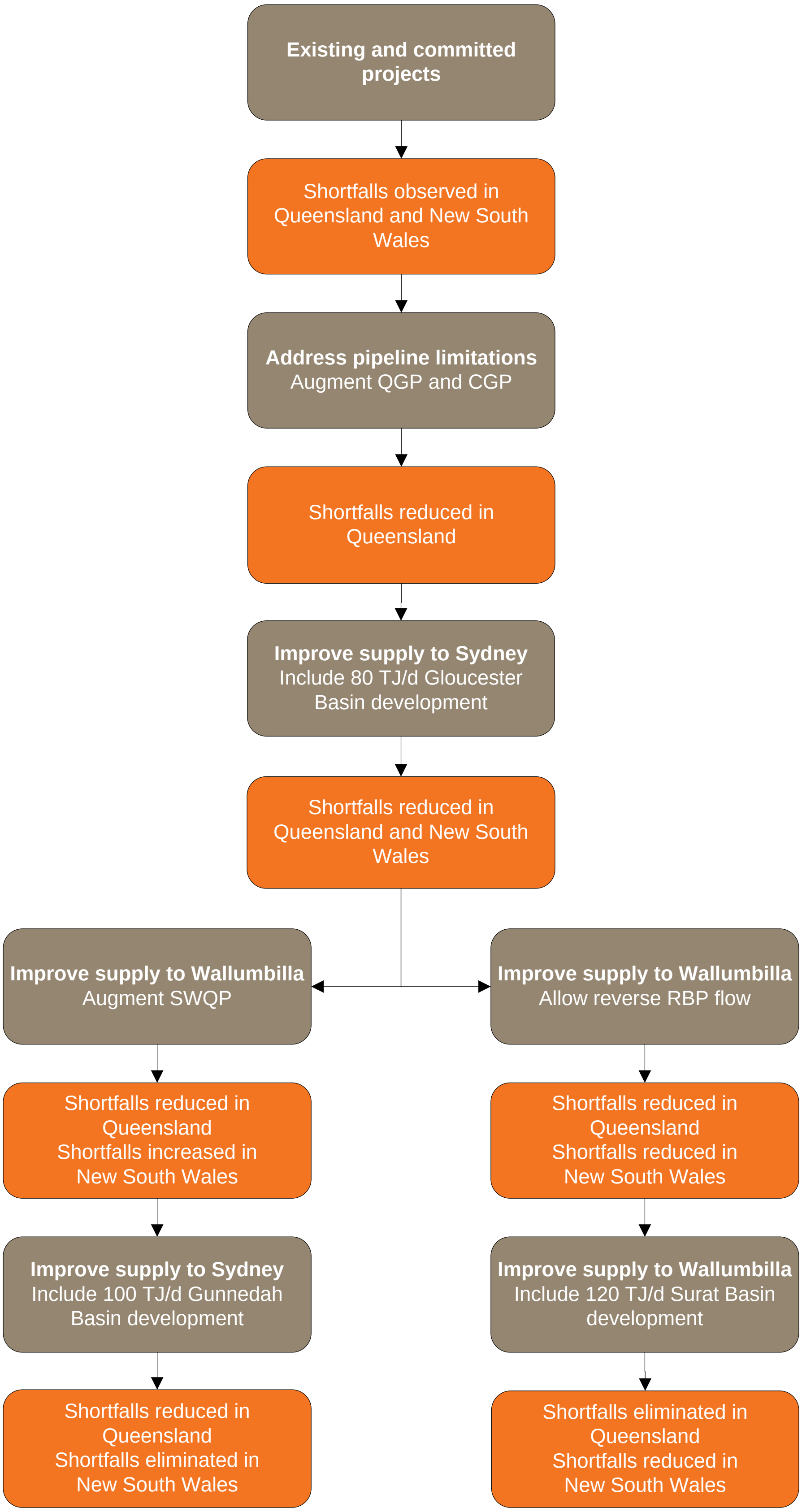
In some cases, AEMO reviews projects that are proposed and well-advanced (but not sufficiently advanced to achieve committed status) to assess the capability of those projects to defer or relocate observed shortfalls and enrich discussion surrounding the scale of investment required to ensure security of supply. In 2013, AEMO considered the following as sensitivities:

- A gas production project located in the Gloucester Basin, with transmission to Newcastle, capable of delivering 80 TJ/d, similar to a proposal currently under consideration by AGL.
- A gas production project located in the Surat Basin, connecting to the existing Darling Downs pipeline, capable of 120 TJ/d, similar to a proposal currently under consideration by Origin.
- A gas production project located in the Gunnedah Basin, with transmission to the Moomba–Sydney Pipeline (MSP), capable of delivering 100 TJ/d, similar to a proposal currently under consideration by Santos.
- A pipeline augmentation project increasing the capability of the South West Queensland Pipeline (SWQP) for eastern haul by 80 TJ/d to 420 TJ/d, as it is apparent that production is available west of Wallumbilla, all of which cannot be transferred to Wallumbilla due to pipeline limitations.
- A pipeline augmentation project, enabling western haul on the Roma–Brisbane Pipeline (RBP) between Kogan and Wallumbilla at its existing eastern haul capability (233 TJ/d), as it is apparent that production is available east of Wallumbilla, all of which cannot be transferred to Wallumbilla due to pipeline limitations.

Figure 1 shows the sensitivity analysis approach, where AEMO considered a series of pipeline or production augmentations in the context of the 10-year infrastructure outlook period.

- Shortfalls are observed in Queensland and New South Wales when considering existing and committed projects only.
- Some shortfalls appear because pipeline capacity is not increased to match assumed growth in demand at locations supplied by a single pipeline. Augmentations of the Queensland Gas Pipeline (QGP) and Carpentaria Gas Pipeline (CGP) were implemented to allow assessment of total system production capacity.
- Shortfalls in New South Wales may be reduced by inclusion of new production at the Gloucester Basin.
- In Queensland, challenges arise as production at Fairview and Spring Gully is diverted to supply demand for LNG export. The Comet Ridge pipeline, formerly injecting gas at Wallumbilla, changes to a withdrawal operating mode leading to challenges supplying gas to Wallumbilla. Further development sensitivities focus on increasing supply from Wallumbilla, either from the west by augmenting the South West Queensland Pipeline (SWQP), or from the east by allowing pipeline flow reversal and increasing Surat Basin production.
- When supply to Wallumbilla is increased by augmenting the SWQP, production at Moomba is diverted from New South Wales supply to Queensland supply. New production in the Gunnedah Basin was implemented to restore supply to New South Wales.

Figure 1 — Infrastructure sensitivity study approach



Modelling of existing and committed projects only indicated that potential shortfalls may occur in New South Wales from winter 2018, as the sixth LNG export train approaches full output. AEMO is aware of other third party analyses that indicate higher shortfalls occurring earlier.

To improve understanding of the supply challenges for New South Wales, AEMO modelled a sensitivity where reserves, not infrastructure, were considered as the critical factor limiting supply. In this sensitivity, reserves in the Cooper Basin were preserved for supply to demand in Queensland, with no flow occurring on eastern sections of the Moomba to Sydney Pipeline (MSP) after 2017. The sensitivity assesses the capability of the system to supply New South Wales from production located only in Victoria and New South Wales.

The assessment approach is illustrated in Figure 2.

Reserves assessment

For the reserves adequacy assessment, shortfalls observed when considering only existing and committed projects were eliminated for the duration of the 20-year outlook period by augmenting gas supply in simple, but ultimately unrealistic ways. Eliminating all shortfalls is necessary because not supplying demand is not an acceptable strategy for ensuring adequate reserves.

Simplified strategies for augmenting gas supply focus on concentrating new supply on a single reserves tranche. By doing so, the model provides information about the total size of investment that may be required over the 20-year outlook period in a convenient form. In 2013, AEMO considered:

- Supply from 2P reserves located in the Surat Basin and currently earmarked for, but not committed to, LNG export.
- Supply from reserves and resources in the Gunnedah Basin.
- Supply from unconventional reserves and resources in the Cooper Basin.

Each supply strategy was implemented exclusively, to assess the adequacy of each reserves tranche to exclusively supply demand for the duration of the 20-year outlook period.

The single supply source strategy employed leads to unrealistic development because a single development is not expected to supply growing demand in the future. There are, however, a very large number of potential development scenarios that involve a mix of the proposed single-source developments, each with a very low likelihood of proceeding. Modelling a large number of potential mixed supply scenarios is time-consuming and of limited value when all of those scenarios conclude that reserves are adequate. By considering single-source strategies, the modelling approach defines an envelope for potential future reserves development that is likely to contain the true development path.

