2012

ELECTRICITY STATEMENT OF OPPORTUNITIES - UPDATE

For the National Electricity Market

Published on 22 February 2013

Published by

AEMO
Australian Energy Market Operator
ABN 94 072 010 327

1. Purpose

The Electricity Statement of Opportunity (ESOO) broadly analyses opportunities for generation and demand-side investment in the National Electricity Market (NEM).

Recent changes in the electricity generation fleet such as deregistrations, revised availability, or reclassification have warranted an update to the August 2012 ESOO. Changes reported in this ESOO Update are based on information current as at 8 February 2013.

This ESOO Update has determined that the changes in the generation fleet have had minimal impact on the Low Reserve Condition (LRC) outlook provided in the 2012 ESOO.

2. Changes in electricity supply

The following confirmed changes in electricity supply have impacts on the supply-demand outlook results. Details of these changes are published on AEMO's website.[1]

QUEENSLAND

- Deregistration of Collinsville Power Station (190 MW) from 31 December 2012.
- Reduced availability of Tarong Power Station from 1400 MW to 700 MW until after summer 2014-15.[2]
- Reduced availability of Millmerran Power Station from 856 MW to 760 MW in all summers across the ESOO study period.
- Revision of Braemar Power Station from 435 MW to 480 MW in all summers across the ESOO study period.

NEW SOUTH WALES

- Revision of Colongra Power Station from 668 MW to 724 MW in all summers across the ESOO study period.
- Reduced availability of Wallerawang Power Station from 1000 MW to 500 MW until winter 2014.[2]

VICTORIA

- Reduced availability of Morwell Power Station from 104 MW to 75 MW in all seasons across the ESOO study period.

SOUTH AUSTRALIA

- Reclassification of the 270 MW Snowtown 2 project from 'public' to 'committed'.

TASMANIA

- Revision of Poatina Power Station from 300 MW to 342 MW in all seasons across the ESOO study period.

3. Low reserve conditions

The 2012 ESOO provided a 10-year supply adequacy assessment. This assessment identifies the LRC points indicating when additional investment in generation may be needed to maintain electricity grid reliability within the NEM Reliability Standard.[3]

The impacts of the confirmed changes in electricity supply on LRC are assessed as follows:

- No material impact on longer-term reserve adequacy for reliable operation of the electricity grid.
- Changes impact the amount of reserves needed and in some cases the timing of the LRC points.

1 AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information. Viewed 1 February 2013.

2 A sensitivity study has been conducted to investigate this generation reduction being extended across the ESOO study period (see Section 4).

3 The Reliability Standard specifies that, over the long-term, the maximum expected unserved energy should be no more than 0.002% of a region's annual energy consumption.

Table 1 and Table 2 compare the LRC points published in the 2012 ESOO with the ESOO Update LRC points.

LRC points are based on summer generation, as this is when maximum demand (MD) occurs in the majority of states. The exception is Tasmania, where MD occurs in winter. The Tasmanian winter outlook is included below.

Table 2 highlights that the timing of the LRC points has changed for Queensland and South Australia under the high economic growth scenario, and for Victoria under the low economic growth scenario. It also shows that in most cases, reserve deficits have increased or LRC points have advanced due to reduced generator availability. The exception is the reserve deficit decrease in South Australia under the medium economic growth scenario due to the commitment of the Snowtown 2 project.

Table 1 — LRC points published in the 2012 ESOO

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland	> 2021–22	-	2020–21	79	2016–17	93
New South Wales	> 2021–22	-	> 2021–22	-	> 2021–22	-
Victoria	2021–22	54	2018–19	115	2015–16	50
South Australia	> 2021–22	-	2019–20	24	2015–16	3
Tasmania (summer)	> 2021–22	-	>2020–21	-	>2020–21	-
Tasmania (winter)[a]	>2022	-	>2022	-	>2022	-

Table 2 — LRC points updated for the confirmed changes in electricity supply

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland	> 2021–22	-	2020–21	172	2015-16	7
New South Wales	> 2021–22	-	> 2021–22	-	> 2021–22	-
Victoria	2020-21	7	2018–19	128	2015–16	65
South Australia	> 2021–22	-	2019–20	1	2016-17	37
Tasmania (summer)	> 2021–22	-	>2020–21	-	>2020–21	-
Tasmania (winter)	>2021	-	>2021	-	>2021	-

4. LRC sensitivity study

Since publication of the 2012 ESOO, two power stations have reduced their availability in the short term:

- Tarong Power Station reduced from 1400 MW to 700 MW until after summer 2014-15.
- Wallerawang Power Station reduced from 1000 MW to 500 MW until winter 2014.

AEMO conducted a sensitivity study to assess the potential impact of these generation reductions being extended across the ESOO study period. The results of the sensitivity study show:

- A reduction of 700 MW at Tarong Power Station across the ESOO study period would require additional generation investment in Queensland by 2016–17 to avoid an LRC assuming medium economic growth.
- A reduction of 500 MW at Wallerawang Power Station across the ESOO study period has no impact on LRC points in New South Wales, which remain outside the study horizon.

Table 3 shows the impact on regional LRC points of indefinite reductions in generation capacity at Tarong and Wallerawang Power Stations, where highlighted changes are in comparison to Table 2 above.