Figure 3 illustrates the reserves adequacy assessment approach. The block at the top of Figure 3 represents Figure 1, and shows where the reserves adequacy assessment branches from the infrastructure adequacy assessment.

Figure 2 — Reduced New South Wales supply sensitivity assessment

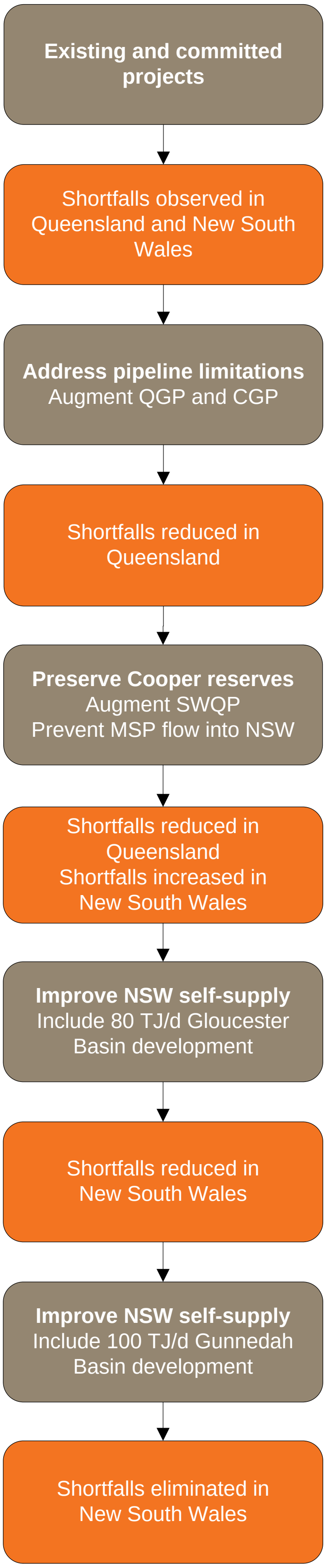
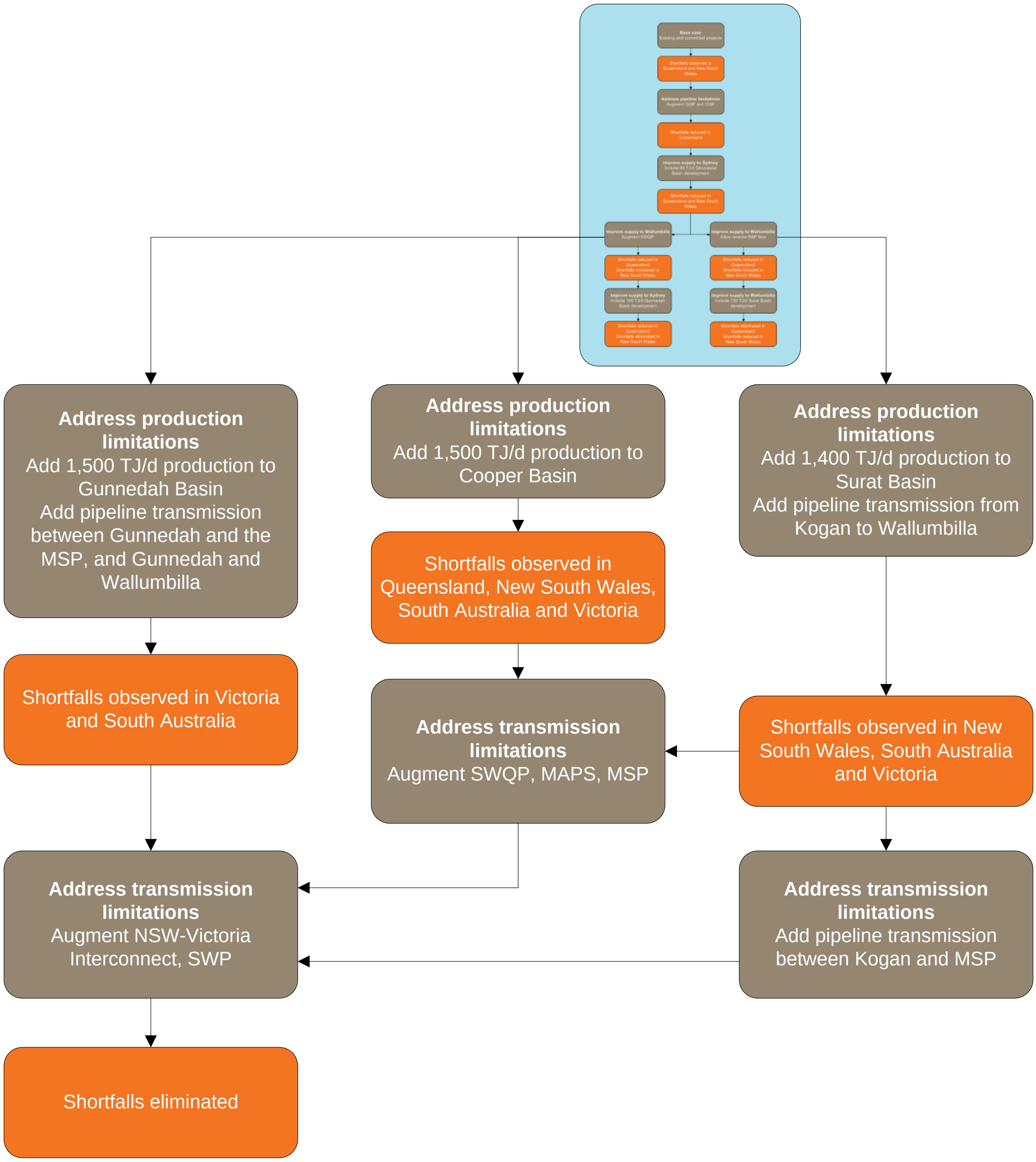


Figure 3 — Reserves adequacy assessment approach



4. GAS MODEL

The GSOO supply and demand model (gas model) is a linear program model that simulates gas market supply and demand conditions over the 20-year reserves outlook period, from 2014 to 2033. The linear program calculates optimum production and flow by minimising the cost to supply demand. It solves a network transport problem for each day in the outlook period, assessing:

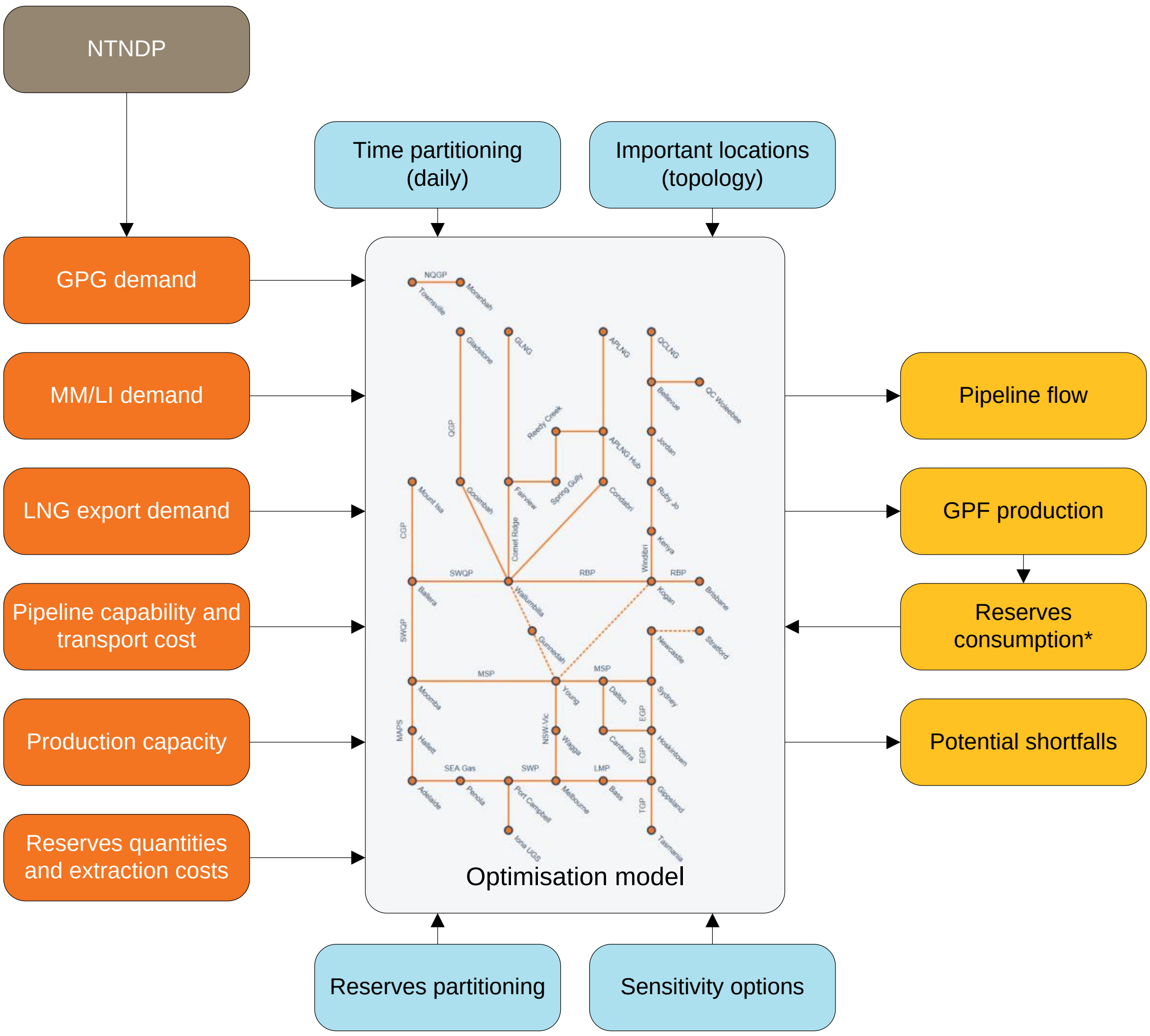
- The capability of transmission system (gas pipelines) to deliver gas to demand centres.

- The capacity of gas processing facilities to supply sufficient gas into the transmission system.
- The availability of reserves to maintain gas processing facility throughput.

The model contains representations of pipelines, mass market, large industrial, gas-powered generation (GPG) and liquefied natural gas (LNG) export demand, pipeline flow capabilities and transport costs, gas processing facility processing capacities and reserves, and resources with associated partition costs. These are all defined at a resolution in time and space that is high enough to capture important details in the network transport problem. It produces a daily production profile for each defined reserves tranche and processing facility, a flow on each defined connection, an estimation of potential shortfalls, and a reserves consumption profile developed by feeding production information back into the model. A representation of the model with its inputs and outputs is shown in Figure 4.

The network transport problem is solved by implementing a series of connected locations. At each location, gas may be injected or withdrawn from the system, or flow redirected. Connections between locations define paths over which gas can flow. Together, locations and their connections define a *topology*. The topology used for modelling in 2013 is shown in Figure 5, designed to capture key features of the physical system shown in Figure 6. In Figure 5, dotted lines represent notional connections that do not exist as existing or committed pipelines, but which may be useful for studying sensitivities.

Figure 4 — Model inputs and outputs



* Reserves consumption is calculated from production, which is set to zero when associated reserves are fully consumed.

Figure 5 — Gas model topology for 2013 GSOO

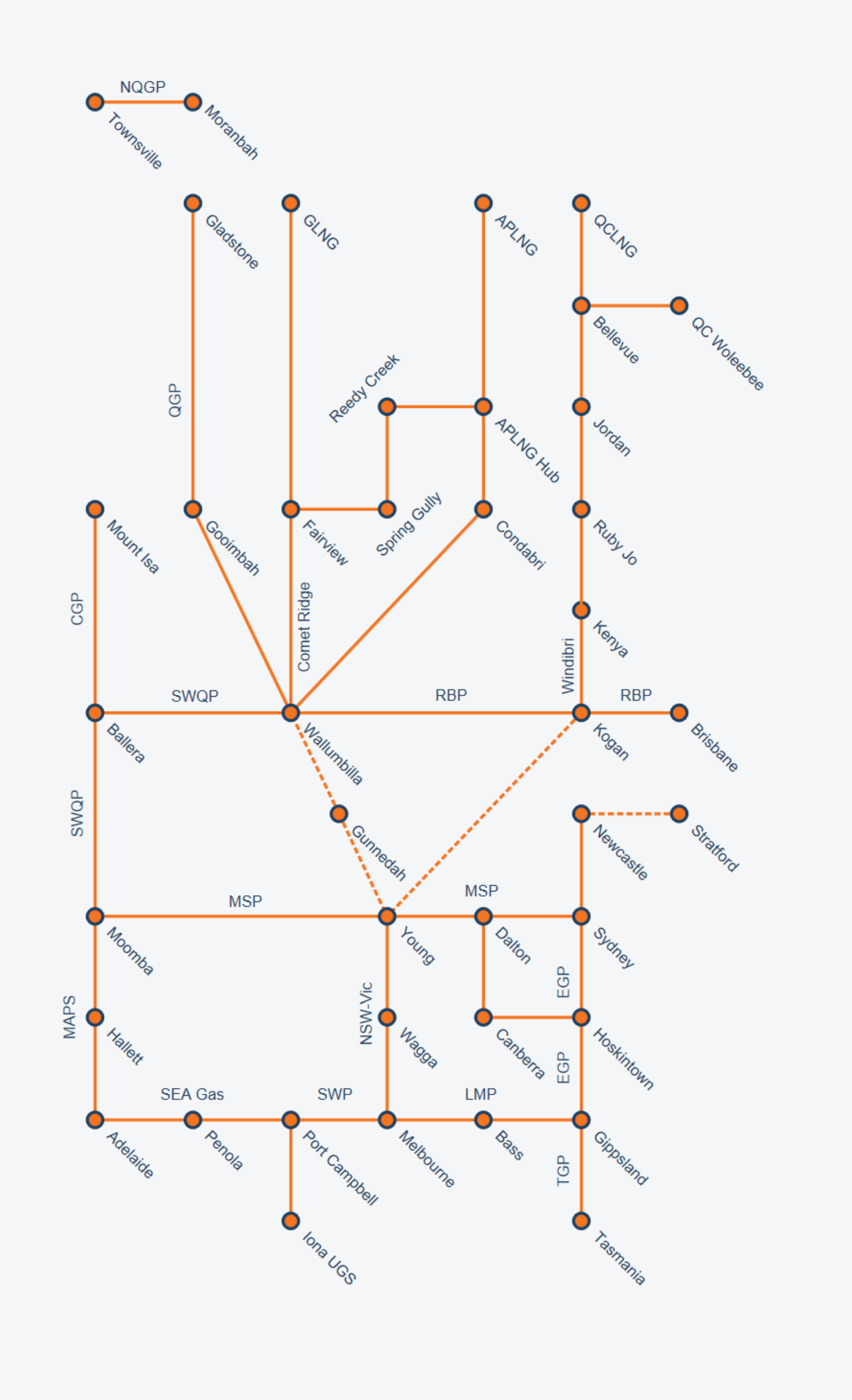
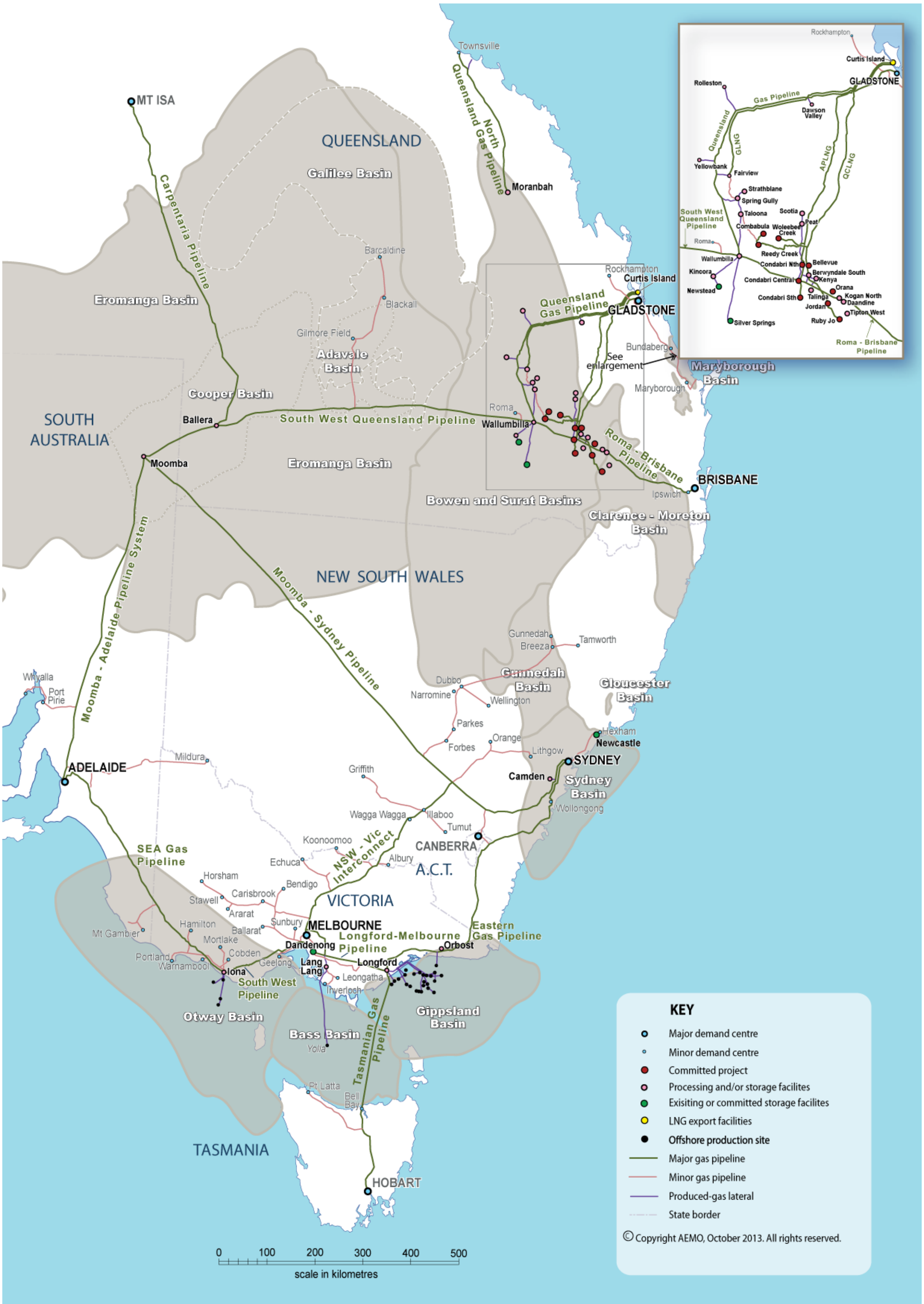