Table 3 — Regional LRC points: indefinite reductions in committed generation capacity

Region	Low Economic Growth		Medium Economic Growth		High Economic Growth	
	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)	LRC Point	Reserve Deficit (MW)
Queensland	> 2021–22	-	2016–17	124	2015-16	554
New South Wales	> 2021–22	-	> 2021–22	-	> 2021–22	-
Victoria	2020–21	7	2018–19	128	2015–16	65
South Australia	> 2021–22	-	2019–20	1	2016–17	37
Tasmania (summer)	> 2021–22	-	> 2021–22	-	> 2021–22	-
Tasmania (winter)	>2021	-	>2021	-	>2021	-

5. Changes in demand and forecast accuracy

The National Energy Forecasting Report (NEFR), produced for the first time in 2012, provides transparent and consistent forecasts for the National Electricity Market (NEM) and each of its five regions. The NEFR methodology makes available forecasts for distinct components of demand, including the mass market, transmission losses, auxiliary loads, large industrial loads, rooftop PV and energy efficiency, which has allowed the impact of each component to be measured.

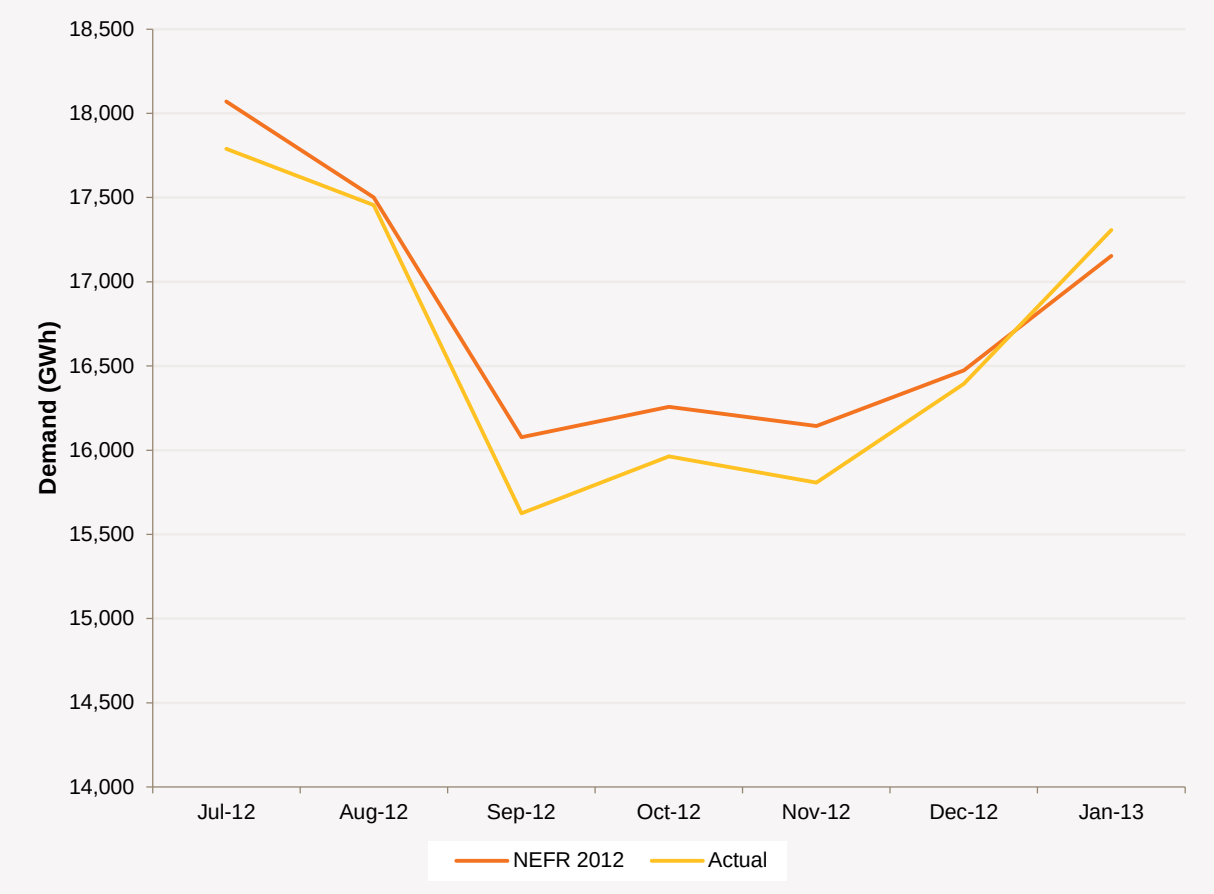
AEMO is not aware of any notable changes in the demand components that would impact the MD projections reported in the 2012 NEFR.

The accuracy of the demand forecasts published in the 2012 NEFR has improved when compared to the 2011 ESOO. Table 4 compares the performance of the 2012 NEFR forecasts against the 2011 ESOO forecasts and shows forecast against actual demand. For the NEM the average variance between forecast and actual operational demand is 1.1% for the 2012 NEFR forecasts compared to 4.9% for the 2011 ESOO forecasts. Figure 1 compares the monthly NEFR 2012 forecast operational demand against actual monthly operational demand for the NEM for 2012–13.

Table 4 — Comparison and accuracy of operational demand forecasts (Medium Scenario)[4]

Operational Demand (GWh)	2012 NEFR July 2012 to 31 January 2013	2011 ESOO Financial Year 2011/2012
NEM		
Forecast	**117,678**	**212,814**
Actual	**116,342**	**202,286**
Difference (forecast minus actual operational demand)	**1,336**	**10,529**
Variance (%) (difference as a proportion of forecast operational demand)	**1.1%**	**4.9%**

Figure 1 — Comparison of monthly forecast and actual operational demand in 2012–13 (Medium Scenario)



[4] Forecasts are tracked monthly using data on an operational demand basis. Operational demand is calculated as native demand less small non-scheduled generation, with the 2012 NEFR reporting forecasts for native demand.