Figure 6 — Eastern and south-eastern Australian gas transmission network



4.1 Pipelines

Figure 5 and Figure 5 show abbreviated pipeline labels associated with connections. In many cases, a connection (or series of connections) is representative of an actual pipeline. Flow on connections is limited in the model by capacity limitations on the associated pipeline.

In practice, pipeline flow capacity is variable, subject to a range of factors impacting gas pressure gradients between injection and withdrawal points. The northerly flow capacity of the NSW–Victoria Interconnect, for example, is higher during summer because summer demand in Melbourne is lower, allowing for higher pressures at the southern end of the pipeline. For the purposes of modelling, AEMO selects a single pipeline capacity value for use throughout the simulation. In many cases this value is at the low end of the pipeline's real-world (variable) capacity, because it is times at which flow is constrained that are of interest for adequacy assessments.

Table 2 provides detail of modelled pipelines and their capacity limitations. Pipeline data was acquired by direct survey of market participants.

Flow is controlled in the model using a *transport cost*. AEMO engaged Core Energy Group (Core) in 2012 to determine transport costs on each pipeline in the modelled system.[6] These costs were used for 2013 modelling in most cases. In some instances, the transport costs developed by Core were not compatible with the gas model, resulting in unrealistic flows or suppressed production in certain locations. Transport costs were adjusted when this was the case.

Table 2 — Modelled pipelines

Pipeline	Abbreviation	Description
Australia Pacific LNG Pipeline	APLNGP	The pipeline between the Condabri/Talinga/Orana processing facilities and Gladstone, and its lateral extending to Reedy Creek, capable of 1,560 TJ/d.
Carpentaria Gas Pipeline	CGP	The pipeline between the Ballera processing facility and Mount Isa and its laterals, capable of 119 TJ/d.
Comet Ridge Pipeline	CRP	The pipeline between Wallumbilla and Fairview linking production at Fairview and the GLNGP to the domestic system.
Dalton–Canberra Pipeline	DCP	The lateral of the MSP between Dalton and Canberra, capable of 56 TJ/d.
Eastern Gas Pipeline	EGP	The pipeline connecting processing in the Gippsland Basin to Sydney, via Woolongong and the ACT, capable of 288 TJ/d.
Gladstone LNG Pipeline	GLNGP	The pipeline between Fairview and the GLNG facility at Gladstone, capable of 1,420 TJ/d.
Gloucester Pipeline	GP	A notional future pipeline between future gas processing in the Gloucester Basin and Newcastle.
Hoskintown–Canberra Pipeline	HCP	The lateral of the EGP between Hoskintown and Canberra, capable of 77 TJ/d.
Longford to Melbourne Pipeline	LMP	The pipeline connecting the Longford processing facility in Gippsland with Melbourne, capable of 1,030 TJ/d.

[6] Core Energy Group. April 2012. *Gas Transmission Costs*. Available: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Gas_Transmission_Costs_Report.ashx. Viewed: 1 November 2013.

Pipeline	Abbreviation	Description
Moomba–Adelaide Pipeline System	MAPS	The pipeline between Moomba and Adelaide, including laterals to Port Augusta and the Riverlands, capable of 253 TJ/d.
Moomba–Sydney Pipeline	MSP	The pipeline between Moomba and Sydney, including the Central Ranges and Central West laterals, capable of 420 TJ/d.
New South Wales–Victoria Interconnect	IC	The pipeline connecting Wollert north of Melbourne with the MSP lateral extending south from Young to Wagga Wagga, capable of 120 TJ/d in a southerly direction and 71 TJ/d in a northerly direction.
North Queensland Gas Pipeline	NQGP	The pipeline between Moranbah and Townsville, capable of 110 TJ/d.
Queensland Curtis LNG Pipeline	QCLNGP	The pipeline between the Ruby Jo/Jordan/Bellevue processing facilities and Gladstone, and its lateral extending to Woleebee Creek, capable of 1,410 TJ/d.
Queensland Gas Pipeline	QGP	The pipeline between Wallumbilla and Gladstone, capable of 142 TJ/d.
Roma–Brisbane Pipeline	RBP	The pipeline between Wallumbilla and Brisbane, capable of 233 TJ/d.
South East Australia Gas Pipeline	SEA Gas	The pipeline connecting Otway Basin processing facilities at Port Campbell with Adelaide, capable of 314 TJ/d.
South West Pipeline	SWP	The pipeline connecting Otway Basin processing facilities at Port Campbell with Melbourne, capable of 353 TJ/d in an easterly direction and 129 TJ/d in a westerly direction.
South West Queensland Pipeline	SWQP	The pipeline between Moomba and Wallumbilla, capable of 385 TJ/d flow in a westerly direction and 340 TJ/d in an easterly direction.
Sydney–Newcastle Pipeline	SNP	The pipeline between Sydney and Newcastle, supplying Newcastle demand. The capability of this pipeline is not modelled, with all demand at Newcastle referred to Sydney.
Tasmanian Gas Pipeline	TGP	The pipeline connecting processing in the Gippsland Basin to Tasmania, capable of 130 TJ/d.
Walloons Pipeline	WLP	The pipeline between Wallumbilla and Condabri, linking production near Talinga and the APLNG main line to the domestic system.
Wallumbilla–Young Pipeline	WYP	A notional future pipeline between Wallumbilla and the MSP at Young, via future processing facilities in the Gunnedah Basin.
Windibri Pipeline	WBP	The pipeline between processing at Kenya–Argyle and the RBP at Condamine, linking the QCLNG main line to the domestic system.

4.2 Production

Gas production in the model occurs at *processing facilities*. At each daily step, a modelled processing facility may add gas to the supply–demand balance up to its processing capacity. Processing facilities draw their gas from *fields*, and may not draw more gas than the sum of the gas in their connected fields. Adding gas to the system incurs a cost. The optimisation process attempts to minimise this cost by drawing gas from the fields with the lowest cost first.

AEMO engaged Core to provide production costs for input into the GSOO in 2012.[7] Production costs in 2012 were associated with processing facilities. AEMO modified the gas model in 2013 to better reflect the changing cost to extract gas from different reserves tranches, rather than the facility that processes the gas. Production costs are now associated with reserves.

Table 3 provides detail of modelled processing facilities and their capacity limitations. Facility data was acquired by direct survey of market participants.

Table 3 — Modelled processing facilities

Facility	Location (see Figure 5)	Capacity (TJ/d)
Ballera	Ballera	100
Bellevue	Bellevue	300
Berwyndale South	Kenya	140
Camden	Sydney	26
Combabula	Reedy Creek	270
Condabri Central	Condabri	180
Condabri North	Condabri	180
Condabri South	Condabri	180
Daandine	Kogan	58.7
Dawson Valley	Gooimbah	30
Eurombah Creek	Reedy Creek	180
Fairview123	Fairview	133
Fairview4	Fairview	250
Fairview5	Fairview	170
Gloucester	Stratford	80
Iona	Port Campbell	120
Jordan	Jordan	300
Kenya	Kenya	160
Kincora	N/A mothballed	0
Kogan North	Kogan	12
Lang Lang	Bass	70
Longford	Gippsland	1145
Minerva	Port Campbell	81
Moomba	Moomba	390
Moranbah	Moranbah	68
Orana	Condabri	180
Orbost (Patricia–Baleen)	Gippsland	100
Otway Gas Project	Port Campbell	205
Peat	Kogan	17
Reedy Creek	Reedy Creek	180
Rolleston	Gooimbah	26
Roma Hub 2	Fairview	145
Ruby Jo	Ruby Jo	435

[7] Core Energy. *Gas Production Costs*. August 2012. Available: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/~/media/Files/Other/planning/Gas_Production_Costs_Report_Updated.ashx. Viewed: 12 September 2013.

Facility	Location (see Figure 5)	Capacity (TJ/d)
Scotia	Kogan	30
Spring Gully	Spring Gully	65
Strathblane	Spring Gully	78
Talinga	Condabri	90
Taloona	Spring Gully	65
Tipton West	Kogan	26
Woleebee Creek	QC Woleebee	300
Yellowbank	Gooimbah	26

4.3 Fields/reserves

Each modelled processing facility may be associated with one or more fields. In the gas model, a *field* is any defined accumulation of gas with a specific uniform extraction cost. A modelled field may correspond to a real-world field (for example, Minerva or Longtom); an aggregation of fields (for example, the Casino, Henry and Netherby fields are represented by a single field in the model); or a partition of a field or aggregate of fields (for example, all of the Cooper–Eromanga Basin 2P reserves are represented by a single field, and all the Cooper–Eromanga Basin 3P/2C reserves and resources are represented by another field).

The gas model draws gas from lowest-cost fields first, subject to processing and transmission limitations. At the beginning of each time step, the gas model removes from each field the gas produced in the previous time step. When reserves in a field reach zero, processing facilities associated with the field may no longer draw on it.

Most processing facilities are associated with more than one field. When a processing facility empties its lowest-cost field to zero, it begins to draw on the next-lowest-cost field. In this way, fuel supply moves up the supply cost curve as model time proceeds.

AEMO engaged Core in 2013 to develop reserves and resource quantities available to the model. AEMO requested that the 2013 GSOO reserve proposals categorise reserves and resources to reflect the likelihood of their commercial development to provide a more detailed outlook of how these reserves will be developed. This resulted in a categorisation of reserves that enables higher resolution results, providing the points across the outlook period when 3P/2C reserves and resources need to be developed to ensure supply. The categorisation provided was based on Core’s knowledge of contracted reserves, and the internationally recognised Petroleum Resources Management System[8], resulting in the following reserves tranches:

- 2P reserves.
- 2C/3P reserves and resources.
- Prospective resources.

The reserve projections provided in Core’s report provide a high-level assessment of reserves likely to be available to meet demand[9], excluding consideration of gas infrastructure capability and constraints (processing facilities, pipelines, and storage facilities). This high-level assessment included consideration of contracted (or committed) and available reserves.

Core’s assessment of reserves included a cost to extract gas from each reserves tranche. In some cases these costs were modified to ensure sensible model outcomes.

[8] Available: http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf. Viewed: 12 November 2013.

[9] Final demand figures were not available during the reserves development. Draft figures were provided to Core for the development of reserves projections, including the 2012 GPG market segment demand.

The reserve production profile produced by AEMO's gas model includes consideration of gas infrastructure capability and constraints. This results in minor differences between Core's reserves projections and reserves consumption profiles developed by the GSOO modelling.

Further detail about reserves quantities used in the 2013 GSOO is available from AEMO's Gas Reserves Update and Projections web page.[10] Reserves and resources used in the model are shown in Table 4.

Table 4 — Modelled reserves and resources

Basin	2P Reserves (PJ)	3P/2C Reserves and resources (Additional to 2P) (PJ)	Prospective Resources (PJ)	Total Reserves and Resources (PJ)
Conventional				
Adavale	22	0	0	22
Bass	268	291	0	559
Cooper & Eromanga	1,943	2,006	0	3,949
Denison	74	0	0	74
Gippsland	3,937	2,530	2,000	8,467
Otway	756	285	0	1,041
Surat & Bowen	93	97	0	190
Sydney	0	0	0	0
Subtotal Conventional	**7,093**	**5,209**	**2,000**	**14,302**
CSG				
Clarence Moreton	445	0	0	445
Galilee	0	0	1,969	1,969
Gloucester	669	0	0	669
Gunnedah	1,426	1,654	0	3,080
Surat & Bowen	43,251	17,331	33,929	94,511
Sydney	340	136	0	476
Subtotal CSG	**46,131**	**19,121**	**35,898**	**101,150**
Unconventional				
Cooper & Eromanga	5	4,945	11,300	16,250
Subtotal Unconventional	**5**	**4,945**	**11,300**	**16,250**
Total	**53,229**	**29,275**	**49,198**	**131,702**

4.4 Storage

The gas model contains representations of gas storage facilities for the first time in 2013. Gas storage facility operation is particularly sensitive to assumptions about commercial behaviour, with decisions about whether to inject into or withdraw from storage on any one modelled day subject to assumed prices.

Price information in the gas model is not of a suitable resolution to allow the model to self-determine storage facility injection and withdrawal behaviour. However, the number of storage facilities is small enough to allow each one to be treated on a heuristic basis.

[10] Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

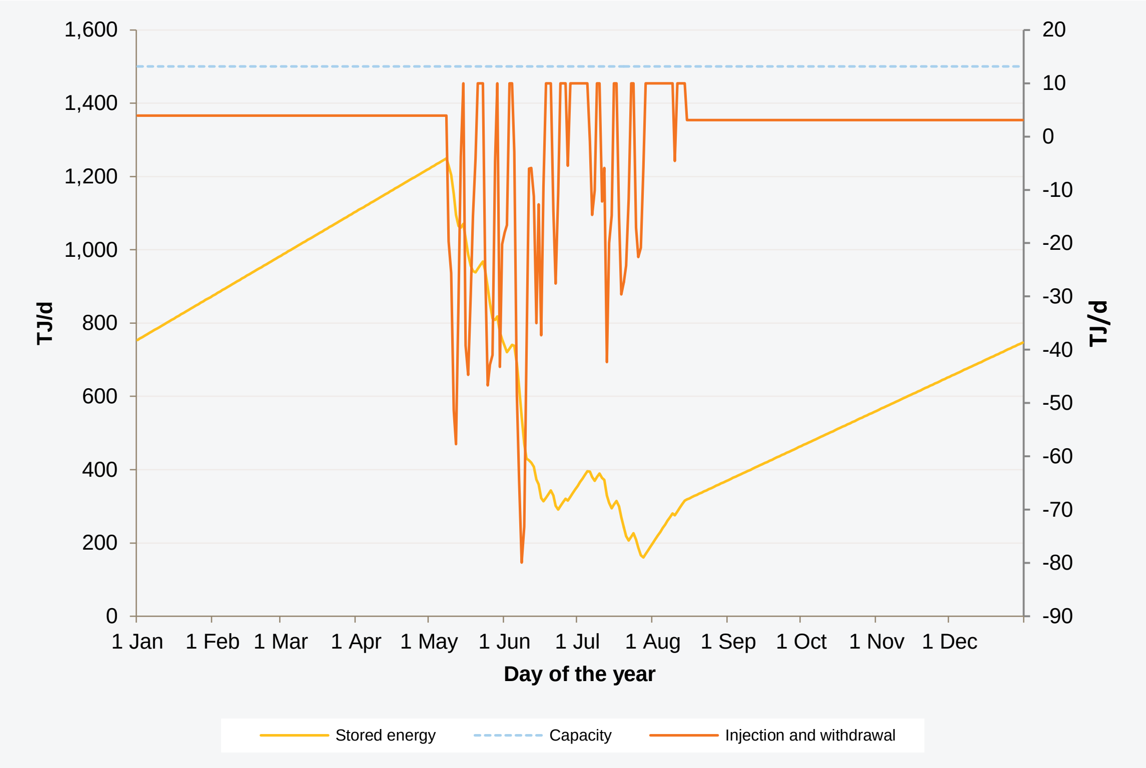
LNG storage facilities are typically operated in a peak-shaving mode. Capacities are small, in the order of 1 PJ. Withdrawal rates are typically an order of magnitude higher than injection rates. This leads to a reasonable operation strategy where LNG storage facilities liquefy gas during off-peak times, and vaporise gas during peak times.

There is one existing LNG storage facility in eastern Australia, located at Dandenong near Melbourne. Another facility, located at Newcastle, is under construction and expected to be available in 2015. To use these facilities in a peak-shaving mode, AEMO analysed daily demand in Melbourne and Sydney[11] and used the demand profile to determine which days each facility would operate in vaporisation mode. On other days the facilities operated in liquefaction mode.

The result is an injection and withdrawal profile like that shown in Figure 7. In the figure, the orange line represents injection and withdrawal, with reference to the right-hand vertical axis. The facility injects (liquefies) at a rate of between 3 TJ/d and 4 TJ/d for most of the year, filling steadily between mid-August and mid-May. During winter peak days the facility withdraws gas from storage (vaporises) at a rate that allows the facility to support every winter demand peak. Between these days the facility injects at its maximum rate (10 TJ/d), “topping up” storage wherever possible.

The result is an energy-in-storage profile, represented by the yellow line in Figure 7, which refers to the left-hand vertical axis. This profile is compared with the facility’s total storage capacity, represented by the blue line. Commercial uncertainty in the operation of the facility is captured by the fact that the facility never reaches full capacity, nor is it allowed to be completely empty.

Figure 7 — Newcastle storage facility injection and withdrawal profile



[11] Specific demand forecasts for Newcastle are not available. The gas model considers demand in Newcastle and Sydney as a single demand located at the Sydney model node shown in Figure 5.

There are six consumed underground reservoir storage facilities in eastern Australia: Iona, Silver Springs, Moomba, Chookoo (Ballera), Newstead, and Roma. Of these, Moomba, Chookoo, Newstead, and Roma were assumed to operate in a load-balancing mode, helping to maintain the output of nearby processing facilities during maintenance works or unforseen events impacting processing facility output. They were not explicitly modelled. Specific operational rules were implemented to model Silver Springs and Iona.

The Silver Springs storage facility has a capacity of 35 PJ, a maximum injection rate of 42 TJ/d, and a maximum withdrawal rate of 30 TJ/d. It is presently being used as a coal seam gas (CSG) ramp gas balancing facility, accepting gas from QCLNG-operated facilities around Kenya-Argyle, via the Berwyndale South to Wallumbilla pipeline. Once the QCLNG LNG liquefaction facility is commissioned, the storage facility is expected to be emptied over the course of approximately three years.

For 2013 GSOO modelling, Silver Springs is assumed to hold a full 35 PJ at the beginning of the simulation, with gas extracted at 42 TJ/d after that time until empty. After this time, the gas model does not use the Silver Springs storage facility, because:

- Intention for its future use remain unknown.
- Demand in Queensland does not exhibit the seasonal variation typical of demand in southern states, and it is not clear that seasonal inject and withdrawal cycles are necessary in that environment.
- While it would be reasonable to operate Silver Springs as a load balancing facility, the gas model does not incorporate outages (either planned or unplanned) and cannot reasonably assess the utility provided by this mode of operation.

The Iona underground storage (UGS) facility has a capacity of 22 PJ, a maximum injection rate of 140 TJ/d, and a maximum withdrawal rate of 380 TJ/d. To model the Iona UGS:

- The cost to produce gas from the storage facility was adjusted to be the highest of all Victorian production, resulting in the facility being used by the model as a “last resort”.
- Production capacity at Port Campbell was reduced by 60 TJ/d to mimic diversion of production for storage injection.
- 1.5 PJ/a of Gippsland Basin reserves were transferred to the Otway Basin to mimic summer charging of the storage from Gippsland production.
- After consumption of the Otway Basin, the storage facility was no longer used.

AEMO expects that the Iona storage facility will continue to serve a critical supply function even after Otway Basin reserves are consumed. This expected use was not modelled because:

- The operational characteristics of the facility may be reasonably expected to change significantly after a time where production is not available in Port Campbell.
- The consumption of Otway Basin reserves occurs outside the 10-year infrastructure outlook period, and use of the storage facility is unlikely to materially change reserves adequacy outcomes.

4.5 Facilities survey

AEMO surveyed gas market participants in 2013 to obtain updated information on the gas facility details:

- Processing facility capacities and potential or committed future expansions.
- Pipeline capacities and potential or committed future expansions.
- LNG facility capacities and potential or committed future expansions.
- Reserves developments.
- Storage facility capacities and potential or committed future developments.

Where possible, the information provided was used directly by the model. In some cases the model used modified values to account for new information received after completion of the participant survey.

Collated results from the facilities survey are available from AEMO's website.[12]

4.6 Contract positions

As a supply adequacy model, the gas model assesses the physical capability of the eastern Australian gas supply system to meet growing demand. In most cases, commercial arrangements are not modelled, because they do not reflect physical limitations to supply.

In 2013, reserves data detail was increased. Reserves are typically reported on the basis of the companies that own the rights to them, and the reserves data necessarily contain information about ownership as a result. The ownership of reserves can impact supply adequacy if specific demand centres are known to draw on specific reserves. This is particularly the case for LNG export, where reserves are earmarked for either QCLNG, APLNG, or GLNG. It is of lower concern for domestic demand, which is often supplied from a portfolio of contracts.

Where specific information was available for supply contracts to LNG export demand centres, these were included in the model:

- A 100 TJ/d supply contract from Origin reserves to GLNG at Fairview.[13] Although this contract is defined for a 10-year period from 2015, it remains in place in the gas model to the end of the outlook period because no further information is available to substitute supply for GLNG after contract expiry. The contract is defined for delivery at Wallumbilla; however, it was implemented as a dedicated link between processing at Spring Gully and Fairview, sequestering the arrangement from the domestic system.
- QCLNG to use up to 190 PJ of APLNG-owned reserves in the first two years of operation, and 25 PJ subsequently.[14] This was implemented in the model by implementing a link (nominally representing the Walloons Pipeline) that allowed Berwyndale South and Kenya facilities to supply only QCLNG or domestic demand, as these facilities are co-owned by APLNG.
- GLNG to use up to 140 TJ/d supplied from Santos' Cooper Basin production facilities. In practice, the assumption that LNG export demand is prioritised, combined with increased eastern haul capability of the SWQP, ensures that this contract is satisfied. Flows from Moomba to Wallumbilla were significantly above 140 TJ/d for most of the modelled outlook period.

AEMO is aware of a gas swap arrangement between APLNG and GLNG, involving production at Spring Gully, Fairview, Scotia, and potentially Reedy Creek. This arrangement was not announced in time to be incorporated into modelling for 2013, but is not expected to materially impact modelled outcomes.

4.7 Demand

The gas model defines three classes of gas demand:

- MM and LI demand, as forecast by the National Institute of Economic and Industry Research (NIEIR).[15]
- Demand for GPG, as forecast by modelling undertaken for the 2013 NTNDP.[16]

[12] AEMO. *2013 GSOO Facilities Data*. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

[13] See http://www.santos.com/Archive/NewsDetail.aspx?id=1328.

[14] See http://www.bg-group.com/OurBusiness/WhereWeOperate/Pages/Australia.aspx.

[15] AEMO. *Gas Demand Forecasts for the GSOO 2013.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

[16] Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. It is anticipated that the 2013 NTNDP will be published in early December 2013.

- Demand for LNG liquefaction facilities, as forecast by Core.[17]

Each class of gas demand is considered separately by the model. Demand has an associated value of customer reliability (VCR), which allows the gas model operator to control which class of demand is supplied first.[18] In 2013, gas demand is supplied in the following order:

1. Demand for LNG export.
2. Mass market and large industrial demand.
3. Demand for GPG.

A consequence of the VCR ordering is that demand for GPG will be the first to be replaced by a potential shortfall. In some cases, gas will flow past a location with demand for GPG in order to supply mass market and large industrial demand further away, despite the higher transmission cost incurred to do so.

The GSOO defines two aggregations of demand:

- Total gas demand, which is the sum of all three classes of demand.
- Domestic gas demand, which is the sum of mass market, large industrial, and GPG demand.

4.7.1 Demand forecasts

Demand forecasts are expressed on different bases for each class of demand:

- Demand for LNG export is expressed as an annual demand in petajoules for each LNG export project.
- Demand for GPG is expressed as an hourly generation in gigajoules from NTNDP electricity modelling, for each modelled gas generator.
- MM and LI demand is expressed as a combination of annual energy in petajoules and summer and winter peak day maximum demand in terajoules, for each demand zone as defined in Appendix A, Gas demand forecasts.

In each case, AEMO converted the demand forecasts into a daily demand profile for use by the model.

Comparisons are made between 2012 and 2013 forecasts for gas demand in Section 3 of the 2013 GSOO. AEMO has made improvements to the gas demand projections in 2013 to ensure that gas demand market segments are reported on the same basis. As a result, 2012 demand as reported in the 2013 GSOO does not exactly correspond to the forecasts reported in the 2012 GSOO. Demand presented in the 2013 GSOO includes transmission losses.

To meaningfully compare 2012 and 2013 GSOO forecasts, AEMO adjusted the 2012 GPG and LNG market segments. More specifically, AEMO made the following adjustments to the 2012 forecasts:

- GPG demand (sourced from the NTNDP[19] modelling) was adjusted to assume 1.5% transmission losses.
- LNG projections, sourced from Core were recalculated, excluding the assumed 5.0% gas field processing losses.[20]
- The MM and LI market segment demand projections sourced from NIEIR included transmission losses in both 2012 and 2013.

[17] AEMO. *Projection of Gas Demand for LNG Export from Eastern and South Eastern Australia.* Available at: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

[18] Unlike AEMO's electricity modelling, the gas model's VCR values are not determined by consultation with market stakeholders, because the VCR is not used to provide a valuation of augmentation proposals. Instead, the gas model VCR values are merely large numbers that ensure demand is supplied to the capacity of the system before a potential shortfall is reported, and ordered to allow prioritisation of some classes of demand over others.

[19] See note 16.

[20] AEMO. *Projection of Gas Demand for LNG Export from Eastern and South Eastern Australia.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

In addition, the 2012 GPG demand projections were adjusted to use an updated version of the model consistent with that used for the 2013 projections. The 2013 GPG projections were compared to the adjusted 2012 projections developed using the updated version of the model.

4.7.2 Key demand factors

Over the outlook period, AEMO projects that changes to annual gas demand in eastern and south-eastern Australia will be influenced[21] by:

- Global and national macroeconomic factors, including:
  - The installation of LNG export facilities, which is influenced by international energy prices, demand and supply.
  - Climate and weather pattern changes, which influence the amount of gas used for heating.
  - Population and dwelling stock growth or decline, which drives changes in the number of residential gas connections.
  - Economic output and household income growth or decline at territory, state, or national level.
- Infrastructure development and exploration, including:
  - Capital and operating costs for GPG and for competing energy technologies.
  - Technological developments in the gas industry and in competing industries.
  - Gas processing and transmission capacity.
  - Gas reserves and availability.
- Policy settings, including:
  - Carbon pricing.
  - Energy efficiency policy measures.
  - Renewable energy support policies.
- Market factors, including:
  - Electricity demand growth or decline.
  - Prices and availability of competing energy sources.
  - Gas prices.

4.7.3 Demand forecast data sources

The demand projections (developed using historical and projection data provided by various industry participants) are informed by:

- Economic, demographic, and dwelling stock projections for residential growth by NIEIR.[22]
- Historical data provided by gas pipeline owners and distributors.
- Weather projections, based on historical weather data from the Bureau of Meteorology.
- Gas distributor access arrangements.

[21] Not all of the factors listed are specifically modelled, but may be accounted for in any estimations or historical information used.

[22] AEMO. *Economic Outlook Information Paper*. 28 June 2013. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013/~/media/Files/Other/planning/NEFR/2013/Economic_Outlook_Information_Paper_2013.pdf.ashx. Viewed: 19 September 2013.

- Industry output projections and surveys of industrial gas consumers conducted by NIEIR.
- Projections of gas demand for LNG export.[23]
- Historical and projected National Electricity Market (NEM) GPG data.[24]
- Projections of demand for electricity in the NEM, as presented in the National Electricity Forecasting Report (NEFR).[25]
- Gas Bulletin Board historical data.[26]
- Victorian Wholesale Gas Market Data.[27]

4.7.4 Demand forecast assumptions

In developing gas demand forecasts, AEMO assumes that gas processing, transmission, and distribution facilities have sufficient capacity to ensure they never constrain gas from reaching downstream consumers.

Modelled outcomes show that this is frequently not the case. To prevent distortions between assumed conditions for demand growth and modelled outcomes, AEMO considers minor system augmentations where possible. For example, reversal of flow of an existing pipeline is relatively inexpensive compared to installing a new pipeline route). This minimises additional costs required to ensure sufficient capacity and alignment with assumed conditions for demand growth. The GSOO reports such augmentations wherever they are required by the modelling.

Mass market and large industrial market segment annual demand

AEMO commissioned NIEIR to prepare annual gas demand projections for eastern and south-eastern Australia over the outlook period for the MM and LI market segments.

These projections were developed using NIEIR's state energy model, which is an industry-based model that partitions fuel usage by industry and fuel type. From this framework, NIEIR developed a set of models for each demand area.

NIEIR developed economic and demographic projections for each demand area using NIEIR's extensive regional data sets collated on a local government area basis across Australia. The data sets also recognise large non-reticulated gas areas in some states.

NIEIR used five key elements to develop the annual demand projections:

- Developing an industry-based model for each customer class over defined demand areas in each state.
- Surveying medium and large industrial and commercial customers in each demand area.
- Assessing the impact of Australian, state, and territory government climate change and energy policy initiatives.
- Assessing and updating the prospects for co-generation and tri-generation by demand area.
- Assessing the prospects for greenfield developments by demand area.

[23] AEMO. *Projection of Gas Demand for LNG Export from Eastern and South Eastern Australia.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

[24] AEMO. *National Transmission Network Development Plan*. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. It is anticipated that the 2013 NTNDP will be published in early December 2013.

[25] AEMO. *National Electricity Forecasting Report*. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013. Viewed: 13 November 2013.

[26] AEMO. *National Gas Market Bulletin Board*: Archive. Available: http://www.gasbb.com.au/viewArchive.aspx?node=archive. Viewed: 13 November 2013.

[27] AEMO. *Victorian Wholesale Gas Market Data*. Available: http://www.aemo.com.au/Gas/Market-Data/Victorian-Wholesale-Gas-Market-Data. Viewed: 13 November 2013.

NIEIR modelled residential demand, which dominates the MM market segment, using an end-use type model that disaggregates residential usage into projected customer numbers across new and established dwellings. The residential projections were prepared on a weather-normalised basis and incorporate the impact of real household disposable incomes and real gas prices.

The residential gas consumption projection model accounts for:

- The energy ratings for new homes implemented since July 2004, including 6-star ratings introduced in 2011.
- The program to review and standardise gas appliance energy labelling followed by the development of Minimum Energy Performance Standards (MEPS) for new gas appliances.
- The ongoing impact of high sales of reverse-cycle air conditioning equipment.
- Additional gas load growth from extensions to the existing gas distribution network.
- Other new policies or developments in different state and territory markets.

NIEIR derived projections for the business and small industrial sectors using a regression model that accounts for commercial output growth and movements in real gas prices.

For the LI market segment, NIEIR developed gas demand projections on an industry basis for each demand area. This segment's demand projections were aggregated and input into NIEIR's existing state gas demand projection model. The industry regression models for this segment relate its gas demand to the following:

- The change in output for that industry within the gas distribution area.
- The change in real gas prices for that industry.

These models also incorporate information about plant closures and proposed new investment projects for each industry based on information obtained from a major customer survey undertaken by NIEIR.

Demand projections are presented for two peak day probability conditions:

- 1-in-2 peak day demand has a 50% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded once in two years.
- 1-in-20 peak day demand has a 5% POE. This projected level of demand is expected, on average, to be exceeded only once in 20 years.

GPG market segment annual demand

AEMO produced gas demand projections for the GPG market segment using modelling and input assumptions consistent with the 2013 NTNDP. The majority of scenario assumptions for the 2013 NTNDP are consistent with the 2012 NTNDP as AEMO did not refresh the scenario planning assumptions for 2013. Key differences are:

- Updated electricity demand forecasts.[28]
- Updated generator availability, including the commitment of new projects.[29]
- Updated carbon price trajectory (see Section 2).
- Inclusion of Heywood interconnector upgrade in the NTNDP network constraints.

AEMO modelled investment in or retirement of generating systems (including GPG and other generation technologies) with the aim of minimising the power system's combined capital and operating costs. This optimisation is subject to satisfaction of three main criteria:

- The supply–demand balance for electricity across the NEM.

[28] See the 2013 NEFR for further information. AEMO. National Electricity Forecasting Report. 28 June 2013. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013. Viewed: 19 September 2013.

[29] See AEMO's Generation Information Page. 13 August 2013. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. Viewed: 19 September 2013.

- Reserve capacity requirements at the time of a projected 10% POE maximum electricity demand.
- The Large-scale Renewable Energy Target (LRET) that mandates an annual level of generation to be sourced from renewable resources.

In general, the electricity supply–demand balance will be met by a mix of technologies (including renewable energy, coal, and combined cycle gas turbines), while the reserve requirement will be met by open cycle gas turbines that are cheaper to install and are required to run only at times of peak electricity demand.

Wind generation is currently the most competitive renewable energy technology being deployed on a large scale. Technologies such as large-scale geothermal and solar thermal generation, however, start becoming economic toward the end of the 20-year outlook period, depending on electricity demand and the impact of carbon pricing on other generation sources.

GPG projection methodology

The NTNDP least-cost modelling (using the PLEXOS model) aims to minimise the combined capital and operating cost expenses of the electricity system. PLEXOS also provides an expansion plan of generation investment and retirement patterns, which is analysed in detail through a time-sequential Monte Carlo approach that simulates hourly dispatch of the electricity market (using the Prophet model). AEMO extracted the GPG market segment gas demand projections from this detailed modelling.

The time-sequential approach assumes constant thermal efficiency and heat-rate factors for individual generating systems. It makes assumptions about generator fuel contracts (input into the gas prices) and fuel availability. It uses a short-run marginal costs bidding strategy that models an ideal market where participant risk appetite and short-term trading or other commercial decision-making is not taken into account. This may lead to a different generation mix compared to historical figures in the short term, but is a better long-term approximation for planning purposes.

See the 2013 NTNDP webpage on the AEMO website for more information.[30]

LNG export annual demand

Four key factors influence the level and timing of gas demand for LNG export from eastern and south-eastern Australia:

- Demand for LNG, particularly in the Asia Pacific region.
- Existing LNG contracts.
- The volume and timing of competing sources of LNG supply.
- The status of proposed projects, including the reserve and resource base, status of exploration or appraisal activity, ability of proposed operators to execute project, financial capacity to fund the project, and political factors.

Core analysed each of these factors to determine the level of LNG export from eastern and south-eastern Australia expected under the planning scenario. The planning scenario assumes six committed LNG trains come online over the outlook period, which is consistent with the planning scenario assumptions in the NEFR.

Core also provided sensitivities to the planning scenario, including a seven train scenario which assumes one train in addition to the six already committed comes online over the outlook period.[31] To assess long-term adequacy, the GSOO modelling assumed six trains.

[30] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan. It is anticipated that the 2013 NTNDP will be published in early December 2013.

[31] AEMO. *Projection of Gas Demand for LNG Export from Eastern and South Eastern Australia.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

AEMO calculated gas demand for LNG production assuming that approximately 10.5% of gas is lost or used in transmission to the project and in the liquefaction process.

4.7.5 Daily demand profile development

AEMO developed a daily demand profile for each MM and LI demand area, each gas-powered generator, and each LNG export project. The development process is different in each case.

For MM and LI demand areas, AEMO developed a daily reference profile using historical data from either the Gas Bulletin Board, Victorian Declared Transmission System data (for Victorian demand only), or pipeline operator-provided flow data where available. The reference data is based on flows observed in 2011, selected as a typical year from analysis of historical flows over the range of available data.

Using Prophet, AEMO combined the daily reference profile with energy and peak demand forecasts for the 20-year outlook period, producing 20 years of daily demand for each MM and LI demand area, where the maximum demand in each year matches forecast maximum demands, and the sum of the daily demand over the year matches the annual energy forecast. Each demand area is assigned to a specific location (node) in the gas model.

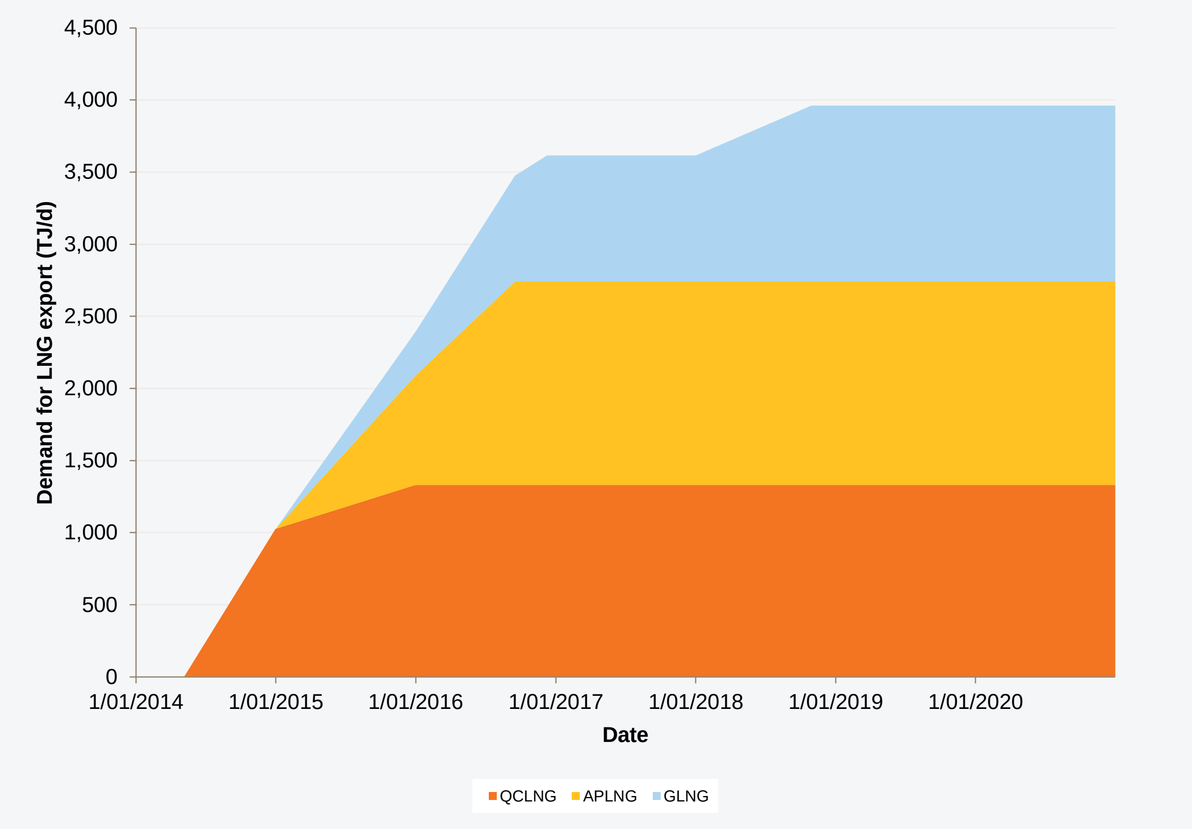
For GPG, NTNDP simulations produce hourly generation data for the 20-year outlook period. This data is combined with estimates of the heat rates of gas-powered generators to develop gas consumption values for each generator in each hour of the outlook period. Hourly demand profiles are aggregated to daily demand before being applied to the model. Each generator's demand is assigned to a specific location (node) in the gas model.

The NTNDP projects the expansion of generation to meet growing electricity demand. New gas-powered generators are installed by the NTNDP model in locations that minimise the total cost to the electricity generation and transmission network. A key NTNDP modelling assumption is that gas transmission infrastructure is less expensive compared to electricity infrastructure. Consequently, new GPG is located close to electrical demand, and gas transmission for supply is assumed to occur where this is required.

AEMO assumed LNG demand to be constant on a daily basis once both trains in a project reach full output. For modelled days where LNG export facilities are yet to reach full output for both, AEMO assumed a linear growth in demand. Ramp up in daily demand was specified such that the sum of daily demand in each year matched forecasts as developed by Core, and that the demand on each day was either higher or the same as demand on the previous day.

Demand at the QCLNG export facility was assumed to begin in mid-2014. Demand at GLNG and APLNG was assumed to begin in 2015. The resulting curves are shown in Figure 8.

Figure 8 — LNG export facility daily demand profiles



5. LINKS TO SUPPORTING INFORMATION

Table 5 provides links to additional information provided either as part of the 2013 ESOO accompanying information suite, or other related AEMO planning information.

Table 5 — Links to supporting information

Supporting Information	Website address
2013 GSOO	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
2012 scenario descriptions	http://www.aemo.com.au/~/media/Files/Other/planning/2418-0005%20pdf.ashx
Gas Reserves Update and Projections	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Reserves-Update-and-Projections
LNG export demand projections	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-LNG-Projections
Gas production costs	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/Production-Costs
Gas transmission costs	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/Transmission-Costs
Gas facility information	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Processing-Transmission-and-Storage-Facilities
Gas Demand Forecasts for the 2013 GSOO	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Maps and diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Supply–demand analysis data files	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Supply-Demand-Modelling-files

IMPORTANT NOTICE

Purpose

AEMO publishes the Gas Statement of Opportunities in accordance with Section 91DA of the National Gas Law. This publication is based on information available to AEMO as at 31 July 2013, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

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